November 2, 2010

Alberta Utilities Commission

4th Floor, 425 – 1st Street S.W.
Calgary, Alberta
T2P 3L8

Attention: Mr. Mike Hagan
Executive Director
Rates Division

Dear Sir:

RE: ATCO Electric Ltd. 2011 Interim Tariff Application

Attached please find ATCO Electric's Application for Alberta Utilities Commission (AUC) approval on an interim refundable basis for the following:

(i) 2011 Interim Distribution Tariff
(ii) 2011 Interim Transmission Facility Owners (TFO) Tariff, and
(iii) Method to address revisions to Rider B - Balancing Pool Adjustment Tariff.

Should you have any questions, please contact me at (780) 420-7613.

Sincerely,

Original Signed by Nick Palladino

Nick Palladino, P. Eng.
Manager, Electric Pricing

NP/by
Att.

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2011 DISTRIBUTION TARIFF APPLICATION

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Section 1 – 2011 Interim Tariff

1.1 Introduction

Pursuant to Section 102 of the *Electric Utilities Act* (EUA), ATCO Electric hereby applies to the Alberta Utilities Commission (AUC) for approval, on an interim refundable basis, of its 2011 Interim Distribution Tariff, and 2011 Interim Transmission Facility Owners (TFO) Tariff, commencing on January 1, 2011.

ATCO Electric is proposing that its 2011 Interim Distribution Tariff be based on the same methodology and application of scaling factors as used to establish interim distribution rates in past interim tariff applications. This is consistent with the approved scaling methodology used to scale rates to meet a target forecast revenue requirement for the proceeding year. The AUC approved the implementation of interim rates based on this scaling methodology in previous Decisions.

ATCO Electric believes the same scaling approach is appropriate to arrive at a 2011 interim tariff since ATCO Electric anticipates that it will be filing a detailed 2011 Phase II Application shortly. It would be more effective to deal only with this interim rate request at this time and handle all Phase II related matters during the upcoming 2011 DTA proceedings. ATCO Electric does not expect a decision on final 2011 rates until the fourth quarter of 2011. As a result, ATCO Electric requires interim rates in place effective January 1 to begin collecting its forecast costs for 2011.

In Decision 2005-102[1], the AUC set out a two-part test to evaluate whether the proposed target revenue requirement amount to be used to establish interim rates is appropriate. Based on the two-part test analysis, and ATCO Electric's review of the cost drivers associated with the transmission and distribution revenue requirements set out in the 2011 – 2012 GTA, the proposed 2011 interim tariff will recover 37% of the proposed revenue requirement increase for Transmission and 90% of the proposed revenue requirement increase for Distribution, for 2011. ATCO Electric proposes to reduce the

[1] Decision 2005-102 from ATCO Electric's 2005 Interim Transmission Facility Owner Tariff Application

distribution function of the distribution tariffs and recover 100% of the Transmission Access Payments. Table 3 is provided herein, which sets out the 2011 – 2012 GTA proposed revenue requirement, proposed revenue increase, and the proposed 2011 revenue amount used for the design of 2011 interim rates.

There are a number of significant factors for both Transmission and Distribution that have contributed to the increase in proposed revenue requirements for 2011 and 2012. These factors can be summarized as follows:

Transmission

The significant factors contributing to the increase in revenue requirement for Transmission are driven by: i) increased return on rate base (return, income taxes and depreciation) due to rate base additions, ii) inclusion of Direct Assigned Construction Work in Progress ("CWIP") in rate base due to need to maintain strong credit metrics in this period of significant growth, iii) increased operating costs primarily attributable to: an increase in ATCO Electric's labor force associated with significant growth of ATCO Electric's transmission assets, changes in Annual Right-of-Way payments, impacts of IFRS on IT costs and inflation, iv) recovery of Federal future income taxes and v) impact of pension contributions.

Distribution

The significant factors contributing to the increase in revenue requirement for Distribution are primarily attributable to: i) increases in return on rate base (return, income taxes and depreciation) associated with increases in rate base, ii) impact of pension contributions and iii) operating cost increases largely attributable to: inflationary costs; added labour to support ongoing technology initiatives and increased number of customers, system related costs, high growth and aging infrastructure.

For a complete explanation of the cost drivers that support the change in revenue requirements, please refer to ATCO Electric's 2011 – 2012 GTA.

ATCO Electric is of the view that full recovery of the proposed revenue requirement amounts detailed in the Phase I GTA are necessary in order to allow ATCO Electric to continue to provide safe and reliable service in the test periods, and in order to meet increased capital and operating requirements that support forecasted growth. This approach will also ensure that the financial integrity of ATCO Electric is not jeopardized. Given the proposed level of rate increases over the next two years, a key issue that was taken into consideration to support the basis of ATCO Electric's proposed changes to 2011 interim rates is maintaining rate stability and moderating the transition to final 2011 and 2012 rates as reasonably as possible. In arriving at the decision respecting what level of interim rate increase would be appropriate, a discussion of the two-part test is set out below.

Section 2 – 2011 Interim Distribution Tariff Proposal

2.1 ATCO Electric's Proposed Target Revenue Requirement: Two-Part Test

In Decision 2006-132[2], the AUC identified a number of factors that should be considered when seeking the approval of interim rate adjustments. The factors are grouped into two main categories under the AUC's two-part test. The categories address items that relate to:

1. The quantum of, and need for the rate increase, and
2. General public interest considerations.

ATCO Electric will address each category separately.

[2] Decision 2006-132 from ATCO Electric's Interim 2007 Distribution Tariff and Transmission Facility Owner's Tariff Application

Category 1: The Quantum of Increase

The factors set out in Decision 2006-132 are intended to address the need and quantum of the proposed interim increase: whether any reduction in collection of the proposed revenue requirement increase may result in financial hardship to the Applicant, as well as an assessment of the risk to the Applicant of whether its performance to ensure safe utility operations is impacted.

With respect to the transmission revenue requirement, ATCO Electric does not consider there to be any contentious cost drivers. Notwithstanding, issues related to including Transmission Direct Assigned Construction Work in Progress ("CWIP") in rate base, and Federal future income taxes are issues that are subject to debate and which will be addressed on December 6, 2010 under Module 2 of ATCO Electric's 2011-212 GTA proceedings. As a result, ATCO Electric considers it appropriate to remove the associated costs from the related Transmission requested rate increase for the purpose only of establishing interim rates for 2011 on an interim refundable basis.

With respect to the distribution revenue requirement, ATCO Electric does not consider there to be any contentious and specific cost drivers that might be appropriate to remove for the purpose of this Interim Tariff Application. However, based on previously approved Interim Tariff Applications and final approved revenue requirements, and the estimated rate impact to customers, ATCO Electric considers that 90% of the requested rate increase to be a reasonable amount to allow for an Interim rate increase. The amounts that ATCO Electric is proposing to exclude and the reductions to the requested overall rate increase for the purpose of this Application are detailed in Table 1 and Table 2 for the Transmission and Distribution business units, respectively.

As noted in Section 1, the majority of the proposed revenue requirement increase for Transmission and Distribution is primarily attributable to increases in return on rate base (return, income taxes, and depreciation), CWIP in rate base, recovery of future income taxes, pension contributions, inflationary pressures and increases in ATCO Electric's labor force. To support the high growth that ATCO Electric is experiencing, the substantial

pressures on operating and capital costs and the aging infrastructure within its service area, ATCO Electric considers the requested rate increases essential towards supporting operating and maintenance programs that ensure ATCO Electric's continuing ability to provide safe and reliable utility operations. As well, any interim revenue requirement reductions will impact the timely recovery of cost increases and, in turn the stability of cash flows. The importance of cash flow metrics and cash flow stability have become ever more important since the recent credit crises and the continued uncertainty in financial markets, caused by global economic events. While the proposed target revenue reduction will likely result in unwarranted and undesirable cash flow deficiencies in 2011, ATCO Electric recognizes the AUCs previously enunciated criteria and the fact that several contentious issues are being debated in the Phase I proceedings.

Category 2: General Public Interest Considerations

With respect to the key factors forming this category, ATCO Electric has focused on the principle of gradualism in determining appropriate rates. This factor is of critical importance, given the overall magnitude of the requested rate increase. As described at the outset of this Application, ATCO Electric anticipates that it will be filing a detailed 2011 Phase II Application shortly. The AUC has observed in the past its preference that interim rate adjustments should provide for gradual changes, ease rate shock and provide a rate level that transitions customers to final rates. ATCO Electric took these views into consideration in its determination of the recommended reduction in requested interim 2011 rates, as well as the final increase customers will experience in 2012. Given the circumstances of the issues described under Category 1 and the relative weighting of all the factors that support the proposed reduction, it remains important to minimize, to the extent reasonably practical, the level of rate swings from 2010 to 2012. As noted by the AUC in Decision 2006-132, "…it is preferable to have an interim increase that reflects an intermediate position between current and the proposed final rates". ATCO Electric submits that the 2011 proposed interim transmission and distribution rates strike a reasonable balance between meeting the conditions of Category 1, while still providing an appropriate transition to 2011 and 2012 final approved rates.

The proposed reductions and associated target revenue requirements are set out in Table 1 and Table 2 below for the Transmission and Distribution business units.

Table 1: 2011 Proposed Reductions in Transmission Target Revenue Requirement for Interim Rates

Category	2011-2012 GTA Proposed $ million	2011 Interim Tariff Proposed Reduction (Transmission) $ million	% change
CWIP in Rate Base	$45.0	($45.0)	100%
Future Income Tax	$9.3	($9.3)	100%

Table 2: 2011 Proposed Reductions in Distribution Target Revenue Requirement for Interim Rates

Category	2011-2012 GTA Proposed $ million	2011 Interim Tariff Proposed Reduction (Distribution) $ million	% change
Overall Rate Increase	$33.4	($3.3)	10%

Based on the above proposed reductions, Table 3 below identifies the adjusted proposed revenue requirement levels for design of 2011 interim rates.

Table 3: Proposed Increases to 2011 Transmission and Distribution Revenue Requirements for 2011 Interim Rates

	(a)	(b)	(c)	(e)=(b+c)	(f)=(e/b)	(g)=(a+c)
	11/12 GTA Proposed RR $ million	**11/12 GTA Proposed RR Increase $ million**	**Proposed Reduction $ million**	**Adj. 2011 Proposed RR Increase $ million**	**% recovery of GTA Proposed RR Increase**	**2011 Interim Tariff Propsed RR $ million**
Transmission	$336.6	$86.6	($54.3)	$32.2	37%	$282.2
Distribution	$493.6	$33.4	($3.3)	$30.0	90% *	$490.2

* Based on recovery of 100% of Transmission Access Payments - target reduction is from distribution function of distribution rates.

2.2 Proposed Methodology to Establish Interim and Final Distribution Rates

As noted in the 2011-2012 Phase I application ATCO Electric is proposing to file a 2011 Phase II Application in the fourth quarter of 2010. ATCO Electric expects a final decision

on 2011 rates sometime in the fourth quarter of 2011. As a result, ATCO Electric has proposed the 2011 interim distribution rates for 2011 based on scaling the 2010 final distribution rates that were approved in 2010-205[3]. This scaling methodology was first introduced in ATCO Electric's 2005 – 2006 GTA. This methodology remains a reasonable and appropriate alternative for implementing rates, as opposed to a full Phase II Application, with the intention of minimizing the fluctuations in customer rates as much as possible. In this Application, ATCO Electric proposes its 2011 Interim Distribution Tariff be updated to reflect the proposed revenue requirement adjustments set out in Table 1 and Table 2 of this Application. To the extent the interim rates collect a proposed 2011 revenue requirement different than the final 2011 approved revenue requirement (from the 2011 – 2012 GTA), the difference between the forecast revenues collected on the approved interim and final rates will be addressed via a future Rider G application approved by the AUC.

The proposed revenue requirement for 2011, which the interim rates are designed to achieve, is set out in Table 3. To collect the proposed 2011 revenue requirement for rates starting January 1, 2011, ATCO Electric proposes to scale the distribution components of all the distribution rates by a scaling factor which recovers costs specifically assigned to the distribution function. The scaling adjustment to the transmission component is based on collecting the Transmission Access Payment (TAP) charges that are charged to ATCO Electric by the AESO. Since ATCO Electric continues its flow-through method of the AESO rates to direct connect transmission customers served on Price Schedules T31 and T33, there is no requirement to adjust the transmission rates applied to those price schedules.

The proposed scaling adjustments are outlined in Section 2.3 below. It is important to note that the scaling adjustments are based on the proposed 2011 billing determinants as filed in the 2011 – 2012 GTA. Proposed Price Schedules are provided in Appendix A. Rate impact schedules are provided in Appendix B, to illustrate the net impact to customers after the scaling adjustments have been applied.

[3] 2010-205 from ATCO Electric's Final 2010 Distribution Tariff

2.3 2011 Interim Distribution Tariff Scaling Factors

Based on the approach outlined above, ATCO Electric proposes to base the scaling factors for the proposed 2011 Interim Distribution rates on the 2011 – 2012 GTA requested amounts, updated to reflect the proposed adjusted 2011 revenue requirement in Table 3. The scaling factors are applied against the current approved 2010 final distribution rates to obtain the 2011 interim refundable rates effective January 1, 2011. The proposed scaling factors to arrive at 2011 interim refundable rates are outlined in Table 4 below.

Table 4: Proposed Scaling Factors to Arrive at 2011 Interim Distribution Rates

	Transmission Access		Distribution		
Rate Class	**Demand**	**Energy**	**Customer**	**Demand**	**Energy**
D11	N/A	1.082	1.070	1.070	1.070
D25 & D26	1.152	0.863	1.352	1.352	1.352
D61	1.071	N/A	1.257	1.257	1.257
D63	1.071	N/A	1.070	1.070	1.070
T31	1.000	1.000	1.070	1.070	1.070
Others	1.152	0.863	1.070	1.070	1.070

Implementing the 2011 interim distribution rates proposed above, effective January 1, 2011, would provide a smooth transition to 2012 rates and reduce the impact of future true-ups. As well, the proposed rates would be based on the rates approved by the AUC in a recent Phase II decision (i.e., 2010 DTA). As mentioned at the outset of this Application, since ATCO Electric is anticipating filing a detailed 2011 Phase II Application shortly, it would be more effective to deal only with this interim request at this time and handle all Phase II related matters during those upcoming proceedings.

When all factors are taken into consideration, ATCO Electric is of the view this proposal provides a balanced and practical approach that would provide a stable transition for 2011 and 2012 distribution rates.

2.4 ATCO Electric's Rider B – Balancing Pool Adjustment

ATCO Electric's Rider B – Balancing Pool Adjustment was implemented as a refund of $2.00/MW.h to all ATCO Electric customers effective July 1, 2010 to December 31, 2010. This separate rider is required to be as visible as possible to end-use consumers to reflect a Balancing Pool refund/collection received from the AESO through its Rider F – Balancing Pool Consumer Allocation Rider.

To properly flow through this rider to customers in ATCO Electric's service area, ATCO Electric sets its Rider B – Balancing Pool Adjustment Rider based on the same rate set out in the AESO's tariff schedule, even though the AESO's Rider F is calculated at the substation Point of Delivery, while ATCO Electric's Rider B is calculated based on the readings taken at the customer meter. Any difference between the amounts charged or refunded to ATCO Electric from the AESO and the amount charged or refunded to customers from ATCO Electric is dealt with through a future Rider application.

ATCO Electric proposes to continue the previously Commission approved approach for the determination of the Rider B rate to customers, by taking into account the effects of distribution losses by rate class as set out in the most recently approved ATCO Electric DTA.

At the time of this Application, the Balancing Pool has not announced any change to the annual consumer allocation amount. Any changes to the allocation amount will result in the need for the AESO to amend its Rider F – Balancing Pool Consumer Allocation Rider. This step is required before ATCO Electric is able to flow through the change in its Rider B. As a result, ATCO Electric proposes that any amendment to the Balancing Pool Rider in 2010 that still allows ATCO Electric sufficient time to properly test and implement this Rider before January 1, 2011 will form part of the proposed 2011 interim tariff. Any changes thereafter will form part of a separate application to adopt Rider B.

Section 3 – 2011 Interim Transmission Facility Owners (TFO) Tariff

3.1 ATCO Electric's Interim Transmission Facility Owners Tariff Proposal

In accordance with Section 124(2) of the *Electric Utilities Act*, ATCO Electric is applying for an interim Transmission Facility Owner ("TFO") tariff that will take effect January 1, 2011.

ATCO Electric currently has before the AUC its 2011 – 2012 Transmission and Distribution GTA, which it filed on May 21, 2010. Based on the proposed adjustment to the 2011 revenue requirement target set out in this Application, ATCO Electric is proposing to utilize an Interim TFO Tariff until such time as it receives approval for its final 2011 rates.

This application requests that the following TFO Tariff be approved on an interim refundable basis effective January 1, 2011.

	$Millions
2011 Transmission Tariff as set out in Table 3 of this Application	282.2
Monthly Charge (on an interim basis)	23.519

This monthly charge to the AESO will be on an interim refundable basis. All amounts included in this filing, which are currently before the AUC, will be trued up once final AUC Decisions have been received.

ATCO Electric's primary objective in requesting an Interim TFO Tariff increase is explained in Section 2 of this Application. These approaches balance the interests of ATCO Electric and its customers. The proposed Price Schedule is attached in Appendix C.

Section 4 – Approvals Requested

1. Approval of the proposed 2011 Interim Distribution Tariff on an interim refundable basis based on the approach outlined in Section 2.1.

2. Approval of the proposed 2011 Interim Transmission Facility Owners Tariff on an interim refundable basis.

3. Approval of the proposed method to address revisions to Rider B – Balancing Pool Adjustment tariff.

ATCO Electric respectfully requests the AUC's approval by December 15, 2010, in order to implement the new tariff effective January 1, 2011.

Section 5 – Attachments & Appendices

Attachment 1 – Determination of Adjustment Factors

Appendix A – 2011 Interim Distribution Price Schedules

Appendix B – Bill Comparisons and Rate Impact Sheets

Appendix C – 2011 Interim Transmission Facility Owner Price Schedule

Table 1

Scaling Factor Determination

All Revenue in $'000's

Year	Column No.	Scenario	(A) Trans Demand Revenue	(B) Trans Energy Revenue	(C) T31 Trans Demand Revenue	(D) T31 Trans Energy Revenue	(E) Dist Revenue	Power Factor	Total
Before Scaling									
		12 mo. 2010 Final rates	78,613	51,089	23,459	5,980	270,618	5,408	435,167
		D25 &D26	52.482	12			96		160
		D61	315				7,628		7,943
		Adj for D11	14,240	(14,240)					
2011		Adj for D61	(88)	88					
		Adj for D63	(14)	14					
	(1)	Total	93,120	36,963	23,459	5,980	278,341	5,408	443,270
	(2)	Target	107,248	31,907	23,459	5,980	299,291	5,408	473,293
	(3)	Scaling Factor	**1.151720**	**0.863227**	**1.000000**	**1.000000**	**1.070038**	**1.000**	**1.067731**
		D25 &D26					**1.351695**		**1.250000**
		D61					**1.257405**		**1.250000**
After Scaling									
		12 mo. 2010 Final rates after scaling	90,536	48,210	23,459	5,980	289,571	5,408	463,164
2011		D25 &D26	60	10			129		200
		D61	338				9,591		9,929
		Adj for D11	16,401	(16,401)					
		Adj for D61	(76)	76					
		Adj for D63	(12)	12					
	(4)	Total	107,248	31,907	23,459	5,980	299,291	5,408	473,293

Table 2

Breakdown of Transmission Rate

All Revenue in $'000's

Based on 2010 Final Rate Application

	Demand Related Portion	Energy Related Portion	Total Trans Revenue
D11	14,240	4,533	18,774
D61	227	88	315
D63	35	14	48

Factored Future Costs for 2011

	Demand Related Portion	Energy Related Portion	Total Trans Revenue	(F) Scaling Factor
D11	16,401	3,913	20,314.33933	**1.082057**
D61	261	76	337.73300	**1.070896**
D63	40	12	51.92197	**1.071095**

Table Summary

Table 1, Row 1 sets out the forecast revenue for 2011 based on ATCO Electric's current 2010 Final Rates. The revenues are split out by the transmission component in Column (A) and Column (B), which relates to recovery of costs under the distribution rates associated with transmission access - by demand and energy. An adjustment to revenues (between Demand and Energy components) for D11, D61, and D63 was made to align it with the allocation of costs based on ATCO Electric's Phase II transmission cost of service study. Column (C) and (D) relate to demand and energy revenue associated with direct connect transmission customers, and Column (E) relates to the revenue required to collect costs specifically associated with the distribution and service functions by all classes. Rider A1 has been excluded from this calculation. Row (2) sets out the revenue requirement for 2011, or the "target" revenue in which the rates are designed to achieve. In order to get the forecast revenue equal to the forecast revenue requirement, the distribution and transmission components of the distribution rates will be adjusted by the scaling factor in Row (3). This applies to all rate classes except for the distribution component for Rates D25, D26 and D61.

In Decision 2009-231, ATCO Electric was ordered to transition rates D25, D26 and D61 to within the 95-105% revenue to cost ratio over a 5 year time frame. To do so, the distribution scaling factor for these rate classes are higher than the other rate classes. This transition process will be evaluated during the next Phase II application.

However, for rates D11, D61, and D63 -- since these rates recover total transmission revenue under only one component (demand or energy) while the costs are incurred under both demand and energy, the scaling factor is iterated against the weighted average of the demand and energy related costs until the revenue equals the costs recovered under the rate.

Since ATCO Electric now flows through the AESO rates to direct connect transmission customers, there is no requirement to adjust the transmission demand and energy revenue in Column (C) and (D).

The total revenue after the scaling factor is applied is set out in Row (4), Table 1.

PRICE SCHEDULE INDEX

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company. Price Schedule D11 is available for use by a single and separate household through a single-phase service at secondary voltage through a single meter. Price Schedule D11 is not applicable for commercial or industrial use.

Price

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

	Customer Charge	Energy Charge
Transmission	-	1.89 ¢ / kW.h
Distribution	69.66 ¢ / day	5.68 ¢ / kW.h
Service	27.05 ¢ / day	-
TOTAL PRICE	**96.71 ¢ / day**	**7.57 ¢ / kW.h**

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 period 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	-	10.62 ¢/kW/day	0.37 ¢ / kW.h	0.37 ¢ / kW.h
Distribution	-	19.06 ¢/kW/day	3.51 ¢ / kW.h	-
Service	34.86 ¢ / day	-	-	-
TOTAL PRICE	**34.86 ¢ / day**	**29.68 ¢/kW/day**	**3.88 ¢ / kW.h**	**0.37 ¢ / kW.h**

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

(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) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

(e) 5 kilowatts.

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 period 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	22.55 ¢ / kW.h	7.48 ¢ / kW.h
Service	-	-
TOTAL PRICE	**23.06 ¢ / kW.h**	**7.99 ¢ / kW.h**

The billing demand applied to determine the billing energy per block of energy charge for the Transmission, Distribution and Service charges shall be the higher of:

(a) the highest metered demand during the billing period;

(b) the estimated demand;

(c) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

(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)

ATCO Electric

Price Schedule D24
Standard Small General Service
Isolated Industrial Areas

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 period 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	-	19.06 ¢/kW/day	3.51 ¢ / kW.h	-
Service	34.86 ¢ / day	-	-	-
TOTAL PRICE	**34.86 ¢ / day**	**19.06 ¢/kW/day**	**3.51 ¢ / 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 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 Distribution Contract Demand (DCD);

(e) 5 kilowatts.

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 period 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	-	11.00 ¢/kW/day	0.37 ¢ / kW.h
Distribution	-	16.09 ¢/kW/day	-
Service	32.17 ¢ / day	-	-
TOTAL PRICE	**32.17 ¢ / day**	**27.09 ¢/kW/day**	**0.37 ¢ / kW.h**

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

(a) the highest metered demand during the billing period;

(b) the estimated demand;

(c) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

(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. **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.

2. **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.

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, 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 period 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	-	11.00 ¢/kW/day	0.37 ¢ / kW.h
Distribution	-	5.07 ¢/kW/day	-
Service	32.17 ¢ / day	-	-
TOTAL PRICE	**32.17 ¢ / day**	**16.07 ¢/kW/day**	**0.37 ¢ / kW.h**

Customers outside of the REA O & M Pool

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	11.00 ¢/kW/day	0.37 ¢ / kW.h
Distribution	-	-	-
Service	32.17 ¢ / day	-	-
TOTAL PRICE	**32.17 ¢ / day**	**11.00 ¢/kW/day**	**0.37 ¢ / kW.h**

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

(a) the highest metered demand during the billing period;

(b) the estimated demand;

(c) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

(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. **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.

2. **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.

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, single or three-phase distribution connected, for all Points of Service throughout the territory served by the Company. This rate is not applicable for any new Small Oilfield and Pumping Power service with yearly average operating demands of less than 75 kW, effective January 1, 2008.
- 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 period 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	-	15.68 ¢/kW/day	18.22 ¢/kW/day	0.36 ¢ / kW.h
Distribution	15.25 ¢ /day	22.18 ¢/kW/day	17.40 ¢/kW/day	-
Service	$2.3616 /day	-	0.71 ¢/kW/day	-
TOTAL PRICE	**$2.5141 /day**	**37.86 ¢/kW/day**	**36.33 ¢/kW/day**	**0.36 ¢ / 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 24-month 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 shall 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 20.17 ¢/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, for all Points of Service throughout the territory served by the Company 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 period 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	1.50 ¢/kW/day	-	-
Service	10.21 ¢/kW/day	-	-
TOTAL PRICE	**11.71 ¢/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) for Customers served from diversified PODs, or 90%of the TCD for Customers served from dedicated PODs;

(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 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 period 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	-	15.68 ¢/kW/day	18.22 ¢/kW/day	0.36 ¢ / kW.h
Distribution	15.25 ¢ /day	22.18 ¢/kW/day	17.40 ¢/kW/day	-
Service	$2.3616 /day	-	0.71 ¢/kW/day	-
TOTAL PRICE	**$2.5141 /day**	**37.86 ¢/kW/day**	**36.33 ¢/kW/day**	**0.36 ¢ / 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 24-month period including 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 shall 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 20.17 ¢/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:

(0.014% 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:

(0.005% 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

1. **Price Options** - the following price options may apply:
   Idle Service (Option F)
   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)
   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 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.
- Telemetering 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 period 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	15.25 ¢ /day	22.18 ¢/kW/day	17.40 ¢/kW/day	-	-
Service	$2.3616 /day	-	0.71 ¢/kW/day	-	-
TOTAL PRICE	**$2.5141 /day + AESO DOS Rate**	**22.18 ¢/kW/day**	**18.11 ¢/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 and third 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)

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: _____

Date of Request: _____

Time of Request: _____

1. OPPORTUNITY CONTRACT PERIOD:

Start Date: _____ **Start Time:** _____

End Date: _____ **End Time:** _____

Number of Hours in Contract Period: _____ **Hours**

2. TRANSMISSION OPPORTUNITY SERVICE OPTION:

AESO "DEMAND OPPORTUNITY SERVICE": DOS 7 Minutes: _____

DOS 1 Hour: _____

DOS Term: _____

3. OPPORTUNITY CONTRACT DEMAND: _____ **kW**

4. BASE DEMAND:

Large General Service/Industrial Price Schedule D31 Base Demand: _____ kW

Sum of Demands on all Opportunity Service Contracts: _____ kW

Total Base Demand: _____ kW

Confirmation: 1) _____ for ATCO Electric

2) _____ for _____

Availability

- For System Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company 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.
- Telemetering 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 period 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)

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: _____

Date of Request: _____

Time of Request: _____

1. OPPORTUNITY CONTRACT PERIOD

Start Date: _____ **Start Time:** _____

End Date: _____ **End Time:** _____

Number of Hours in Contract Period: _____ **Hours**

2. TRANSMISSION OPPORTUNITY SERVICE OPTION:

AESO "DEMAND OPPORTUNITY SERVICE":

DOS 7 Minutes: _____

DOS 1 Hour: _____

DOS Term: _____

3. OPPORTUNITY CONTRACT DEMAND: _____ **kW**

4. BASE DEMAND:

Large General Service/Industrial Price Schedule T31 Base Demand: _____ kW

Sum of Demands on all Opportunity Service Contracts: _____ kW

Total Base Demand: _____ kW

Confirmation: 1) _____ for ATCO Electric

2) _____ for _____

ATCO Electric

Price Schedule D34
Large General Service/Industrial
Isolated Industrial Areas

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. This rate is not applicable for any new Small Oilfield and Pumping Power service with yearly average operating demands of less than 75 kW, effective January 1, 2008.

Price

Charges for service in any one billing period 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**		**Energy Charge**
		For the first 500 kW of billing demand	For all billing demand over 500 kW	
Distribution	15.25 ¢ /day	22.18 ¢/kW/day	17.40 ¢/kW/day	-
Service	$2.3616 /day	-	0.71 ¢/kW/day	-
TOTAL PRICE	**$2.5141 /day**	**22.18 ¢/kW/day**	**18.11 ¢/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 shall 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 20.17 ¢/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. This rate is available only to new Points of Service for production energy requirements in the petroleum and natural gas industries including related operations, such as rectifiers, cathodic protection and radio transmitters with yearly average operating demand less than 75 kilowatts, effective January 1, 2008.

Price

Charges for service in any one billing period 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	-	13.32 ¢/kW/day	0.37 ¢ / kW.h
Distribution	52.72 ¢ / day	48.98 ¢/kW/day	-
Service	92.79 ¢ / day	-	-
TOTAL PRICE	**$1.4551 / day**	**62.30 ¢/kW/day**	**0.37 ¢ / kW.h**

The billing demand for the Transmission, 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) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

(e) 4 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**.

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 44.59¢/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. This rate is available only to new Points of Service for production energy requirements in the petroleum and natural gas industries including related operations, such as rectifiers, cathodic protection and radio transmitters with yearly average operating demand less than 75 kilowatts, effective January 1, 2008.

Price

Charges for service in any one billing period 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	52.72 ¢ / day	48.98 ¢/kW/day
Service	92.79 ¢ / day	-
TOTAL PRICE	**$1.4551 / day**	**48.98 ¢/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) 4 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**.

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 44.59¢/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 period 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	-	7.02 ¢/kV.A/day	0.37 ¢ / kW.h
Distribution	-	9.08 ¢/kV.A/day	-
Service	30.85 ¢ / service / day	-	-
REA Specific Charges	See REA Tariff	-	-
Total Price	**C_1 ¢ / service/ day**	**16.10 ¢/kV.A/day**	**0.37 ¢ / kW.h**

REA Farms Outside of O & M Pool

	Customer Charge	Demand Charge	Energy Charge
Transmission	-	7.02 ¢/kV.A/day	0.37 ¢ / kW.h
Distribution	See REA Tariff	See REA Tariff	-
Service	See REA Tariff	-	-
REA Specific Charges	See REA Tariff	-	-
Total Price	**C_1 ¢ / service /day**	**D_1 ¢/kV.A/day**	**0.37 ¢ / 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.

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 set out 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 period 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	-	7.02 ¢/kV.A/day	0.37 ¢ / kW.h
Distribution	-	-	-
Service	26.12 ¢/service/day	-	-
TOTAL PRICE	**26.12 ¢/service/day**	**7.02 ¢/kV.A/day**	**0.37 ¢ / 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.

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 period 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	-	7.02 ¢/kV.A/day	0.37 ¢ / kW.h
Distribution	27.37 ¢/service/day	11.93 ¢/kV.A/day	0.59 ¢ / kW.h
Service	30.85 ¢/service/day	-	-
TOTAL PRICE	**58.22 ¢/service/day**	**18.95 ¢/kV.A/day**	**0.96 ¢ / 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.

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 period 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	-	0.017 ¢/watt/day
Distribution	31.15 ¢/fixture/day	0.031 ¢/watt/day
Service	7.25 ¢/fixture/day	-
TOTAL PRICE	**38.40 ¢/fixture/day**	**0.048 ¢/watt/day**

Investment Option (61 B)

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

	All Lamps	
	Customer Charge	**Demand Charge**
Transmission	-	0.017 ¢/watt/day
Distribution	85.51 ¢/fixture/day	0.031 ¢/watt/day
Service	7.25 ¢/fixture/day	-
TOTAL PRICE	**92.76 ¢/fixture/day**	**0.048 ¢/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	-	0.017 ¢/watt/day
Distribution	41.11 ¢/fixture/day	0.031 ¢/watt/day
Service	7.25 ¢/fixture/day	-
TOTAL PRICE	**48.36 ¢/fixture/day**	**0.048 ¢/watt/day**

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	-	0.017 ¢/watt/day
Distribution	31.15 ¢/fixture/day	0.031 ¢/watt/day
Service	7.25 ¢/fixture/day	-
TOTAL PRICE	**38.40 ¢/fixture/day**	**0.048 ¢/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 period 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	-	0.019 ¢/watt/day
Distribution	25.90 ¢/fixture/day	0.022 ¢/watt/day
Service	13.54 ¢/fixture/day	-
TOTAL PRICE	**39.44 ¢/fixture/day**	**0.041 ¢/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	-	0.019 ¢/watt/day
Distribution	41.76 ¢/fixture/day	0.022 ¢/watt/day
Service	13.54 ¢/fixture/day	-
TOTAL PRICE	**55.30 ¢/fixture/day**	**0.041 ¢/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	-	0.019 ¢/watt/day
Distribution	13.74 ¢/fixture/day	0.006 ¢/watt/day
Service	13.54 ¢/fixture/day	-
TOTAL PRICE	**27.28 ¢/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	-	0.019 ¢/watt/day
Distribution	27.49 ¢/fixture/day	0.022 ¢/watt/day
Service	13.54 ¢/fixture/day	-
TOTAL PRICE	**41.03 ¢/fixture/day**	**0.041 ¢/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	-	0.019 ¢/watt/day
Distribution	17.97 ¢/fixture/day	0.022 ¢/watt/day
Service	13.54 ¢/fixture/day	-
TOTAL PRICE	**31.51 ¢/fixture/day**	**0.041 ¢/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, First Nations reserves and Metis settlements	The price schedule monthly Distribution Customer Charge plus the Transmission Customer Charge.
D21 D22	Service outside cities, towns, villages, hamlets, First Nations 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 the installed breaker size or the contracted demand whichever is greater.
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

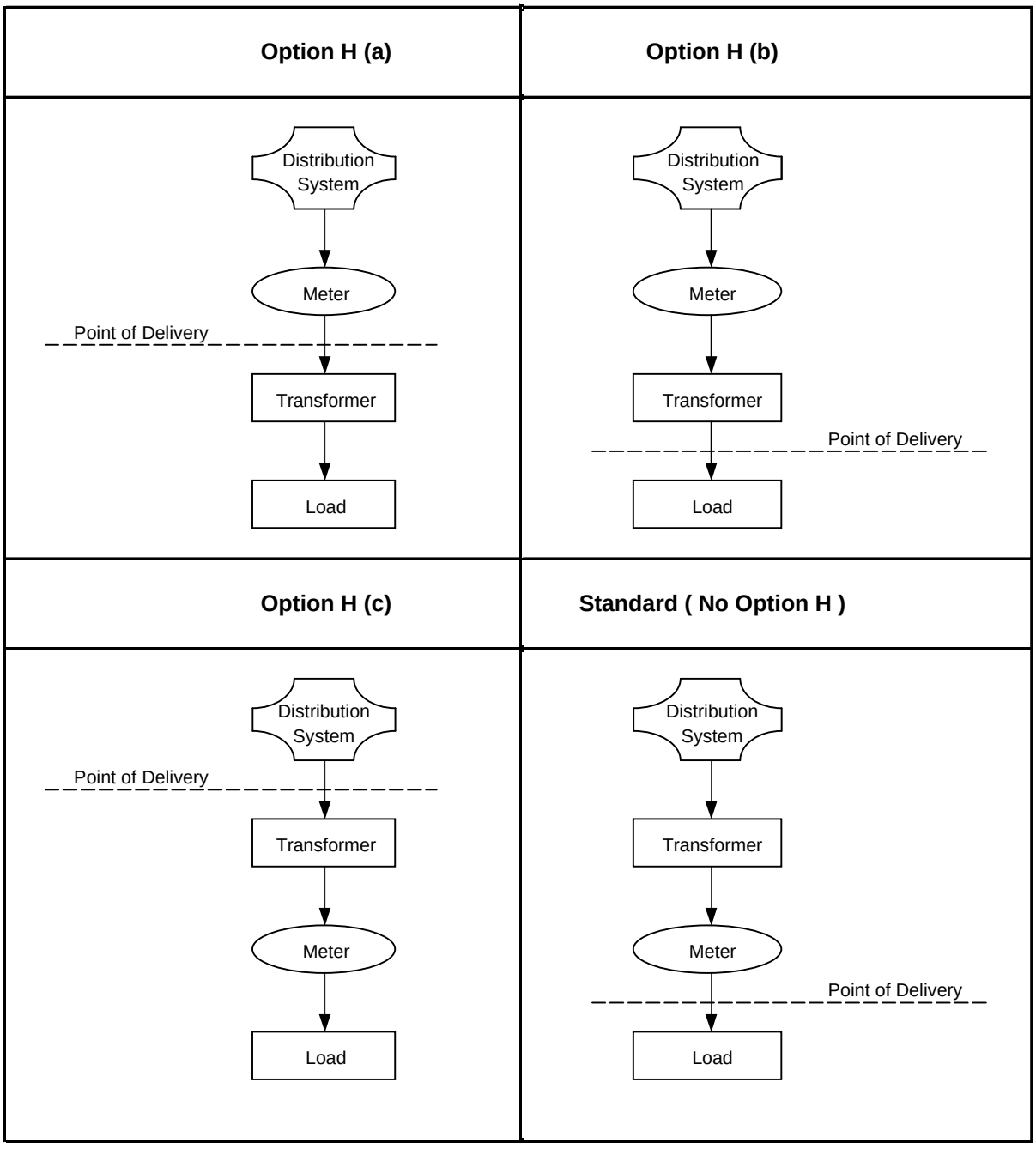
(a) If the point of delivery and metering is on the primary side (25 kV) of a transformer (including cases where one-point service is required by the customer for more than a single utilization voltage or point of use), and the customer owns or rents the necessary transformer(s), a **discount of 3.67 ¢/kW/day** of billing demand will be applied. This adjustment does not apply o 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.

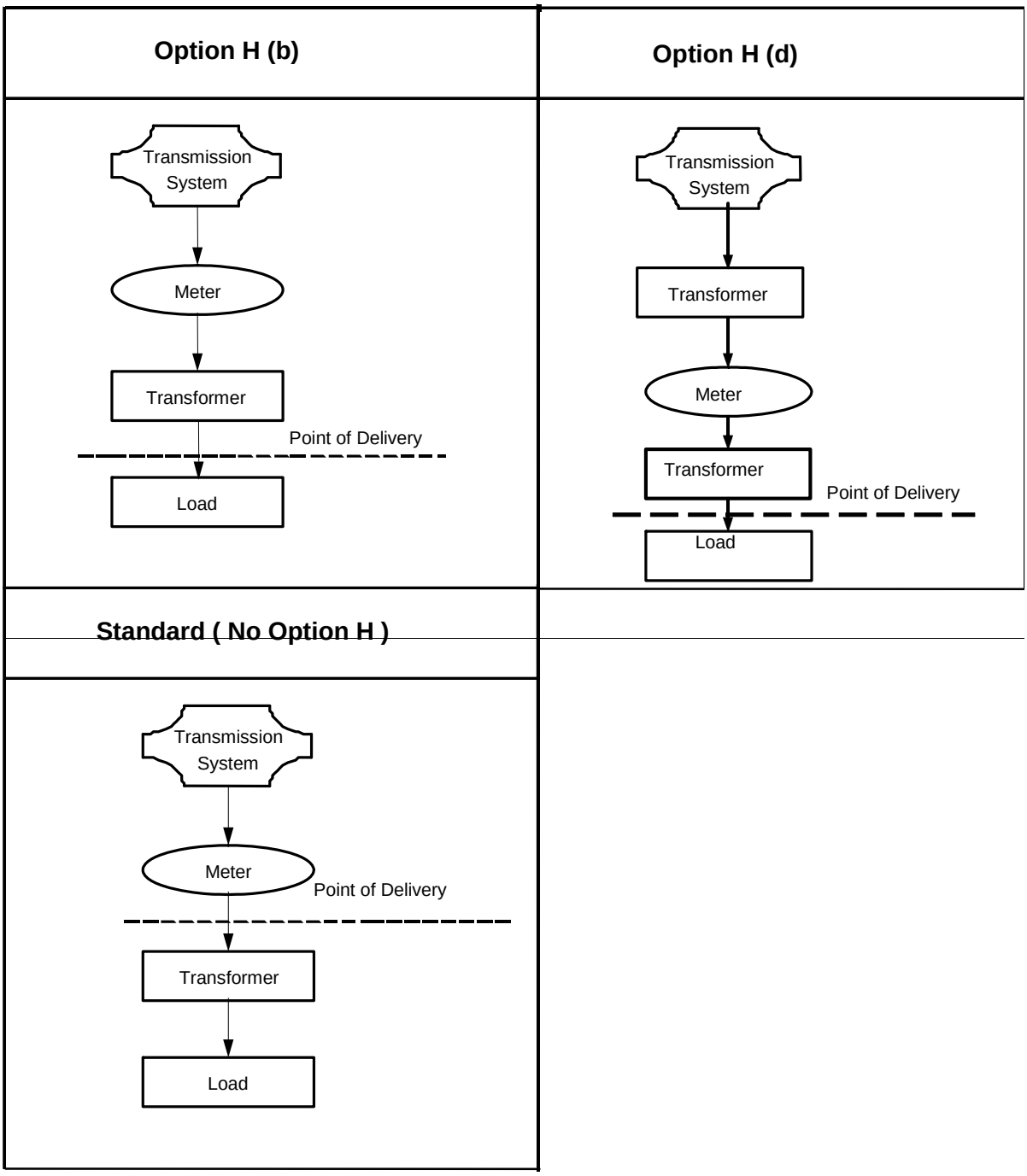
(c) If primary or higher voltage delivery is made to customer owned transformers, but metering is at secondary or utilization voltage for the Company's convenience, **demand and energy measurements will be increased by 1%** so as to approximate primary or transmission voltage delivery conditions and **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 3.67 ¢/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 46% 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 33% 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 First Nations 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
Andrew 8+6
Beaverlodge 8+6
Berwyn 8+6
Big Valley 8+6
Bonnyville 8+6
Botha 8+6
Carbon 7
Castor 8+6
Cereal 7
Cold Lake 8+6
Consort 8+6
Coronation 8+6
Delburne 8+6
Delia 8+6
Derwent 8+6
Dewberry 8+6
Donalda 8+6
Donnelly 8+6
Drumheller 8+6
Elk Point 8+6
Elnora 8+6
Empress 8+6
Fairview 8+6
Falher 8+6
Forestburg 8+6
Fort McMurray 7
Fox Creek 8+6
Gadsby 8+6
Galahad 8+6
Girouxville 7
Glendon 8+6
Grande Cache 8+6
Grande Prairie 8+6
Grimshaw 8+6
Halkirk 8+6
Hanna 8+6
Heisler 8+6
High Level 8+6
High Prairie 8+6
Hines Creek 8+6
Hythe 8+6
Innisfree 8+6
ID Jasper 7
Jasper Nat'l Park 5
Kinuso 8+6
Kitscoty 8+6
Linden 8+6
Lloydminster 8+6
Manning 7
Mannville 8+6
Marwayne 8+6
McLennan 7
Minburn 8+6
Morrin 7
Mundare 6
Munson 8+6
Myrnam 8+6
Nampa 7
Oyen 8+6
Paradise Valley 8+6
Peace River 8+6
Radway (County 7) 8+6
Rainbow Lake 8+6
Rosalind 8+6
Rycroft 8+6
Sexsmith 7
Slave Lake 8+6
Smoky Lake 8+6
Spirit River 8+6
St Paul 8+6
Stettler 7+6
Swan Hills 8+6
Three Hills 8+6
Trochu 8+6
Two Hills 8+6
Valleyview 8+6
Vegreville 8+6
Vermilion 8+6
Veteran 8+6
Vilna 8+6
Waskatenau 8+6
Wembley 7
Willingdon 8+6
Youngstown 7+6

Table 2 – Category Numbers of Municipalities

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

Bonnyville Beach
Horseshoe Bay
Lavoy
Pelican Narrows
Rochon Sands
Wanham
Warspite
Whitesands
County No. 01 Grande Pr.
County No. 06 Stettler
County No. 07 Thorhild
County No. 13 Smoky Lake
County No. 16 Wheatland
County No. 18 Paintearth
County No. 19 St. Paul
County No. 21 Two Hills
County No. 22 Camrose
County No. 23 Red Deer
County No. 24 Vermilion R.
County No. 27 Minburn
County No. 29 Flagstaff
County No. 30 Lamont
County No. 89 Lakeland
M.D. of Badlands No. 07
M.D. of Greenview No. 16
M.D. of Opportunity No. 17
M.D. of Wood Buffalo No. 18
M.D. of Birch Hills No. 19
M.D. of Saddle Hills No. 20
M.D. of Clear Hills No. 21
M.D. of Northern Lights No. 22
M.D. of Mackenzie No. 23
M.D. of Acadia No. 34
M.D. of Starland No. 47
M.D. of Kneehill No. 48
M.D. of Bonnyville No. 87
M.D. of Bonnyville Annexed No. 88
M.D. of Lesser Slave River No. 124
M.D. of Big Lake No. 125
M.D. of Smoky R. No. 130
M.D. of East Peace No. 131
M.D. of Spirit River No. 133
M.D. of Peace No. 135
M.D. of Fairview No. 136
I.D. No. 12 & ID No. 24
Allison Bay B219
Fort McMurray Band B352
Peavine N172
Gift Lake N173
East Prairie N174
Elizabeth N187
Fishing Lake N188
Paddle Prairie N221
Special Areas
Sturgeon Lake I.R. #154
Whitefish Lake Band B924
Ft. Mackay Settlement B982

*Move to Category 8+6, with the new Franchise Agreement

Table 3 – Original Style Franchise Agreement (Percent of Wires Revenue by Municipality - Category 7)

Carbon	3.50%	McLennan	8.25%	Youngstown	4.00%
Cereal	5.00%	Morrin	6.00%		
Fort McMurray	7.60%	Nampa	5.00%		
Girouxville	7.00%	Sexsmith	8.20%		
Jasper (ID)	7.50%	Stettler	7.50%		
Manning	7.50%	Wembley	6.70%		

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

Alliance	6.00%	Fox Creek	4.50%	Oyen	6.00%
Andrew	2.00%	Gadsby	5.00%	Paradise Valley	2.00%
Beaverlodge	6.50%	Galahad	3.00%	Peace River	6.00%
Berwyn	1.75%	Glendon	1.50%	Radway	0.00%
Big Valley	1.00%	Grande Cache	4.60%	Rainbow Lake	7.75%
Bonnyville	6.80%	Grande Prairie	7.75%	Rosalind	0.50%
Botha	3.00%	Grimshaw	6.00%	Rycroft	1.04%
Castor	5.00%	Halkirk	1.00%	Slave Lake	9.30%
Cold Lake	4.25%	Hanna	3.50%	Smoky Lake	3.25%
Consort	3.50%	Heisler	0.00%	Spirit River	4.50%
Coronation	3.75%	High Level	6.50%	St Paul	7.00%
Delia	0.50%	High Prairie	6.25%	Swan Hills	4.00%
Delburne	1.50%	Hines Creek	2.25%	Three Hills	6.00%
Derwent	6.00%	Hythe	5.00%	Trochu	3.50%
Dewberry	0.00%	Innisfree	1.50%	Two Hills	4.25%
Donalda	1.50%	Kinuso	3.50%	Valleyview	5.25%
Donnelly	2.25%	Kitscoty	5.00%	Vegreville	5.00%
Drumheller	9.00%	Linden	4.00%	Vermilion	3.50%
Elk Point	3.60%	Lloydminster	10.50%	Veteran	3.00%
Elnora	1.00%	Mannville	4.50%	Vilna	5.00%
Empress	2.00%	Marwayne	2.30%	Waskatenau	0.00%
Fairview	6.00%	Minburn	1.00%	Willingdon	2.00%
Falher	6.25%	Munson	1.00%		
Forestburg	5.00%	Myrnam	2.00%		

Price

Charges in any one billing period will be the application of the Rider A1 Surcharge determined for each individual Point of Service. The surcharge for each municipality is listed in Table 5.

Table 5 - Rider A1 Surcharges

	Rider A1 (Due to Cat. 5,6 & 7) Surcharge	Effective Date	Rider A1 (Due to Cat.8) Surcharge	Effective Date	Rider A1 Total Surcharge
ALLIANCE	0.00	1-Oct-2010	6.00	1-Jan-2005	6.00
ANDREW	1.10	1-Oct-2010	2.00	1-Jan-2005	3.10
BEAVERLODGE	5.57	1-Oct-2010	6.50	1-Jul-2010	12.07
BERWYN	2.85	1-Oct-2010	1.75	1-Jan-2007	4.60
BIG VALLEY	5.47	1-Oct-2010	1.00		6.47
BONNYVILLE	1.48	1-Oct-2010	6.80	1-Jan-2003	8.28
BONNYVILLE BEACH S.V.	0.00	1-Oct-2010	0.00		0.00
BOTHA	3.48	1-Oct-2010	3.00	1-Jan-2010	6.48
CARBON	3.52	1-Oct-2010	0.00		3.52
CASTOR	0.87	1-Oct-2010	5.00	1-Jan-2007	5.87
CEREAL	4.87	1-Oct-2010	0.00		4.87
COLD LAKE	0.27	1-Oct-2010	4.25	1-Jan-2003	4.52
CONSORT	2.97	1-Oct-2010	3.50	1-Jan-2007	6.47
CORONATION	2.38	1-Oct-2010	3.75	1-Jan-2004	6.13
DELBURNE	2.24	1-Oct-2010	1.50	1-Jan-2008	3.74
DELIA	0.00	1-Oct-2010	0.50	1-Jan-2003	0.50
DERWENT	2.19	1-Oct-2010	6.00	1-Aug-2008	8.19
DEWBERRY	0.00	1-Oct-2010	0.00	1-Jan-2003	0.00
DONALDA	0.00	1-Oct-2010	1.50	1-Nov-2002	1.50
DONNELLY	5.96	1-Oct-2010	2.25	1-Jan-2010	8.21
DRUMHELLER	0.99	1-Oct-2010	9.00	1-Apr-2003	9.99
ELK POINT	2.77	1-Oct-2010	3.60	1-Jan-2003	6.37
ELNORA	0.39	1-Oct-2010	1.00	1-Jan-2003	1.39
EMPRESS	0.00	1-Oct-2010	2.00	1-Jan-2007	2.00
FAIRVIEW	0.00	1-Oct-2010	6.00	1-Jan-2003	6.00
FALHER	1.44	1-Oct-2010	6.25	1-Jan-2006	7.69
FORESTBURG	3.46	1-Oct-2010	5.00	1-Jan-2010	8.46
FORT MCMURRAY	4.22	1-Oct-2010	0.00		4.22
FOX CREEK	0.49	1-Oct-2010	4.50	1-Jan-2003	4.99
GADSBY	0.00	1-Oct-2010	5.00	1-Jan-2008	5.00
GALAHAD	1.91	1-Oct-2010	3.00	1-Jan-2010	4.91
GIROUXVILLE	4.39	1-Oct-2010	0.00		4.39
GLENDON	2.38	1-Oct-2010	1.50	1-Jan-2003	3.88
GRANDE CACHE	1.96	1-Oct-2010	4.60	1-Jan-2003	6.56
GRANDE PRAIRIE	2.27	1-Oct-2010	7.75	1-Jan-2005	10.02
GRIMSHAW	4.51	1-Oct-2010	6.00	1-Jul-2010	10.51
HALKIRK	0.00	1-Oct-2010	1.00	1-Jan-2003	1.00
HANNA	0.37	1-Oct-2010	3.50	1-Jan-2003	3.87
HEISLER	2.72	1-Oct-2010	0.00	24-Mar-2003	2.72
HIGH LEVEL	0.02	1-Oct-2010	6.50	1-Jan-2003	6.52
HIGH PRAIRIE	3.64	1-Oct-2010	6.25	1-Feb-2008	9.89
HINES CREEK	3.68	1-Oct-2010	2.25	1-Jan-2009	5.93
HORSESHOE BAY S.V.	0.00	1-Oct-2010	0.00		0.00
HYTHE	5.49	1-Oct-2010	5.00	1-Jul-2010	10.49
INNISFREE	1.26	1-Oct-2010	1.50	1-Jan-2006	2.76

Table 5 - Rider A1 Surcharges

	Rider A1 (Due to Cat. 5,6 & 7) Surcharge	Effective Date	Rider A1 (Due to Cat.8) Surcharge	Effective Date	Rider A1 Total Surcharge
JASPER OUTSIDE TOWN	0.00	1-Jul-2009	0.00		0.00
JASPER INSIDE TOWN	7.59	1-Oct-2010	0.00		7.59
KINUSO	0.35	1-Oct-2010	3.50	1-Jan-2003	3.85
KITSCOTY	3.94	1-Oct-2010	5.00	1-Jan-2010	8.94
LAVOY	0.79	1-Oct-2010	0.00		0.79
LINDEN	4.11	1-Oct-2010	4.00	1-Jan-2003	8.11
LLOYDMINSTER (AB)	0.47	1-Oct-2010	10.50	1-Jan-2008	10.97
LLOYDMINSTER (SASK)	0.47	1-Oct-2010	10.50	1-Jan-2008	10.97
MANNING	7.05	1-Dec-2003	0.00		7.05
MANNVILLE	1.33	1-Oct-2010	4.50	1-Jan-2009	5.83
MARWAYNE	2.16	1-Oct-2010	2.30	1-Jan-2006	4.46
MCLENNAN	4.54	1-Oct-2010	0.00		4.54
MEDLEY	0.00	1-Sep-2001	0.00		0.00
MINBURN	0.00	1-Oct-2010	1.00	15-Apr-2008	1.00
MORRIN	5.56	1-Jun-2005	0.00		5.56
MUNDARE	1.26	1-Oct-2010	0.00		1.26
MUNSON	6.14	1-Oct-2010	1.00	1-Jul-2010	7.14
MYRNAM	0.00	1-Oct-2010	2.00	1-Feb-2008	2.00
NAMPA	4.72	1-Jun-2005	0.00		4.72
OYEN	0.00	1-Oct-2010	6.00	1-Jan-2009	6.00
PARADISE VALLEY	2.08	1-Jul-2009	2.00	1-Jan-2006	4.08
PEACE RIVER	1.68	1-Oct-2010	6.00	1-Jan-2010	7.68
PELICAN NARROWS S.V.	0.00	1-Oct-2010	0.00		0.00
RADWAY	0.00	1-Oct-2010	0.00	1-Jul-2010	0.00
RAINBOW LAKE	0.61	1-Oct-2010	7.75	1-Jan-2005	8.36
ROCHON SANDS S.V.	0.00	1-Oct-2010	0.00		0.00
ROSALIND	0.21	1-Oct-2010	0.50	1-Jan-2003	0.71
RYCROFT	6.34	1-Oct-2010	1.04	1-Jul-2010	7.38
SEXSMITH	5.66	1-Oct-2010	0.00		5.66
SLAVE LAKE	1.28	1-Jul-2009	9.30	1-Jan-2010	10.58
SMOKY LAKE	1.05	1-Oct-2010	3.25	1-Jan-2004	4.30
SPIRIT RIVER	1.51	1-Oct-2010	4.50	1-Jan-2003	6.01
ST. PAUL	1.45	1-Jul-2009	7.00	1-Jan-2003	8.45
STETTLER	5.41	1-Oct-2010	0.00		5.41
SWAN HILLS TOWN	1.96	1-Oct-2010	4.00	1-Jan-2003	5.96
THREE HILLS	1.53	1-Oct-2010	6.00	1-Jan-2009	7.53
TORRINGTON	0.92	1-Jul-2009	0.00		0.92
TROCHU	2.63	1-Oct-2010	3.50	1-Jan-2003	6.13
TWO HILLS	1.68	1-Oct-2010	4.25	1-Jan-2009	5.93
VALLEYVIEW	1.83	1-Oct-2010	5.25	1-Jan-2006	7.08
VEGREVILLE	0.00	1-Oct-2010	5.00	1-Feb-2008	5.00
VERMILION	0.55	1-Oct-2010	3.50	1-Jan-2003	4.05
VETERAN	1.67	1-Oct-2010	3.00	1-Jan-2008	4.67
VILNA	2.36	1-Oct-2010	5.00	1-Feb-2010	7.36

Table 5 - Rider A1 Surcharges

	Rider A1 (Due to Cat. 5,6 & 7) Surcharge	Effective Date	Rider A1 (Due to Cat.8) Surcharge	Effective Date	Rider A1 Total Surcharge
WANHAM	0.79	1-Oct-2010	0.00		0.79
WARSPITE	1.16	1-Oct-2010	0.00		1.16
WASKATENAU	0.00	1-Oct-2010	0.00	1-Feb-2008	0.00
WEMBLEY	6.23	1-May-2006	0.00		6.23
WHITE SANDS S.V.	3.30	1-Oct-2010	0.00		3.30
WILLINGDON	0.00	1-Oct-2010	2.00	1-Jan-2008	2.00
YOUNGSTOWN	2.39	1-Oct-2010	0.00		2.39
COUNTY OF GRANDE PRAIRIE	0.79	1-Oct-2010	0.00		0.79
COUNTY OF STETTLER	1.47	1-Oct-2010	0.00		1.47
COUNTY OF THORHILD	9.39	1-Jul-2009	0.00		9.39
COUNTY OF SMOKY LAKE	1.16	1-Oct-2010	0.00		1.16
COUNTY OF WHEATLAND	0.39	1-Oct-2010	0.00		0.39
COUNTY OF PAINTEARTH	0.85	1-Oct-2010	0.00		0.85
COUNTY OF ST. PAUL	1.31	1-Jul-2009	0.00		1.31
COUNTY OF TWO HILLS	1.61	1-Oct-2010	0.00		1.61
COUNTY OF CAMROSE	0.61	1-Oct-2010	0.00		0.61
COUNTY OF RED DEER	0.19	1-Oct-2010	0.00		0.19
COUNTY OF VERMILION RIVER (AB)	1.04	1-Jul-2009	0.00		1.04
COUNTY OF VERMILION RIVER (SK)	1.04	1-Jul-2009	0.00		1.04
COUNTY OF MINBURN	0.79	1-Oct-2010	0.00		0.79
COUNTY OF FLAGSTAFF	0.61	1-Oct-2010	0.00		0.61
COUNTY OF LAMONT	1.19	1-Oct-2010	0.00		1.19
COUNTY OF LAKELAND	0.00	1-Mar-2000	0.00		0.00
IMPROVEMENT DISTRICT #12	0.00	1-May-2006	0.00		0.00
IMPROVEMENT DISTRICT #24	0.00	1-Oct-2010	0.00		0.00
SPECIAL AREAS	0.43	1-Oct-2010	0.00		0.43
BIGSTONE-WABASCA I.R. 166	1.42	1-Oct-2010	0.00		1.42
DOGHEAD I.R. 218	0.00	1-Oct-2010	0.00		0.00
ALLISON BAY RESERVE	0.00	1-Oct-2010	0.00		0.00
DRIFTPILE I.R. 150	0.00	1-Oct-2007	0.00		0.00
FT. McMURRAY FIRST NATION	0.24	1-Oct-2010	0.00		0.24
LOON RIVER CREE BAND	6.73	1-Oct-2010	0.00		6.73
BUSHE RIVER I.R. 207	0.51	1-Oct-2010	0.00		0.51
HAY LAKE I.R. 209	0.19	1-Oct-2010	0.00		0.19
UPPER HAY RIVER I.R. 212	0.06	1-Oct-2010	0.00		0.06
STURGEON LAKE I.R. 154	0.40	1-Oct-2010	0.00		0.40
WHITEFISH I.R. 155	0.55	1-Oct-2010	0.00		0.55
FT. MACKAY SETTLEMENT #467	3.34	1-Oct-2010	0.00		3.34
PEAVINE (Metis Sett)	0.75	1-Oct-2010	0.00		0.75
GIFT LAKE (Metis Sett)	1.95	1-Oct-2010	0.00		1.95
EAST PRAIRIE (Metis Sett)	3.88	1-Oct-2010	0.00		3.88
ELIZABETH (Metis Sett)	0.00	1-Oct-2010	0.00		0.00
FISHING LAKE (Metis Sett)	2.39	1-Oct-2010	0.00		2.39
PADDLE PRAIRIE (Metis Sett)	3.32	1-Oct-2010	0.00		3.32
M.D. OF BADLANDS	0.99	1-Oct-2010	9.00		9.99
M.D. OF GREENVIEW	0.50	1-Jul-2009	0.00		0.50

Table 5 - Rider A1 Surcharges

	Rider A1 (Due to Cat. 5,6 & 7) Surcharge	Effective Date	Rider A1 (Due to Cat.8) Surcharge	Effective Date	Rider A1 Total Surcharge
M.D. OF OPPORTUNITY	1.72	1-Jul-2009	0.00		1.72
M.D. OF WOOD BUFFALO	0.34	1-Oct-2010	0.00		0.34
M.D. OF BIRCH HILLS	0.79	1-Oct-2010	0.00		0.79
M.D. OF SADDLE HILLS	0.70	1-Oct-2010	0.00		0.70
M.D. OF CLEAR HILLS	0.24	1-Oct-2010	0.00		0.24
M.D. OF NORTHERN LIGHT	0.29	1-Oct-2010	0.00		0.29
M.D. OF MACKENZIE	0.73	1-Oct-2010	0.00		0.73
M.D. OF ACADIA	0.00	1-Oct-2010	0.00		0.00
M.D. OF STARLAND	0.02	1-Oct-2010	0.00		0.02
M.D. OF KNEEHILL	0.92	1-Jul-2009	0.00		0.92
M.D. OF BONNYVILLE	0.00	1-Jul-2009	0.00		0.00
M.D. OF BONNYVILLE ANNEXD	0.83	1-Jul-2009	0.00		0.83
M.D. OF LESSER SLAVE RIVER	0.43	1-Oct-2010	0.00		0.43
M.D. OF BIG LAKE	1.12	1-Oct-2010	0.00		1.12
M.D. OF SMOKY RIVER	0.43	1-Oct-2010	0.00		0.43
NORTHERN SUNRISE COUNTY	0.70	1-Oct-2010	0.00		0.70
M.D. OF SPIRIT RIVER	0.68	1-Oct-2010	0.00		0.68
M.D. OF PEACE	1.39	1-Oct-2010	0.00		1.39
M.D. OF FAIRVIEW	0.84	1-Jun-2005	0.00		0.84

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 July 1, 2010.
- 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	-0.210
D21 Small General Service	-0.211
D22 Small General Service – Energy Only	-0.211
D25 Irrigation Pumping Service	-0.215
D26 REA Irrigation Pumping Service	-0.215
D31 Large General Service/Industrial – Distribution Connected	-0.210
T31 Large General Service/Industrial – Transmission Connected	Flow through
D32 Generator Interconnection and Standby Power	-0.210
D33 Transmission Opportunity Rate – Distribution Connected	-0.210
T33 Transmission Opportunity Rate – Transmission Connected	Flow through
D41 Small Oilfield and Pumping Power	-0.214
D51 REA Farm Service	-0.212
D52 REA Farm Service – Excluding Wires Service Provider	-0.212
D56 Farm Service	-0.212
D61 Street Lighting Service	-0.209
D63 Private Lighting Service	-0.211

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

Availability

- Applicable to all customers, at points of service, throughout the territory served by the Company for energy consumption effective from August 1, 2010 to July 31, 2011.
- 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	-0.362
D21 Small General Service	-0.089
D22 Small General Service – Energy Only	-0.089
D25 Irrigation Pumping Service	-0.266
D26 REA Irrigation Pumping Service	-0.266
D31 Large General Service/Industrial – Distribution Connected	0.073
T31 Large General Service/Industrial – Transmission Connected	0.003
D32 Generator Interconnection and Standby Power	0.073
D33 Transmission Opportunity Rate – Distribution Connected	0.073
T33 Transmission Opportunity Rate – Transmission Connected	0.003
D41 Small Oilfield and Pumping Power	-0.106
D51 REA Farm Service	0.132
D52 REA Farm Service – Excluding Wires Service Provider	0.132
D56 Farm Service	-0.016
D61 Street Lighting Service	-0.007 ¢/watt/day
D63 Private Lighting Service	-0.004 ¢/watt/day

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

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 outstanding 2003 and 2004 Non-Energy Regulated Rate Tariff (RRT) matters.
- 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, 2010.

Regulated Rate	Applicable Distribution Tariff Price Schedule	Charge (¢/kW.h) "+" = Charge "-" = Refund
E1	D11 Residential	0.000
E2	D21, D22 Small General Service	0.000
E3	D31, T31, D32 Large General Service/Industrial & Generator Interconnection	0.000
E4	D41 Small Oilfield and Pumping Power	0.000
E51	D51, D52 REA Farm Service	0.000
E56	D56 Farm Service	0.000
E6	D61, D63 Lighting Service	0.000
E7	D25, D26 Irrigation Pumping Service	0.000

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

ATCO Electric 2011 Interim Tariff Application
Summary of Rate Impact to Typical Bills (Distribution Tariff Base Rates - Without Retail Energy Purchases)

	January 1, 2010				June 1, 2010				August 1, 2010				January 1, 2011			
Rate Class	DT Base Rates	Rider G	Rider B	Net	DT Base Rates	Rider G	Rider B	Net	DT Base Rates	Rider G	Rider B	Net	DT Base Rates	Rider G	Rider B	Net
D11 Residential **600 kWh**	$69.03	-$6.02	-$2.53	$60.48	$69.47	-$6.02	-$2.53	$60.92	$69.47	-$2.17	-$1.26	$66.04	$74.45	-$2.17	-$1.26	$71.02
D21 Commercial **20 kW; 7300 kWh**	$325.22	-$15.33	-$30.81	$279.09	$333.81	-$15.33	-$30.81	$287.68	$333.81	-$6.50	-$15.40	$311.92	$355.51	-$6.50	-$15.40	$333.61
D25 Irrigation **40 kW; 11,680 kWh**	$1,892.32	-$48.47	-$50.11	$1,793.75	$1,937.28	-$48.47	-$50.11	$1,838.70	$1,937.28	-$31.03	-$25.11	$1,881.14	$2,430.84	-$31.03	-$25.11	$2,374.70
D26 REA Irrigation **40 kW; 11,680 kWh**	$1,151.03	-$48.47	-$50.11	$1,052.45	$1,239.64	-$48.47	-$50.11	$1,141.06	$1,239.64	-$31.03	-$25.11	$1,183.50	$1,487.40	-$31.03	-$25.11	$1,431.26
D31 Industrial **50 kW; 16,650 kWh**	$627.84	$30.30	-$69.93	$588.21	$655.52	$30.30	-$69.93	$615.89	$655.52	$12.22	-$34.97	$632.77	$704.00	$12.22	-$34.97	$681.25
D41 Oilfield **20 kW; 8,760 kWh**	$415.49	-$25.14	-$37.41	$352.94	$422.51	-$25.14	-$37.41	$359.96	$422.51	-$9.24	-$18.75	$394.51	$449.95	-$9.24	-$18.75	$421.96
D51 REA Pooled **7.5 kVA; 1,255 kWh**	$45.89	-$1.20	-$5.33	$39.35	$46.85	-$1.20	-$5.33	$40.31	$46.85	$1.65	-$2.66	$45.84	$50.10	$1.65	-$2.66	$49.09
D56 Farm **7.5 kVA; 1,255 kWh**	$65.62	-$4.64	-$5.33	$55.64	$67.41	-$4.64	-$5.33	$57.43	$67.41	-$0.20	-$2.66	$64.56	$72.11	-$0.20	-$2.66	$69.25
D61 Street Lights **250 Watts**	$12.23	-$3.98	-$0.37	$7.88	$12.24	-$3.98	-$0.37	$7.89	$12.24	-$0.50	-$0.18	$11.55	$15.15	-$0.50	-$0.18	$14.47
D63 Private Lights **250 Watts**	$13.70	-$5.10	-$0.37	$8.23	$13.91	-$5.10	-$0.37	$8.44	$13.91	-$0.29	-$0.19	$13.43	$14.88	-$0.29	-$0.19	$14.40
T31 Industrial **2 MW; 1,022 MWh**	$24,528.62	-$378.14	-$4,088.00	$20,062.48	$24,851.12	-$378.14	-$4,088.00	$20,384.98	$24,851.12	$27.98	-$2,044.00	$22,835.10	$24,966.63	$27.98	-$2,044.00	$22,950.60

Appendix B.1 - Example Rate Rider Effects: Residential Class - RRO Eligible *GST not included*

Row	Rate Component		Rate		Residential Class Consumption Levels Cost per Customer ($/month) 300 kW.h per month	Typical 600 kW.h per month	1,200 kW.h per month
	Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge						
	Effective Date: January *1, 2010*						
1	Energy Rate: January 1, 2010	Energy Charge	$ 0.07139 /kW.h		**$29.37**	**$50.78**	**$93.62**
		Energy Admin Fee	$ 7.95 /month				
2	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h		$0.00	$0.00	$0.00
3	**2010 Energy Related Charge** Row 1 + Row 2				**$29.37**	**$50.78**	**$93.62**
4	AE Interim DT Base Rates	Customer Charge	$ 0.8990 /day		**$48.00**	**$69.03**	**$111.09**
		Energy Charge	$ 0.0701 /kW.h				
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00421 /kW.h		-$4.28	-$8.55	-$17.10
		Rider G	-$ 0.0100 /kW.h				
6	**Net DT Charges** Row 4 + Row 5				**$43.73**	**$60.48**	**$93.99**
7	**Combined Rate: January 1, 2010** Row 3 + Row 6				**$73.09**	**$111.26**	**$187.61**
	Effective Date: June *1, 2010*						
8	Forecast Energy Rate: June 1, 2010	Energy Charge	$ 0.07468 /kW.h		**$30.35**	**$52.76**	**$97.57**
		Energy Admin Fee	$ 7.95 /month				
9	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h		$0.00	$0.00	$0.00
10	**2010 Energy Related Charge** Row 8 + Row 9				**$30.35**	**$52.76**	**$97.57**
11	AE Final DT Base Rates	Customer Charge	$ 0.9038 /day		**$48.29**	**$69.47**	**$111.83**
		Energy Charge	$ 0.0706 /kW.h				
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00421 /kW.h		-$4.28	-$8.55	-$17.10
		Rider G	-$ 0.0100 /kW.h				
13	**Net DT Charges** Row 11 + Row 12				**$44.02**	**$60.92**	**$94.73**
14	**Predicted Combined Rate: June 1, 2010** Row 10 + Row 13				**$74.37**	**$113.68**	**$192.30**
	Effective Date: *August 1, 2010*						
15	Forecast Energy Rate: August 1, 2010	Energy Charge	$ 0.08744 /kW.h		**$34.18**	**$60.41**	**$112.88**
		Energy Admin Fee	$ 7.95 /month				
16	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h		$0.00	$0.00	$0.00
17	**2010 Energy Related Charge** Row 15 + Row 16				**$34.18**	**$60.41**	**$112.88**
18	AE Final DT Base Rates	Customer Charge	$ 0.9038 /day		**$48.29**	**$69.47**	**$111.83**
		Energy Charge	$ 0.0706 /kW.h				
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00210 /kW.h		-$1.72	-$3.43	-$6.86
		Rider G	-$ 0.00362 /kW.h				
20	**Net DT Charges** Row 18 + Row 19				**$46.58**	**$66.04**	**$104.97**
21	**Predicted Combined Rate: August 1, 2010** Row 17 + Row 20				**$80.76**	**$126.46**	**$217.85**
	Effective Date: *January 1, 2011*						
22	Forecast Energy Rate: January 1, 2011	Energy Charge	$ 0.08744 /kW.h		**$34.18**	**$60.41**	**$112.88**
		Energy Admin Fee	$ 7.95 /month				
23	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h		$0.00	$0.00	$0.00
24	**2011 Energy Related Charge** Row 22 + Row 23				**$34.18**	**$60.41**	**$112.88**
25	AE Proposed DT Base Rates	Customer Charge	$ 0.9671 /day		**$51.73**	**$74.45**	**$119.88**
		Energy Charge	$ 0.0757 /kW.h				
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00210 /kW.h		-$1.72	-$3.43	-$6.86
		Rider G	-$ 0.00362 /kW.h				
27	**Net DT Charges** Row 25 + Row 26				**$50.02**	**$71.02**	**$113.02**
28	**Predicted Combined Rate: January 1, 2011** Row 24 + Row 27				**$84.20**	**$131.43**	**$225.90**
	Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010) Row 14 vs Row 7			difference	$1.28	$2.42	$4.69
				%	2%	2%	3%
	Combined Rate (June 1, 2010 - August 1, 2010) Row 21 vs Row 14			difference	$6.39	$12.77	$25.55
				%	9%	11%	13%
	Combined Rate (August 1, 2010 - January 1, 2011) Row 28 vs Row 21			difference	$3.44	$4.98	$8.05
				%	4%	4%	4%

Appendix B.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**		**Rate**	**5,475 kW.h per month Demand 15 kW**	**Typical 7,300 kW.h per month Demand 20 kW**	**9,125 kW.h per month Demand 25 kW**
Effective Date: *January 1, 2010*						
1	Energy Rate: January 1, 2010	Energy Charge	$ 0.07037 /kW.h	**$393.74**	**$522.16**	**$650.59**
		Energy Admin Fee	$ 8.46 /month			
2	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
3	**2010 Energy Related Charge** Row 1 + Row 2			**$393.74**	**$522.16**	**$650.59**
4	AE Interim DT Base Rates	Customer Charge	$ 0.3287 /day	**$246.38**	**$325.22**	**$404.06**
		Energy Charge Blk 1	$ 0.0357 /kW.h			
		Energy Charge Blk 2	$ 0.0048 /kW.h			
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge	$ 0.2612 /kW/day	-$34.60	-$46.14	-$57.67
		Balancing Pool Refund Rider	-$ 0.00422 /kW.h			
		Rider G	-$ 0.0021 /kW.h			
6	**Net DT Charges** Row 4 + Row 5			**$211.78**	**$279.09**	**$346.39**
7	**Combined Rate: January 1, 2010** Row 3 + Row 6			**$605.51**	**$801.25**	**$996.98**
Effective Date: *June 1, 2010*						
8	Forecast Energy Rate: June 1, 2010	Energy Charge	$ 0.07625 /kW.h	**$425.93**	**$565.09**	**$704.24**
		Energy Admin Fee	$ 8.46 /month			
9	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
10	**2010 Energy Related Charge** Row 8 + Row 9			**$425.93**	**$565.09**	**$704.24**
11	AE Final DT Base Rates	Customer Charge	$ 0.3258 /day	**$252.80**	**$333.81**	**$414.82**
		Energy Charge Blk 1	$ 0.0370 /kW.h			
		Energy Charge Blk 2	$ 0.0042 /kW.h			
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge	$ 0.2703 /kW/day	-$34.60	-$46.14	-$57.67
		Balancing Pool Refund Rider	-$ 0.00422 /kW.h			
		Rider G	-$ 0.0021 /kW.h			
13	**Net DT Charges** Row 11 + Row 12			**$218.20**	**$287.68**	**$357.15**
14	**Predicted Combined Rate: June 1, 2010** Row 10 + Row 13			**$644.13**	**$852.76**	**$1,061.40**
Effective Date: *August 1, 2010*						
15	Forecast Energy Rate: August 1, 2010	Energy Charge	$ 0.08789 /kW.h	**$489.66**	**$650.06**	**$810.46**
		Energy Admin Fee	$ 8.46 /month			
16	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
17	**2010 Energy Related Charge** Row 15 + Row 16			**$489.66**	**$650.06**	**$810.46**
18	AE Final DT Base Rates	Customer Charge	$ 0.3258 /day	**$252.80**	**$333.81**	**$414.82**
		Energy Charge Blk 1	$ 0.0370 /kW.h			
		Energy Charge Blk 2	$ 0.0042 /kW.h			
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge	$ 0.2703 /kW/day	-$16.42	-$21.90	-$27.37
		Balancing Pool Refund Rider	-$ 0.00211 /kW.h			
		Rider G	-$ 0.00089 /kW.h			
20	**Net DT Charges** Row 18 + Row 19			**$236.38**	**$311.92**	**$387.45**
21	**Predicted Combined Rate: August 1, 2010** Row 17 + Row 20			**$726.04**	**$961.97**	**$1,197.91**
Effective Date: *January 1, 2011*						
22	Forecast Energy Rate: January 1, 2011	Energy Charge	$ 0.08789 /kW.h	**$489.66**	**$650.06**	**$810.46**
		Energy Admin Fee	$ 8.46 /month			
23	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
24	**2011 Energy Related Charge** Row 22 + Row 23			**$489.66**	**$650.06**	**$810.46**
25	AE Proposed DT Base Rates	Customer Charge	$ 0.3486 /day	**$269.25**	**$355.51**	**$441.78**
		Energy Charge Blk 1	$ 0.0387 /kW.h			
		Energy Charge Blk 2	$ 0.0037 /kW.h			
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge	$ 0.2968 /kW/day	-$16.42	-$21.90	-$27.37
		Balancing Pool Refund Rider	-$ 0.00211 /kW.h			
		Rider G	-$ 0.00089 /kW.h			
27	**Net DT Charges** Row 25 + Row 26			**$252.83**	**$333.61**	**$414.40**
28	**Predicted Combined Rate: January 1, 2011** Row 24 + Row 27			**$742.48**	**$983.67**	**$1,224.86**
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010) Row 14 vs Row 7		difference	$38.62	$51.52	$64.42
			%	6%	6%	6%
	Combined Rate (June 1, 2010 - August 1, 2010) Row 21 vs Row 14		difference	$81.91	$109.21	$136.51
			%	13%	13%	13%
	Combined Rate (August 1, 2010 - January 1, 2011) Row 28 vs Row 21		difference	$16.45	$21.70	$26.95
			%	2%	2%	2%

Appendix B.3 - Example Rate Rider Effects: Small General Service Class - Non 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		Rate	5,475 kW.h per month Demand 15 kW	Typical 7,300 kW.h per month Demand 20 kW	9,125 kW.h per month Demand 25 kW
Effective Date: *January 1, 2010*						
1	Energy Rate: January 1, 2010	Energy Charge	$ 0.07037 /kW.h	**$393.74**	**$522.16**	**$650.59**
		Energy Admin Fee	$ 8.46 /month			
2	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
3	**2010 Energy Related Charge** Row 1 + Row 2			**$393.74**	**$522.16**	**$650.59**
4	AE Interim DT Base Rates	Customer Charge	$ 0.3287 /day	**$246.38**	**$325.22**	**$404.06**
		Energy Charge Blk 1	$ 0.0357 /kW.h			
		Energy Charge Blk 2	$ 0.0048 /kW.h			
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge	$ 0.2612 /kW/day	-$34.60	-$46.14	-$57.67
		Balancing Pool Refund Rider	-$ 0.00422 /kW.h			
		Rider G	-$ 0.0021 /kW.h			
6	**Net DT Charges** Row 4 + Row 5			**$211.78**	**$279.09**	**$346.39**
7	**Combined Rate: January 1, 2010** Row 3 + Row 6			**$605.51**	**$801.25**	**$996.98**
Effective Date: *June 1, 2010*						
8	Forecast Energy Rate: June 1, 2010	Energy Charge	$ 0.07625 /kW.h	**$425.93**	**$565.09**	**$704.24**
		Energy Admin Fee	$ 8.46 /month			
9	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
10	**2010 Energy Related Charge** Row 8 + Row 9			**$425.93**	**$565.09**	**$704.24**
11	AE Final DT Base Rates	Customer Charge	$ 0.3258 /day	**$252.80**	**$333.81**	**$414.82**
		Energy Charge Blk 1	$ 0.0370 /kW.h			
		Energy Charge Blk 2	$ 0.0042 /kW.h			
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge	$ 0.2703 /kW/day	-$34.60	-$46.14	-$57.67
		Balancing Pool Refund Rider	-$ 0.00422 /kW.h			
		Rider G	-$ 0.0021 /kW.h			
13	**Net DT Charges** Row 11 + Row 12			**$218.20**	**$287.68**	**$357.15**
14	**Predicted Combined Rate: June 1, 2010** Row 10 + Row 13			**$644.13**	**$852.76**	**$1,061.40**
Effective Date: *August 1, 2010*						
15	Forecast Energy Rate: August 1, 2010	Energy Charge	$ 0.08789 /kW.h	**$489.66**	**$650.06**	**$810.46**
		Energy Admin Fee	$ 8.46 /month			
16	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
17	**2010 Energy Related Charge** Row 15 + Row 16			**$489.66**	**$650.06**	**$810.46**
18	AE Final DT Base Rates	Customer Charge	$ 0.3258 /day	**$252.80**	**$333.81**	**$414.82**
		Energy Charge Blk 1	$ 0.0370 /kW.h			
		Energy Charge Blk 2	$ 0.0042 /kW.h			
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge	$ 0.2703 /kW/day	-$16.42	-$21.90	-$27.37
		Balancing Pool Refund Rider	-$ 0.00211 /kW.h			
		Rider G	-$ 0.00089 /kW.h			
20	**Net DT Charges** Row 18 + Row 19			**$236.38**	**$311.92**	**$387.45**
21	**Predicted Combined Rate: August 1, 2010** Row 17 + Row 20			**$726.04**	**$961.97**	**$1,197.91**
Effective Date: *January 1, 2011*						
22	Forecast Energy Rate: January 1, 2011	Energy Charge	$ 0.08789 /kW.h	**$489.66**	**$650.06**	**$810.46**
		Energy Admin Fee	$ 8.46 /month			
23	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
24	**2011 Energy Related Charge** Row 22 + Row 23			**$489.66**	**$650.06**	**$810.46**
25	AE Proposed DT Base Rates	Customer Charge	$ 0.3486 /day	**$269.25**	**$355.51**	**$441.78**
		Energy Charge Blk 1	$ 0.0387 /kW.h			
		Energy Charge Blk 2	$ 0.0037 /kW.h			
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge	$ 0.2968 /kW/day	-$16.42	-$21.90	-$27.37
		Balancing Pool Refund Rider	-$ 0.00211 /kW.h			
		Rider G	-$ 0.00089 /kW.h			
27	**Net DT Charges** Row 25 + Row 26			**$252.83**	**$333.61**	**$414.40**
28	**Predicted Combined Rate: January 1, 2011** Row 24 + Row 27			**$742.48**	**$983.67**	**$1,224.86**
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010) Row 14 vs Row 7		difference	$38.62	$51.52	$64.42
			%	6%	6%	6%
	Combined Rate (June 1, 2010 - August 1, 2010) Row 21 vs Row 14		difference	$81.91	$109.21	$136.51
			%	13%	13%	13%
	Combined Rate (August 1, 2010 - January 1, 2011) Row 28 vs Row 21		difference	$16.45	$21.70	$26.95
			%	2%	2%	2%

Appendix B.4 - Example Rate Rider Effects: Irrigation Pumping Service *GST not included*

Row	Rate Component		Rate	Irrigation Pumping Service Class Consumption Levels Cost per Customer ($/season) 8,760 kW.h per month Demand 30 kW	Typical 11,680 kW.h per month Demand 40 kW	14,600 kW.h per month Demand 50 kW
	Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge					
	Effective Date: *January 1, 2010*					
1	Energy Rate: January 1, 2010	Energy Charge	$ 0.07014 /kW.h	**$681.19**	**$886.00**	**$1,090.81**
		Energy Admin Fee	$ 9.36 /month			
2	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
3	**2010 Energy Related Charge** Row 1 + Row 2			**$681.19**	**$886.00**	**$1,090.81**
4	AE Interim DT Base Rates	Customer Charge	$ 0.2592 /day	**$1,433.11**	**$1,892.32**	**$2,351.54**
		Energy Charge	$ 0.0049 /kW.h			
		Demand Charge	$ 0.2079 /kW/day			
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00429 /kW.h	-$73.93	-$98.58	-$123.22
		Rider G	-$ 0.0042 /kW.h			
6	**Net DT Charges** Row 4 + Row 5			**$1,359.18**	**$1,793.75**	**$2,228.31**
7	**Combined Rate: January 1, 2010** Row 3 + Row 6			**$2,040.37**	**$2,679.75**	**$3,319.13**
	Effective Date: *June 1, 2010*					
8	Forecast Energy Rate: June 1, 2010	Energy Charge	$ 0.07311 /kW.h	**$707.21**	**$920.69**	**$1,134.17**
		Energy Admin Fee	$ 9.36 /month			
9	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
10	**2010 Energy Related Charge** Row 8 + Row 9			**$707.21**	**$920.69**	**$1,134.17**
11	AE Final DT Base Rates	Customer Charge	$ 0.2380 /day	**$1,465.69**	**$1,937.28**	**$2,408.86**
		Energy Charge	$ 0.0043 /kW.h			
		Demand Charge	$ 0.2145 /kW/day			
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00429 /kW.h	-$73.93	-$98.58	-$123.22
		Rider G	-$ 0.0042 /kW.h			
13	**Net DT Charges** Row 11 + Row 12			**$1,391.76**	**$1,838.70**	**$2,285.64**
14	**Predicted Combined Rate: June 1, 2010** Row 10 + Row 13			**$2,098.97**	**$2,759.39**	**$3,419.81**
	Effective Date: *August 1, 2010*					
15	Forecast Energy Rate: August 1, 2010	Energy Charge	$ 0.08542 /kW.h	**$815.05**	**$1,064.47**	**$1,313.90**
		Energy Admin Fee	$ 9.36 /month			
16	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
17	**2010 Energy Related Charge** Row 15 + Row 16			**$815.05**	**$1,064.47**	**$1,313.90**
18	AE Final DT Base Rates	Customer Charge	$ 0.2380 /day	**$1,465.69**	**$1,937.28**	**$2,408.86**
		Energy Charge	$ 0.0043 /kW.h			
		Demand Charge	$ 0.2145 /kW/day			
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00215 /kW.h	-$42.10	-$56.14	-$70.17
		Rider G	-$ 0.00266 /kW.h			
20	**Net DT Charges** Row 18 + Row 19			**$1,423.59**	**$1,881.14**	**$2,338.69**
21	**Predicted Combined Rate: August 1, 2010** Row 17 + Row 20			**$2,238.63**	**$2,945.61**	**$3,652.59**
	Effective Date: *January 1, 2011*					
22	Forecast Energy Rate: January 1, 2011	Energy Charge	$ 0.08542 /kW.h	**$815.05**	**$1,064.47**	**$1,313.90**
		Energy Admin Fee	$ 9.36 /month			
23	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
24	**2011 Energy Related Charge** Row 22 + Row 23			**$815.05**	**$1,064.47**	**$1,313.90**
25	AE Proposed DT Base Rates	Customer Charge	$ 0.3217 /day	**$1,840.34**	**$2,430.84**	**$3,021.34**
		Energy Charge	$ 0.0037 /kW.h			
		Demand Charge	$ 0.2709 /kW/day			
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00215 /kW.h	-$42.10	-$56.14	-$70.17
		Rider G	-$ 0.00266 /kW.h			
27	**Net DT Charges** Row 25 + Row 26			**$1,798.24**	**$2,374.70**	**$2,951.16**
28	**Predicted Combined Rate: January 1, 2011** Row 24 + Row 27			**$2,613.29**	**$3,439.17**	**$4,265.06**
	Comparisons					
	Combined Rate (January 1, 2010 - June 1, 2010) **Row 14 vs Row 7**		difference	$58.60	$79.64	$100.69
			%	3%	3%	3%
	Combined Rate (June 1, 2010 - August 1, 2010) **Row 21 vs Row 14**		difference	$139.67	$186.22	$232.78
			%	7%	7%	7%
	Combined Rate (August 1, 2010 - January 1, 2011) **Row 28 vs Row 21**		difference	$374.65	$493.56	$612.48
			%	17%	17%	17%

Appendix B.5 - Example Rate Rider Effects: REA Irrigation Pumping Service *GST not included*

Row	Rate Component		Rate	REA Irrigation Pumping Service Class Consumption Levels Cost per Customer ($/season) 8,760 kW.h per month Demand 30 kW	Typical 11,680 kW.h per month Demand 40 kW	14,600 kW.h per month Demand 50 kW
	Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge					
	Effective Date: *January 1, 2010*					
1	Energy Rate: January 1, 2010	Energy Charge Energy Admin Fee	$ 0.07014 /kW.h $ 9.36 /month	**$681.19**	**$886.00**	**$1,090.81**
2	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
3	**2010 Energy Related Charge** Row 1 + Row 2			**$681.19**	**$886.00**	**$1,090.81**
4	AE Interim DT Base Rates	Customer Charge Energy Charge Demand Charge	$ 0.2592 /day $ 0.0049 /kW.h $ 0.1213 /kW/day	**$877.14**	**$1,151.03**	**$1,424.92**
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G	-$ 0.00429 /kW.h -$ 0.0042 /kW.h	-$73.93	-$98.58	-$123.22
6	**Net DT Charges** Row 4 + Row 5			**$803.20**	**$1,052.45**	**$1,301.69**
7	**Combined Rate: January 1, 2010** Row 3 + Row 6			**$1,484.40**	**$1,938.45**	**$2,392.51**
	Effective Date: *June 1, 2010*					
8	Forecast Energy Rate: June 1, 2010	Energy Charge Energy Admin Fee	$ 0.07311 /kW.h $ 9.36 /month	**$707.21**	**$920.69**	**$1,134.17**
9	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
10	**2010 Energy Related Charge** Row 8 + Row 9			**$707.21**	**$920.69**	**$1,134.17**
11	AE Final DT Base Rates	Customer Charge Energy Charge Demand Charge	$ 0.2380 /day $ 0.0043 /kW.h $ 0.1330 /kW/day	**$942.46**	**$1,239.64**	**$1,536.81**
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G	-$ 0.00429 /kW.h -$ 0.0042 /kW.h	-$73.93	-$98.58	-$123.22
13	**Net DT Charges** Row 11 + Row 12			**$868.53**	**$1,141.06**	**$1,413.59**
14	**Predicted Combined Rate: June 1, 2010** Row 10 + Row 13			**$1,575.74**	**$2,061.75**	**$2,547.76**
	Effective Date: *August 1, 2010*					
15	Forecast Energy Rate: August 1, 2010	Energy Charge Energy Admin Fee	$ 0.08542 /kW.h $ 9.36 /month	**$815.05**	**$1,064.47**	**$1,313.90**
16	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
17	**2010 Energy Related Charge** Row 15 + Row 16			**$815.05**	**$1,064.47**	**$1,313.90**
18	AE Final DT Base Rates	Customer Charge Energy Charge Demand Charge	$ 0.2380 /day $ 0.0043 /kW.h $ 0.1330 /kW/day	**$942.46**	**$1,239.64**	**$1,536.81**
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G	-$ 0.00215 /kW.h -$ 0.00266 /kW.h	-$42.10	-$56.14	-$70.17
20	**Net DT Charges** Row 18 + Row 19			**$900.36**	**$1,183.50**	**$1,466.64**
21	**Predicted Combined Rate: August 1, 2010** Row 17 + Row 20			**$1,715.40**	**$2,247.97**	**$2,780.54**
	Effective Date: *January 1, 2011*					
22	Forecast Energy Rate: January 1, 2011	Energy Charge Energy Admin Fee	$ 0.08542 /kW.h $ 9.36 /month	**$815.05**	**$1,064.47**	**$1,313.90**
23	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
24	**2011 Energy Related Charge** Row 22 + Row 23			**$815.05**	**$1,064.47**	**$1,313.90**
25	AE Proposed DT Base Rates	Customer Charge Energy Charge Demand Charge	$ 0.3217 /day $ 0.0037 /kW.h $ 0.1606 /kW/day	**$1,132.76**	**$1,487.40**	**$1,842.04**
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G	-$ 0.00215 /kW.h -$ 0.00266 /kW.h	-$42.10	-$56.14	-$70.17
27	**Net DT Charges** Row 25 + Row 26			**$1,090.66**	**$1,431.26**	**$1,771.86**
28	**Predicted Combined Rate: January 1, 2011** Row 24 + Row 27			**$1,905.70**	**$2,495.73**	**$3,085.76**
	Comparisons					
	Combined Rate (January 1, 2010 - June 1, 2010) Row 14 vs Row 7		difference %	$91.34 6%	$123.30 6%	$155.26 6%
	Combined Rate (June 1, 2010 - August 1, 2010) Row 21 vs Row 14		difference %	$139.67 9%	$186.22 9%	$232.78 9%
	Combined Rate (August 1, 2010 - January 1, 2011) Row 28 vs Row 21		difference %	$190.30 11%	$247.76 11%	$305.22 11%

Appendix B.6 - 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		Rate	12,200 kW.h per month Demand 50 kW	Typical 16,650 kW.h per month Demand 50 kW	20,800 kW.h per month Demand 59 kW
	Effective Date: *January 1, 2010*					
1	Energy Rate: January 1, 2010	Energy Charge	$ 0.06853 /kW.h	**$854.10**	**$1,159.05**	**$1,443.45**
		Energy Admin Fee	$ 18.03 /month			
2	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
3	**2010 Energy Related Charge** Row 1 + Row 2			**$854.10**	**$1,159.05**	**$1,443.45**
4	AE Interim DT Base Rates	Customer Charge	$ 2.3340 /day	**$606.48**	**$627.84**	**$733.78**
		Energy Charge	$ 0.0048 /kW.h			
		Demand Charge Blk 1	$ 0.3186 /kW/day			
		Demand Charge Blk 2	$ 0.3051 /kW/day			
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00420 /kW.h	-$29.04	-$39.63	-$49.50
		Rider G	$ 0.0018 /kW.h			
6	**Net DT Charges** Row 4 + Row 5			**$577.44**	**$588.21**	**$684.28**
7	**Combined Rate: January 1, 2010** Row 3 + Row 6			**$1,431.54**	**$1,747.27**	**$2,127.73**
	Effective Date: *June 1, 2010*					
8	Forecast Energy Rate: June 1, 2010	Energy Charge	$ 0.07323 /kW.h	**$911.44**	**$1,237.31**	**$1,541.21**
		Energy Admin Fee	$ 18.03 /month			
9	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
10	**2010 Energy Related Charge** Row 8 + Row 9			**$911.44**	**$1,237.31**	**$1,541.21**
11	AE Final DT Base Rates	Customer Charge	$ 2.3495 /day	**$636.83**	**$655.52**	**$765.66**
		Energy Charge	$ 0.0042 /kW.h			
		Demand Charge Blk 1	$ 0.3434 /kW/day			
		Demand Charge Blk 2	$ 0.3275 /kW/day			
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00420 /kW.h	-$29.04	-$39.63	-$49.50
		Rider G	$ 0.0018 /kW.h			
13	**Net DT Charges** Row 11 + Row 12			**$607.79**	**$615.89**	**$716.16**
14	**Predicted Combined Rate: June 1, 2010** Row 10 + Row 13			**$1,519.23**	**$1,853.20**	**$2,257.37**
	Effective Date: *August 1, 2010*					
15	Forecast Energy Rate: August 1, 2010	Energy Charge	$ 0.08493 /kW.h	**$1,054.18**	**$1,432.11**	**$1,784.57**
		Energy Admin Fee	$ 18.03 /month			
16	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
17	**2010 Energy Related Charge** Row 15 + Row 16			**$1,054.18**	**$1,432.11**	**$1,784.57**
18	AE Final DT Base Rates	Customer Charge	$ 2.3495 /day	**$636.83**	**$655.52**	**$765.66**
		Energy Charge	$ 0.0042 /kW.h			
		Demand Charge Blk 1	$ 0.3434 /kW/day			
		Demand Charge Blk 2	$ 0.3275 /kW/day			
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00210 /kW.h	-$16.67	-$22.75	-$28.42
		Rider G	$ 0.00073 /kW.h			
20	**Net DT Charges** Row 18 + Row 19			**$620.16**	**$632.77**	**$737.25**
21	**Predicted Combined Rate: August 1, 2010** Row 17 + Row 20			**$1,674.33**	**$2,064.88**	**$2,521.82**
	Effective Date: *January 1, 2011*					
22	Forecast Energy Rate: January 1, 2011	Energy Charge	$ 0.08493 /kW.h	**$1,054.18**	**$1,432.11**	**$1,784.57**
		Energy Admin Fee	$ 18.03 /month			
23	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
24	**2011 Energy Related Charge** Row 22 + Row 23			**$1,054.18**	**$1,432.11**	**$1,784.57**
25	AE Proposed DT Base Rates	Customer Charge	$ 2.5141 /day	**$687.79**	**$704.00**	**$821.35**
		Energy Charge	$ 0.0036 /kW.h			
		Demand Charge Blk 1	$ 0.3786 /kW/day			
		Demand Charge Blk 2	$ 0.3633 /kW/day			
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00210 /kW.h	-$16.67	-$22.75	-$28.42
		Rider G	$ 0.00073 /kW.h			
27	**Net DT Charges** Row 25 + Row 26			**$671.12**	**$681.25**	**$792.93**
28	**Predicted Combined Rate: January 1, 2011** Row 24 + Row 27			**$1,725.30**	**$2,113.37**	**$2,577.50**
	Comparisons					
	Combined Rate (January 1, 2010 - June 1, 2010) Row 14 vs Row 7		difference	$87.68	$105.93	$129.64
			%	6%	6%	6%
	Combined Rate (June 1, 2010 - August 1, 2010) Row 21 vs Row 14		difference	$155.11	$211.68	$264.45
			%	10%	11%	12%
	Combined Rate (August 1, 2010 - January 1, 2011) Row 28 vs Row 21		difference	$50.96	$48.49	$55.68
			%	3%	2%	2%

Appendix B.7 - Example Rate Rider Effects: Large General Service Distribution - Not RRO Eligible *GST not included*

Row	Rate Component		Rate	Large General Service Class Consumption Levels Cost per Customer ($/month) 657,000 kW.h per month Demand 1,500 kW	Typical 876,000 kW.h per month Demand 2,000 kW	1,095,000 kW.h per month Demand 2,500 kW
	Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge					
	Effective Date: *January 1, 2010*					
1	Energy Rate: January 1, 2010	Energy Charge	$ 0.06853 /kW.h	**$45,042.24**	**$60,050.31**	**$75,058.38**
		Energy Admin Fee	$ 18.03 /month			
2	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
3	**2010 Energy Related Charge** Row 1 + Row 2			**$45,042.24**	**$60,050.31**	**$75,058.38**
4	AE Interim DT Base Rates	Customer Charge	$ 2.3340 /day	**$17,155.62**	**$22,783.32**	**$28,411.02**
		Energy Charge	$ 0.0048 /kW.h			
		Demand Charge Blk 1	$ 0.3186 /kW/day			
		Demand Charge Blk 2	$ 0.3051 /kW/day			
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00420 /kW.h	-$1,563.66	-$2,084.88	-$2,606.10
		Rider G	$ 0.0018 /kW.h			
6	**Net DT Charges** Row 4 + Row 5			**$15,591.96**	**$20,698.44**	**$25,804.92**
7	**Combined Rate: January 1, 2010** Row 3 + Row 6			**$60,634.20**	**$80,748.75**	**$100,863.30**
	Effective Date: *June 1, 2010*					
8	Forecast Energy Rate: June 1, 2010	Energy Charge	$ 0.07323 /kW.h	**$48,130.14**	**$64,167.51**	**$80,204.88**
		Energy Admin Fee	$ 18.03 /month			
9	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
10	**2010 Energy Related Charge** Row 8 + Row 9			**$48,130.14**	**$64,167.51**	**$80,204.88**
11	AE Final DT Base Rates	Customer Charge	$ 2.3495 /day	**$17,805.89**	**$23,638.19**	**$29,470.49**
		Energy Charge	$ 0.0042 /kW.h			
		Demand Charge Blk 1	$ 0.3434 /kW/day			
		Demand Charge Blk 2	$ 0.3275 /kW/day			
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00420 /kW.h	-$1,563.66	-$2,084.88	-$2,606.10
		Rider G	$ 0.0018 /kW.h			
13	**Net DT Charges** Row 11 + Row 12			**$16,242.23**	**$21,553.31**	**$26,864.39**
14	**Predicted Combined Rate: June 1, 2010** Row 10 + Row 13			**$64,372.37**	**$85,720.82**	**$107,069.27**
	Effective Date: *August 1, 2010*					
15	Forecast Energy Rate: August 1, 2010	Energy Charge	$ 0.08493 /kW.h	**$55,817.04**	**$74,416.71**	**$93,016.38**
		Energy Admin Fee	$ 18.03 /month			
16	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
17	**2010 Energy Related Charge** Row 15 + Row 16			**$55,817.04**	**$74,416.71**	**$93,016.38**
18	AE Final DT Base Rates	Customer Charge	$ 2.3495 /day	**$17,805.89**	**$23,638.19**	**$29,470.49**
		Energy Charge	$ 0.0042 /kW.h			
		Demand Charge Blk 1	$ 0.3434 /kW/day			
		Demand Charge Blk 2	$ 0.3275 /kW/day			
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00210 /kW.h	-$897.62	-$1,196.83	-$1,496.03
		Rider G	$ 0.00073 /kW.h			
20	**Net DT Charges** Row 18 + Row 19			**$16,908.27**	**$22,441.36**	**$27,974.45**
21	**Predicted Combined Rate: August 1, 2010** Row 17 + Row 20			**$72,725.31**	**$96,858.07**	**$120,990.83**
	Effective Date: *January 1, 2011*					
22	Forecast Energy Rate: January 1, 2011	Energy Charge	$ 0.08493 /kW.h	**$55,817.04**	**$74,416.71**	**$93,016.38**
		Energy Admin Fee	$ 18.03 /month			
23	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
24	**2011 Energy Related Charge** Row 22 + Row 23			**$55,817.04**	**$74,416.71**	**$93,016.38**
25	AE Proposed DT Base Rates	Customer Charge	$ 2.5141 /day	**$19,048.14**	**$25,295.97**	**$31,543.80**
		Energy Charge	$ 0.0036 /kW.h			
		Demand Charge Blk 1	$ 0.3786 /kW/day			
		Demand Charge Blk 2	$ 0.3633 /kW/day			
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00210 /kW.h	-$897.62	-$1,196.83	-$1,496.03
		Rider G	$ 0.00073 /kW.h			
27	**Net DT Charges** Row 25 + Row 26			**$18,150.52**	**$24,099.14**	**$30,047.77**
28	**Predicted Combined Rate: January 1, 2011** Row 24 + Row 27			**$73,967.56**	**$98,515.85**	**$123,064.15**
	Comparisons					
	Combined Rate (January 1, 2010 - June 1, 2010) Row 14 vs Row 7		difference	$3,738.17	$4,972.07	$6,205.97
			%	6%	6%	6%
	Combined Rate (June 1, 2010 - August 1, 2010) Row 21 vs Row 14		difference	$8,352.94	$11,137.25	$13,921.57
			%	13%	13%	13%
	Combined Rate (August 1, 2010 - January 1, 2011) Row 28 vs Row 21		difference	$1,242.25	$1,657.78	$2,073.32
			%	2%	2%	2%

Appendix B.8 - Example Rate Rider Effects: Small Oilfield Class - RRO Eligible *GST not included*

Row	Rate Component		Rate	Small Oilfield Class Consumption Levels Cost per Customer ($/month) 6,570 kW.h per month Demand 15 kW	Typical 8,760 kW.h per month Demand 20 kW	10,950 kW.h per month Demand 25 kW
	Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge					
	Effective Date: *January 1, 2010*					
1	Energy Rate: January 1, 2010	Energy Charge Energy Admin Fee	$ 0.06807 /kW.h $ 8.88 /month	**$456.10**	**$605.17**	**$754.25**
2	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
3	**2010 Energy Related Charge** Row 1 + Row 2			**$456.10**	**$605.17**	**$754.25**
4	AE Interim DT Base Rates	Customer Charge Energy Charge Demand Charge	$ 1.3607 /day $ 0.0049 /kW.h $ 0.5529 /kW/day	**$321.82**	**$415.49**	**$509.15**
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G	-$ 0.00427 /kW.h -$ 0.0029 /kW.h	-$46.91	-$62.55	-$78.18
6	**Net DT Charges** Row 4 + Row 5			**$274.91**	**$352.94**	**$430.97**
7	**Combined Rate: January 1, 2010** Row 3 + Row 6			**$731.01**	**$958.11**	**$1,185.21**
	Effective Date: *June 1, 2010*					
8	Forecast Energy Rate: June 1, 2010	Energy Charge Energy Admin Fee	$ 0.07236 /kW.h $ 8.88 /month	**$484.29**	**$642.75**	**$801.22**
9	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
10	**2010 Energy Related Charge** Row 8 + Row 9			**$484.29**	**$642.75**	**$801.22**
11	AE Final DT Base Rates	Customer Charge Energy Charge Demand Charge	$ 1.3599 /day $ 0.0043 /kW.h $ 0.5734 /kW/day	**$327.08**	**$422.51**	**$517.93**
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G	-$ 0.00427 /kW.h -$ 0.0029 /kW.h	-$46.91	-$62.55	-$78.18
13	**Net DT Charges** Row 11 + Row 12			**$280.17**	**$359.96**	**$439.75**
14	**Predicted Combined Rate: June 1, 2010** Row 10 + Row 13			**$764.45**	**$1,002.71**	**$1,240.97**
	Effective Date: *August 1, 2010*					
15	Forecast Energy Rate: August 1, 2010	Energy Charge Energy Admin Fee	$ 0.08452 /kW.h $ 8.88 /month	**$564.18**	**$749.28**	**$934.37**
16	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
17	**2010 Energy Related Charge** Row 15 + Row 16			**$564.18**	**$749.28**	**$934.37**
18	AE Final DT Base Rates	Customer Charge Energy Charge Demand Charge	$ 1.3599 /day $ 0.0043 /kW.h $ 0.5734 /kW/day	**$327.08**	**$422.51**	**$517.93**
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G	-$ 0.00214 /kW.h -$ 0.00106 /kW.h	-$20.99	-$27.99	-$34.99
20	**Net DT Charges** Row 18 + Row 19			**$306.09**	**$394.51**	**$482.94**
21	**Predicted Combined Rate: August 1, 2010** Row 17 + Row 20			**$870.26**	**$1,143.79**	**$1,417.32**
	Effective Date: *January 1, 2011*					
22	Forecast Energy Rate: January 1, 2011	Energy Charge Energy Admin Fee	$ 0.08452 /kW.h $ 8.88 /month	**$564.18**	**$749.28**	**$934.37**
23	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
24	**2011 Energy Related Charge** Row 22 + Row 23			**$564.18**	**$749.28**	**$934.37**
25	AE Proposed DT Base Rates	Customer Charge Energy Charge Demand Charge	$ 1.4551 /day $ 0.0037 /kW.h $ 0.6230 /kW/day	**$348.38**	**$449.95**	**$551.53**
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G	-$ 0.00214 /kW.h -$ 0.00106 /kW.h	-$20.99	-$27.99	-$34.99
27	**Net DT Charges** Row 25 + Row 26			**$327.39**	**$421.96**	**$516.54**
28	**Predicted Combined Rate: January 1, 2011** Row 24 + Row 27			**$891.56**	**$1,171.24**	**$1,450.91**
	Comparisons					
	Combined Rate (January 1, 2010 - June 1, 2010) Row 14 vs Row 7		difference %	$33.44 5%	$44.60 5%	$55.76 5%
	Combined Rate (June 1, 2010 - August 1, 2010) Row 21 vs Row 14		difference %	$105.81 14%	$141.08 14%	$176.35 14%
	Combined Rate (August 1, 2010 - January 1, 2011) Row 28 vs Row 21		difference %	$21.30 2%	$27.45 2%	$33.60 2%

Appendix B.9 - Example Rate Rider Effects: Small Oilfield Class - Non RRO Eligible *GST not included*

Row	Rate Component		Rate	Small Oilfield Class Consumption Levels Cost per Customer ($/month) 6,570 kW.h per month Demand 15 kW	Typical 8,760 kW.h per month Demand 20 kW	10,950 kW.h per month Demand 25 kW
	Effective Date: *January 1, 2010*					
1	Energy Rate: January 1, 2010	Energy Charge Energy Admin Fee	$ 0.06807 /kW.h $ 8.88 /month	**$456.10**	**$605.17**	**$754.25**
2	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
3	**2010 Energy Related Charge** Row 1 + Row 2			**$456.10**	**$605.17**	**$754.25**
4	AE Interim DT Base Rates	Customer Charge Energy Charge Demand Charge	$ 1.3607 /day $ 0.0049 /kW.h $ 0.5529 /kW/day	**$321.82**	**$415.49**	**$509.15**
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G	-$ 0.00427 /kW.h -$ 0.0029 /kW.h	-$46.91	-$62.55	-$78.18
6	**Net DT Charges** Row 4 + Row 5			**$274.91**	**$352.94**	**$430.97**
7	**Combined Rate: January 1, 2010** Row 3 + Row 6			**$731.01**	**$958.11**	**$1,185.21**
	Effective Date: *June 1, 2010*					
8	Forecast Energy Rate: June 1, 2010	Energy Charge Energy Admin Fee	$ 0.07236 /kW.h $ 8.88 /month	**$484.29**	**$642.75**	**$801.22**
9	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
10	**2010 Energy Related Charge** Row 8 + Row 9			**$484.29**	**$642.75**	**$801.22**
11	AE Final DT Base Rates	Customer Charge Energy Charge Demand Charge	$ 1.3599 /day $ 0.0043 /kW.h $ 0.5734 /kW/day	**$327.08**	**$422.51**	**$517.93**
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G	-$ 0.00427 /kW.h -$ 0.0029 /kW.h	-$46.91	-$62.55	-$78.18
13	**Net DT Charges** Row 11 + Row 12			**$280.17**	**$359.96**	**$439.75**
14	**Predicted Combined Rate: June 1, 2010** Row 10 + Row 13			**$764.45**	**$1,002.71**	**$1,240.97**
	Effective Date: *August 1, 2010*					
15	Forecast Energy Rate: August 1, 2010	Energy Charge Energy Admin Fee	$ 0.08452 /kW.h $ 8.88 /month	**$564.18**	**$749.28**	**$934.37**
16	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
17	**2010 Energy Related Charge** Row 15 + Row 16			**$564.18**	**$749.28**	**$934.37**
18	AE Final DT Base Rates	Customer Charge Energy Charge Demand Charge	$ 1.3599 /day $ 0.0043 /kW.h $ 0.5734 /kW/day	**$327.08**	**$422.51**	**$517.93**
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G	-$ 0.00214 /kW.h -$ 0.00106 /kW.h	-$20.99	-$27.99	-$34.99
20	**Net DT Charges** Row 18 + Row 19			**$306.09**	**$394.51**	**$482.94**
21	**Predicted Combined Rate: August 1, 2010** Row 17 + Row 20			**$870.26**	**$1,143.79**	**$1,417.32**
	Effective Date: *January 1, 2011*					
22	Forecast Energy Rate: January 1, 2011	Energy Charge Energy Admin Fee	$ 0.08452 /kW.h $ 8.88 /month	**$564.18**	**$749.28**	**$934.37**
23	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
24	**2011 Energy Related Charge** Row 22 + Row 23			**$564.18**	**$749.28**	**$934.37**
25	AE Proposed DT Base Rates	Customer Charge Energy Charge Demand Charge	$ 1.4551 /day $ 0.0037 /kW.h $ 0.6230 /kW/day	**$348.38**	**$449.95**	**$551.53**
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G	-$ 0.00214 /kW.h -$ 0.00106 /kW.h	-$20.99	-$27.99	-$34.99
27	**Net DT Charges** Row 25 + Row 26			**$327.39**	**$421.96**	**$516.54**
28	**Predicted Combined Rate: January 1, 2011** Row 24 + Row 27			**$891.56**	**$1,171.24**	**$1,450.91**
	Comparisons					
	Combined Rate (January 1, 2010 - June 1, 2010) Row 14 vs Row 7		difference %	$33.44 5%	$44.60 5%	$55.76 5%
	Combined Rate (June 1, 2010 - August 1, 2010) Row 21 vs Row 14		difference %	$105.81 14%	$141.08 14%	$176.35 14%
	Combined Rate (August 1, 2010 - January 1, 2011) Row 28 vs Row 21		difference %	$21.30 2%	$27.45 2%	$33.60 2%

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge

Appendix B.10 - Example Rate Rider Effects: REA Farm Service Class (Pooled) - RRO Eligible *GST not included*

Row	Rate Component		Rate		REA Farm Service Class Consumption Levels Cost per Customer ($/month) 755 kW.h per month Demand 7.5 kVA	Typical 1,255 kW.h per month Demand 7.5 kVA	1,755 kW.h per month Demand 7.5 kVA
	Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge						
	Effective Date: *January 1, 2010*						
1	Energy Rate: January 1, 2010	Energy Charge	$ 0.07014 /kW.h		**$61.18**	**$96.25**	**$131.32**
		Energy Admin Fee	$ 8.22 /month				
2	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h		$0.00	$0.00	$0.00
3	**2010 Energy Related Charge** Row 1 + Row 2				**$61.18**	**$96.25**	**$131.32**
4	AE Interim DT Base Rates	Customer Charge	$ 0.2916 /day		**$43.49**	**$45.89**	**$48.29**
		Energy Charge	$ 0.0048 /kW.h				
		Demand Charge	$ 0.1383 /kVA/day				
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00425 /kW.h		-$3.93	-$6.54	-$9.14
		Rider G	-$ 0.0010 /kW.h				
6	**Net DT Charges** Row 4 + Row 5				**$39.56**	**$39.35**	**$39.15**
7	**Combined Rate: January 1, 2010** Row 3 + Row 6				**$100.73**	**$135.60**	**$170.46**
	Effective Date: *June 1, 2010*						
8	Forecast Energy Rate: June 1, 2010	Energy Charge	$ 0.07520 /kW.h		**$65.00**	**$102.60**	**$140.20**
		Energy Admin Fee	$ 8.22 /month				
9	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h		$0.00	$0.00	$0.00
10	**2010 Energy Related Charge** Row 8 + Row 9				**$65.00**	**$102.60**	**$140.20**
11	AE Final DT Base Rates	Customer Charge	$ 0.2883 /day		**$44.70**	**$46.85**	**$49.00**
		Energy Charge	$ 0.0043 /kW.h				
		Demand Charge	$ 0.1458 /kVA/day				
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00425 /kW.h		-$3.93	-$6.54	-$9.14
		Rider G	-$ 0.0010 /kW.h				
13	**Net DT Charges** Row 11 + Row 12				**$40.77**	**$40.31**	**$39.86**
14	**Predicted Combined Rate: June 1, 2010** Row 10 + Row 13				**$105.76**	**$142.91**	**$180.05**
	Effective Date: *August 1, 2010*						
15	Forecast Energy Rate: August 1, 2010	Energy Charge	$ 0.08824 /kW.h		**$74.84**	**$118.96**	**$163.08**
		Energy Admin Fee	$ 8.22 /month				
16	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h		$0.00	$0.00	$0.00
17	**2010 Energy Related Charge** Row 15 + Row 16				**$74.84**	**$118.96**	**$163.08**
18	AE Final DT Base Rates	Customer Charge	$ 0.2883 /day		**$44.70**	**$46.85**	**$49.00**
		Energy Charge	$ 0.0043 /kW.h				
		Demand Charge	$ 0.1458 /kVA/day				
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00212 /kW.h		-$0.61	-$1.01	-$1.41
		Rider G	$ 0.00132 /kW.h				
20	**Net DT Charges** Row 18 + Row 19				**$44.09**	**$45.84**	**$47.59**
21	**Predicted Combined Rate: August 1, 2010** Row 17 + Row 20				**$118.94**	**$164.80**	**$210.67**
	Effective Date: *January 1, 2011*						
22	Forecast Energy Rate: January 1, 2011	Energy Charge	$ 0.08824 /kW.h		**$74.84**	**$118.96**	**$163.08**
		Energy Admin Fee	$ 8.22 /month				
23	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h		$0.00	$0.00	$0.00
24	**2011 Energy Related Charge** Row 22 + Row 23				**$74.84**	**$118.96**	**$163.08**
25	AE Proposed DT Base Rates	Customer Charge	$ 0.3085 /day		**$48.26**	**$50.10**	**$51.94**
		Energy Charge	$ 0.0037 /kW.h				
		Demand Charge	$ 0.1610 /kVA/day				
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00212 /kW.h		-$0.61	-$1.01	-$1.41
		Rider G	$ 0.00132 /kW.h				
27	**Net DT Charges** Row 25 + Row 26				**$47.65**	**$49.09**	**$50.53**
28	**Predicted Combined Rate: January 1, 2011** Row 24 + Row 27				**$122.50**	**$168.05**	**$213.61**
	Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010) Row 14 vs Row 7			difference	$5.03	$7.31	$9.59
				%	5%	5%	6%
	Combined Rate (June 1, 2010 - August 1, 2010) Row 21 vs Row 14			difference	$13.17	$21.90	$30.62
				%	12%	15%	17%
	Combined Rate (August 1, 2010 - January 1, 2011) Row 28 vs Row 21			difference	$3.56	$3.25	$2.94
				%	3%	2%	1%

Appendix B.11 - Example Rate Rider Effects: Farm Service Class - RRO Eligible *GST not included*

Row	Rate Component		Rate	REA Farm Service Class Consumption Levels Cost per Customer ($/month) 755 kW.h per month Demand 7.5 kVA	Typical 1,255 kW.h per month Demand 7.5 kVA	1,755 kW.h per month Demand 7.5 kVA
	Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge					
	Effective Date: *January 1, 2010*					
1	Energy Rate: January 1, 2010	Energy Charge	$ 0.07014 /kW.h	**$61.18**	**$96.25**	**$131.32**
		Energy Admin Fee	$ 8.22 /month			
2	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
3	**2010 Energy Related Charge** Row 1 + Row 2			**$61.18**	**$96.25**	**$131.32**
4	AE Interim DT Base Rates	Customer Charge	$ 0.5299 /day	**$60.87**	**$65.62**	**$70.37**
		Energy Charge	$ 0.0095 /kW.h			
		Demand Charge	$ 0.1680 /kVA/day			
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00425 /kW.h	-$6.00	-$9.98	-$13.95
		Rider G	-$ 0.0037 /kW.h			
6	**Net DT Charges** Row 4 + Row 5			**$54.87**	**$55.64**	**$56.42**
7	**Combined Rate: January 1, 2010** Row 3 + Row 6			**$116.04**	**$151.89**	**$187.73**
	Effective Date: *June 1, 2010*					
8	Forecast Energy Rate: June 1, 2010	Energy Charge	$ 0.07520 /kW.h	**$65.00**	**$102.60**	**$140.20**
		Energy Admin Fee	$ 8.22 /month			
9	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
10	**2010 Energy Related Charge** Row 8 + Row 9			**$65.00**	**$102.60**	**$140.20**
11	AE Final DT Base Rates	Customer Charge	$ 0.5441 /day	**$62.51**	**$67.41**	**$72.31**
		Energy Charge	$ 0.0098 /kW.h			
		Demand Charge	$ 0.1724 /kVA/day			
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00425 /kW.h	-$6.00	-$9.98	-$13.95
		Rider G	-$ 0.0037 /kW.h			
13	**Net DT Charges** Row 11 + Row 12			**$56.51**	**$57.43**	**$58.36**
14	**Predicted Combined Rate: June 1, 2010** Row 10 + Row 13			**$121.51**	**$160.03**	**$198.56**
	Effective Date: *August 1, 2010*					
15	Forecast Energy Rate: August 1, 2010	Energy Charge	$ 0.08824 /kW.h	**$74.84**	**$118.96**	**$163.08**
		Energy Admin Fee	$ 8.22 /month			
16	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
17	**2010 Energy Related Charge** Row 15 + Row 16			**$74.84**	**$118.96**	**$163.08**
18	AE Final DT Base Rates	Customer Charge	$ 0.5441 /day	**$62.51**	**$67.41**	**$72.31**
		Energy Charge	$ 0.0098 /kW.h			
		Demand Charge	$ 0.1724 /kVA/day			
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00212 /kW.h	-$1.72	-$2.86	-$3.99
		Rider G	-$ 0.00016 /kW.h			
20	**Net DT Charges** Row 18 + Row 19			**$60.79**	**$64.56**	**$68.32**
21	**Predicted Combined Rate: August 1, 2010** Row 17 + Row 20			**$135.63**	**$183.52**	**$231.40**
	Effective Date: *January 1, 2011*					
22	Forecast Energy Rate: January 1, 2011	Energy Charge	$ 0.08824 /kW.h	**$74.84**	**$118.96**	**$163.08**
		Energy Admin Fee	$ 8.22 /month			
23	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
24	**2011 Energy Related Charge** Row 22 + Row 23			**$74.84**	**$118.96**	**$163.08**
25	AE Proposed DT Base Rates	Customer Charge	$ 0.5822 /day	**$67.32**	**$72.11**	**$76.89**
		Energy Charge	$ 0.0096 /kW.h			
		Demand Charge	$ 0.1895 /kVA/day			
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00212 /kW.h	-$1.72	-$2.86	-$3.99
		Rider G	-$ 0.00016 /kW.h			
27	**Net DT Charges** Row 25 + Row 26			**$65.61**	**$69.25**	**$72.89**
28	**Predicted Combined Rate: January 1, 2011** Row 24 + Row 27			**$140.45**	**$188.21**	**$235.97**
	Comparisons					
	Combined Rate (January 1, 2010 - June 1, 2010) Row 14 vs Row 7		difference	$5.46	$8.14	$10.82
			%	5%	5%	6%
	Combined Rate (June 1, 2010 - August 1, 2010) Row 21 vs Row 14		difference	$14.13	$23.49	$32.84
			%	12%	15%	17%
	Combined Rate (August 1, 2010 - January 1, 2011) Row 28 vs Row 21		difference	$4.81	$4.69	$4.57
			%	4%	3%	2%

Appendix B.12 - Example Rate Rider Effects: Street Light Service Class D61 Option A *GST not included*

Row	Rate Component		Rate		Street Light Service Class Consumption Levels Cost per Customer ($/month) 35 kW.h 1 Fixture Demand 100 Watt	Typical 88 kW.h 1 Fixture Demand 250 Watt	140 kW.h 1 Fixture Demand 400 Watt
	Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge						
	Effective Date: *January 1, 2010*						
1	Energy Rate: January 1, 2010		Energy Charge Energy Admin Fee	$ 0.05837 /kW.h $ 2.61 /month	**$4.65**	**$7.75**	**$10.78**
2	+/- RRO Deferral		RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
3	**2010 Energy Related Charge**	Row 1 + Row 2			**$4.65**	**$7.75**	**$10.78**
4	AE Interim DT Base Rates		Customer Charge Energy Charge Demand Charge	$ 0.3075 /day $ 0.0000 /kW.h $ 0.0004 /W/day	**$10.43**	**$12.23**	**$14.03**
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)		Balancing Pool Refund Rider Rider G	-$ 0.00419 /kW.h -$ 0.0005 /W/day	-$1.74	-$4.34	-$6.95
6	**Net DT Charges**	Row 4 + Row 5			**$8.69**	**$7.88**	**$7.08**
7	**Combined Rate: January 1, 2010**	Row 3 + Row 6			**$13.34**	**$15.63**	**$17.86**
	Effective Date: *June 1, 2010*						
8	Forecast Energy Rate: June 1, 2010		Energy Charge Energy Admin Fee	$ 0.04120 /kW.h $ 2.61 /month	**$4.05**	**$6.24**	**$8.38**
9	+/- RRO Deferral		RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
10	**2010 Energy Related Charge**	Row 8 + Row 9			**$4.05**	**$6.24**	**$8.38**
11	AE Final DT Base Rates		Customer Charge Energy Charge Demand Charge	$ 0.3054 /day $ 0.0000 /kW.h $ 0.0004 /W/day	**$10.39**	**$12.24**	**$14.08**
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)		Balancing Pool Refund Rider Rider G	-$ 0.00419 /kW.h -$ 0.0005 /W/day	-$1.74	-$4.34	-$6.95
13	**Net DT Charges**	Row 11 + Row 12			**$8.66**	**$7.89**	**$7.14**
14	**Predicted Combined Rate: June 1, 2010**	Row 10 + Row 13			**$12.71**	**$14.13**	**$15.51**
	Effective Date: *August 1, 2010*						
15	Forecast Energy Rate: August 1, 2010		Energy Charge Energy Admin Fee	$ 0.05392 /kW.h $ 2.61 /month	**$4.50**	**$7.35**	**$10.16**
16	+/- RRO Deferral		RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
17	**2010 Energy Related Charge**	Row 15 + Row 16			**$4.50**	**$7.35**	**$10.16**
18	AE Final DT Base Rates		Customer Charge Energy Charge Demand Charge	$ 0.3054 /day $ 0.0000 /kW.h $ 0.0004 /W/day	**$10.39**	**$12.24**	**$14.08**
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)		Balancing Pool Refund Rider Rider G	-$ 0.00209 /kW.h -$ 0.00007 /W/day	-$0.27	-$0.68	-$1.09
20	**Net DT Charges**	Row 18 + Row 19			**$10.12**	**$11.55**	**$12.99**
21	**Predicted Combined Rate: August 1, 2010**	Row 17 + Row 20			**$14.62**	**$18.91**	**$23.15**
	Effective Date: *January 1, 2011*						
22	Forecast Energy Rate: January 1, 2011		Energy Charge Energy Admin Fee	$ 0.05392 /kW.h $ 2.61 /month	**$4.50**	**$7.35**	**$10.16**
23	+/- RRO Deferral		RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
24	**2011 Energy Related Charge**	Row 22 + Row 23			**$4.50**	**$7.35**	**$10.16**
25	AE Proposed DT Base Rates		Customer Charge Energy Charge Demand Charge	$ 0.3840 /day $ 0.0000 /kW.h $ 0.0005 /W/day	**$12.97**	**$15.15**	**$17.33**
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)		Balancing Pool Refund Rider Rider G	-$ 0.00209 /kW.h -$ 0.00007 /W/day	-$0.27	-$0.68	-$1.09
27	**Net DT Charges**	Row 25 + Row 26			**$12.70**	**$14.47**	**$16.24**
28	**Predicted Combined Rate: January 1, 2011**	Row 24 + Row 27			**$17.20**	**$21.82**	**$26.40**
	Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	**Row 14 vs Row 7**		difference %	-$0.63 -5%	-$1.50 -10%	-$2.35 -13%
	Combined Rate (June 1, 2010 - August 1, 2010)	**Row 21 vs Row 14**		difference %	$1.91 15%	$4.78 34%	$7.64 49%
	Combined Rate (August 1, 2010 - January 1, 2011)	**Row 28 vs Row 21**		difference %	$2.58 18%	$2.91 15%	$3.25 14%

Appendix B.13 - Example Rate Rider Effects: Private Lighting Service Class D63 Option A *GST not included*

Row	Rate Component		Rate	Private Street Light Service Class Consumption Levels Cost per Customer ($/month) 35 kW.h 1 Fixture Demand 100 Watt	Typical 88 kW.h 1 Fixture Demand 250 Watt	140 kW.h 1 Fixture Demand 400 Watt
	Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge					
	Effective Date: *January 1, 2010*					
1	Energy Rate: January 1, 2010	Energy Charge	$ 0.05837 /kW.h	**$4.65**	**$7.75**	**$10.78**
		Energy Admin Fee	$ 2.61 /month			
2	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
3	**2010 Energy Related Charge** Row 1 + Row 2			**$4.65**	**$7.75**	**$10.78**
4	AE Interim DT Base Rates	Customer Charge	$ 0.3668 /day	**$12.08**	**$13.70**	**$15.32**
		Energy Charge	$ 0.0000 /kW.h			
		Demand Charge	$ 0.0004 /W/day			
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00422 /kW.h	-$2.19	-$5.47	-$8.75
		Rider G	-$ 0.0007 /W/day			
6	**Net DT Charges** Row 4 + Row 5			**$9.90**	**$8.23**	**$6.57**
7	**Combined Rate: January 1, 2010** Row 3 + Row 6			**$14.55**	**$15.98**	**$17.36**
	Effective Date: *June 1, 2010*					
8	Forecast Energy Rate: June 1, 2010	Energy Charge	$ 0.04120 /kW.h	**$4.05**	**$6.24**	**$8.38**
		Energy Admin Fee	$ 2.61 /month			
9	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
10	**2010 Energy Related Charge** Row 8 + Row 9			**$4.05**	**$6.24**	**$8.38**
11	AE Final DT Base Rates	Customer Charge	$ 0.3686 /day	**$12.20**	**$13.91**	**$15.62**
		Energy Charge	$ 0.0000 /kW.h			
		Demand Charge	$ 0.0004 /W/day			
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00422 /kW.h	-$2.19	-$5.47	-$8.75
		Rider G	-$ 0.0007 /W/day			
13	**Net DT Charges** Row 11 + Row 12			**$10.01**	**$8.44**	**$6.87**
14	**Predicted Combined Rate: June 1, 2010** Row 10 + Row 13			**$14.06**	**$14.67**	**$15.25**
	Effective Date: *August 1, 2010*					
15	Forecast Energy Rate: August 1, 2010	Energy Charge	$ 0.05392 /kW.h	**$4.50**	**$7.35**	**$10.16**
		Energy Admin Fee	$ 2.61 /month			
16	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
17	**2010 Energy Related Charge** Row 15 + Row 16			**$4.50**	**$7.35**	**$10.16**
18	AE Final DT Base Rates	Customer Charge	$ 0.3686 /day	**$12.20**	**$13.91**	**$15.62**
		Energy Charge	$ 0.0000 /kW.h			
		Demand Charge	$ 0.0004 /W/day			
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00211 /kW.h	-$0.19	-$0.48	-$0.77
		Rider G	-$ 0.00004 /W/day			
20	**Net DT Charges** Row 18 + Row 19			**$12.01**	**$13.43**	**$14.85**
21	**Predicted Combined Rate: August 1, 2010** Row 17 + Row 20			**$16.50**	**$20.78**	**$25.01**
	Effective Date: *January 1, 2011*					
22	Forecast Energy Rate: January 1, 2011	Energy Charge	$ 0.05392 /kW.h	**$4.50**	**$7.35**	**$10.16**
		Energy Admin Fee	$ 2.61 /month			
23	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
24	**2011 Energy Related Charge** Row 22 + Row 23			**$4.50**	**$7.35**	**$10.16**
25	AE Proposed DT Base Rates	Customer Charge	$ 0.3944 /day	**$13.05**	**$14.88**	**$16.72**
		Energy Charge	$ 0.0000 /kW.h			
		Demand Charge	$ 0.0004 /W/day			
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	-$ 0.00211 /kW.h	-$0.19	-$0.48	-$0.77
		Rider G	-$ 0.00004 /W/day			
27	**Net DT Charges** Row 25 + Row 26			**$12.86**	**$14.40**	**$15.95**
28	**Predicted Combined Rate: January 1, 2011** Row 24 + Row 27			**$17.36**	**$21.76**	**$26.11**
	Comparisons					
	Combined Rate (January 1, 2010 - June 1, 2010) **Row 14 vs Row 7**		difference	-$0.49	-$1.31	-$2.11
			%	-3%	-8%	-12%
	Combined Rate (June 1, 2010 - August 1, 2010) **Row 21 vs Row 14**		difference	$2.44	$6.11	$9.77
			%	17%	42%	64%
	Combined Rate (August 1, 2010 - January 1, 2011) **Row 28 vs Row 21**		difference	$0.85	$0.98	$1.10
			%	5%	5%	4%

Appendix B.14 - Example Rate Rider Effects: Large General Service Transmission - Not RRO Eligible *GST not included*

Row	Rate Component		Rate	Large General Service Class Consumption Levels Cost per Customer ($/month) 766,500 kW.h per month Demand 1,500 kW	Typical 1,022,000 kW.h per month Demand 2,000 kW	1,277,500 kW.h per month Demand 2,500 kW
	Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge					
	Note: Assume coincident metered demand equals to 50% of the metered demand					
	Effective Date: *January 1, 2010*					
1	Energy Rate: January 1, 2010	Energy Charge	$ 0.06853 /kW.h	**$52,546.28**	**$70,055.69**	**$87,565.11**
		Energy Admin Fee	$ 18.03 /month			
2	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
		Pool Price	$57.30			
3	**2010 Energy Related Charge** Row 1 + Row 2			**$52,546.28**	**$70,055.69**	**$87,565.11**
4	AE and AESO Rates	Customer Charge	$ 0.0000 /day	**$20,483.59**	**$24,528.62**	**$28,573.65**
		Energy Charge	$ 0.0045 /kW.h			
		Demand Charge Blk 1	$ 0.15 /kW/day			
		Demand Charge Blk 2	$ 0.06 /kW/day			
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge (1st 7.5MW)	$ 3.96 /kW/month	-$3,349.61	-$4,466.14	-$5,582.68
		POD Charge fixed	$ 7,030.00 /month			
		Balancing Pool Refund Rider	-$ 0.00400 /kW.h			
		Rider G	-$ 0.0004 /kW.h			
6	**Net DT Charges** Row 4 + Row 5			**$17,133.99**	**$20,062.48**	**$22,990.98**
7	**Combined Rate: January 1, 2010** Row 3 + Row 6			**$69,680.26**	**$90,118.17**	**$110,556.08**
	Effective Date: *June 1, 2010*					
8	Forecast Energy Rate: June 1, 2010	Energy Charge	$ 0.07323 /kW.h	**$56,148.83**	**$74,859.09**	**$93,569.36**
		Energy Admin Fee	$ 18.03 /month			
9	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
		Pool Price	$57.30			
10	**2010 Energy Related Charge** Row 8 + Row 9			**$56,148.83**	**$74,859.09**	**$93,569.36**
11	AE and AESO Rates	Customer Charge	$ 0.0000 /day	**$20,806.09**	**$24,851.12**	**$28,896.15**
		Energy Charge	$ 0.0045 /kW.h			
		Demand Charge Blk 1	$ 0.17 /kW/day			
		Demand Charge Blk 2	$ 0.06 /kW/day			
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge (1st 7.5MW)	$ 3.96 /kW/month	-$3,349.61	-$4,466.14	-$5,582.68
		POD Charge fixed	$ 7,030.00 /month			
		Balancing Pool Refund Rider	-$ 0.00400 /kW.h			
		Rider G	-$ 0.0004 /kW.h			
13	**Net DT Charges** Row 11 + Row 12			**$17,456.49**	**$20,384.98**	**$23,313.48**
14	**Predicted Combined Rate: June 1, 2010** Row 10 + Row 13			**$73,605.31**	**$95,244.07**	**$116,882.83**
	Effective Date: *August 1, 2010*					
15	Forecast Energy Rate: August 1, 2010	Energy Charge	$ 0.08493 /kW.h	**$65,116.88**	**$86,816.49**	**$108,516.11**
		Energy Admin Fee	$ 18.03 /month			
16	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
		Pool Price	$57.30			
17	**2010 Energy Related Charge** Row 15 + Row 16			**$65,116.88**	**$86,816.49**	**$108,516.11**
18	AE and AESO Rates	Customer Charge	$ 0.0000 /day	**$20,806.09**	**$24,851.12**	**$28,896.15**
		Energy Charge	$ 0.0045 /kW.h			
		Demand Charge Blk 1	$ 0.17 /kW/day			
		Demand Charge Blk 2	$ 0.06 /kW/day			
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge (1st 7.5MW)	$ 3.96 /kW/month	-$1,512.02	-$2,016.02	-$2,520.03
		POD Charge fixed	$ 7,030.00 /month			
		Balancing Pool Refund Rider	-$ 0.00200 /kW.h			
		Rider G	$ 0.00003 /kW.h			
20	**Net DT Charges** Row 18 + Row 19			**$19,294.07**	**$22,835.10**	**$26,376.12**
21	**Predicted Combined Rate: August 1, 2010** Row 17 + Row 20			**$84,410.95**	**$109,651.59**	**$134,892.23**
	Effective Date: *January 1, 2011*					
22	Forecast Energy Rate: January 1, 2011	Energy Charge	$ 0.08493 /kW.h	**$65,116.88**	**$86,816.49**	**$108,516.11**
		Energy Admin Fee	$ 18.03 /month			
23	+/- RRO Deferral	RRO Deferral	$ 0.0000 /kW.h	$0.00	$0.00	$0.00
		Pool Price	$57.30			
24	**2011 Energy Related Charge** Row 22 + Row 23			**$65,116.88**	**$86,816.49**	**$108,516.11**
25	AE and AESO Rates	Customer Charge	$ 0.0000 /day	**$20,921.60**	**$24,966.63**	**$29,011.66**
		Energy Charge	$ 0.0045 /kW.h			
		Demand Charge Blk 1	$ 0.18 /kW/day			
		Demand Charge Blk 2	$ 0.06 /kW/day			
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge (1st 7.5MW)	$ 3.96 /kW/month	-$1,512.02	-$2,016.02	-$2,520.03
		POD Charge fixed	$ 7,030.00 /month			
		Balancing Pool Refund Rider	-$ 0.00200 /kW.h			
		Rider G	$ 0.00003 /kW.h			
27	**Net DT Charges** Row 25 + Row 26			**$19,409.58**	**$22,950.60**	**$26,491.63**
28	**Predicted Combined Rate: January 1, 2011** Row 24 + Row 27			**$84,526.45**	**$109,767.09**	**$135,007.73**
	Comparisons					
	Combined Rate (January 1, 2010 - June 1, 2010) Row 14 vs Row 7		difference	$3,925.05	$5,125.90	$6,326.75
			%	6%	6%	6%
	Combined Rate (June 1, 2010 - August 1, 2010) Row 21 vs Row 14		difference	$10,805.64	$14,407.52	$18,009.39
			%	15%	15%	15%
	Combined Rate (August 1, 2010 - January 1, 2011) Row 28 vs Row 21		difference	$115.51	$115.51	$115.51
			%	0%	0%	0%

ATCO ELECTRIC
ATCO ELECTRIC 2011 DISTRIBUTION INTERIM TARIFF APPLICATION
Energy Rates Used in Appendix B-1 to B-14

	Admin. Charges	Cost of Energy for			
	Fixed	January 2010	June 2010	August 2010	January 2011
	($ / Day)	($ / kWh)	($ / kWh)	($ / kWh)	($ / kWh)
D11	0.265	0.07139	0.07468	0.08744	0.08744
D21	0.282	0.07037	0.07625	0.08789	0.08789
D25	0.312	0.07014	0.07311	0.08542	0.08542
D26	0.312	0.07014	0.07311	0.08542	0.08542
D31	0.601	0.06853	0.07323	0.08493	0.08493
T31	0.601	0.06853	0.07323	0.08493	0.08493
D41	0.296	0.06807	0.07236	0.08452	0.08452
D51	0.274	0.07014	0.07520	0.08824	0.08824
D56	0.274	0.07014	0.07520	0.08824	0.08824
D61	0.087	0.05837	0.04120	0.05392	0.05392
D63	0.087	0.05837	0.04120	0.05392	0.05392

Rates used are the RRO Rates as posted on AUC website September 30, 2010
January 2011 rate is the same as August 2010 rate

EFFECTIVE: 2011-01-01
SUPERSEDES: 2010-01-01

ATCO ELECTRIC LTD.
2011 RATE SCHEDULE
INTERIM TRANSMISSION TARIFF

AVAILABLE: To the Transmission Administrator

APPLICABLE: To the Transmission Administrator for use of the Company's transmission facility for the 2011 calendar year.

RATE: Interim Charges to the Transmission Administrator for the 2011 calendar year shall be:

Annual Tariff: $282,234,000

Monthly Charges: $23,519,000