



May 9, 2006

Alberta Energy and Utilities Board
5th Floor, 640 - 5th Avenue S.W.
Calgary, Alberta
T2P 3G4

Attention: Mr. Robert D. Heggie
Executive Manager, Utilities Branch

Dear Sir:

RE: ATCO Electric Ltd. 2006 Rider G and Rider Q Application

Please find attached ATCO Electric Ltd. 2006 Rider G and Rider Q Application for Board approval.

Should you have any questions, please contact the undersigned at (780) 420-5501.

Sincerely,

Original Signed by Satar Parhar

Satar Parhar, P. Eng.
Manager, Electric Pricing

SP/jm
Att.



2006 Rider Application

May 9, 2006



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1 1.0 Introduction

2 On March 17, 2006, the Alberta Energy and Utilities Board (EUB or Board) rendered
3 Decision 2006-024, regarding ATCO Electric's 2005-2006 General Tariff Application
4 (GTA). A number of decisions from that Application impact the approach to this
5 Application, which seeks approval of two new Riders for 2006, to dispense existing
6 deferral account balances and true-up previous approved Riders. The applicable issues
7 from the GTA that impact this Application include approval of the 2005-2006 distribution
8 revenue requirements, approval to establish final distribution tariffs for 2006, and
9 approval of the 2004 distribution deferral accounts. Explanations of how these
10 components factor into the design of this Application are discussed in subsequent
11 sections.

12 Accordingly, ATCO Electric is now seeking Board approval to put in place two new
13 Riders effective August 1, 2006, consistent with its proposal to implement new rates
14 effective August 1, 2006, in the GTA refiling submitted on April 28, 2006. ATCO Electric
15 is of the view that seeking to implement both the riders and the final rates resulting from
16 the GTA refiling concurrently (with an effective date of August 1, 2006) will minimize the
17 rate change on customers in ATCO Electric's service area. The two Riders proposed
18 for the period August 1, 2006 – December 31, 2006, are: **Rider G** – applicable to
19 Distribution Tariff customers, and **Rider Q** – applicable to the inventory of customers on
20 ATCO Electric's RROT at December 31, 2003. Consistent with previous Rider
21 applications, ATCO Electric has provided summary schedules ([Appendix A](#)) with the
22 same labeling format to illustrate and assist the Board and interested parties in
23 understanding the proposed Rider components.

24 Also included in this Application in Appendix C are rate impact sheets and a summary of
25 sample bill calculations incorporating proposed rates for August 1, 2006, as set out in
26 ATCO Electric's GTA Refiling, submitted on April 28, 2006, including updated Rider G
27 and Q amounts.



2.0 2006 Rider G Proposal

In total, the 2006 Rider G consists of five unique components and will provide a refund to customers of \$5.259M over a five-month period between August 1, 2006 – December 31, 2006. The components consist of a true-up of residual amounts from the previous Rider G, new deferral account estimates for 2005, plus amounts to reflect the impact from the difference between ATCO Electric’s proposed and Board approved revenue requirements as set out in Board Decision 2006-024 and ATCO Electric’s 2005-2006 GTA Refiling dated April 28, 2006. The amounts to be refunded/collected under the new Rider G are set out in [Schedule A.1](#) and further summarized in the following Table 1. Carrying charges supporting these amounts are set out in [Appendix B](#) – Summary of Monthly Interest Charges on Rider G Items.

Table 1: 2006 Rider G Component Summary (source: [Appendix A](#), Schedules A.1 – A.6)

Component	(Refund) Collection \$000
Component A: (Schedule A.2)	
2005 Interim Rates to 2005-2006 GTA (2005 Revenue Requirement)...	(4,500)
Component B: (Schedule A.3)	
Continuation of 2004 Rider G in 2005 (May 31, 2005 Completion)...	68
Component C: (Schedule A.4)	
2005 Rider G Residual & 2000 PPDA Outstanding Component (2004 Rider G Residual)...	(141)
Component D: (Schedule A.5)	
2006 Interim Rates to 2005-2006 GTA (2006 Revenue Requirement)...	(4,265)
Component E: (Schedule A.6)	
2005 Deferral Estimates...	3,579
Total Rider (Refund)/Collection	(5,259)

The following sub-sections describe the determination of the magnitude of each component of the proposed 2006 Rider G as well as the proposed allocation to each rate class.



1 **Component A. Interim Rates to 2005-2006 GTA (2005 Revenue Requirement)**

2 ATCO Electric in its original filed Phase I GTA (Schedule 12-B-1) dated May 9, 2005,
3 set out its 2005 revenue requirement forecast at \$242.8M. In that original application,
4 ATCO Electric estimated that, on a forecast basis, it would receive revenue of \$249.4M,
5 resulting in an over collection of \$6.6M (refer to Column B, [Schedule A.2](#)). This
6 estimated amount, including associated carrying costs, was used as a placeholder
7 refund in the 2005 Rider G application, submitted on May 13, 2005, subject to the final
8 approval of the 2005 revenue requirement. The 2005 Rider G was approved in
9 Decision 2005-075.

10 On March 17, 2006, the Board rendered Decision 2006-024 approving ATCO Electric's
11 2005 and 2006 transmission and distribution revenue requirements. The impact from
12 the Decision resulted in a final 2005 revenue requirement of \$238.3M (net of \$0.8M
13 refund from the Balancing Pool) as filed in the GTA refiling dated April 28, 2006. This
14 resulted in a further reduction of \$4.5M from the original forecast of \$242.8M. As such,
15 the total over collection for 2005 is \$11.1M (refer to Column D, [Schedule A.2](#)), of which
16 ATCO Electric has already refunded \$6.6M via the 2005 Rider G between
17 August 1, 2005 to December 31, 2005. As outlined in Column F, [Schedule A.2](#),
18 ATCO Electric is proposing to refund, on an interim refundable basis, an amount of
19 \$4.5M, which is the remaining balance between the final 2005 revenue requirement and
20 the amount that has been refunded to customers in ATCO Electric's 2005 Rider G.

21 The target amount by rate class is divided by five months of ATCO Electric's approved
22 2006 energy forecast per rate class from Decision 2006-024 to arrive at a rate in ¢/kWh.

23 Accordingly, ATCO Electric requests Board approval to refund the balance of the over
24 collection of the 2005 Interim Rates to 2005 GTA approved distribution revenue
25 requirement amounts by rate class in the amount of \$4.5M.



1 **Component B. Continuation of 2004 Rider G in 2005 (May 31, 2005 Completion)**

2 ATCO Electric estimated in its 2005 Rider G application that it would, on a forecast
3 basis, over refund its 2004 Rider G by an amount of \$32.315M, as shown in Column A,
4 [Schedule A.3](#). Estimated carrying costs of \$0.114M are to be added to this amount.
5 This target estimate was a result of the continuation of the 2004 Rider G from
6 January 1, 2005 – May 31, 2005.

7 As shown in Column C, [Schedule A.3](#), based on reconciliation of actual customer bills
8 from billing between January 1, 2005 – May 31, 2005, the actual target has been
9 determined to be \$32.342M, resulting in a small under collection from customers. As a
10 result, the total amount to collect from customers including associated carrying costs is
11 \$0.068M. In [Schedule A.3](#), the rider component is calculated based on revenue per
12 rate class divided by five months of ATCO Electric's approved 2006 energy forecast
13 from Decision 2006-024 to arrive at a rate in ¢/kWh.

14 Accordingly, ATCO Electric requests Board approval of the collection of the small under
15 collection of the 2004 Rider G, between January 1, 2005 – May 31, 2005, by rate class
16 in the amount of \$0.068M.

17 **Component C. 2005 Rider G Residual**

18 The two key elements that make up this component of the rider that are discussed in
19 this section are the 2005 Rider G Collection and the 2004 Rider G Residual relating to
20 the Outstanding 2000 PPDA.

21 On May 13, 2005, ATCO Electric applied for an interim 2005 Rider G for consumption
22 from August 1, 2005 to December 31, 2005. The 2005 Rider G consisted of five main
23 components and was a net collection from customers of \$9.536M. The Board approved
24 collection of this rider and the allocation to rate classes in Decision 2005-075, dated
25 July 14, 2005.



1 As noted in Column G, [Schedule A.4](#), ATCO Electric collected \$9.886M from customers
2 during the collection period, which resulted in an over collection of \$0.350M. The
3 collection amount relating to the 2004 Deferrals (refer to part (d) in Schedule B.1 of the
4 2005 Rider G application) was approved in ATCO Electric's Phase I GTA. Amounts
5 relating to 2003 deferrals are handled through this component of the 2006 Rider G.
6 After adding the associated carrying costs, the 2005 Rider G residual by rate class is
7 divided by five months of ATCO Electric's approved 2006 energy forecast from Decision
8 2006-024 to arrive at a rate in ¢/kWh.

9 As part of the 2004 Rider G residual (as set out in the 2004 and 2005 Rider G
10 applications) the total estimated targets relating to the 2000 Pool Price Deferral Account
11 True-up did not include a collection amount from one greater than 2MW customer
12 totaling \$0.250M. The customer owing this amount did not intend to pay its share of the
13 2000 PPDA. As a result, ATCO Electric initiated legal action in 2003 in an attempt to
14 collect the balance owing.

15 This amount was not included in past Rider applications since ATCO Electric was
16 attempting to collect the balance owing through litigation (this amount is shown from
17 taking the difference in Column A and Column C, [Schedule A.4](#)). As a result,
18 ATCO Electric proposed in the 2004 Rider G application to wait until the final disposition
19 of the ongoing legal action was known before application to collect this amount was
20 made.

21 During the litigation proceedings, ATCO Electric assessed the financial circumstances
22 of the customer and its successors, the costs of pursuing the litigation and the likely
23 financial outcome, including the ability to collect the full outstanding amount and
24 determined that the likelihood of collecting the full balance owing was very low. Based
25 on an assessment of the potential outcomes, ATCO Electric determined that the best
26 outcome was to reach a negotiated settlement and thereby ensure recovery of a
27 significant portion of the costs. Part of the concern related to the fact that even if



1 ATCO Electric obtained a successful judgment against the defendant, the poor financial
2 situation of the defendant likely meant that collection of any judgment would be unlikely.

3 The negotiated settlement resulted in a shortfall of approximately \$0.209M in the
4 outstanding balance, including interest and legal expense incurred to date (refer to
5 Column E, [Schedule A.4](#)). Now that this matter has been resolved, ATCO Electric
6 proposes to dispense this amount (for a total of \$0.209M) in this 2006 Rider G. This
7 amount is set out in Column E, [Schedule A.4](#).

8 The target amount from this customer has been allocated to customers greater than
9 2 MW based on ATCO Electric's approved 2006 energy forecast from
10 Decision 2006-024 to arrive at a rate in ¢/kWh.

11 Accordingly, ATCO Electric requests Board approval of the refund from the over
12 collection of the 2005 Rider G by rate class, and collection of the remaining 2000 PPDA
13 from customers greater than 2MW. The total amount relating to this component is a net
14 refund to customers in the amount of \$0.141M.

15 **Component D. 2006 Interim Rates to 2005-2006 GTA (2006 Revenue Requirement)**

16 On October 12, 2005, ATCO Electric submitted its 2006 Interim Distribution Tariff
17 Application for approval, on an interim refundable basis. ATCO Electric proposed to
18 apply the same scaling factors to arrive at a 2006 distribution tariff based on the
19 proposed 2006 revenue requirement as outlined in the Phase I GTA. ATCO Electric
20 received approval in Decision 2005-133, dated December 13, 2005, to apply its scaling
21 methodology for interim rates effective January 1, 2006.

22 As also outlined in ATCO Electric's GTA refiling, dated April 28, 2006, ATCO Electric is
23 proposing to implement its 2006 final tariff effective August 1, 2006. Column A,
24 [Schedule A.5](#), sets out the forecast revenue from the interim rates applied to
25 ATCO Electric's 2006 load forecast approved in Decision 2006-024 for the
26 January - July period. In accordance with the proposed final rates as shown in



1 Column B, [Schedule A.5](#), the 2006 revenue for January – July is estimated at
2 \$162.108M as opposed to the estimate based on the interim rates of \$166.372M shown
3 in Column A. As a result, ATCO Electric is proposing to refund, on an interim
4 refundable basis, the difference between the Board approved revenue based on the
5 interim and final rates in an amount of \$4.265M over the period between
6 January 1, 2006 – July 31, 2006.

7 The target refund amount for this component per rate class is divided by five months of
8 ATCO Electric's approved 2006 energy forecast from Decision 2006-024 to arrive at a
9 rate in ¢/kWh.

10 Accordingly, ATCO Electric requests Board approval of the refund of the over collection
11 of revenue due to the 2006 Interim Rates for the January – July, 2006, period by rate
12 class in the amount of \$4.265M.

13 **Component E. 2005 Deferrals**

14 Consistent with the approach in its 2005 Rider G application, ATCO Electric is
15 proposing to dispense of the 2005 deferral accounts in this Rider G application on an
16 interim refundable basis. ATCO Electric will apply for approval of the 2005 deferral
17 accounts later in 2006. ATCO Electric has estimated the deferral accounts to be a
18 collection of approximately \$3.579M. This amount includes balances relating to
19 transmission access payments and remainder of other deferral balances. In addition,
20 an amount of \$0.164M relating to carrying costs associated with these 2005 deferral
21 accounts has been included. ATCO Electric proposes that this estimated target of
22 \$3.579M be used as a placeholder subject to the final approval of the amounts in
23 ATCO Electric's upcoming application for disposal of 2005 Deferral Accounts.

24 Consistent with the approach used in ATCO Electric's 2005 Rider G regarding the
25 2004 deferral account balances, ATCO Electric has allocated the refund/collection of
26 the 2005 deferral estimate associated with transmission access payments, based on its
27 approved 2005 energy forecast by rate class. The amount relating to the remainder of



1 deferral balances, as outlined in Column C, [Schedule A.6](#), has been allocated by rate
2 class based on the 2005 forecast revenue at existing rates, as originally applied for in
3 ATCO Electric's GTA (and set out in Column A, [Schedule A.2](#)). The total amounts by
4 rate class including carrying costs are then divided by five months of ATCO Electric's
5 approved 2006 energy forecast from Decision 2006-024 to arrive at a rate in ¢/kWh.

6 ATCO Electric believes that the estimated amounts will not substantively change in the
7 upcoming 2005 Deferral application. In addition, ATCO Electric is of the view that
8 including the collection of this amount will minimize the overall rate impact to customers
9 with the removal of 2006 Rider G in January 2007.

10 Accordingly, ATCO Electric requests Board approval of the collection of the proposed
11 2005 deferral account by rate class in the amount of \$3.579M on an interim refundable
12 basis.

13 **3.0 Approvals Requested for Rider G Implementation**

14 Accordingly, ATCO Electric hereby respectfully requests Board approval of:

Component A – refund the balance of the over collection of the 2005 Interim Rates to 2005 GTA approved distribution revenue requirement amounts by rate class in the amount of \$4.500M.

Component B – collection of the small under collection of the 2004 Rider G by rate class in the amount of \$0.068M.

Component C – refund from the over collection of the 2005 Rider G by rate class, and collection of the remaining 2000 PPDA from customers greater than 2MW. The total amount relating to this component is a net refund to customers in the amount of \$0.141M.

Component D – refund of the over collection of revenue due to the 2006 Interim Rates for the January – July, 2006, period by rate class in the amount of \$4.265M.

Component E – collection of the proposed 2005 deferral account by rate class in the amount of \$3.579M on an interim refundable basis.



1 **4.0 2006 Rider Q Proposal**

2 ATCO Electric seeks Board approval to collect \$4.876M from customers in relation to
3 outstanding 2003 and 2004 Non-Energy Regulated Rate Tariff (RRT) matters.
4 Additionally, ATCO Electric will reduce this collection amount by \$164,200 to reflect the
5 2005 Rider Q over collection, resulting in a net collection for this 2006 Rider Q
6 application of \$4.712M. Details of the 2005 Rider Q over collection are provided in
7 [Schedule A.14](#).

8 For the outstanding 2003 and 2004 Non-Energy Regulated Rate Tariff (RRT) matters,
9 the collection amount consists of \$2.712M from 2003 and \$2.165M from 2004. These
10 amounts stem from using 2002 interim rates for Non-Energy costs in each of the years
11 2003 and 2004. The requested collection amounts were provided and tested in
12 ATCO Electric's 2003 Revised Amended 2003-2004 Regulated Rate Option Tariff
13 Non-Energy Rates Application No. 1282255. The decision of this Application is still
14 pending.

15 ATCO Electric will treat the amounts as a placeholder until the Board decision related to
16 Application No. 1282255 is issued, expected by mid-May, 2006. ATCO Electric will file
17 a revision to the amounts soon after the Board Decision in the event that the approved
18 amounts are different from the filed amounts. ATCO Electric has filed the Rider Q
19 proposal to dispense with the RRO shortfall in conjunction with the Rider G application
20 for regulatory efficiency and rate stability.

21 When the decision for Application No. 1282255 is received, ATCO Electric will make
22 any adjustments to the principle amounts as required and will update all carrying cost
23 calculations as well as provide carrying cost calculations for the 2005 Rider Q over
24 collection.

25 It is acknowledged that certain values are subject to an IT benchmarking process
26 currently in progress. ATCO Electric submits that any changes that may result from the



1 benchmarking process will be trued-up and become a part of a future rider application.
2 Therefore, ATCO Electric seeks approval to dispense with these RRT Non-Energy Cost
3 matters.

4 **4.1 Background**

5 **A. 2003-2004 RROT Non-energy Costs**

6 On November 8, 2002 ATCO Electric originally filed its 2003 Regulated Rate Option
7 Tariff Non-Energy Rate application (Number 1282255). On December 8, 2002
8 ATCO Electric submitted a letter to the Board requesting to stay the application. The
9 stay was granted via Board letter on December 20, 2002. Through communication with
10 the Board and given the extended period that the application was held in abeyance,
11 ATCO Electric notified the Board by letter on October 5, 2005, that the application
12 should proceed to finalize the volume component of the costs. The application was
13 amended to include 2004 results and filed with the Board on October 18, 2005. There
14 was a revised filing chiefly to include ITBS volumes on October 31, 2005. The Board
15 issued a process for proceeding with the application on November 10, 2005. The
16 record for the proceeding was closed as of February 16, 2006. As mentioned earlier a
17 decision is expected shortly.

18 [Schedule A.13](#) shows revenues and costs by rate class and by fixed and variable
19 elements for each of the years 2003 and 2004. Carrying costs are prorated to each rate
20 class based on net collection/refund with the final column showing the net amount to be
21 collected/refunded to each rate class. Revenues for 2003 and 2004 are actual
22 revenues as collected from each rate class and costs are actual costs applied to the
23 rate classes using previously approved cost of service methodologies. Consistent with
24 the previous cost of service model, Customer Accounting Costs are allocated based on
25 number of customers, DT Fixed and Overhead Costs are allocated by number of bills
26 sent, and the remaining variable charge costs are allocated based on energy



1 consumption by customer class. Cost of service models for 2003 and 2004 have been
2 provided with this application and the results are shown in [Schedules A.7 to A.12](#).

3 Again, if the decision from Application No. 1282255 approves an amount different from
4 the applied for in this Rider Q application, then this application will be adjusted
5 accordingly. Any changes that arise from the benchmarking process will be
6 incorporated into a future rider application.

7 **B. Rider Q Collection/Refund Methodology**

8 The Rider for a rate class is determined by dividing the allocated amount to the rate
9 class by the actual consumption for the rate class during the period from
10 August 1 through December 31, 2003 inclusive. ATCO Electric is proposing this
11 approach to recover the RROT shortfall over the same period as Rider G –
12 August 1, 2006, to December 31, 2006. The determination of customer eligibility for
13 dispensing its RROT outstanding account balance is based on the same manner in
14 which it has been done in previous RROT deferral account applications. ATCO Electric
15 is proposing to determine customer eligibility based on the inventory of its RROT
16 customers on December 31, 2003. The calculation of the Rider Q rate is shown in
17 Schedule A.14.

18 **5.0 Implementation Date and Board Approval**

19 To implement Rider G and Rider Q effective August 1, 2006, a Board Decision is
20 required by July 14, 2006. The time period between July 14, 2006 and July 31, 2006, is
21 required to adequately implement and test the approved rates to minimize billing errors.

22 Proposed price schedules are set out in [Appendix D](#) based on the same schedules
23 submitted in ATCO Electric's GTA refiling, submitted on April 28, 2006, updated to
24 include Rider G and Rider Q rates.



- 1 [Appendix A](#) – Rider G Schedules
- 2 [Appendix B](#) – Summary of Monthly Interest Charges on Rider G Items
- 3 [Appendix C](#) – Rate Impact Sheets and Summary of Sample Bill Calculations
- 4 [Appendix D](#) – Price Schedules

ATCO Electric
2006 Rider Application
Schedule A.1: Rider G Summary

Component:	A	B	C	C	D	E	F=A thru E
Cross Reference:	Schedule A.2	Schedule A.3	Schedule A.4	Schedule A.4	Schedule A.5	Schedule A.6	
Rate Class	Interim Rates to 2005 GTA (\$'000)	2004 Rider G Total Collection less 2004 Amt (\$ 000's)	2005 Rider G Residual (\$ 000's)	2004 Rider G Residual Component (\$ 000's)	2006 Rates Applied to 2006 GTA Forecast Jan-Jul (\$ 000's)	2005 Deferral Accounts (\$ 000's)	Rider Total (\$ 000's)
D11	-1,355	508	-336	0	-1,537	213	-2,507
D21/D22	-638	-32	-60	0	-579	214	-1,096
D25/D26	-7	4	-7	0	-2	0	-13
D31/D32/D33	-1,699	339	-96	1	-1,292	2,835	88
D31/D32/T31 >2 MW	0	0	0	208	0	0	208
T31/T33	-9	-126	66	0	-19	-2	-90
D41	-391	-277	72	0	-417	143	-870
D51/D52	-77	-103	5	0	-65	69	-171
D56	-245	-168	-9	0	-262	108	-576
D61	-65	-64	13	0	-76	-2	-194
D63	-13	-13	2	0	-15	0	-39
	-4,500	68	-350	209	-4,265	3,579	-5,259

	G	H	I	J	K	L	M=G thru L
Rate Class	Interim Rates to 2005 GTA Rider Component (¢/kW.h)	2004 Rider G Total Collection less 2004 Amt Rider Component (¢/kW.h)	Total 2005 Rider G Residual Component (¢/kW.h)	Total 2000 PPDA Outstanding Rider Component (¢/kW.h)	2006 Rates Applied to 2006 GTA Forecast Jan-Jul Rider Component (¢/kW.h)	2005 Deferral Accounts Rider Component (¢/kW.h)	Rider Component (¢/kW.h)
D11	-0.358	0.134	-0.089	0.000	-0.406	0.056	-0.662
D21/D22	-0.247	-0.012	-0.023	0.000	-0.224	0.083	-0.423
D25/D26	-1.085	0.543	-1.089	0.000	-0.305	-0.029	-1.965
D31/D32/D33 <2MW	-0.069	0.014	-0.004	0.000	-0.052	0.115	0.004
D31/D32 >2MW	-0.069	0.014	-0.004	0.012	-0.052	0.115	0.015
T31/T33<2MW	-0.001	-0.018	0.009	0.000	-0.003	0.000	-0.013
T31 >2MW	-0.001	-0.018	0.009	0.012	-0.003	0.000	-0.001
D41	-0.234	-0.166	0.043	0.000	-0.249	0.086	-0.520
D51/D52	-0.122	-0.165	0.008	0.000	-0.105	0.111	-0.274
D56	-0.209	-0.143	-0.007	0.000	-0.223	0.092	-0.490
D61	-0.668	-0.656	0.134	0.000	-0.782	-0.016	-1.987
D63	-0.692	-0.679	0.117	0.000	-0.787	-0.018	-2.059

ATCO Electric
2006 Rider Application
Schedule A.2: 2005 Interim Rates to 2005-2006 GTA (2005 Revenue Requirement)

Component A

	A	B (via A)	C (via B)	D (via A)	F=D+E-B-C	G	H=F/G*100
		Applied For In 2005 Rider G	Applied For In 2005 Rider G				
	2005 Forecast Revenue at Existing Rates	Interim Rates to 2005 GTA Forecast	Interim Rates to 2005 GTA Forecast Carrying Costs	Interim Rates to 2005 GTA	Total Difference	Forecast of 5 months of 2006 Energy	Rider Component
<u>Rate Class</u>	<u>(\$ 000's)</u>	<u>(\$ 000's)</u>	<u>(\$'000)</u>	<u>(\$'000)</u>	<u>(\$'000)</u>	<u>(MW.h)</u>	<u>(¢/kW.h)</u>
D11	68,767	-1,987	-3	-3,344	-1,355	378,771	-0.358
D21/D22	32,413	-936	-1	-1,576	-638	258,720	-0.247
D25/D26	358	-10	0	-17	-7	650	-1.085
D31/D32/D33	86,264	-2,492	-4	-4,195	-1,699	2,475,488	-0.069
T31/T33*	470	-14	0	-23	-9	712,559	-0.001
D41	19,868	-574	-1	-966	-391	167,320	-0.234
D51/D52	3,885	-112	0	-189	-77	62,473	-0.122
D56	12,462	-360	-1	-606	-245	117,570	-0.209
D61	3,312	-96	0	-161	-65	9,773	-0.668
D63	<u>662</u>	<u>-19</u>	<u>0</u>	<u>-32</u>	<u>-13</u>	<u>1,884</u>	<u>-0.692</u>
Total	228,460	-6,600	-10	-11,110	-4,500	4,185,210	

*Distribution Revenue Only since Transmission Cost are flow through

ATCO Electric
2006 Rider Application
Schedule A.3: Continuation of 2004 Rider G in 2005 (May 31, 2005 completion)

Component B

	A	B	C	D	E=C+D-A-B	F	G=E/F*100
	Applied For In 2005 Rider G	(via A) Applied For In 2005 Rider G		(via C)			
<u>Rate Class</u>	Estimated 2004 Rider G Total Collection less 2004 Amt (\$ 000's)	Estimated Carrying Costs (\$'000)	Actual 2004 Rider G Total Collection less 2004 Amt (\$ 000's)	Actual Carrying Costs (\$'000)	Total (\$'000)	Forecast of 5 months of 2006 Energy (MW.h)	Rider Component (¢/kW.h)
D11	6,762	24	7,259	35	508	378,771	0.134
D21/D22	3,981	14	3,945	19	-32	258,720	-0.012
D25/D26	-5	0	-1	0	4	650	0.543
D31/D32/D33	14,862	52	15,181	73	339	2,475,488	0.014
T31/T33	2,357	8	2,229	11	-126	712,559	-0.018
D41	2,060	7	1,781	9	-277	167,320	-0.166
D51/D52	525	2	422	2	-103	62,473	-0.165
D56	1,409	5	1,240	6	-168	117,570	-0.143
D61	314	1	250	1	-64	9,773	-0.656
D63	49	0	36	0	-13	1,884	-0.679
Total	32,315	114	32,342	154	68	4,185,210	

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Schedule A.4: 2005 Rider G Residual

Component C

	A	B (Via A)	C	D (Via C)	E=C+D-A-B	F	G	H=F-G	I=E+H	J	K=I/J*100
	2004 Rider G Residual Component (\$ 000's)	Carrying Costs (\$'000)	Revised 2004 Rider G Residual Component (\$ 000's)	Carrying Costs (\$'000)	Sub Total (\$'000)	2005 Rider G Component (\$ 000's)	2005 Rider G Collection (\$ 000's)	Sub Total (\$'000)	Total (\$'000)	Forecast of 5 months of 2006 Energy (MW.h)	Rider Component (¢/kW.h)
D11	-453	-2	-453	-2	0	3,526	3,862	-336	-336	378,771	-0.089
D21/D22	-567	-3	-567	-3	0	1,880	1,940	-60	-60	258,720	-0.023
D25/D26	0	0	0	0	0	-18	-11	-7	-7	650	-1.089
D31/D32/D33	-1,990	-10	-1,990	-10	1	4,811	4,908	-96	-96	2,475,488	-0.004
D31/D32/T31>2MW	0	0	208	0	208	0	0	0	208	1,743,749	0.012
T31/T33	-295	-2	-295	-1	0	-1,957	-2,023	66	66	712,559	0.009
D41	-488	-2	-488	-2	0	600	528	72	72	167,320	0.043
D51/D52	-140	-1	-140	-1	0	87	82	5	5	62,473	0.008
D56	-291	-1	-291	-1	0	462	471	-9	-8	117,570	-0.007
D61	-66	0	-66	0	0	133	120	13	13	9,773	0.134
D63	-12	0	-12	0	0	13	11	2	2	1,884	0.117
	-4,301	-22	-4,093	-21	209	9,536	9,886	-350	-141		

ATCO Electric
2006 Rider Application
Schedule A.5: 2006 Interim Rates to 2005-2006 GTA (2006 Revenue Requirement)

Component D

	A	B	C=B-A	D	E=C/D*100
<u>Rate Class</u>	<u>Interim Rates Applied to 2006 GTA Forecast Jan-Jul (\$ 000's)</u>	<u>2006 Rates Applied to 2006 GTA Forecast Jan-Jul (\$ 000's)</u>	<u>Total Difference (\$'000)</u>	<u>Forecast of 5 months of 2006 Energy (MW.h)</u>	<u>Rider Component (¢/kW.h)</u>
D11	46,275	44,738	-1,537	378,771	-0.406
D21/D22	19,428	18,848	-579	258,720	-0.224
D25/D26	74	72	-2	650	-0.305
D31/D32/D33	70,964	69,673	-1,292	2,475,488	-0.052
T31/T33*	481	462	-19	712,559	-0.003
D41	14,265	13,848	-417	167,320	-0.249
D51/D52	3,184	3,118	-65	62,473	-0.105
D56	9,229	8,966	-262	117,570	-0.223
D61	2,071	1,995	-76	9,773	-0.782
D63	402	387	-15	1,884	-0.787
Total	166,372	162,108	-4,265	4,185,210	

*Distribution Revenue Only since Transmission Cost are flow through

ATCO Electric
2006 Rider Application
Schedule A.6: 2005 Deferrals

Component E

	A	B	C (via A, Sch. A.2)	D (via B+C)	E=B thru D (via A)	J	K=J/I*100
<u>Rate Class</u>	<u>2005 Energy (MW.h)</u>	<u>2005 Transmission Access Payments (\$ 000's)</u>	<u>Remainder of Deferral Accounts (\$ 000's)</u>	<u>Carrying Costs (\$'000)</u>	<u>Total (\$'000)</u>	<u>Forecast of 5 months of 2006 Energy (MW.h)</u>	<u>Rider Component (¢/kW.h)</u>
D11	861,254	460	-257	10	213	378,771	0.056
D21/D22	610,143	326	-121	10	214	258,720	0.083
D25/D26	2,168	1	-1	0	0	650	-0.029
D31/D32/D33	5,673,267	3,027	-322	130	2,835	2,475,488	0.115
T31/T33	1,568,836	0	-2	0	-2	712,559	0.000
D41	395,311	211	-74	7	143	167,320	0.086
D51/D52	150,969	81	-15	3	69	62,473	0.111
D56	280,887	150	-47	5	108	117,570	0.092
D61	20,406	11	-12	0	-2	9,773	-0.016
D63	4,013	2	-2	0	0	1,884	-0.018
Total	9,567,254	4,268	-853	164	3,579	4,185,210	

ATCO Electric
2003 RRO Forecast Costs

RRO Cost Summary

	Actual 2003 RRO <u>(\$000)</u>
Customer Accounting Costs	
Customer Billing Expenses	1,515.9
Call Center Services	1,497.8
Credit and Collections	1,790.2
Customer Billing and Accounting (Credit Mgt System)	136.5
Collection of Revenue	-
Bad Debt	1,429.5
Penalty Revenue	(989.0)
Total Customer Accounting Costs	<u>5,380.9</u>
Additional Administrative Costs	
Pool Price Flow-Through System Changes	194.5
RRO Regulatory and Deferral Account Management	157.3
Necessary Working Capital	650.0
Management Fees	-
Share of DT Fixed Costs and Overhead	1,175.0
2003 RRO Hearing Costs	-
Trading Fees	217.0
Total Additional Administrative Costs	<u>2,393.8</u>
Total Non-Energy Revenue Requirement	<u><u>7,774.7</u></u>

ATCO Electric
2003 RRO Forecast Costs

	----- Additional Administrative Costs -----										Fixed Customer Charge (\$000)	Variable Charge (\$000)	Total RRO Costs (\$000)
	Customer Accounting Costs (\$000)	Share of DT Fixed Costs & Overhead (\$000)	Trading Fees (\$000)	Pool Price Flow- Through System Changes (\$000)	RRO Regulatory & Deferral Account Management (\$000)	Working Capital (\$000)	Management Fees (\$000)	2003 RRO Hearing Costs (\$000)	Total Additional Administrative Costs (\$000)				
By RRO Rate Class	5,380.9	1,175.0	217.0	194.5	157.3	650.0	-	-	2,393.8	6,555.9	1,218.8	7,774.7	
Residential	4,239.5	811.5	92.8	83.2	67.3	278.1	-	-	1,332.9	5,051.0	521.4	5,572.4	
General Service	605.0	125.3	52.9	47.4	38.3	158.4	-	-	422.3	730.4	297.0	1,027.4	
Industrial	27.6	5.5	18.3	16.4	13.3	54.9	-	-	108.5	33.2	102.9	136.1	
Oilfields	23.9	7.1	5.3	4.8	3.9	16.0	-	-	37.1	31.0	30.0	61.0	
Company Farm	214.1	123.0	29.3	26.2	21.2	87.6	-	-	287.3	337.1	164.3	501.4	
REA Farm	130.8	75.1	17.3	15.5	12.6	51.9	-	-	172.5	206.0	97.3	303.3	
Street Light	7.6	1.5	0.3	0.3	0.2	0.9	-	-	3.1	9.0	1.7	10.7	
Sentinel Light	132.2	25.6	0.4	0.4	0.3	1.2	-	-	27.9	157.8	2.3	160.1	
Irrigation	0.2	0.2	0.3	0.3	0.2	1.0	-	-	2.1	0.5	1.8	2.3	
Total	5,380.9	1,175.0	217.0	194.5	157.3	650.0	-	-	2,393.8	6,555.9	1,218.8	7,774.7	

Fixed Customer Charge includes:

- Customer Accounting Costs
- Share of DT Fixed Costs & Overhead

Variable Charge includes:

- Pool Price Flow-Through System Changes
- RRO Regulatory and Deferral Account Management
- Working Capital
- Management Fees
- 2003 RRO Hearing Costs
- Trading Fees

ATCO Electric
2003 RRO Forecast Costs

This page tabulates 2003 RRO Number of Customers and Energy Purchases

	2003 No of	2003 Total	2003 No of	2003 No of	Total Energy	Total Energy	No. of RRO
	D-Tariff	D-Tariff	RRO	RRO	Purchases for	Purchases for	Bills After
By RRO Rate Class	Customers	Energy Sale	Customers	Customers	RRO	RRO	Consolidated
	(No.)	(MWh)	(No.)	(No.)	(MWh)	(\$000)	Billing (1)
Residential	113,606	819,967	112,887	1,354,646	844,770	58,322	1,354,646
General Service	20,648	641,190	17,436	209,231	481,209	33,327	193,329
Industrial	4,604	7,046,195	771	9,256	166,798	10,772	8,821
Oilfields	8,478	393,119	994	11,922	48,564	3,140	7,630
Company Farm	17,968	254,978	17,104	205,253	266,256	18,175	68,418
REA Farm	11,734	134,922	10,452	125,427	157,718	10,766	41,809
Street Light	772	20,215	203	2,432	2,732	153	2,420
Sentinel Light	4,055	4,794	3,565	42,785	3,684	207	42,229
Irrigation	35	2,059	35	416	2,985	177	69
Total Distribution	181,900	9,317,440	163,447	1,961,368	1,974,717	135,038.3	1,719,372

Notes (1) Percent of bills that are consolidated to be part of another bill and number of bills sent out each year are based on the following:

	Percent Consolidated	# Bills per Year
Residential	0.0%	12.0
Company Farm	0.0%	4.0
REA	0.0%	4.0
General Service	7.6%	12.0
Irrigation	0.0%	2.0
Industrial	4.7%	12.0
Oilfields	36.0%	12.0
Street Light	0.5%	12.0
Sentinel Light	1.3%	12.0

ATCO Electric
2004 RRO Forecast Costs

RRO Cost Summary

	Forecast 2004 RRO <u>(\$000)</u>
Customer Accounting Costs	
Customer Billing Expenses	911.1
Call Center Services	711.2
Credit and Collections	755.9
Customer Billing and Accounting (Credit Mgt System)	58.6
Collection of Revenue	-
Bad Debt	1,497.4
Penalty Revenue	(467.0)
Total Customer Accounting Costs	<u>3,467.2</u>
Additional Administrative Costs	
Pool Price Flow-Through System Changes	-
RRO Regulatory and Deferral Account Management	101.0
Necessary Working Capital	69.0
Management Fees	-
Share of DT Fixed Costs and Overhead	385.0
2004 RRO Hearing Costs	-
Trading Fees	105.0
Total Additional Administrative Costs	<u>660.0</u>
Total Non-Energy Revenue Requirement	<u><u>4,127.2</u></u>

ATCO Electric
2004 RRO Forecast Costs

	----- Additional Administrative Costs -----											
	Customer Accounting Costs (\$000)	Share of DT Fixed Costs & Overhead (\$000)	Trading Fees (\$000)	Pool Price Flow-Through System Changes (\$000)	RRO Regulatory & Deferral Account Management (\$000)	Working Capital (\$000)	Management Fees (\$000)	2004 RRO Hearing Costs (\$000)	Total Additional Administrative Costs (\$000)	Fixed Customer Charge (\$000)	Variable Charge (\$000)	Total RRO Costs (\$000)
By RRO Rate Class	3,467.2	385.0	105.0	-	101.0	69.0	-	-	660.0	3,852.2	275.0	4,127.2
Residential	2,423.8	266.5	45.9	-	44.1	30.2	-	-	386.6	2,690.3	120.2	2,810.4
General Service	320.7	38.2	23.3	-	22.4	15.3	-	-	99.1	358.8	60.9	419.8
Industrial	15.9	1.8	8.6	-	8.3	5.6	-	-	24.3	17.8	22.5	40.3
Oilfields	11.8	2.0	2.1	-	2.0	1.4	-	-	7.6	13.8	5.6	19.4
Company Farm	380.9	41.9	15.5	-	14.9	10.2	-	-	82.5	422.7	40.7	463.4
REA Farm	232.7	25.6	9.2	-	8.8	6.0	-	-	49.7	258.3	24.1	282.4
Street Light	4.4	0.5	0.2	-	0.2	0.1	-	-	0.9	4.9	0.4	5.3
Sentinel Light	76.7	8.5	0.2	-	0.2	0.1	-	-	9.1	85.3	0.6	85.9
Irrigation	0.2	0.0	0.0	-	0.0	0.0	-	-	0.1	0.2	0.1	0.3
Total	3,467.2	385.0	105.0	-	101.0	69.0	-	-	660.0	3,852.2	275.0	4,127.2

Fixed Customer Charge includes:

- Customer Accounting Costs
- Share of DT Fixed Costs & Overhead

Variable Charge includes:

- Pool Price Flow-Through System Changes
- RRO Regulatory and Deferral Account Management
- Working Capital
- Management Fees
- 2004 RRO Hearing Costs
- Trading Fees

ATCO Electric
2004 RRO Forecast Costs

	2004 No of	2004 Total	2004 No of	2004 No of	Total Energy	Total Energy	No. of RRO
	D-Tariff	D-Tariff	RRO	RRO	Purchases for	Purchases for	Bills After
By RRO Rate Class	Customers	Energy Sale	Customers	Customers	RRO	RRO	Consolidated
	(No.)	(MWh)	(No.)	(No.)	(MWh)	(\$000)	Billing (1)
Residential	118,020	833,637	43,450	521,397	337,102	18,600	521,397
General Service	20,986	600,463	6,222	74,659	170,887	9,358	68,985
Industrial	5,083	7,156,165	300	3,596	63,089	3,258	3,427
Oilfields	8,534	386,180	330	3,964	15,588	799	2,537
Company Farm	17,988	248,138	6,828	81,932	114,104	6,141	81,932
REA Farm	11,415	152,648	4,172	50,067	67,591	3,638	50,067
Street Light	749	19,607	79	953	1,193	54	948
Sentinel Light	3,933	4,650	1,394	16,727	1,608	74	16,510
Irrigation	36	2,131	4	43	307	19	43
Total Distribution	186,744	9,403,620	62,778	753,339	771,469	41,941.7	745,846

Notes (1) Percent of bills that are consolidated to be part of another bill and number of bills sent out each year are based on the following that are the same used in the 2001 RRO:

	Percent	# Bills per Year
Residential	0.0%	12.0
Company Farm	0.0%	12.0
REA	0.0%	12.0
General Service	7.6%	12.0
Irrigation	0.0%	12.0
Industrial	4.7%	12.0
Oilfields	36.0%	12.0
Street Light	0.5%	12.0
Sentinel Light	1.3%	12.0

ATCO Electric
Compare RROT Revenues to Costs
(\$000)

2003	Customer			Variable			Total			Carrying Costs	Refund/ (Collection)
	Revenue	Costs	Difference	Revenue	Costs	Difference	Revenue	Costs	Difference		
By RRO Rate Class											
Residential	2,539.7	5,051.0	(2,511.3)	970.5	521.4	449.1	3,510.1	5,572.4	(2,062.3)	(362.1)	(2,424.4)
General Service	384.9	730.4	(345.5)	550.2	297.0	253.2	935.1	1,027.4	(92.3)	(16.2)	(108.5)
Industrial	17.0	33.2	(16.1)	189.3	102.9	86.3	206.3	136.1	70.2	12.3	82.5
Oilfields	21.9	31.0	(9.1)	56.6	30.0	26.6	78.5	61.0	17.5	3.1	20.6
Farm	205.0	543.1	(338.0)	486.8	261.7	225.1	691.8	804.7	(112.9)	(19.8)	(132.8)
Lights	35.1	166.8	(131.7)	7.4	4.0	3.4	42.5	170.8	(128.3)	(22.5)	(150.8)
Irrigation	0.4	0.5	(0.1)	3.3	1.8	1.5	3.7	2.3	1.4	0.2	1.6
Total	3,204.0	6,555.9	(3,351.9)	2,264.0	1,218.8	1,045.2	5,468.0	7,774.7	(2,306.7)	(405.0)	(2,711.7)

2004	Customer			Variable			Total			Carrying Costs	Refund/ (Collection)
	Revenue	Costs	Difference	Revenue	Costs	Difference	Revenue	Costs	Difference		
By RRO Rate Class											
Residential	959.3	2,690.3	(1,731.0)	391.2	120.2	271.0	1,350.5	2,810.4	(1,460.0)	(103.7)	(1,563.6)
General Service	137.4	358.8	(221.5)	198.0	60.9	137.1	335.4	419.8	(84.3)	(6.0)	(90.3)
Industrial	6.6	17.8	(11.2)	72.1	22.5	49.6	78.7	40.3	38.4	2.7	41.1
Oilfields	7.3	13.8	(6.5)	17.9	5.6	12.3	25.2	19.4	5.8	0.4	6.2
Farm	81.8	681.1	(599.2)	209.7	64.8	144.9	291.5	745.8	(454.3)	(32.3)	(486.6)
Lights	14.2	90.2	(76.0)	3.3	1.0	2.3	17.4	91.2	(73.8)	(5.2)	(79.0)
Irrigation	-	0.2	(0.2)	0.3	0.1	0.2	0.3	0.3	0.0	0.0	0.0
Total	1,206.5	3,852.2	(2,645.7)	892.5	275.0	617.5	2,099.0	4,127.2	(2,028.2)	(144.0)	(2,172.2)

Notes:

1) Farm billing went from quarterly billing in 2003 to monthly billing in 2004; hence, actual costs allocated to farm customers increased from 2003 relative to 2004.

**ATCO Electric
2006 Rider Application
Schedule B.6: RRO Deferrals**

	A	B	C	D=A thru C (via A)	J	K=J/I*100
Rate Class	2003 Non-Energy RRT Matters (\$ 000's)	2004 Non-Energy RRT Matters (\$ 000's)	Total 2005 Rider Q Residual (\$ 000's)	Total (\$'000)	Forecast of 5 months of 2006 Energy (MW.h)	Rider Component (¢/kW.h)
Residential	2,424.4	1,563.6	0.4	3,988.4	335,216	1.190
General Service	108.5	90.3	-7.9	191.0	192,604	0.099
Industrial	-82.5	-41.1	-75.9	-199.5	68,202	-0.293
Oilfields	-20.6	-6.2	-226.6	-253.4	23,368	-1.084
Farm	132.8	486.6	131.3	750.7	177,106	0.424
Lights	150.8	79.0	-7.0	222.8	2,833	7.866
Irrigation	-1.6	0.0	21.4	19.8	1,303	1.519
Total	2,711.7	2,172.2	-164.2	4,719.7	800,631	

**2006 Rider Application
Appendix C
Schedule C.0
Page 1 of 16**

Summary of Rate Impact to Typical Bills (Distribution Tariff Base Rates - Without Retail Energy Purchases)

Rate Class	June 1, 2005				August 1, 2005				January 1, 2006					Rider G & Q apply from August 1 - December 31, 2006 August 1, 2006				
	DT Base Rates	Rider G	Rider Q	Net	DT Base Rates	Rider G	Rider Q	Net	DT Base Rates	Rider G	Rider Q	Rider F	Net	DT Base Rates	Rider G	Rider Q	Rider F	Net
D11 Residential 600 kWh	\$48.78			\$48.78	\$45.87	\$6.40	-\$0.31	\$51.96	\$53.45			-\$0.60	\$52.85	\$51.65	-\$3.97	\$7.14	-\$0.60	\$54.22
D21 Commercial 20 kW; 7300 kWh	\$295.60			\$295.60	\$218.30	\$54.09	-\$3.94	\$268.45	\$262.96			-\$7.30	\$255.66	\$255.43	-\$30.88	\$7.23	-\$7.30	\$224.48
D31 Industrial 50 kW; 16,650 kWh	\$380.57			\$380.57	\$377.84	\$33.63	\$156.01	\$567.48	\$498.21			-\$16.65	\$481.56	\$487.54	\$0.67	-\$48.78	-\$16.65	\$422.78
D41 Oilfield 20 kW; 8,760 kWh	\$260.46			\$260.46	\$280.05	\$29.78	-\$214.27	\$95.56	\$332.19			-\$8.76	\$323.43	\$322.64	-\$45.55	-\$94.96	-\$8.76	\$173.37
D51 REA Pooled 7.5 kVA; 1,255 kWh	\$36.76			\$36.76	\$36.04	\$1.62	\$10.01	\$47.67	\$47.59			-\$1.26	\$46.34	\$46.49	-\$3.43	\$5.32	-\$1.26	\$47.13
D56 Farm 7.5 kVA; 1,255 kWh	\$53.82			\$53.82	\$54.94	\$5.13	\$10.01	\$70.08	\$67.51			-\$1.26	\$66.26	\$65.66	-\$6.14	\$5.32	-\$1.26	\$63.59
D61 Street Lights 250 Watts	\$7.29			\$7.29	\$7.84	\$1.36	-\$2.54	\$6.66	\$9.03			-\$0.09	\$8.94	\$8.73	-\$1.75	\$6.92	-\$0.09	\$13.81
D63 Private Lights 250 Watts	\$10.50			\$10.50	\$11.05	\$0.66	-\$2.54	\$9.17	\$12.38			-\$0.09	\$12.29	\$11.96	-\$1.81	\$6.92	-\$0.09	\$16.98

Schedule C.1 - Example Rate Rider Effects: Residential Class - RRO Eligible

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Residential Class Consumption Levels Cost per Customer (\$/month)			
			300 kWh per month	Typical 600 kWh per month	1200 kWh per month	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$32.81	\$54.25	\$97.13	
2	Dec 2000 Rate	2000	\$39.72	\$61.94	\$106.39	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$33.34	\$84.85	\$187.86	
4	Combined Rate, Jan. 1, 2002	Jan 1, 2002	\$51.46	\$80.02	\$137.14	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$51.41	\$79.91	\$136.92	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$53.22	\$83.54	\$144.18	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$63.58	\$104.26	\$185.61	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$57.01	\$91.11	\$159.32	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$49.78	\$76.67	\$130.43	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$54.85	\$86.81	\$150.71	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$64.59	\$103.18	\$180.34	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$28.70	\$51.22	\$96.25	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$28.70	\$51.22	\$96.25	
	Row 12 + Row 13					
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$37.16	\$53.45	\$86.03	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$0.30	-\$0.60	-\$1.20	
17	Net DT Charges	Jan 1, 2006	\$36.86	\$52.85	\$84.83	
	Row 15 + Row 16					
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$65.56	\$104.06	\$181.08	
	Row 14 + Row 17					
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$28.70	\$51.22	\$96.25	
20	+/- RRO Deferral	Aug 1, 2006	\$3.57	\$7.14	\$14.28	
21	2006 Energy Related Charge	Aug 1, 2006	\$32.27	\$58.36	\$110.53	
	Row 19 + Row 20					
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$35.84	\$51.65	\$83.27	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$2.29	-\$4.57	-\$9.14	
24	Net DT Charges	Aug 1, 2006	\$33.55	\$47.07	\$74.12	
	Row 22 + Row 23					
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$65.82	\$105.43	\$184.65	
	Row 21 + Row 24					
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$0.05 0%	-\$0.11 0%	-\$0.22 0%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$1.82 4%	\$3.63 5%	\$7.26 5%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	\$10.36 19%	\$20.71 25%	\$41.43 29%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	-\$6.57 -10%	-\$13.15 -13%	-\$26.29 -14%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$7.22 -13%	-\$14.44 -16%	-\$28.89 -18%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$14.81 30%	\$26.51 35%	\$49.91 38%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference %	\$9.74 18%	\$16.37 19%	\$29.63 20%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference %	\$0.96 1%	\$0.89 1%	\$0.74 0%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference %	\$0.26 0%	\$1.37 1%	\$3.57 2%

Schedule C.2 - Example Rate Rider Effects: Small General Service Class - RRO Eligible			GST not included			
Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Small General Service Class Consumption Levels Cost per Customer (\$/month)			
Row	Rate Component	Effective Date	Typical			
			5475 kWh per month Demand 15 kW	7300 kWh per month Demand 20 kW	9125 kWh per month Demand 25 kW	
1	Dec. 1999 Rate	1999	\$353.79	\$471.72	\$589.65	
2	Dec 2000 Rate	2000	\$396.05	\$528.07	\$660.09	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$740.70	\$983.25	\$1,225.80	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$498.05	\$659.52	\$820.99	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$481.46	\$637.40	\$793.34	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$777.65	\$1,032.32	\$1,286.99	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$532.43	\$705.36	\$878.30	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$583.92	\$774.01	\$964.11	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$500.98	\$663.43	\$825.88	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$572.82	\$759.21	\$945.60	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$635.37	\$840.62	\$1,045.86	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$430.69	\$572.17	\$713.64	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$430.69	\$572.17	\$713.64	
Row 12 + Row 13						
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$200.74	\$262.96	\$325.19	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$5.48	-\$7.30	-\$9.13	
17	Net DT Charges	Jan 1, 2006	\$195.26	\$255.66	\$316.06	
Row 15 + Row 16						
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$625.96	\$827.83	\$1,029.70	
Row 14 + Row 17						
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$430.69	\$572.17	\$713.64	
20	+/- RRO Deferral	Aug 1, 2006	\$5.42	\$7.23	\$9.03	
21	2006 Energy Related Charge	Aug 1, 2006	\$436.11	\$579.39	\$722.67	
Row 19 + Row 20						
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$194.95	\$255.43	\$315.92	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$28.63	-\$38.18	-\$47.72	
24	Net DT Charges	Aug 1, 2006	\$166.31	\$217.25	\$268.19	
Row 22 + Row 23						
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$602.42	\$796.65	\$990.87	
Row 21 + Row 24						
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference	-\$16.59	-\$22.12	-\$27.65
			%	-3%	-3%	-3%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference	\$296.19	\$394.92	\$493.65
			%	62%	62%	62%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference	-\$245.22	-\$326.96	-\$408.70
			%	-32%	-32%	-32%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference	\$51.49	\$68.65	\$85.81
			%	10%	10%	10%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference	-\$82.94	-\$110.58	-\$138.23
			%	-14%	-14%	-14%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference	\$134.39	\$177.18	\$219.98
			%	27%	27%	27%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference	\$62.55	\$81.41	\$100.26
			%	11%	11%	11%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference	-\$9.41	-\$12.79	-\$16.16
			%	-2%	-2%	-2%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference	-\$23.53	-\$31.19	-\$38.84
			%	-4%	-4%	-4%

Schedule C.3 - Example Rate Rider Effects: Small General Service Class - Not RRO Eligible

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Small General Service Class Consumption Levels Cost per Customer (\$/month)			
			5475 kWh per month Demand 15 kW	Typical 7300 kWh per month Demand 20 kW	9125 kWh per month Demand 25 kW	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$353.79	\$471.72	\$589.65	
2	Dec 2000 Rate	2000	\$396.05	\$528.07	\$660.09	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$740.70	\$983.25	\$1,225.80	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$498.05	\$659.52	\$820.99	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$543.88	\$720.62	\$897.37	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$777.65	\$1,032.32	\$1,286.99	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$506.10	\$670.25	\$834.40	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$583.92	\$774.01	\$964.11	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$500.98	\$663.43	\$825.88	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$572.82	\$759.21	\$945.60	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$638.33	\$844.56	\$1,050.79	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$430.69	\$572.17	\$713.64	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$430.69	\$572.17	\$713.64	
			Row 12 + Row 13			
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$200.74	\$262.96	\$325.19	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$5.48	-\$7.30	-\$9.13	
17	Net DT Charges	Jan 1, 2006	\$195.26	\$255.66	\$316.06	
			Row 15 + Row 16			
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$625.96	\$827.83	\$1,029.70	
			Row 14 + Row 17			
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$430.69	\$572.17	\$713.64	
20	+/- RRO Deferral	Aug 1, 2006	\$0.00	\$0.00	\$0.00	
21	2006 Energy Related Charge	Aug 1, 2006	\$430.69	\$572.17	\$713.64	
			Row 19 + Row 20			
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$194.95	\$255.43	\$315.92	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$28.63	-\$38.18	-\$47.72	
24	Net DT Charges	Aug 1, 2006	\$166.31	\$217.25	\$268.19	
			Row 22 + Row 23			
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$597.00	\$789.42	\$981.83	
			Row 21 + Row 24			
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	\$45.83 9%	\$61.10 9%	\$76.38 9%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$233.78 43%	\$311.70 43%	\$389.63 43%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$271.55 -35%	-\$362.07 -35%	-\$452.59 -35%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$77.82 15%	\$103.76 15%	\$129.70 16%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$82.94 -14%	-\$110.58 -14%	-\$138.23 -14%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$137.34 27%	\$181.13 27%	\$224.91 27%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference %	\$65.51 11%	\$85.35 11%	\$105.19 11%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference %	-\$12.37 -2%	-\$16.73 -2%	-\$21.09 -2%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference %	-\$28.95 -5%	-\$38.41 -5%	-\$47.87 -5%

Schedule C.4 - Example Rate Rider Effects: Large General Service Distribution - RRO Eligible			GST not included			
Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Large General Service Class Consumption Levels Cost per Customer (\$/month)			
Row	Rate Component	Effective Date	Typical			
			12,200 kWh per month Demand 50 kW	16,650 kWh per month Demand 50 kW	20,800 kWh per month Demand 59 kW	
1	Dec. 1999 Rate	1999	\$1,031.32	\$1,113.38	\$1,335.04	
2	Dec 2000 Rate	2000	\$816.46	\$984.14	\$1,204.73	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$1,390.02	\$1,785.23	\$2,206.62	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$959.64	\$1,193.27	\$1,466.13	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$675.14	\$804.99	\$981.07	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$1,574.01	\$2,031.73	\$2,513.58	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$1,037.54	\$1,299.58	\$1,598.94	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$1,134.98	\$1,432.56	\$1,765.07	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$1,002.49	\$1,251.74	\$1,539.18	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$1,076.66	\$1,352.97	\$1,665.64	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$1,366.68	\$1,748.76	\$2,154.76	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$866.79	\$1,181.28	\$1,474.56	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$866.79	\$1,181.28	\$1,474.56	
Row 12 + Row 13						
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$476.85	\$498.21	\$586.11	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$12.20	-\$16.65	-\$20.80	
17	Net DT Charges	Jan 1, 2006	\$464.65	\$481.56	\$565.31	
Row 15 + Row 16						
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$1,331.44	\$1,662.83	\$2,039.87	
Row 14 + Row 17						
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$866.79	\$1,181.28	\$1,474.56	
20	+/- RRO Deferral	Aug 1, 2006	-\$35.75	-\$48.78	-\$60.94	
21	2006 Energy Related Charge	Aug 1, 2006	\$831.05	\$1,132.49	\$1,413.61	
Row 19 + Row 20						
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$466.04	\$487.54	\$573.86	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$11.71	-\$15.98	-\$19.97	
24	Net DT Charges	Aug 1, 2006	\$454.32	\$471.56	\$553.90	
Row 22 + Row 23						
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$1,285.37	\$1,604.05	\$1,967.51	
Row 21 + Row 24						
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$284.50 -30%	-\$388.28 -33%	-\$485.06 -33%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$898.87 133%	\$1,226.74 152%	\$1,532.50 156%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$536.47 -34%	-\$732.15 -36%	-\$914.64 -36%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$97.44 9%	\$132.98 10%	\$166.13 10%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$132.49 -12%	-\$180.82 -13%	-\$225.89 -13%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$364.20 36%	\$497.02 40%	\$615.58 40%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference %	\$290.02 27%	\$395.79 29%	\$489.11 29%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference %	-\$35.24 -3%	-\$85.93 -5%	-\$114.89 -6%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference %	-\$46.07 -4%	-\$58.78 -4%	-\$72.36 -4%

Schedule C.5 - Example Rate Rider Effects: Large General Service Distribution - Not RRO Eligible			GST not included			
Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Large General Service Class Consumption Levels Cost per Customer (\$/month)			
Row	Rate Component	Effective Date	657,000 kWh per month Demand 1500 kW	Typical 876,000 kWh per month Demand 2000 kW	1,095,000 kWh per month Demand 2500 kW	
			1	Dec. 1999 Rate	1999	\$34,380.07
2	Dec 2000 Rate	2000	\$32,564.31	\$42,924.70	\$53,285.08	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$64,616.21	\$85,725.60	\$106,834.99	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$40,981.14	\$54,188.64	\$67,396.14	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$46,624.77	\$61,713.48	\$76,802.19	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$74,066.35	\$98,302.25	\$122,538.15	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$40,991.00	\$54,201.78	\$67,412.57	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$50,423.54	\$66,778.51	\$83,133.48	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$43,288.52	\$58,763.11	\$73,114.23	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$47,283.08	\$62,591.23	\$77,899.38	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$56,807.12	\$75,433.43	\$94,059.74	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$46,434.81	\$61,911.54	\$77,388.27	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$46,434.81	\$61,911.54	\$77,388.27	
		Row 12 + Row 13				
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$12,725.19	\$16,653.39	\$20,581.59	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$657.00	-\$876.00	-\$1,095.00	
17	Net DT Charges	Jan 1, 2006	\$12,068.19	\$15,777.39	\$19,486.59	
		Row 15 + Row 16				
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$58,503.00	\$77,688.93	\$96,874.86	
		Row 14 + Row 17				
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$46,434.81	\$61,911.54	\$77,388.27	
20	+/- RRO Deferral	Aug 1, 2006	\$0.00	\$0.00	\$0.00	
21	2006 Energy Related Charge	Aug 1, 2006	\$46,434.81	\$61,911.54	\$77,388.27	
		Row 19 + Row 20				
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$10,649.34	\$15,389.03	\$20,128.73	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$630.72	-\$744.60	-\$930.75	
24	Net DT Charges	Aug 1, 2006	\$10,018.62	\$14,644.43	\$19,197.98	
		Row 22 + Row 23				
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$56,453.43	\$76,555.97	\$96,586.25	
		Row 21 + Row 24				
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	\$5,643.63 14%	\$7,524.84 14%	\$9,406.05 14%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$27,441.58 59%	\$36,588.77 59%	\$45,735.96 60%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$33,075.35 -45%	-\$44,100.47 -45%	-\$55,125.59 -45%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$9,432.55 23%	\$12,576.73 23%	\$15,720.92 23%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$7,135.02 -14%	-\$8,015.40 -12%	-\$10,019.25 -12%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$13,518.60 31%	\$16,670.32 28%	\$20,945.51 29%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference %	\$9,524.04 20%	\$12,842.20 21%	\$16,160.36 21%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference %	\$1,695.88 3%	\$2,255.50 3%	\$2,815.12 3%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference %	-\$2,049.57 -4%	-\$1,132.96 -1%	-\$288.61 0%

Schedule C.6 - Example Rate Rider Effects: Small Oilfield Class - RRO Eligible

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge		Small Oilfield Class Consumption Levels Cost per Customer (\$/month)				
		6570 kWh per month Demand 15 kW	Typical 8760 kWh per month Demand 20 kW	10950 kWh per month Demand 25 kW		
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$383.64	\$511.52	\$639.40	
2	Dec 2000 Rate	2000	\$414.19	\$552.25	\$690.31	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$753.67	\$1,000.51	\$1,247.35	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$524.06	\$694.17	\$864.28	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$309.16	\$407.63	\$506.11	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$867.99	\$1,152.74	\$1,437.49	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$508.32	\$654.52	\$814.71	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$611.98	\$811.40	\$1,010.81	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$524.41	\$694.63	\$864.85	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$586.89	\$777.94	\$968.98	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$567.49	\$747.44	\$927.40	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$490.48	\$651.88	\$813.29	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$490.48	\$651.88	\$813.29	
		Row 12 + Row 13				
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$254.76	\$332.19	\$409.61	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$6.57	-\$8.76	-\$10.95	
17	Net DT Charges	Jan 1, 2006	\$248.19	\$323.43	\$398.66	
		Row 15 + Row 16				
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$738.67	\$975.31	\$1,211.95	
		Row 14 + Row 17				
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$490.48	\$651.88	\$813.29	
20	+/- RRO Deferral	Aug 1, 2006	-\$71.22	-\$94.96	-\$118.70	
21	2006 Energy Related Charge	Aug 1, 2006	\$419.26	\$556.92	\$694.59	
		Row 19 + Row 20				
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$247.37	\$322.64	\$397.90	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$40.73	-\$54.31	-\$67.89	
24	Net DT Charges	Aug 1, 2006	\$206.64	\$268.33	\$330.01	
		Row 22 + Row 23				
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$625.90	\$825.25	\$1,024.60	
		Row 21 + Row 24				
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$214.90 -41%	-\$286.54 -41%	-\$358.17 -41%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$558.83 181%	\$745.11 183%	\$931.39 184%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$359.67 -41%	-\$498.23 -43%	-\$622.78 -43%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$103.67 20%	\$156.88 24%	\$196.10 24%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$87.58 -14%	-\$116.77 -14%	-\$145.96 -14%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$43.09 8%	\$52.82 8%	\$62.55 7%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference %	-\$19.40 -3%	-\$30.49 -4%	-\$41.59 -4%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference %	\$171.18 23%	\$227.86 23%	\$284.55 23%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference %	-\$112.77 -18%	-\$150.06 -18%	-\$187.35 -18%

Schedule C.7 - Example Rate Rider Effects: Small Oilfield Class - Not RRO Eligible

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Small Oilfield Class Consumption Levels Cost per Customer (\$/month)			
			6570 kWh per month Demand 15 kW	Typical 8760 kWh per month Demand 20 kW	10950 kWh per month Demand 25 kW	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$383.64	\$511.52	\$639.40	
2	Dec 2000 Rate	2000	\$414.19	\$552.25	\$690.31	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$753.67	\$1,000.51	\$1,247.35	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$524.06	\$694.17	\$864.28	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$610.79	\$809.80	\$1,008.82	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$867.99	\$1,152.74	\$1,437.49	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$525.13	\$695.60	\$866.06	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$611.98	\$811.40	\$1,010.81	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$524.41	\$694.63	\$864.85	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$586.89	\$777.94	\$968.98	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$728.19	\$961.71	\$1,195.24	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$490.48	\$651.88	\$813.29	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$490.48	\$651.88	\$813.29	
			Row 12 + Row 13			
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$254.76	\$332.19	\$409.61	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$6.57	-\$8.76	-\$10.95	
17	Net DT Charges	Jan 1, 2006	\$248.19	\$323.43	\$398.66	
			Row 15 + Row 16			
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$738.67	\$975.31	\$1,211.95	
			Row 14 + Row 17			
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$490.48	\$651.88	\$813.29	
20	+/- RRO Deferral	Aug 1, 2006	\$0.00	\$0.00	\$0.00	
21	2006 Energy Related Charge	Aug 1, 2006	\$490.48	\$651.88	\$813.29	
			Row 19 + Row 20			
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$247.37	\$322.64	\$397.90	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$40.73	-\$54.31	-\$67.89	
24	Net DT Charges	Aug 1, 2006	\$206.64	\$268.33	\$330.01	
			Row 22 + Row 23			
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$697.12	\$920.21	\$1,143.30	
			Row 21 + Row 24			
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference	\$86.72	\$115.63	\$144.54
			%	17%	17%	17%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference	\$257.20	\$342.94	\$428.67
			%	42%	42%	42%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference	-\$342.86	-\$457.14	-\$571.43
			%	-39%	-40%	-40%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference	\$86.85	\$115.80	\$144.75
			%	17%	17%	17%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference	-\$87.58	-\$116.77	-\$145.96
			%	-14%	-14%	-14%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference	\$203.79	\$267.09	\$330.39
			%	39%	38%	38%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference	\$141.31	\$183.78	\$226.25
			%	24%	24%	23%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference	\$10.48	\$13.60	\$16.71
			%	1%	1%	1%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference	-\$41.55	-\$55.10	-\$68.65
			%	-6%	-6%	-6%

Schedule C.8 - Example Rate Rider Effects: REA Farm Service Class (Pooled) - RRO Eligible GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			REA Farm Service Class Consumption Levels Cost per Customer (\$/month)			
			Typical			
			755 kWh per month 7.5 kVA	1255 kWh per month 7.5 kVA	1755 kWh per month 7.5 kVA	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$62.68	\$87.81	\$112.94	
2	Dec 2000 Rate	2000	\$58.50	\$78.26	\$98.01	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$59.88	\$105.41	\$150.94	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$72.60	\$99.25	\$125.90	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$74.85	\$102.99	\$131.13	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$77.04	\$106.63	\$136.22	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$79.56	\$110.82	\$142.08	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$85.06	\$119.96	\$154.87	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$76.62	\$105.93	\$135.24	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$80.59	\$112.53	\$144.47	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$103.05	\$146.44	\$189.82	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$61.91	\$98.76	\$135.61	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$61.91	\$98.76	\$135.61	
			Row 12 + Row 13			
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$45.19	\$47.59	\$49.99	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$0.76	-\$1.26	-\$1.76	
17	Net DT Charges	Jan 1, 2006	\$44.44	\$46.34	\$48.24	
			Row 15 + Row 16			
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$106.35	\$145.10	\$183.85	
			Row 14 + Row 17			
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$61.91	\$98.76	\$135.61	
20	+/- RRO Deferral	Aug 1, 2006	\$3.20	\$5.32	\$7.44	
21	2006 Energy Related Charge	Aug 1, 2006	\$65.11	\$104.08	\$143.05	
			Row 19 + Row 20			
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$44.08	\$46.49	\$48.91	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$2.82	-\$4.69	-\$6.56	
24	Net DT Charges	Aug 1, 2006	\$41.25	\$41.80	\$42.35	
			Row 22 + Row 23			
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$106.37	\$145.89	\$185.40	
			Row 21 + Row 24			
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	\$2.25 3%	\$3.74 4%	\$5.23 4%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$2.19 3%	\$3.64 4%	\$5.09 4%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	\$2.52 3%	\$4.19 4%	\$5.86 4%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$5.50 7%	\$9.14 8%	\$12.79 9%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$8.44 -10%	-\$14.04 -12%	-\$19.63 -13%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$26.43 35%	\$40.51 38%	\$54.59 40%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference %	\$22.46 28%	\$33.91 30%	\$45.35 31%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference %	\$3.30 3%	-\$1.33 -1%	-\$5.97 -3%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference %	\$0.02 0%	\$0.78 1%	\$1.55 1%

Schedule C.9 - Example Rate Rider Effects: Farm Service Class - RRO Eligible

GST not included

Row		Rate Component	Effective Date	Farm Service Class Consumption Levels Cost per Customer (\$/month)		
				Typical		
				755 kWh per month 7.5 kVA	1255 kWh per month 7.5 kVA	1755 kWh per month 7.5 kVA
1	Dec. 1999 Rate	1999	\$83.32	\$108.45	\$133.57	
2	Dec 2000 Rate	2000	\$96.04	\$123.84	\$151.65	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$62.35	\$101.33	\$140.30	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$88.06	\$116.31	\$144.56	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$84.23	\$109.94	\$135.65	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$92.74	\$124.09	\$155.44	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$95.02	\$127.88	\$160.74	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$100.52	\$137.03	\$173.53	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$89.69	\$119.02	\$148.35	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$96.05	\$129.59	\$163.13	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$121.66	\$169.85	\$218.03	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$61.91	\$99.76	\$137.61	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$61.91	\$99.76	\$137.61	
		Row 12 + Row 13				
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$62.56	\$67.51	\$72.46	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$0.76	-\$1.26	-\$1.76	
17	Net DT Charges	Jan 1, 2006	\$61.80	\$66.25	\$70.70	
		Row 15 + Row 16				
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$123.71	\$166.01	\$208.31	
		Row 14 + Row 17				
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$61.91	\$98.76	\$135.61	
20	+/- RRO Deferral	Aug 1, 2006	\$3.20	\$5.32	\$7.44	
21	2006 Energy Related Charge	Aug 1, 2006	\$65.11	\$104.08	\$143.05	
		Row 19 + Row 20				
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$60.79	\$65.66	\$70.54	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$4.45	-\$7.40	-\$10.35	
24	Net DT Charges	Aug 1, 2006	\$56.34	\$58.26	\$60.18	
		Row 22 + Row 23				
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$121.45	\$162.34	\$203.24	
		Row 21 + Row 24				
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference	-\$3.84	-\$6.38	-\$8.92
			%	-4%	-5%	-6%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference	\$8.52	\$14.16	\$19.80
			%	10%	13%	15%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference	\$2.28	\$3.79	\$5.30
			%	2%	3%	3%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference	\$5.50	\$9.14	\$12.79
			%	6%	7%	8%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference	-\$10.83	-\$18.00	-\$25.18
			%	-11%	-13%	-15%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference	\$31.97	\$50.83	\$69.68
			%	36%	43%	47%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference	\$25.61	\$40.26	\$54.91
			%	27%	31%	34%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference	\$2.05	-\$3.83	-\$9.72
			%	2%	-2%	-5%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference	-\$2.26	-\$3.67	-\$5.08
			%	-2%	-2%	-2%

Schedule C.10 - Example Rate Rider Effects: Street Light Service Class D61 Option A GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Street Light Service Class Consumption Levels Cost per Customer (\$/month)			
			1 Fixture Demand 100 watts	1 Fixture Demand 250 watts	1 Fixture Demand 400 watts	
Row	Rate Component	Effective Date	Typical			
1	Dec. 1999 Rate	1999	\$9.29	\$13.97	\$18.64	
2	Dec 2000 Rate	2000	\$11.36	\$16.22	\$21.08	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$9.25	\$14.52	\$19.71	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$8.24	\$11.54	\$14.79	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$6.48	\$7.11	\$7.74	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$10.32	\$16.77	\$23.11	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$9.46	\$14.59	\$19.65	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$8.70	\$12.70	\$16.63	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$7.20	\$8.91	\$10.60	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$8.20	\$11.42	\$14.60	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$12.33	\$15.68	\$18.99	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$5.92	\$9.02	\$12.06	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$5.92	\$9.02	\$12.06	
	Row 12 + Row 13					
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$7.55	\$9.03	\$10.52	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$0.04	-\$0.09	-\$0.14	
17	Net DT Charges	Jan 1, 2006	\$7.51	\$8.95	\$10.38	
	Row 15 + Row 16					
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$13.43	\$17.96	\$22.44	
	Row 14 + Row 17					
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$5.92	\$9.02	\$12.06	
20	+/- RRO Deferral	Aug 1, 2006	\$2.75	\$6.92	\$11.01	
21	2006 Energy Related Charge	Aug 1, 2006	\$8.67	\$15.94	\$23.08	
	Row 19 + Row 20					
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$7.27	\$8.73	\$10.19	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$0.73	-\$1.84	-\$2.92	
24	Net DT Charges	Aug 1, 2006	\$6.54	\$6.89	\$7.27	
	Row 22 + Row 23					
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$15.21	\$22.84	\$30.34	
	Row 21 + Row 24					
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference	-\$1.76	-\$4.43	-\$7.05
			%	-21%	-38%	-48%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference	\$3.84	\$9.66	\$15.37
			%	59%	136%	199%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference	-\$0.87	-\$2.18	-\$3.46
			%	-8%	-13%	-15%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference	-\$0.75	-\$1.90	-\$3.02
			%	-8%	-13%	-15%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference	-\$1.51	-\$3.79	-\$6.03
			%	-17%	-30%	-36%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference	\$5.13	\$6.78	\$8.39
			%	71%	76%	79%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference	\$4.13	\$4.26	\$4.39
			%	50%	37%	30%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference	\$1.10	\$2.28	\$3.45
			%	8%	13%	15%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference	\$1.78	\$4.87	\$7.90
			%	12%	21%	26%

Schedule C.11 - Example Rate Rider Effects: Irrigation Pumping Service

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Irrigation Pumping Service Class Consumption Levels Cost per Customer (\$/month)			
			8760 kWh per month Demand 30 kW	Typical 11680 kWh per month Demand 40 kW	14600 kWh per month Demand 50 kW	
Row	Rate Component	Effective Date				
1	Dec. 1999 Rate	1999	\$1,177.79	\$1,570.39	\$1,962.98	
2	Dec 2000 Rate	2000	\$1,259.73	\$1,679.64	\$2,099.55	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$1,304.55	\$1,732.12	\$2,153.85	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$1,032.82	\$1,369.45	\$1,706.09	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$536.74	\$708.02	\$879.29	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$1,373.40	\$1,823.56	\$2,273.72	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$1,077.41	\$1,428.91	\$1,780.40	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$1,170.21	\$1,552.64	\$1,935.08	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$1,189.94	\$1,578.95	\$1,967.96	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$1,152.44	\$1,528.96	\$1,905.47	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$1,560.10	\$2,070.32	\$2,580.54	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$632.26	\$840.92	\$1,049.59	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$632.26	\$840.92	\$1,049.59	
	Row 12 + Row 13					
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$838.74	\$1,110.09	\$1,381.43	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$8.76	-\$11.68	-\$14.60	
17	Net DT Charges	Jan 1, 2006	\$829.98	\$1,098.41	\$1,366.83	
	Row 15 + Row 16					
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$1,462.24	\$1,939.33	\$2,416.41	
	Row 14 + Row 17					
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$632.26	\$840.92	\$1,049.59	
20	+/- RRO Deferral	Aug 1, 2006	\$133.06	\$177.42	\$221.77	
21	2006 Energy Related Charge	Aug 1, 2006	\$765.32	\$1,018.34	\$1,271.36	
	Row 19 + Row 20					
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$820.52	\$1,086.08	\$1,351.64	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$180.89	-\$241.19	-\$301.49	
24	Net DT Charges	Aug 1, 2006	\$639.63	\$844.89	\$1,050.15	
	Row 22 + Row 23					
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$1,404.95	\$1,863.23	\$2,321.51	
	Row 21 + Row 24					
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$496.08 -48%	-\$661.44 -48%	-\$826.80 -48%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$836.66 156%	\$1,115.55 158%	\$1,394.43 159%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$295.99 -22%	-\$394.66 -22%	-\$493.32 -22%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$92.80 9%	\$123.74 9%	\$154.67 9%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	\$19.73 2%	\$26.30 2%	\$32.88 2%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$370.16 31%	\$491.37 31%	\$612.58 31%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference %	\$407.65 35%	\$541.36 35%	\$675.07 35%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference %	-\$97.86 -7%	-\$130.99 -7%	-\$164.13 -7%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference %	-\$57.29 -4%	-\$76.10 -4%	-\$94.90 -4%

Schedule C.12 - Example Rate Rider Effects: REA Irrigation Pumping Service

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			REA Irrigation Pumping Service Class Consumption Levels Cost per Customer (\$/month)			
Row	Rate Component	Effective Date	Typical			
			8760 kWh per month Demand 30 kW	11680 kWh per month Demand 40 kW	14600 kWh per month Demand 50 kW	
1	Dec. 1999 Rate	1999	\$630.68	\$840.90	\$1,051.13	
2	Dec 2000 Rate	2000	\$843.01	\$1,124.02	\$1,405.02	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$1,039.95	\$1,379.32	\$1,718.69	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$754.12	\$997.85	\$1,241.59	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$650.93	\$860.26	\$1,069.60	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$1,094.70	\$1,451.96	\$1,809.22	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$798.71	\$1,057.31	\$1,315.90	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$891.51	\$1,181.04	\$1,470.58	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$725.09	\$959.15	\$1,193.21	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$873.74	\$1,157.36	\$1,440.97	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$1,207.30	\$1,599.92	\$1,992.54	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$632.26	\$840.92	\$1,049.59	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$632.26	\$840.92	\$1,049.59	
			Row 12 + Row 13			
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$463.17	\$609.33	\$755.48	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$8.76	-\$11.68	-\$14.60	
17	Net DT Charges	Jan 1, 2006	\$454.41	\$597.65	\$740.88	
			Row 15 + Row 16			
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$1,086.67	\$1,438.57	\$1,790.46	
			Row 14 + Row 17			
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$632.26	\$840.92	\$1,049.59	
20	+/- RRO Deferral	Aug 1, 2006	\$133.06	\$177.42	\$221.77	
21	2006 Energy Related Charge	Aug 1, 2006	\$765.32	\$1,018.34	\$1,271.36	
			Row 19 + Row 20			
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$457.47	\$602.01	\$746.56	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$180.89	-\$241.19	-\$301.49	
24	Net DT Charges	Aug 1, 2006	\$276.58	\$360.82	\$445.07	
			Row 22 + Row 23			
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$1,041.90	\$1,379.16	\$1,716.43	
			Row 21 + Row 24			
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	-\$103.19 -14%	-\$137.59 -14%	-\$171.99 -14%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$443.77 68%	\$591.70 69%	\$739.62 69%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$295.99 -27%	-\$394.66 -27%	-\$493.32 -27%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$92.80 12%	\$123.74 12%	\$154.67 12%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$166.42 -19%	-\$221.90 -19%	-\$277.37 -19%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$482.21 67%	\$640.77 67%	\$799.33 67%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference %	\$333.55 38%	\$442.56 38%	\$551.57 38%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference %	-\$120.63 -11%	-\$161.35 -11%	-\$202.08 -11%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference %	-\$44.77 -4%	-\$59.40 -4%	-\$74.04 -4%

Schedule C.13 - Example Rate Rider Effects: Private Lighting Service Class D63 Option A

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Private Street Light Service Class Consumption Levels Cost per Customer (\$/month)			
			Typical			
Row	Rate Component	Effective Date	1 Fixture Demand 100 watts	1 Fixture Demand 250 watts	1 Fixture Demand 400 watts	
1	Dec. 1999 Rate	1999	\$8.36	\$12.59	\$16.82	
2	Dec 2000 Rate	2000	\$9.95	\$14.17	\$18.36	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$11.87	\$17.59	\$23.23	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$10.99	\$14.75	\$18.47	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$9.16	\$10.14	\$11.13	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$13.06	\$19.95	\$26.73	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$11.14	\$17.43	\$22.73	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$11.45	\$15.91	\$20.31	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$10.20	\$12.75	\$15.28	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kWh)	May 1, 2004	\$10.95	\$14.64	\$18.28	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$15.15	\$18.18	\$21.17	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$5.92	\$9.02	\$12.06	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$5.92	\$9.02	\$12.06	
	Row 12 + Row 13					
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$10.81	\$12.38	\$13.96	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$0.04	-\$0.09	-\$0.14	
17	Net DT Charges	Jan 1, 2006	\$10.77	\$12.29	\$13.82	
	Row 15 + Row 16					
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$16.69	\$21.31	\$25.88	
	Row 14 + Row 17					
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$5.92	\$9.02	\$12.06	
20	+/- RRO Deferral	Aug 1, 2006	\$2.75	\$6.92	\$11.01	
21	2006 Energy Related Charge	Aug 1, 2006	\$8.67	\$15.94	\$23.08	
	Row 19 + Row 20					
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$10.40	\$11.96	\$13.52	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$0.76	-\$1.90	-\$3.02	
24	Net DT Charges	Aug 1, 2006	\$9.65	\$10.06	\$10.50	
	Row 22 + Row 23					
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$18.32	\$26.00	\$33.57	
	Row 21 + Row 24					
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference	-\$1.84	-\$4.61	-\$7.34
			%	-17%	-31%	-40%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference	\$3.90	\$9.81	\$15.60
			%	43%	97%	140%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference	-\$1.92	-\$2.52	-\$4.00
			%	-15%	-13%	-15%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference	\$0.31	-\$1.52	-\$2.42
			%	3%	-9%	-11%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference	-\$1.26	-\$3.16	-\$5.03
			%	-11%	-20%	-25%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference	\$4.95	\$6.43	\$5.89
			%	49%	43%	39%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference	\$4.20	\$3.54	\$2.89
			%	38%	24%	16%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference	\$1.54	\$3.13	\$4.70
			%	9%	15%	18%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference	\$1.63	\$4.69	\$7.69
			%	9%	18%	23%

Schedule C.14 - Example Rate Rider Effects: Large General Service Transmission - Not RRO Eligible		GST not included				
Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge		Large General Service Class Consumption Levels Cost per Customer (\$/month)				
Row	Rate Component	Effective Date	766,500 kWh per month Demand 1500 kW	Typical 1,022,000 kWh per month Demand 2000 kW	1,277,500 kWh per month Demand 2500 kW	
1	Dec. 1999 Rate	1999	\$35,949.31	\$47,650.58	\$57,765.87	
2	Dec 2000 Rate	2000	\$32,091.08	\$42,297.53	\$52,503.99	
3	New Combined Rate (AB Government Rebate Included), July 1 - Dec. 31, 2001	July 1 - Dec. 31, 2001	\$72,399.66	\$95,872.26	\$119,344.87	
4	Combined Rate, Jan. 1, 2002	Jan. 1, 2002	\$46,665.94	\$61,525.64	\$76,385.34	
5	Combined Rate, July 1, 2002	Jul 1, 2002	\$55,174.09	\$72,869.84	\$90,565.59	
6	Combined Rate, January 1, 2003	Jan 1, 2003	\$87,779.47	\$116,343.68	\$144,907.89	
7	Predicted Combined Rate, December 1, 2003	Dec 1, 2003	\$46,677.44	\$61,540.97	\$76,404.50	
8	Predicted Combined Rate, January 1, 2004	Jan 1, 2004	\$57,682.08	\$76,213.82	\$94,745.57	
9	Predicted Combined Rate, May 1, 2004	May 1, 2004	\$47,832.55	\$68,477.28	\$85,074.90	
10	Predicted Combined Rate, June 1, 2004 (Rider G set to \$0/kW.h)	May 1, 2004	\$54,018.21	\$71,328.66	\$88,639.12	
11	Predicted Combined Rate, August 1, 2005	Aug 1, 2005	\$55,866.37	\$71,040.82	\$88,799.87	
January 1, 2006						
12	Forecast Energy Rates, Jan 1, 2006	Jan 1, 2006	\$54,173.18	\$72,229.36	\$90,285.55	
13	+No RRO Deferral	Jan 1, 2006	\$0.00	\$0.00	\$0.00	
14	2006 Energy Related Charge	Jan 1, 2006	\$54,173.18	\$72,229.36	\$90,285.55	
		Row 12 + Row 13				
15	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I filed)	Jan 1, 2006	\$26,789.80	\$25,428.39	\$26,624.99	
16	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Jan 1, 2006	-\$766.50	-\$1,022.00	-\$1,277.50	
17	Net DT Charges	Jan 1, 2006	\$26,023.30	\$24,406.39	\$25,347.49	
		Row 15 + Row 16				
18	Predicted Combined Rate, January 1, 2006	Jan 1, 2006	\$80,196.47	\$96,635.75	\$115,633.04	
		Row 14 + Row 17				
August 1, 2006						
19	Forecast Energy Rates, Aug 1, 2006	Aug 1, 2006	\$54,173.18	\$72,229.36	\$90,285.55	
20	+/- RRO Deferral	Aug 1, 2006	\$0.00	\$0.00	\$0.00	
21	2006 Energy Related Charge	Aug 1, 2006	\$54,173.18	\$72,229.36	\$90,285.55	
		Row 19 + Row 20				
22	AE Interim DT Base Rates (Scaled 2004 Final Rates-Phase I Compliance filing)	Aug 1, 2006	\$26,789.80	\$29,265.39	\$31,740.99	
23	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment) - New Refund Rider (Balancing Pool Refund Rider of \$0.001/kWh)	Aug 1, 2006	-\$866.15	-\$1,154.86	-\$1,443.58	
24	Net DT Charges	Aug 1, 2006	\$25,923.65	\$28,110.53	\$30,297.42	
		Row 22 + Row 23				
25	Predicted Combined Rate, August 1, 2006	Aug 1, 2006	\$80,096.83	\$100,339.89	\$120,582.96	
		Row 21 + Row 24				
Comparisons						
	Combined Rate (Jan 2002- Jul 2002)	Row 5 vs Row 4	difference %	\$8,508.15 18%	\$11,344.20 18%	\$14,180.25 19%
	Combined Rate (Jul 2002- Jan 2003)	Row 6 vs Row 5	difference %	\$32,605.38 59%	\$43,473.84 60%	\$54,342.30 60%
	Combined Rate (Jan 2003- Dec 2003)	Row 7 vs Row 6	difference %	-\$41,102.03 -47%	-\$54,802.71 -47%	-\$68,503.38 -47%
	Combined Rate (Dec 2003- Jan 2004)	Row 8 vs Row 7	difference %	\$11,004.64 24%	\$14,672.85 24%	\$18,341.07 24%
	Combined Rate (Jan 2004- May 2004)	Row 9 vs Row 8	difference %	-\$9,849.53 -17%	-\$7,736.54 -10%	-\$9,670.68 -10%
	Combined Rate (May 2004- Aug 2005)	Row 17 vs Row 9	difference %	\$8,033.82 17%	\$2,563.54 4%	\$3,724.98 4%
	Combined Rate (Jun 2005- Aug 2005)	Row 11 vs Row 10	difference %	\$1,848.16 3%	-\$287.84 0%	\$160.75 0%
	Combined Rate (Aug 2005- Jan 2006)	Row 18 vs Row 11	difference %	\$24,330.10 30%	\$25,594.93 26%	\$26,833.17 23%
	Combined Rate (Jan 2006- Aug 2006)	Row 25 vs Row 18	difference %	-\$99.64 0%	\$3,704.14 4%	\$4,949.93 4%

ATCO ELECTRIC
2006 Interim Rate Application
Energy Rates Used in Schedules C.1 to C.14

	Admin. Charges		Cost of Energy (\$ / kWh)
	Fixed (\$ / Month)	Variable (\$ / kWh)	
D11	6.18	0.00031	0.07475
D21	6.27	0.00031	0.07442
D31	4.62	0.00031	0.07036
T31	4.62	0.00031	0.07036
D41	6.27	0.00031	0.07087
D51	6.27	0.00031	0.07339
D56	6.27	0.00031	0.07339
D25	6.27	0.00031	0.07115
D61	3.87	0.00031	0.05821
D63	3.87	0.00031	0.05821
D26	6.27	0.00031	0.07115

Rates used are the RRO Rates as posted on Direct Energy Regulated Services website (Oct. 5/2005)
These rates are used for the August 1, 2005, January 1, 2006 and August 1, 2006 scenarios.

PRICE SCHEDULE INDEX**RESIDENTIAL SERVICE**

Standard Residential Service Price Schedule D11

SMALL GENERAL SERVICE

Standard Small General Service Price Schedule D21

Small General Service - Energy Only Price Schedule D22

Small General Service - Isolated Industrial Areas - Distribution Connected Price Schedule D24

Irrigation Pumping Service Price Schedule D25

REA Irrigation Pumping Service Price Schedule D26

LARGE GENERAL SERVICE/INDUSTRIAL

Large General Service/Industrial - Distribution Connected Price Schedule D31

Large General Service/Industrial - Transmission Connected Price Schedule T31

Generator Interconnection and Standby Power - Distribution Connected Price Schedule D32

Transmission Opportunity Rate - Distribution Connected Price Schedule D33

Transmission Opportunity Rate - Transmission Connected Price Schedule T33

Large General Service/Industrial - Isolated Industrial Areas - Distribution Connected Price Schedule D34

OILFIELD

Small Oilfield and Pumping Power Price Schedule D41

Small Oilfield and Pumping Power - Isolated Industrial Areas - Distribution Connected Price Schedule D44

FARM SERVICE

REA Farm Service Price Schedule D51

REA Farm Service - Excluding Wires Service Provider Functions Price Schedule D52

Farm Service Price Schedule D56

LIGHTING SERVICE

Street Lighting Service Price Schedule D61

Private Lighting Service Price Schedule D63

PRICE OPTIONS

Idle Service Option F

Service for Non-Standard Transformation and Metering Configurations Option H

REA Distribution Price Credit Option P

PRICING ADJUSTMENTS (RIDERS)

Municipal Assessment Rider A-1

Balancing Pool Adjustment Rider B

Special Facilities Charge Rider E

Temporary Adjustment Rider G

Interim Adjustment Rider J

Interim RRT Adjustment Rider Q

Availability

- For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company.
- For single-phase service at secondary voltage through a single meter.
- For normal use by a single and separate household.
- Not applicable to any commercial or industrial use.

Price

The charge for service in any one billing month is the sum of the Customer Charge and Energy Charge, determined for each individual Point of Service.

	Customer Charge	Energy Charge
Transmission	-	1.62 ¢ / kW.h
Distribution	35.78 ¢ / day	3.64 ¢ / kW.h
Service	30.97 ¢ / day	-
TOTAL PRICE	66.75 ¢ / day	5.26 ¢ / kW.h

The minimum monthly charge is the Customer Charge.

Application

1. **Price Option** - the following price option may apply:
Idle Service (Option F)
2. **Price Adjustments** - the following price adjustments (riders) may apply:
Municipal Assessment (Rider A-1)
Balancing Pool Adjustment (Rider B)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
Interim RRT Adjustment (Rider Q)

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, with single or three-phase electric service at secondary voltage. Not applicable for any service in excess of 500 kW.

Price

Charges for service in any one billing month shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

	Customer Charge	Demand Charge	Energy Charge	
			For the first 200 kW.h per kW of billing demand	For energy in excess of 200 kW.h per kW of billing demand
Transmission	-	7.00 ¢/kW/day	0.48 ¢ / kW.h	0.48 ¢ / kW.h
Distribution	-	12.96 ¢/kW/day	2.18 ¢ / kW.h	-
Service	44.97 ¢ / day	-	-	-
TOTAL PRICE	44.97 ¢ / day	19.96 ¢/kW/day	2.66 ¢ / kW.h	0.48 ¢ / kW.h

The billing demand may be estimated or measured and will be the greater of the following:

- (a) the highest metered demand during the billing period;
- (b) 85% of the difference between the highest metered demand in the twelve month period including and ending with the billing period and 150 kW, if this is greater than zero;
- (c) the estimated demand;
- (d) the contract demand;
- (e) 5 kilowatts.

The minimum monthly bill is the sum of the Service Charge and the total Demand Charge.

Application

1. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.
2. **Price Options** - the following price options may apply:
 Idle Service (Option F)
 Service for Non-Standard Transformation and Metering Configurations (Option H)
 REA Distribution Price Credit (Option P)
3. **Price Adjustments** - the following price adjustments (riders) may apply:
 Municipal Assessment (Rider A-1)
 Balancing Pool Adjustment (Rider B)
 Temporary Adjustment (Rider G)
 Interim Adjustment (Rider J)
 Interim RRT Adjustment (Rider Q)

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, with single or three-phase electric service at secondary voltage. Not applicable for any service in excess of 50 kW.

Price

Charges for service in any one billing month shall be the Energy Charge, determined for each individual Point of Service.

	Energy Charge	
	For the first 50 kW.h per kW of billing demand	For energy in excess of 50 kW.h per kW of billing demand
Transmission	0.51 ¢ / kW.h	0.51 ¢ / kW.h
Distribution	14.24 ¢ / kW.h	6.00 ¢ / kW.h
Service	-	-
TOTAL PRICE	14.75 ¢ / kW.h	6.51 ¢ / kW.h

The billing demand may be estimated or measured and will be the greater of the following:

- (a) the highest metered demand during the billing period;
- (b) the estimated demand;
- (c) the contract demand;
- (d) 5 kilowatts.

The minimum annual charge is 12 times the sum of:

- (a) the Service Charge from Price Schedule D21; and
- (b) the Total Demand Charge from Price Schedule D21 multiplied by the higher of the DCD or 5 kW.

Application

1. **Power Factor Correction** - where the power factor at a Point of Service is found to be less than 90%, the Company may require the installation of corrective equipment.
2. **Price Options** - the following price option may apply:
Idle Service (Option F)
Service for Non-Standard Transformation and Metering Configurations (Option H)
3. **Price Adjustments** - the following additional charges (riders) may apply:
Municipal Assessment (Rider A-1)
Balancing Pool Adjustment (Rider B)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
Interim RRT Adjustment (Rider Q)

Availability

For Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company distribution connected from an isolated industrial areas. Not applicable for any service in excess of 500 kW.

Price

Charges for service in any one billing month shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

	Customer Charge	Demand Charge	Energy Charge	
			For the first 200 kW.h per kW of billing demand	For energy in excess of 200 kW.h per kW of billing demand
Distribution	-	12.96 ¢/kW/day	2.18 ¢ / kW.h	-
Service	44.97 ¢ / day	-	-	-
TOTAL PRICE	44.97 ¢ / day	12.96 ¢/kW/day	2.18 ¢ / kW.h	-

The billing demand may be estimated or measured and will be the greater of the following:

- (a) the highest metered demand during the billing period;
- (b) 85% of the difference between the highest metered demand in the twelve month period including and ending with the billing period and 150 kW, if this is greater than zero;
- (c) the estimated demand;
- (d) the contract demand;
- (e) 5 kilowatts.

The minimum monthly bill is the sum of the Service Charge and the total Demand Charge.

Application

1. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.
2. **Price Options** - the following price options may apply:
 Idle Service (Option F)
 Service for Non-Standard Transformation and Metering Configurations (Option H)
 REA Distribution Price Credit (Option P)
3. **Price Adjustments** - the following price adjustments (riders) may apply:
 Municipal Assessment (Rider A-1)
 Temporary Adjustment (Rider G)
 Interim Adjustment (Rider J)

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, between April 1 and October 31 for seasonal irrigation pumping loads. Not applicable for any service in excess of 150 kW.

Price

Charges for service in any one billing month during one Season shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	3.45 ¢/kW/day	0.52 ¢ / kW.h
Distribution	-	8.25 ¢/kW/day	-
Service	11.14 ¢ / day	-	-
TOTAL PRICE	11.14 ¢ / day	11.70 ¢/kW/day	0.52 ¢ / kW.h

The billing demand may be estimated or measured and will be the greater of the following:

- (a) the highest metered demand during the billing period;
- (b) the estimated demand;
- (c) the contract demand;
- (d) 5 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

Application

1. **Billing** - the minimum charge for the month during the season shall be the Service Charge and the Demand Charge. Previously, charges for service for one Season was the sum of the Service Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service, where one Season is defined as the period from April 1 to October 31. Due to monthly billing, rates for the Customer Charge and Demand Charge are one-seventh the season charge.
2. **Idle Service** - in the event the service remains idle for two consecutive seasons, the Company may remove its facilities, unless the Customer pays the minimum charge for the upcoming season prior to December 31, of the preceding year.
3. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.
4. **Price Adjustments** - the following price adjustments (riders) may apply:
 - Balancing Pool Adjustment (Rider B)
 - Temporary Adjustment (Rider G)
 - Interim Adjustment (Rider J)
 - Interim RRT Adjustment (Rider Q)

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, between April 1 and October 31 for seasonal irrigation pumping loads of Rural Electrification Association Customers and individual co-operative and colony farms with their own distribution systems. Not applicable for any service in excess of 150 kW.

Price

Charges for service in any one billing month during one Season shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

Customers in the REA O & M Pool

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	3.45 ¢/kW/day	0.52 ¢ / kW.h
Distribution	-	2.59 ¢/kW/day	-
Service	11.14 ¢ / day	-	-
TOTAL PRICE	11.14 ¢ / day	6.04 ¢/kW/day	0.52 ¢ / kW.h

Customers outside of the REA O & M Pool

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	3.45 ¢/kW/day	0.52 ¢ / kW.h
Distribution	-	-	-
Service	11.14 ¢ / day	-	-
TOTAL PRICE	11.14 ¢ / day	3.45 ¢/kW/day	0.52 ¢ / kW.h

The billing demand may be estimated or measured and will be the greater of the following:

- (a) the highest metered demand during the billing period;
- (b) the estimated demand;
- (c) the contract demand;
- (d) 5 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

REA Specific Charges:

Other charges are applied on behalf of the REAs as defined in contracts and are subject to change from time to time.

These charges include operation and maintenance charges and deposit reserve charges, and are in addition to the charges contained in this price schedule.

The minimum charge for the season shall be 7 times the Service Charge and 7 times the Demand Charge.

Application

1. **Billing** - the minimum charge for the month during the season shall be the Service Charge and the Demand Charge. Previously, charges for service for one Season was the sum of the Service Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service, where one Season is defined as the period from April 1 to October 31. Due to monthly billing, rates for the Customer Charge and Demand Charge are one-seventh the season charge.
2. **Idle Service** - in the event the service remains idle for two consecutive seasons, the Company may remove its facilities, unless the Customer pays the minimum charge for the upcoming season prior to December 31, of the preceding year.
3. **Power Factor Correction** - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.
4. **Price Adjustments** - the following price adjustments (riders) may apply:
 - Balancing Pool Adjustment (Rider B)
 - Temporary Adjustment (Rider G)
 - Interim Adjustment (Rider J)
 - Interim RRT Adjustment (Rider Q)

Availability

- For System Access Service and Distribution Access Service, single or three-phase distribution connected, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System.
- For distribution connected loads greater than 500 kW, the Point of Service must be equipped with interval data metering.

Price

Charges for service in any one billing month shall be the sum of the Customer Charge, Demand Charge, Energy Charge and Charge for Deficient Power Factor, determined for each individual Point of Service:

	Customer Charge	Demand Charge		Energy Charge
		For the first 500 kW of billing demand	For all billing demand over 500 kW	
Transmission	-	9.33 ¢/kW/day	10.82 ¢/kW/day	0.48 ¢ / kW.h
Distribution	-	15.21 ¢/kW/day	7.61 ¢/kW/day	-
Service	\$1.2983 / day	-	1.11 ¢/kW/day	-
TOTAL PRICE	\$1.2983 / day	24.54 ¢/kW/day	19.54 ¢/kW/day	0.48 ¢ / kW.h

The billing demand for the Distribution and Service charges shall be the higher of:

- (a) The highest metered demand during the billing period (including any demand delivered and billed under Price Schedules D32 and D33);
- (b) 85% of the highest metered demand (including any demand delivered and billed under Price Schedules D32 and D33) in the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Distribution Contract Demand (DCD);
- (e) 50 kilowatts.

The billing demand for the Transmission charges shall be the higher of:

- (a) The highest metered demand during the billing period (excluding any demand delivered and billed under Price Schedules D32 and D33);
- (b) 85% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D32 and D33) in the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Transmission Contract Demand (TCD);

- (e) if any of the above are equal to or greater than 1000 kW, 80% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D32 and D33) in the period which is the shorter of:
- i. the 36-month period including and ending with the current billing period; or
 - ii. the period commencing with the first billing period in the year 2000, and ending with the current billing period.
- (f) 50 kilowatts.

If energy is also taken under Transmission Opportunity Rate (Price Schedule D33), during the billing period, the billing demand will be the Price Schedule D31 **Base Demand** as specified under the corresponding agreement.

For non-demand metered services, demand will be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

Charge for Deficient Power Factor - For customer power factor which is less than 90%, an additional charge for deficient power factor of 29.59 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. **Price Options** - the following price options may apply:
Idle Service (Option F)
Service for Non-Standard Transformation and Metering Configurations (Option H)
REA Distribution Price Credit (Option P)
2. **Price Adjustments** - the following price adjustments (riders) may apply:
Municipal Assessment (Rider A-1)
Balancing Pool Adjustment (Rider B)
Special Facilities Charge (Rider E)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
Interim RRT Adjustment (Rider Q)

Availability

- For System Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System, that are directly connected to a transmission substation, and do not make any use of distribution facilities owned by ATCO Electric.
- The Point of Service must be equipped with interval data metering.

Price

Charges for service in any one billing month shall be the sum of the Demand Charge, Energy Charge and charge for deficient power factor, determined for each individual Point of Service.

	Demand Charge		Energy Charge
	For the first 500 kW of billing demand	For all billing demand over 500 kW	
Transmission	Current AESO DTS Rate Schedule less under frequency load shedding credit	Current AESO DTS Rate Schedule less under frequency load shedding credit	Charges per current AESO DTS Rate Schedule
Distribution	2.02 ¢/kW/day	-	-
Service	2.49 ¢/kW/day	-	-
TOTAL PRICE	4.51 ¢/kW/day + Current AESO DTS Rate Schedule less under frequency load shedding credit	Current AESO DTS Rate Schedule less under frequency load shedding credit	

The billing demand for the Distribution and Service charges shall be the higher of:

- (a) The highest metered demand during the billing period (including any contract opportunity demand delivered and billed under Price Schedule T33);
- (b) 85% of the highest metered demand (including any contract opportunity demand delivered and billed under Price Schedule T33) in the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) 50 kilowatts.

The billing demand for the Transmission charge shall be the higher of:

- (a) The billing demand charged to ATCO Electric by AESO at a Point of Delivery, that is attributable to the customer at that Point of Delivery;
- (b) the highest metered demand during the billing period;
- (c) the ratchet level as set out by the AESO at a Point of Delivery,
where (a) through (c) exclude any contracted Opportunity Demand delivered and billed under Price Schedule T33;
- (d) the estimated demand;
- (e) the Transmission Contract Demand (TCD);
- (f) 50 kilowatts

The **'highest metered demand'** is defined for the purposes of this price schedule, according to the current approved AESO DTS Rate Schedule.

If energy is also taken under Transmission Opportunity Rate (Price Schedule T33), during the billing period, the billing demand will be the Price Schedule T31 **Base Demand** as specified under the corresponding agreement.

Charge for Deficient Power Factor – Power Factor Charges according to the current approved AESO DTS Rate Schedule will apply.

Application

1. **Price Options** - the following price option may apply:
Service for Non-Standard Transformation and Metering Configurations (Option H)

2. **Price Adjustments** - the following price adjustments (riders) may apply:
Municipal Assessment (Rider A-1)
Balancing Pool Adjustment (Rider B)
Special Facilities Charge (Rider E)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)

Availability

- For Points of Service served by the Company from the Alberta Interconnected System, with on-site generating equipment connected to the distribution system, which may be used to supply load at the same site.
- To provide standby power to the on-site load in the event of a forced outage or derate of on-site generating equipment, to provide power for generator startup, and to provide supplemental power if the on-site demand requirements exceed the generator capacity.
- To provide credits to Generators for reduced DTS charges from AESO.
- To charge Generators if the Point of Delivery attracts STS charges from AESO.
- For interconnection of the generator to the distribution system.
- The Point of Service must be equipped with 4-quadrant interval data metering, for both supply and demand, the cost of which will be in addition to the charges under this rate.

Price

Charges for service in any one billing month shall be the sum of the Customer Charges, Demand Charges, Energy Charges, Other Charges, Charge for Deficient Power Factor (determined for each individual Point of Service), and Fixed Charges defined below.

	Customer Charge	Demand Charge		Energy Charge
		For the first 500 kW of billing demand	For all billing demand over 500 kW	
Transmission	-	9.33 ¢/kW/day	10.82 ¢/kW/day	0.48 ¢ / kW.h
Distribution	-	15.21 ¢/kW/day	7.61 ¢/kW/day	-
Service	\$1.2983 / day	-	1.11 ¢/kW/day	-
TOTAL PRICE	\$1.2983 / day	24.54 ¢/kW/day	19.54 ¢/kW/day	0.48 ¢ / kW.h

The billing demand for the Distribution and Service charges shall be the higher of:

- (a) The highest metered demand during the billing period (including any demand delivered and billed under Price Schedule D33);
- (b) 85% of the highest metered demand (including any demand delivered and billed under Price Schedule D33) in the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Distribution Contract Demand (DCD).

The billing demand for the Transmission charges shall be the higher of:

- (a) The highest metered demand during the billing period (excluding any demand delivered and billed under Price Schedule D33);
- (b) 85% of the highest metered demand (excluding any demand delivered and billed under Price Schedule D33) in the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Transmission Contract Demand (TCD);
- (e) if any of the above are equal to or greater than 1000 kW, 80% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D33) in the period which is the shorter of:
 - i. the 36-month period including and ending with the current billing period; or
 - ii. the period commencing with the first billing period in the year 2000, and ending with the current billing period.

If energy is also taken under Transmission Opportunity Rate (Price Schedule D33), during the billing period, the billing demand will be the Price Schedule D32 **Base Demand** as specified under the corresponding agreement.

For non-demand metered services, demand will be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

Charge for Deficient Power Factor - For customer power factor which is less than 90%, an additional charge for deficient power factor of 29.59 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest billing kW demand in the same billing period, where billing demand is as defined in this price schedule.

If the Company incurs an increase to the Point-of-Delivery (POD) billing demand with AESO as a result of a standby event of the customer (i.e. the new demand at the POD is coincident with an outage of the generator), then an additional charge may apply, equal to the Transmission Demand Charge for Price Schedule T31, multiplied by the incremental POD demand incurred. This charge will apply for the current billing period, and for the next 11 billing periods.

Capital Recovery Charges:

The cost of the Incremental Interconnection Facilities will be determined as set out in Section 9.6 of the Terms and Conditions for Distribution Service Connections. The total amount will be collected from the customer in accordance with Section 9.8 of the Terms and Conditions for Distribution Service Connections. A contract will be arranged between the customer and the Company, specifying the contract term and the monthly amount, which will be calculated using the Company's Rate of Return, Income Tax and Depreciation in effect at the commencement of the contract term.

The Generating customer will be required to pay all replacement costs for incremental facilities as per Section 9.6 of the Terms and Conditions for Distribution Service Connections.

Incremental Operations and Maintenance Charges:

The minimum monthly incremental Operations and Maintenance charge will be:

(0.0128% X Incremental Interconnection Cost) per day

The Generating customer will be required to pay for switching or isolation as per Section 9.6 of the Terms and Conditions.

Incremental Administration and General Charges:

The minimum monthly incremental Administration and General charge will be:

(0.00422% X Incremental Interconnection Cost) per day

Generator Credits for reduction in Billing Determinants at the Point of Delivery:

Credit = DTS * (A – B) Where:

A = Monthly Gross Billing Determinants at the POD to which the generator is connected (which will be determined by adding the interval output data metered at the generator to the net interval data metered at the POD).

B = Monthly Net Billing determinants at the POD to which the generator is connected.

DTS = The charges as per AESO's effective DTS tariff.

The Company will calculate the generator credits on a calendar quarterly basis after all power production information has been provided to the Company in accordance with Section 9.5.4 of the Terms and Conditions for Distribution Service Connections.

Generator Charges for a Point of Delivery:

Charge = STS * A Where:

A = Monthly **Net** Supply Billing determinants at the POS to which the generator is connected.

STS = The charges as per AESO's effective STS tariff.

Application

- Price Options** - the following price options may apply:
Idle Service (Option F)
Service for Non-Standard Transformation and Metering Configurations (Option H)
- Price Adjustments** - the following price adjustments (riders) may apply:
Municipal Assessment (Rider A-1)
Balancing Pool Adjustment (Rider B)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
Interim RRT Adjustment (Rider Q)

Availability

- Available only to Points of Service which are eligible as determined by AESO for Demand Opportunity Service, throughout the territory served by the Company from the Alberta Interconnected System for loads greater than 1,000 kW.
- Available only when AESO determines that there is sufficient transmission capacity. Service on this rate is interruptible for transmission system security reasons at AESO's request.
- The Point of Service must be equipped with revenue approved time of use metering. The cost of the time of use metering is in addition to the charges in this rate.
- Telemetry is required for all points of service on this rate with demands greater than 2,500 kW, and any associated costs will be in addition to the charges in this rate.

Price

Charges for service in any one billing month shall be the sum of the following charges determined for each individual Point of Service. The AESO DOS charges will be applied according to the terms of the DOS option selected by the Customer:

	Customer Charges	Demand Charges	Demand Charges	Energy Charges	Energy Charges
		For all kW of Opportunity Contract Demand	For the peak kW above the Opportunity Contract Demand	For all kW.h metered above the Base Demand, not exceeding the Opportunity Contract Demand	For all kW.h metered above the Opportunity Contract Demand
Transmission	Transaction Charge per AESO DOS Rate Schedule	-	Per Price Schedule D32	Per AESO DOS Rate Schedule	Per Price Schedule D32
Distribution	-	15.21 ¢/kW/day	7.61 ¢/kW/day	-	-
Service	\$1.2983 / day	0.00 ¢/kW/day	1.11 ¢/kW/day	-	-
TOTAL PRICE	\$1.2983 / day + AESO DOS Rate	15.21 ¢/kW/day	8.72 ¢/kW/day + D32	Per AESO DOS Rate Schedule	Per Price Schedule D32

The attached form must be completed and submitted to the Company, and serves as an Opportunity Contract which specifies the period and the Opportunity Demand requested by the Customer, as well as the DOS option selected.

The charges according to the AESO DOS Rate Schedule will be the approved charges in effect during the billing period, and will be revised in accordance with AESO's charges as required.

Application

1. **Base Demand** - A Customer qualifying for this rate must establish a Base Demand with the Company on Price Schedule D31 prior to receiving service under this rate (which will be submitted as part of the attached form).
 - (a) For existing Customers, the Price Schedule D31 Base Demand will normally be the maximum billing demand in the 12 most recent billing periods.
 - (b) New Customers qualifying for this rate may select the Large General Service/Industrial D31 Base Demand based on forecast loads and economics, provided the Company agrees that the conditions of applicability are satisfied.
 - (c) Once established, the Price Schedule D31 Base Demand remains fixed for the purposes of billing all future service on this rate.
2. **Applicable Charges** – This rate schedule applies in conjunction with rate D31, in that the first block demand charges apply only to the first 500 kW of the combined demand (i.e. D31 and D33, and D32 should there be an excursion above contracted opportunity demand), and the remainder of the combined demand is subject to the second block demand charges. The Service Customer Charge does not apply again as it has already been applied to the base load on Price Schedule D31.
3. **Options** - A Customer requesting service under this rate must select the provisions of one of AESO's DOS Rate Schedules. The Customer is subject to AESO's minimum Opportunity Service charges, attributable to that customer.
4. **Notice Period** - A Customer requesting service under this rate is required to provide notification as prescribed in the AESO tariff in relation to DOS service.
5. **Load Curtailment** - When a load curtailment directive is given, the load at the point of service must not exceed the Price Schedule D31 Base Demand until the Company gives notification that the interruption period is over, at which time consumption of energy may be resumed.
6. **Non-Compliance Charges** – In the event of a load curtailment directive, if the load served under this rate is not curtailed for the entire interruption period, any charges incurred by the Company will be charged to the Point of Service on this rate.
7. **Price Options** – the following price options may apply:
Service for Non-Standard Transformation and Metering Configurations (Option H)
8. **Price Adjustments** - the following price adjustments may apply:
Municipal Assessment (Rider A-1)
Balancing Pool Adjustment (Rider B)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)

Availability

- For System Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System, that are directly connected to a transmission substation, and do not make any use of distribution facilities owned by ATCO Electric.
- Available only to Points of Service which are eligible as determined by AESO for Demand Opportunity Service, throughout the territory served by the Company from the Alberta Interconnected System for loads greater than 1,000 kW.
- Available only when AESO determines that there is sufficient transmission capacity. Service on this rate is interruptible for transmission system security reasons at AESO's request.
- The point of service must be equipped with revenue approved time of use metering. The cost of the time of use metering is in addition to the charges in this rate.
- Telemetry is required for all points of service on this rate with demands greater than 2,500 kW, and any associated costs will be in addition to the charges in this rate.

Price

Charges for service in any one billing month shall be the sum of the following charges determined for each individual Point of Service. The current approved AESO DOS charges will be those according to the terms of the DOS option selected by the Customer:

	Transaction Charge	Demand Charges	Demand Charges	Energy Charges	Energy Charges
		For all kW of Opportunity Contract Demand	For the peak kW above the Opportunity Contract Demand	For all kW.h metered above the Base Demand, not exceeding the Opportunity Contract Demand	For all kW.h metered above the Opportunity Contract Demand
Transmission	Per AESO DOS Rate Schedule	-	Per Price Schedule T31	Per AESO DOS Rate Schedule	Per Price Schedule T31
Distribution	-	Per Price Schedule T31	Per Price Schedule T31	-	-
Service	-	Per Price Schedule T31	Per Price Schedule T31	-	-
TOTAL PRICE	Per AESO DOS Rate Schedule	Per Price Schedule T31	Per Price Schedule T31	Per AESO DOS Rate Schedule	Per Price Schedule T31

The attached form must be completed and submitted to the Company, and serves as an Opportunity Contract which specifies the period and the Opportunity Demand requested by the Customer, as well as the DOS option selected.

The charges according to the AESO DOS Rate Schedule will be the approved charges in effect during the billing period, and will be revised in accordance with AESO's charges as required.

Application

1. **Base Demand** - A Customer qualifying for this rate must establish a Base Demand with the Company on Price Schedule T31 prior to receiving service under this rate.
 - (a) For existing Customers, the Price Schedule T31 Base Demand will normally be the maximum billing demand in the 12 most recent billing periods.
 - (b) New Customers qualifying for this rate may select the Large General Service/Industrial T31 Base Demand based on forecast loads and economics, provided the Company agrees that the conditions of applicability are satisfied.
 - (c) Once established, the Price Schedule T31 Base Demand remains fixed for the purposes of billing all future service on this rate.
2. **Applicable Charges** - This rate schedule applies in conjunction with rate T31, in that the first block demand charges apply only to the first 500 kW of the combined demand (i.e. T31 and T33, and T31 again should there be an excursion above contracted opportunity demand), and the remainder of the combined demand is subject to the second block demand charges.
3. **Options** - A Customer requesting service under this rate must select the provisions of one of AESO's DOS Rate Schedules. The Customer is subject to AESO's minimum Opportunity Service charges, attributable to that customer.
4. **Notice Period** - A Customer requesting service under this rate is required to provide notification as prescribed in the AESO tariff in relation to DOS service.
5. **Load Curtailment** - When a load curtailment directive is given, the load at the point of service must not exceed the Price Schedule T31 Base Demand until the Company gives notification that the interruption period is over, at which time consumption of energy may be resumed.
6. **Non-Compliance Charges** – In the event of a load curtailment directive, if the load served under this rate is not curtailed for the entire interruption period, any charges incurred by the Company will be charged to the Point of Service on this rate.
7. **Price Options** – the following price option may apply:
Service for Non-Standard Transformation and Metering Configurations (Option H(d))
8. **Price Adjustments** - the following price adjustments may apply:
Municipal Assessment (Rider A-1)
Balancing Pool Adjustment (Rider B)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)



**Price Schedule T33
Transmission Opportunity Rate
Transmission Connected**

This form will be completed and signed by ATCO Electric after a telephone request from a Customer for Transmission Opportunity Service. The form will be faxed to the Customer upon which the Customer will confirm the information with a signature and fax the completed form back to ATCO Electric Control Centre – (780) 632-5959.

Customer Name: <input type="text"/>
Date of Request: <input type="text"/>
Time of Request: <input type="text"/>
1. OPPORTUNITY CONTRACT PERIOD
Start Date: <input type="text"/>
Start Time: <input type="text"/>
End Date: <input type="text"/>
End Time: <input type="text"/>
Number of Hours in Contract Period: <input type="text"/> Hours
2. TRANSMISSION OPPORTUNITY SERVICE OPTION:
AESO "DEMAND OPPORTUNITY SERVICE": DOS 7 Minutes: <input type="text"/>
DOS 1 Hour: <input type="text"/>
DOS Term: <input type="text"/>
3. OPPORTUNITY CONTRACT DEMAND: <input type="text"/> kW
4. BASE DEMAND:
Large General Service/Industrial Price Schedule T31 Base Demand: <input type="text"/> kW
Sum of Demands on all Opportunity Service Contracts: <input type="text"/> kW
Total Base Demand: <input type="text"/> kW

Confirmation: 1) _____ for ATCO Electric
2) _____ for _____

Availability

For Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from an isolated industrial area.

Price

Charges for service in any one billing month shall be the sum of the Customer Charge, Demand Charge, and Charge for Deficient Power Factor, determined for each individual Point of Service.

	Customer Charge	Demand Charge	
		For the first 500 kW of billing demand	For all billing demand over 500 kW
Distribution	-	15.21 ¢/kW/day	7.61 ¢/kW/day
Service	\$1.2983 / day	-	1.11 ¢/kW/day
TOTAL PRICE	\$1.2983 / day	15.21 ¢/kW/day	8.72 ¢/kW/day

The billing demand for the Distribution and Service charges shall be the higher of:

- (a) The highest metered demand during the billing period;
- (b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Distribution Contract Demand (DCD);
- (e) 50 kilowatts.

For non-demand metered services, demand will be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

Charge for Deficient Power Factor - For customer power factor which is less than 90%, an additional charge for deficient power factor of 29.59 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

- 1. **Price Options** - the following price options may apply:
 Idle Service (Option F)
 Service for Non-Standard Transformation and Metering Configurations (Option H)
 REA Distribution Price Credit (Option P)
- 2. **Price Adjustments** - the following price adjustments (riders) may apply:
 Municipal Assessment (Rider A-1)
 Special Facilities Charge (Rider E)
 Temporary Adjustment (Rider G)
 Interim Adjustment (Rider J)

Availability

For System Access Service and Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from the Alberta Interconnected System, for production energy requirements in the petroleum and natural gas industries including related operations, such as rectifiers, cathodic protection and radio transmitters.

Price

Charges for service in any one billing month shall be the sum of the Customer Charges, Demand Charges, Energy Charges and charge for deficient power factor, determined for each individual Point of Service.

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	8.11 ¢/kW/day	0.48 ¢ / kW.h
Distribution	-	35.01 ¢/kW/day	-
Service	71.90 ¢ / day	-	-
TOTAL PRICE	71.90 ¢ / day	43.12 ¢/kW/day	0.48 ¢ / kW.h

The billing demand for the Distribution and Service charges shall be the higher of:

- (a) The highest metered demand during the billing period;
- (b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Distribution Contract Demand (DCD);
- (e) 4 kilowatts.

The billing demand for the Transmission charges shall be the higher of:

- (a) The highest metered demand during the billing period;
- (b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Transmission Contract Demand (TCD);
- (e) 4 kilowatts.

For non-demand metered services, demand will be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

The 85% ratchet applies only to demand metered loads. The cost of converting an energy meter to a demand meter will be in addition to the charges on this rate.

Estimated Demands - Where it is impractical to meter a point of service, the Company may bill on the basis of estimated maximum demands. In such case, the monthly bill shall be the demand charge above applied to the estimated demand, plus a flat rate of \$1.47 per kW in lieu of the charge for energy.

The **Metered demand** will be the greater of the registered demand in kW, or 90% of the registered demand in kV.A where a kW reading is not available.

Charge for Deficient Power Factor - where a Customer's power factor is found to be less than 90%, the Company may require such Customers to install corrective equipment. For Customer power factor which is less than 90%, an additional charge for deficient power factor of 29.59 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. **Demand Metered** - where services are demand metered, the meter will normally be read and reset at least once every two months.
2. **Price Options** - the following price option may apply:
Idle Service (Option F)
3. **Price Adjustments** - the following price adjustments (riders) may apply:
Municipal Assessment (Rider A-1)
Balancing Pool Adjustment (Rider B)
Special Facilities Charge (Rider E)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
Interim RRT Adjustment (Rider Q)

Availability

For Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from an isolated industrial area, for production energy requirements in the petroleum and natural gas industries including related operations, such as rectifiers, cathodic protection and radio transmitters.

Price

Charges for service in any one billing month shall be the sum of the Customer Charges, Demand Charges, and charge for deficient power factor, determined for each individual Point of Service:

	Customer Charge	Demand Charge
Distribution	-	35.01 ¢/kW/day
Service	71.90 ¢ / day	-
TOTAL PRICE	71.90 ¢ / day	35.01 ¢/kW/day

The billing demand shall be the higher of:

- (a) The highest metered demand during the billing period;
- (b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Distribution Contract Demand (DCD);
- (e) 4 kilowatts.

For non-demand metered services, demand will be estimated based on equipment nameplate ratings as **kW Billing Demand = kW Nameplate Rating**, or **kW Billing Demand = HP Nameplate x 0.746**.

The 85% ratchet applies only to demand metered loads. The cost of converting an energy meter to a demand meter will be in addition to the charges on this rate.

Estimated Demands - Where it is impractical to meter a point of service, the Company may bill on the basis of estimated maximum demands. In such case, the monthly bill shall be the demand charge above applied to the estimated demand.

The **Metered demand** will be the greater of the registered demand in kW, or 90% of the registered demand in kV.A where a kW reading is not available.

Charge for Deficient Power Factor - where a Customer's power factor is found to be less than 90%, the Company may require such Customers to install corrective equipment. For Customer power factor which is less than 90%, an additional charge for deficient power factor of 29.59 ¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. **Demand Metered** - where services are demand metered, the meter will normally be read and reset at least once every two months.
2. **Price Options** - the following price options may apply:
Idle Service (Option F)
3. **Price Adjustments** - the following price adjustments (riders) may apply:
Municipal Assessment (Rider A-1)
Special Facilities Charge (Rider E)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)

Availability

For System Access Service and Distribution Access Service, for all Points of Service throughout the territory served by the Company, for farming operations which are connected to a Rural Electrification Association's distribution system.

Price

- Charges for service in any one billing month are the sum of the Customer, Demand and Energy charges as indicated below, determined for each individual Point of Service.
- Please refer to individual REA Tariffs to determine applicable REA charges.

REA Farms in O & M Pool

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	6.16 ¢/kV.A/day	0.48 ¢ / kW.h
Distribution	-	6.80 ¢/kV.A/day	-
Service	37.60 ¢ / service / day	-	-
REA Specific Charges	See REA Tariff	-	-
Total Price	C₁ ¢ / service/ day	12.92 ¢/kV.A/day	0.48 ¢ / kW.h

REA Farms Outside of O & M Pool

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	6.16 ¢/kV.A/day	0.48 ¢ / kW.h
Distribution	See REA Tariff	See REA Tariff	-
Service	See REA Tariff	-	-
REA Specific Charges	See REA Tariff	-	-
Total Price	C₁ ¢ / service /day	D₁ ¢/kV.A/day	0.48 ¢ / kW.h

kV.A capacity for billing purposes will be determined as follows:

- (a) For breakered services of 25 kV.A or less, the kV.A capacity will be set by the breaker size as shown below:

Breaker Amperes	25/41	35/50	50/75	75/110	100/150	200
Transformer Capacity in kV.A	3	5	7.5	10	15	25

- (b) For non-breakered REA farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:
- i. the highest metered kV.A demand during the billing period;
 - ii. the estimated demand;
 - iii. 25 kV.A.

REA Specific Charges

Other charges are applied on behalf of the REAs as defined in contracts and are subject to change from time to time.

These charges include operation and maintenance charges and deposit reserve charges, and are in addition to the charges contained in this price schedule.

The minimum monthly charge is the sum of the Customer and demand charges plus any REA specific charges that may apply.

Application

1. **Demand Metering** - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions.
2. **Price Option** - the following price option may apply:
Idle Service (Option F)
3. **Price Adjustments** - the following price adjustments (riders) may apply:
Balancing Pool Adjustment (Rider B)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)

Availability

- Applicable to any Rural Electrification Association, for whom the Company is not acting as the Wire Services Provider, as defined in the EUA.
- For all Points of Service throughout the territory served by the Company, for farming operations which are connected to the Rural Electrification Association's distribution system.

Price

Charges for service in any one billing month are the sum of the Customer, Demand and Energy charges as indicated below, determined for each individual Point of Service.

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	6.16 ¢/kV.A/day	0.48 ¢ / kW.h
Distribution	-	-	-
Service	19.59 ¢/service/day	-	-
TOTAL PRICE	19.59 ¢/service/day	6.16 ¢/kV.A/day	0.48 ¢ / kW.h

kV.A capacity for billing purposes will be determined as follows:

- (a) For breakered services of 25 kV.A or less, the kV.A capacity will be set by the breaker size as shown below:

Breaker Amperes	25/41	35/50	50/75	75/110	100/150	200
Transformer Capacity in kV.A	3	5	7.5	10	15	25

- (b) For non-breakered REA farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:
- i. the highest metered kV.A demand during the billing period;
 - ii. the estimated demand;
 - iii. 25 kV.A.

The minimum monthly charge is the sum of the Customer and Demand charge.

Application

1. **Demand Metering** - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions.
2. **Price Option** - the following price option may apply:
 Idle Service (Option F)
3. **Price Adjustments** - the following price adjustments (riders) may apply:
 Balancing Pool Adjustment (Rider B)
 Temporary Adjustment (Rider G)
 Interim Adjustment (Rider J)
 Interim RRT Adjustment (Rider Q)

Availability

For System Access Service and Distribution Access Service, for all Points of Service throughout the territory served by the Company, for farming operations which are connected to the Company's distribution system.

Price

Charges for service in any one billing month are the sum of the Customer, Demand, and Energy Charges as indicated below, determined for each individual Point of Service.

	Customer Charge	Demand Charge	Energy Charge
Transmission		6.16 ¢/kV.A/day	0.48 ¢ / kW.h
Distribution	15.32 ¢/service/day	10.54 ¢/kV.A/day	0.49 ¢ / kW.h
Service	37.60 ¢/service/day		
TOTAL PRICE	52.92 ¢/service/day	16.70 ¢/kV.A/day	0.97 ¢ / kW.h

kV.A capacity for billing purposes will be determined as follows:

- (a) For breakered services of 25 kV.A or less, the kV.A capacity will be set by the breaker size as shown below:

Breaker Amperes	25/41	35/50	50/75	75/110	100/150	200
Transformer Capacity in kV.A	3	5	7.5	10	15	25

- (b) For non-breakered farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:
- i. the highest metered kV.A demand during the billing period;
 - ii. the estimated demand;
 - iii. the contract demand;
 - iv. 25 kV.A.

The minimum monthly charge is the sum of the Customer and Demand Charges.

Application

1. **Demand Metering** - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions for Distribution Service Connections.
2. **Price Options** - the following price option may apply:
Idle Service (Option F)
3. **Price Adjustments** - the following price adjustments (riders) may apply:
Balancing Pool Adjustment (Rider B)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
Interim RRT Adjustment (Rider Q)

Availability

- For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, for street lighting.
- Not available for private lighting.

Price

Charges for service in any one billing month are the sum of the Customer Charge and Demand Charge, determined for each individual Point of Service.

Decorative Lighting (61 A)

- For decorative lighting fixtures installed, owned and maintained by the Company.
- The customer is responsible for the full cost of installation.
- Includes maintenance only.
- Specific contracts may require customers to purchase and maintain inventory of decorative lamps if the customer's lighting fixtures are not the same as the standard used by the company.

Decorative Lamps

	Customer Charge	Demand Charge
Transmission	-	0.021 ¢ /watt/day
Distribution	19.29 ¢/fixture/day	0.011 ¢ /watt/day
Service	1.72 ¢/fixture/day	-
TOTAL PRICE	21.01 ¢/fixture/day	0.032¢ /watt/day

Investment Option (61 B)

- For standard lighting fixtures installed, owned, and maintained by the Company.

All Lamps

	Customer Charge	Demand Charge
Transmission	-	0.021 ¢ /watt/day
Distribution	40.83 ¢/fixture/day	0.011 ¢ /watt/day
Service	1.72 ¢/fixture/day	-
TOTAL PRICE	42.55 ¢/fixture/day	0.032 ¢ /watt/day

Distribution Investment Option (61 C)

- For customer owned and installed lighting.
- For installation and maintenance of distribution facilities up to, but not including the customer owned conductor serving the light fixtures.
- The Company may require that the Point of Service be metered and served on Price Schedule D21, if the load requirements change over time, or if loads that are not lighting loads are served from the same Point of Service.

	All Lamps	
	Customer Charge	Demand Charge
Transmission	-	0.021 ¢ /watt/day
Distribution	25.51 ¢/fixture/day	0.011 ¢ /watt/day
Service	1.72 ¢/fixture/day	-
TOTAL PRICE	27.23 ¢/fixture/day	0.032 ¢ /watt/day

No Investment Option (61 D) (This option is no longer available)

- ~~The customer is responsible for the full cost of installation.~~
- ~~The customer is responsible for the full cost of replacement.~~
- ~~Includes maintenance only.~~
- ~~This portion of the rate is closed to new Points of Service and will be phased out by the end of 2005.~~
- ~~All customers served under Option 61D may at any time between January 1, 2005 and December 31, 2005, elect to have service billed under Option 61E or Option 61B.~~

YEAR:	All Lamps	
2005	Customer Charge	Demand Charge
Transmission	-	0.31¢ /watt
Distribution	\$5.22	0.33¢ /watt
Service	\$0.51	-
TOTAL PRICE	\$5.73 / fixture	0.64¢ / watt of billing demand

No Investment Option (61 E)

- Available for new installations only.
- For lighting fixtures installed, owned and maintained by the Company.
- The customer is responsible for the full cost of installation.
- The customer is responsible for the full cost of replacement.
- Includes maintenance only.

	All Lamps	
	Customer Charge	Demand Charge
Transmission	-	0.021 ¢ /watt/day
Distribution	18.68 ¢/fixture/day	0.011 ¢ /watt/day
Service	1.72 ¢/fixture/day	-
TOTAL PRICE	20.40 ¢/fixture/day	0.032 ¢ /watt/day

Application

1. **Price Option** - the following price option may apply:
Idle Service (Option F)
2. **Price Adjustments** – the following price adjustments (riders) may apply:
Municipal Assessment (Rider A-1)
Balancing Pool Adjustment (Rider B)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
Interim RRT Adjustment (Rider Q)

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, for sentinel lighting.

Price

Charges for service in any one billing month are the sum of the Customer Charge and Demand Charge determined for each individual Point of Service.

Investment Option (63 A)

For standard sentinel lighting fixtures installed, owned, and maintained by the Company

	Customer Charge	Demand Charge
Transmission	-	0.021 ¢ /watt/day
Distribution	12.93 ¢/fixture/day	0.014 ¢ /watt/day
Service	18.28 ¢/fixture/day	-
TOTAL PRICE	31.21 ¢/ fixture/day	0.035 ¢ / watt/day

Summer Village Option (63 B)

- For standard sentinel lighting fixtures installed, owned and maintained by the Company
- For seasonal use only (six month minimum period) by Municipal Corporations in summer villages.
- This portion of the rate is closed.

	Customer Charge	Demand Charge
Transmission	-	0.021 ¢ /watt/day
Distribution	20.57 ¢/fixture/day	0.014 ¢ /watt/day
Service	18.28 ¢/fixture/day	-
TOTAL PRICE	38.85 ¢/fixture/day	0.035 ¢ / watt/day

No Investment Option (63 C)

- Available for new installations only.
- For standard lighting fixtures installed, owned, and maintained by the Company.
- The customer is responsible for the full cost of installation.
- The customer is responsible for the full cost of replacement.
- Includes maintenance only.

	Customer Charge	Demand Charge
Transmission	-	0.021 ¢ /watt/day
Distribution	6.83 ¢/fixture/day	0.004 ¢ /watt/day
Service	18.28 ¢/fixture/day	-
TOTAL PRICE	25.11 ¢/fixture/day	0.025 ¢ / watt/day

Metering Option (63 D)

- For standard lighting fixtures installed, owned, and maintained by the Company.
- For service through the meter at the Point of Service.
- This portion of the rate is closed.

	Customer Charge	Demand Charge
Transmission	-	0.021 ¢ /watt/day
Distribution	13.57 ¢/fixture/day	0.014 ¢ /watt/day
Service	18.28 ¢/fixture/day	-
TOTAL PRICE	31.85 ¢/fixture/day	0.035 ¢ / watt/day

Distribution Investment Option (63 E)

- For customer owned and installed lighting.
- For installation and maintenance of distribution facilities up to, but not including the customer owned conductor serving the light fixtures.
- The Company may require that the Point of Service be metered and served on Price Schedule D21, if the load requirements change over time, or if loads that are not lighting loads are served from the same Point of Service.

	Customer Charge	Demand Charge
Transmission	-	0.021 ¢ /watt/day
Distribution	8.85 ¢/fixture/day	0.014 ¢ /watt/day
Service	18.28 ¢/fixture/day	-
TOTAL PRICE	27.13 ¢/fixture/day	0.035 ¢ / watt/day

Application

1. **Price Adjustments** - the following price adjustments (riders) may apply:
Municipal Assessment (Rider A-1)
Balancing Pool Adjustment (Rider B)
Temporary Adjustment (Rider G)
Interim Adjustment (Rider J)
Interim RRT Adjustment (Rider Q)

Availability

The Idle Service charge will apply to all Price Schedules listed below for Points of Service served by the Company throughout the territory when the Point of Service is temporarily disconnected with the intention of restoring service at a future date.

Price Adjustment

The Idle Service charges shall be:

Price Schedule	Applicability	Idle Service Charge
D11	Service outside cities, towns, villages, hamlets, Indian reserves and Metis settlements	The price schedule monthly Distribution Customer Charge plus the Transmission Customer Charge.
D21 D22	Service outside cities, towns, villages, hamlets, Indian reserves and Metis settlements	The sum of the Distribution Demand Charge plus the Transmission Demand Charge where: (a) Distribution Demand Charge is the greater of the contract demand or rate minimum, and (b) Transmission Demand Charge is the price schedule rate minimum
D24 D34 D44	All Points of Service	The sum of the Distribution Demand Charge where the Distribution Demand Charge is the greater of the contract demand or rate minimum.
D25 D26	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).
D31 D32 D41	All Points of Service	The sum of the Distribution Demand Charge plus the Transmission Demand Charge where: (a) Distribution Demand Charge is the greater of the contract demand or rate minimum, and (b) Transmission Demand Charge is the greater of the contract demand or rate minimum
D33	All Points of Service	Charges based on base demand level established under Price Schedule D31.
T31	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).
T33	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).
D51 D52 D56	All Points of Service	The sum of the Distribution Customer charge and the Distribution and Transmission Demand Charges applicable to a 3 kV.A service.
D61	All Points of Service	The sum of the Distribution Demand Charge plus the Transmission Demand Charge
D63	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).

Application

1. If the Customer's Point of Service is reconnected within 12 months of disconnection, the minimum monthly charge for each month of disconnection will be applied to the Point of Service.
2. For further information on idle services, refer to Terms and Conditions 14.1 – Disconnection and Idle Service.

The Retailer will be responsible for any costs that the Company incurs from AESO as a result of a point of service going idle. If the point of service is not enrolled with a Retailer, the costs incurred from AESO will be charged directly to the Customer.

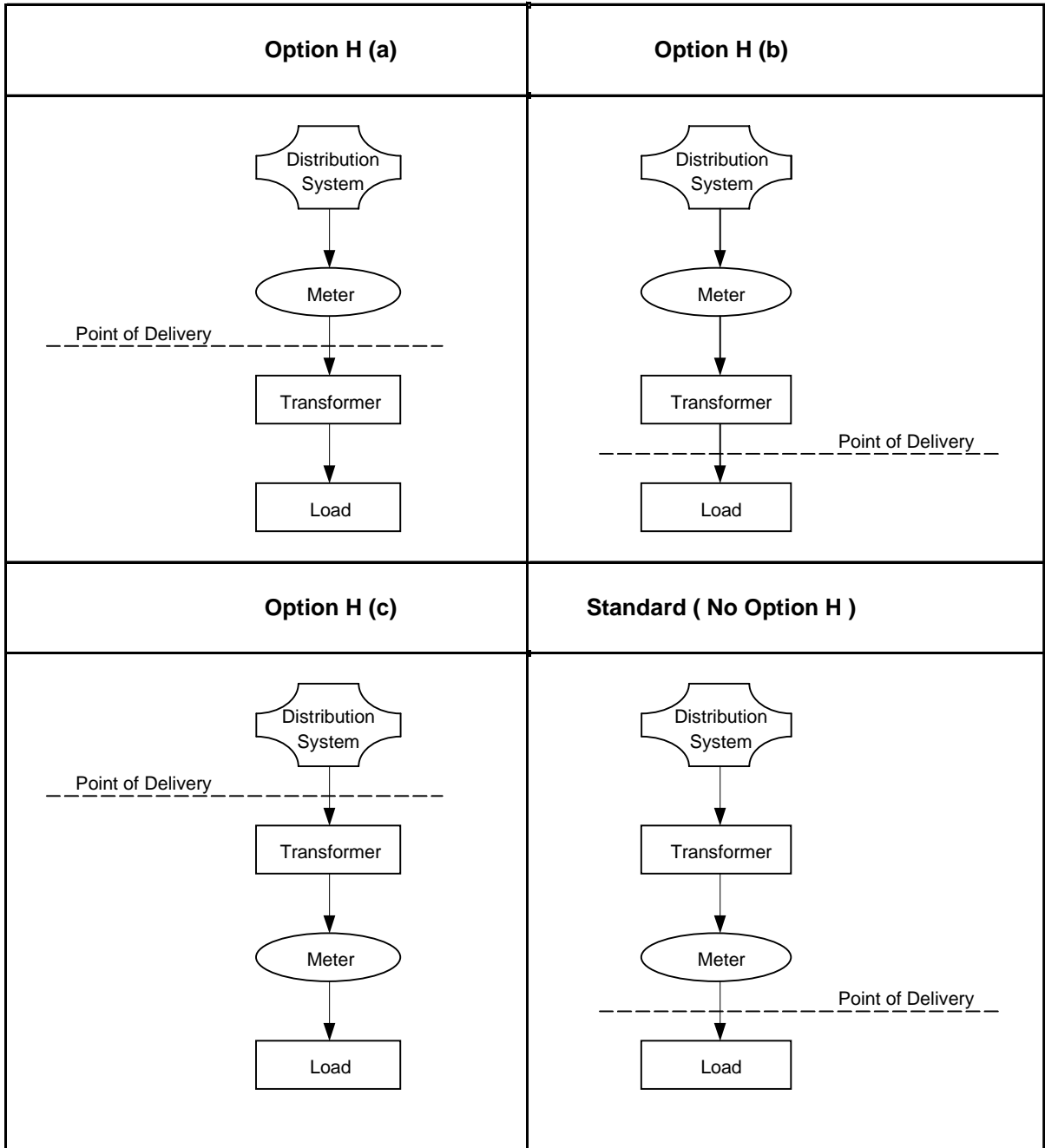
Availability

- For Points of Service throughout the territory served by the Company under Price Schedule D21, D22, D31, T31, D32 where metering and / or delivery voltage are non-standard.
- Standard service for distribution connected customers is delivered and metered at the utilization voltage. When delivery or metering is necessary at other voltages, for the convenience of either the customer or the Company, bills for service will be adjusted as outlined below in (a) to (c).
- Standard service for transmission connected customers is delivered to the customer and metered at the substation voltage. When delivery is required at lower voltages, bills for service will be adjusted as outlined below in (d). Section (b) may also apply to transmission connected customers.

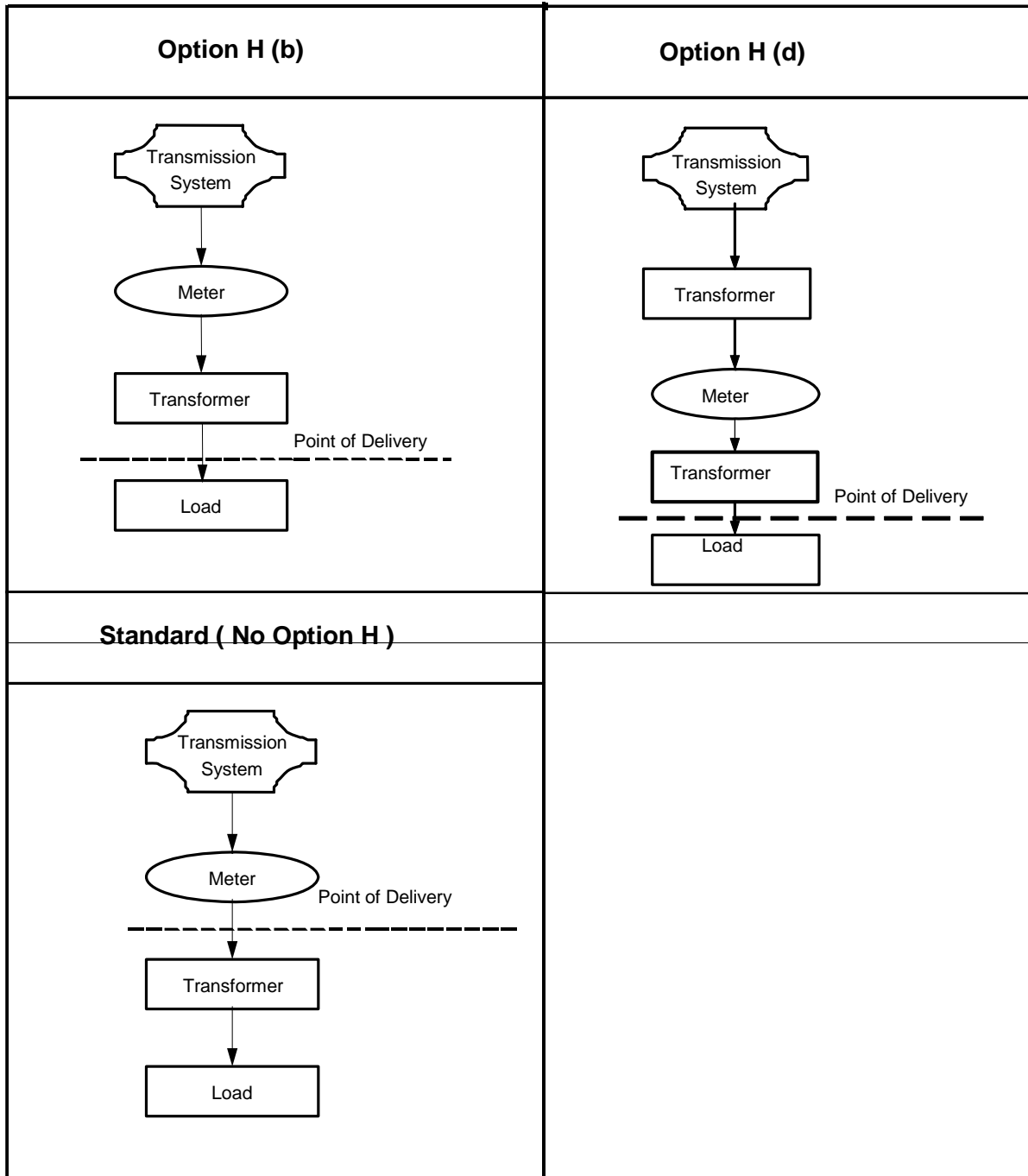
Price Adjustment

- (a) If the point of delivery and metering is on the primary side (25 kV) of a transformer (including cases where one-point service is required by the customer for more than a single utilization voltage or point of use), and the customer owns or rents the necessary transformer(s), a **discount of 2.36 ¢/kW/day** of billing demand will be applied. This adjustment does not apply to customers connected directly to the transmission system who are exempt from the Distribution Charge on the applicable rate.
- (b) If primary or higher voltage delivery metering is desirable for the convenience of the Company, or to improve accessibility, etc., **demand and energy measurements will be reduced by 1%** so as to approximate secondary voltage delivery conditions.
- (c) If primary or higher voltage delivery is made to customer owned transformers, but metering is at secondary or utilization voltage for the Company's convenience, **demand and energy measurements will be increased by 1%** so as to approximate primary or transmission voltage delivery conditions and **a discount, as specified in (a)** shall apply.
- (d) Customers who are connected directly to the transmission system, but take service from the low side of a transformer (with primary side 25kV), and do not own or rent any necessary transformer(s), and are exempt from the Distribution Charge on the applicable rate, a **surcharge of 2.36 ¢/kW/day** of billing demand will apply.

Schematic of Metering and Transformation Configurations for Option H Definitions (Distribution Connected Customers)



Schematic of Metering and Transformation Configurations for Option H Definitions (Transmission Connected Customers)



Availability

For all Pooled O&M REA Farm Points of Service throughout the territory served by the Company, served under Price Schedule D21 or Price Schedule D31.

Price Adjustment

Standard Small General Service Price Schedule D21

For REA farm Points of Service electing to take service under Small General Service Price Schedule D21, a credit adjustment of 49% will be applied to the base bill.

Large General Service / Industrial Price Schedule D31

For REA farm Points of Service electing to take service under Large General Service / Industrial Price Schedule D31, a credit adjustment of 37% will be applied to the base bill.

Availability

- Applicable throughout the territory served by the Company to electric service within the municipalities identified in Table 2.
- The following are exempt from the surcharge:
 - (a) Farm customers (Price Schedules D51, D52 and D56)
 - (b) Irrigation Pumping customers (Price Schedule D25 and D26)
 - (c) Customers within Indian Reservations not listed in Table 2
 - (d) Special Facilities Charge (Rider E) customers

Price Adjustment

- The Company pays to a municipality each year or month, in accordance with the franchise agreement between the Company and the municipality, a percent of the gross revenue, or wires revenue, of the Company derived from the sale or delivery of electricity to the consumers in the municipality.
- The percentage of gross revenue (franchise fee and/or tax), or wires revenue, to be paid by the Company to its franchised municipalities is given by category number in Table 1. The municipalities, and their category numbers, are listed in Table 2. For Category 7 the municipalities and percentages of yearly wires revenue are listed in Table 3. For Category 8 the municipalities and percentages of monthly wires revenue are listed in Table 4.
- For all categories except Category 8, an estimated surcharge will be added to each customer's bill within a municipality in order to recover the above payments. Adjustments will be made once each year for any difference between the estimated surcharge collected and the actual surcharge required.
- For Category 8, the percentages listed in Table 4 will be applied to the monthly billing. The amount billed will be paid to the municipality in accordance with the franchise agreement between the Company and the municipality.

Table 1 – Percent of Gross Revenue by Category

CATEGORY 1	2% of the first \$100,000 of gross revenue; 3% of the next \$200,000 of gross revenue; 4% of the next \$200,000 of gross revenue; 5% of gross revenue in excess of \$500,000.
CATEGORY 5	1.0% of the first \$100,000 of gross revenue; 1.5% of the next \$200,000 of gross revenue; 2.0% of the next \$200,000 of gross revenue; 2.0% of gross revenue in excess of \$500,000.
CATEGORY 6	An amount equal to taxes assessed pursuant to the Municipal Government Act Chap. M-26. 1.
CATEGORY 7	A percentage of the wires revenue of a municipality as listed in Table 3.
CATEGORY 8	A percentage of monthly wires revenue of a municipality as listed in Table 4.

Table 2 – Category Numbers of Municipalities

Alliance 8, 6	Empress 7,6	Jasper Nat'l Park 5	Sexsmith 7
Andrew 7 8, 6	Fairview 8, 6	Kinuso 8, 6	Slave Lake 7
Beaverlodge 7	Falher 8,6	Kitscoty 7, 6	Smoky Lake 8, 6
Berwyn 7	Forestburg 7	Linden 8, 6	Spirit River 8, 6
Big Valley 7	Fort McMurray 7	Lloydminster 7, 6	St Paul 8, 6
Bonnyville 8, 6	Fox Creek 8, 6	Manning 7	Stettler 7,6
Botha 7	Gadsby 6	Mannville 8, 6	Swan Hills 8,6
Carbon 7	Galahad 7	Marwayne 8,6	Three Hills 8, 6
Castor 7	Girouxville 7	McLennan 7	Trochu 8, 6
Cereal 7	Glendon 8, 6	Minburn 6	Two Hills 8, 6
Cold Lake 8, 6	Grande Cache 8, 6	Morrin 7	Valleyview 8,6
Consort 7	Grande Prairie 7 8, 6	Mundare 6	Vegreville 6
Coronation 8, 6	Grimshaw 7	Munson 7,6	Vermilion 8, 6
Delburne 7	Halkirk 8, 6	Myrnam 6	Veteran 7 8, 6
Delia 8, 6	Hanna 8, 6	Nampa 7	Vilna 8, 6
Derwent 6	Heisler 8, 6	Oyen 7	Waskatenau 6
Dewberry 8, 6	High Level 8, 6	Paradise Valley 8,6	Wembley 7
Donalda 8, 6	High Prairie 7	Peace River 8,6	Willingdon 6
Donnelly 7	Hines Creek 7	Radway (County 7) 7	Youngstown 7, 6
Drumheller 8,6	Hythe 7	Rainbow Lake 8, 6	
Elk Point 8, 6	Innisfree 8,6	Rosalind 8, 6	
Elnora 8, 6	ID Jasper 7	Rycroft 7	

Table 2 – Category Numbers of Municipalities

Category 6 also applies to the following non-franchised municipalities:

Bonnyville Beach	County No. 30 Lamont	M.D. of Peace No. 135
Horseshoe Bay	County No. 89 Lakeland	M.D. of Fairview No. 136
Lavoy	M.D. of Greenview No. 16	I.D. No. 12 & ID No. 24
Pelican Narrows	M.D. of Opportunity No. 17	Allison Bay B219
Rochon Sands	M.D. of Wood Buffalo No. 18	Fort McMurray Band B352
Wanham	M.D. of Birch Hills No. 19	Peavine N172
Warspite	M.D. of Saddle Hills No. 20	Gift Lake N173
Whitesands	M.D. of Clear Hills No. 21	East Prairie N174
County No. 01 Grande Pr.	M.D. of Northern Lights No. 22	Elizabeth N187
County No. 06 Stettler	M.D. of MacKenzie No. 23	Fishing Lake N188
County No. 07 Thornhill	M.D. of Acadia No. 34	Paddle Prairie N221
County No. 13 Smoky Lake	M.D. of Starland No. 47	Special Areas
County No. 16 Wheatland	M.D. of Kneehill No. 48	Sturgeon Lake I.R. #154
County No. 18 Paintearth	M.D. of Bonnyville No. 87	Whitefish Lake Band B924
County No. 19 St. Paul	M.D. of Bonnyville Annexed No. 88	Busche River I.R. No. 207*
County No. 21 Two Hills	M.D. of Lesser Slave River No. 124	Hay Lake I.R. No. 209*
County No. 22 Camrose	M.D. of Big Lake No. 125	Upper Hay River I.R. No. 212*
County No. 23 Red Deer	M.D. of Smoky R. No. 130	Doghead I.R. No. 218*
County No. 24 Vermilion R.	M.D. of Northern Sunrise County	Bigstone Wabasca I.R. No. 166*
County No. 27 Minburn	M.D. of Spirit River No. 133	Loon River Cree I.R.*
County No. 29 Flagstaff		

* Additional Municipalities

Table 3 – Percent of Wires Revenue by Municipality (Category 7)

Beaverlodge	7.20%	Fort McMurray	7.60%	Morrin	6.00%
Berwyn	5.25%	Galahad	6.75%	Munson	3.00%
Big Valley	3.75%	Girouxville	7.00%	Nampa	5.00%
Botha	4.50%	Grimshaw	7.50%	Oyen	7.75%
Carbon	3.50%	High Prairie	7.80%	Radway (County 7)	3.00%
Castor	5.00%	Hines Creek	6.50%	Rycroft	4.30%
Cereal	5.00%	Hythe	7.25%	Sexsmith	8.20%
Consort	5.25%	Jasper (ID)	7.50%	Slave Lake	8.70%
Delburne	3.75%	Kitscoty	5.00%	Stettler	7.50%
Donnelly	5.00%	Lloydminster	13.00%	Wembley	6.70%
Empress	5.25%	Manning	7.50%	Youngstown	4.00%
Forestburg	4.00%	McLennan	8.25%		

**Table 4 – Percent of Monthly Wires Revenue by Municipality (Category 8)
Paid in addition to other taxes**

Alliance	6.00%	Glendon	1.50%	Peace River	5.00%
Andrew	2.00%	Grande Cache	4.60%	Rainbow Lake	7.75%
Bonnyville	6.80%	Grande Prairie	7.75%	Rosalind	0.50%
Cold Lake	4.25%	Halkirk	1.00%	Smoky Lake	3.25%
Coronation	3.75%	Hanna	3.50%	Spirit River	4.50%
Delia	0.50%	Heisler	0.00%	St Paul	7.00%
Dewberry	0.00%	High Level	6.50%	Swan Hills	4.00%
Donalda	1.50%	Innisfree	1.50%	Three Hills	5.00%
Drumheller	9.00%	Kinuso	3.50%	Trochu	3.50%
Elk Point	3.60%	Linden	4.00%	Two Hills	2.75%
Elnora	1.00%	Mannville	2.50%	Valleyview	5.25%
Fairview	6.00%	Marwayne	2.30%	Vermilion	3.50%
Falher	6.25%	MD Badlands	9.00%	Veteran	1.00%
Fox Creek	4.50%	Paradise Valley	2.00%	Vilna	4.00%

Note: Fahler, Innisfree, Marwayne, Paradise Valley, Peace River and Valleyview were removed from Table 3 and added to Table 4.

Availability

Applicable to facilities constructed by the Company on customer owned or leased property, as requested by the customer.

Price

The Facilities charge will be set out in a contract, negotiated between the customer and the Company, and will recover the revenue requirement of the applicable facilities. The revenue requirement will be calculated on a rate base of net book value and will include Return, Income Tax, Depreciation, and Operations and Maintenance costs.

Application

- Facility charges will normally be billed monthly. Monthly charges are subject to change as new facilities are added or currently installed facilities are retired.
- For facilities shared among more than one customer, a separate contract will be established for each customer making use of the facilities.
- Facilities constructed under Rider E are owned and maintained by the Company.

Availability

- This Rider B is designed to flow through a Balancing Pool Refund from the Alberta Electric System Operator (AESO).
- Applicable to all customers with the exception of customers served on Price Schedule D24, Price Schedule D34, and Price Schedule D44, at points of service, throughout the territory served by the Company for energy consumption effective January 1, 2006.
- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Applicable Distribution Tariff Price Schedule	Charge (¢/kW.h)
	“+” = Charge
	“-” = Refund
D11 Residential	-0.10
D21 Small General Service	-0.10
D22 Small General Service – Energy Only	-0.10
D25 Irrigation Pumping Service	-0.10
D26 REA Irrigation Pumping Service	-0.10
D31 Large General Service/Industrial – Distribution Connected	-0.10
T31 Large General Service/Industrial – Transmission Connected	-0.10
D32 Generator Interconnection and Standby Power	-0.10
D33 Transmission Opportunity Rate – Distribution Connected	-0.10
T33 Transmission Opportunity Rate – Transmission Connected	-0.10
D41 Small Oilfield and Pumping Power	-0.10
D51 REA Farm Service	-0.10
D52 REA Farm Service – Excluding Wires Service Provider	-0.10
D56 Farm Service	-0.10
D61 Street Lighting Service	-0.10
D63 Private Lighting Service	-0.10

Note: Rider B does not apply to Rider A-1, Rider E, Rider G, Rider J, and Rider Q.

Availability

- This Rider G is designed to true-up 2004 Rider G and dispense of new deferral balances.
- Applicable to all customers, at points of service, throughout the territory served by the Company for energy consumption effective January 1, 2006.
- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Applicable Distribution Tariff Price Schedule	Charge (¢/kW.h)
	“+” = Charge “-” = Refund
D11 Residential	-0.662
D21 Small General Service	-0.423
D22 Small General Service – Energy Only	-0.423
D25 Irrigation Pumping Service	-1.965
D26 REA Irrigation Pumping Service	-1.965
D31 Large General Service/Industrial – Distribution Connected < 2MW	0.004
D31 Large General Service/Industrial – Distribution Connected > 2MW	0.015
T31 Large General Service/Industrial – Transmission Connected < 2MW	-0.013
T31 Large General Service/Industrial – Transmission Connected > 2MW	-0.001
D32 Generator Interconnection and Standby Power < 2 MW	0.004
D32 Generator Interconnection and Standby Power > 2 MW	0.015
D33 Transmission Opportunity Rate – Distribution Connected	0.004
T33 Transmission Opportunity Rate – Transmission Connected	-0.013
D41 Small Oilfield and Pumping Power	-0.520
D51 REA Farm Service	-0.274
D52 REA Farm Service – Excluding Wires Service Provider	-0.274
D56 Farm Service	-0.490
D61 Street Lighting Service	-1.987
D63 Private Lighting Service	-2.059

Notes: **Rider G does not apply to Rider A-1, Rider E, Rider J, and Rider Q.
To be updated in upcoming Rider G Application.**

Availability

Applies to all electric service throughout the territory served by the Company when a charge or refund is approved by the AEUB.

Availability

- Rider Q is designed to true-up 2001 to 2004 RROT deferral account balances.
- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Price

This Rider will apply on energy consumption effective January 1, 2006.

Regulated Rate	Applicable Distribution Tariff Price Schedule	Charge (¢/kW.h)
		“+” = Charge “-” = Refund
E1	D11 Residential	1.190
E2	D21, D22 Small General Service	0.099
E3	D31, T31, D32 Large General Service/Industrial & Generator Interconnection	-0.293
E4	D41 Small Oilfield and Pumping Power	-1.084
E51	D51, D52 REA Farm Service	0.424
E56	D56 Farm Service	0.424
E6	D61, D63 Lighting Service	7.866
E7	D25, D26 Irrigation Pumping Service	1.519

Note: Rider Q does not apply to Rider A-1, Rider E, Rider J and Rider G.