



Submitted Via Email DDS

November 23, 2010

Alberta Utilities Commission
#400, 425-1st Street S.W.
Calgary, Alberta
T2P 3L8

Attention: David Cherniwchan
Application Officer

Dear Sir:

RE: ATCO Electric Ltd. – 2011 Interim Tariff Application
Application No. 1606728, Proceeding ID 918

Responses to AUC Information Requests

Please find attached ATCO Electric's responses to the AUC's Information Requests with respect to its 2011 Interim Tariff Application.

This information has been uploaded onto the AUC Electronic Application System.

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

Sincerely,

Original Signed by Nick Palladino

Nick Palladino, P.Eng.
Manager, Pricing

NP/by
Att.

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Alberta Utilities Commission (AUC)
Round 1**

Received: November 18, 2010

AUC-AE-1

Reference: Application, page 4, lines 17-20 and page 5, lines 13-14

Issue/Sub-Issue: Proposed Distribution Interim Rate Increase

Quote: *"... 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 [Distribution] rate increase to be a reasonable amount to allow for an Interim rate increase."*

"...ATCO Electric has focused on the principle of gradualism in determining appropriate rates."

Request:

- (a) Please explain how AE determined that 90 percent of the requested Distribution revenue requirement increase would be a reasonable amount to request for an interim rate increase?
- (b) Please discuss how 90 percent of the requested revenue requirement increase represents a gradual change between the existing and proposed rates?

Response:

- (a) Following the completion of ATCO Electric's 2011-2012 GTA on October 25, ATCO Electric conducted a review of the cost drivers contributing to the increases in the proposed distribution revenue requirement in an effort to strike a reasonable balance between setting aside contentious issues that may be excluded from the determination of the proposed interim rates and ensuring ATCO Electric can begin its timely recovery of forecast cost increases. This process was done for both the Transmission and Distribution business units.

Unlike establishing the proposed interim rates for the Transmission business unit whereby ATCO Electric determined two contentious issues that were subject to debate and which will be addressed under Module 2 of the 2011-2012 GTA, ATCO Electric does not consider there to be any contentious and specific issues that might be appropriate to remove for the purpose of establishing interim distribution rates.

However, as set out in the Application, based on previously approved Interim Tariff Applications and final approved revenue requirements, and the estimated rate impact to customers, ATCO Electric considered that 90% of the requested rate increase to be a reasonable amount to allow for an interim rate increase. It is important to note that the proposed reduction is strictly related to recovery of costs associated with the 'distribution' function. In other words, the proposed interim distribution tariff adjustments allow ATCO Electric to recover 100% of the costs associated with recovery of transmission access payments (TAP) from the AESO (100% recovery of the 'transmission' function). In essence, the proposed reduction of 10% of the proposed revenue requirement increase targets the cost drivers from the Phase I Application attributable to: i) increases in return on rate base, ii) impact of pension contributions and iii) operating cost increases (not including TAP). 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. This also serves to link rate revenue to the period when the costs are forecasted to occur.

- (b) As mentioned above and consistent with previous interim tariff applications, the approach ATCO Electric takes in determination of its scaling factors is based on: (1) ensuring the interim rates are designed to recover 100% of its forecast costs that it anticipates it will receive from the AESO, and (2) any proposed reduction in the target revenue requirement is associated with the 'distribution' function of the distribution tariff. ATCO Electric is of the view that it is preferred to have an interim increase that reflects an intermediate position between current and the proposed final rates. Setting interim rates must strike a reasonable balance between meeting the conditions of the Commission's two-part test as set out in the Application, while still providing an appropriate transition to 2011 and 2012 final approved rates. While the Commission will ultimately decide the final approved revenue requirement, ATCO Electric does not anticipate that it will vary significantly from the target revenue requirement set out for the purpose of establishing interim rates. This will help provide a gradual change between current approved rates to 2011 interim rates and final 2012 rates. As noted in part (a) above, ATCO Electric believes that its proposed interim rates closely reflect the circumstances that are forecasted to exist in the test year.

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Alberta Utilities Commission (AUC)
Round 1**

Received: November 18, 2010

AUC-AE-2

Reference: Application, page 5, lines 5-11

Issue/Sub-Issue: Impact of Proposed Level of Interim Rate Increase on Credit Metrics

Quote: *“...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 AUC’s previously enunciated criteria and the fact that several contentious issues are being debated in the Phase I proceedings.”*

Request:

- (a) Please explain and quantify what level of Transmission and Distribution interim rate increases would harm or impact the credit metrics mentioned by AE above.
- (b) Please provide the latest bond rating for AE and discuss how the level of Transmission and Distribution interim rate increases would impact its bond rating going forward.
- (c) Please explain how the proposed level of Transmission and Distribution interim rate increases would mitigate changes in AE’s credit metrics.
- (d) Please explain and quantify the “unwarranted and undesirable cash flow deficiencies in 2011” anticipated by AE based on the requested level of Transmission and Distribution interim rate increases.

Response:

(a),(c),(d)

As indicated in Table 3 of the Interim Rate Application, ATCO Electric has applied in its 2011-2012 GTA Application for an increase in 2011 revenue requirement of \$86.6 million for Transmission and \$33.4 million for Distribution. To the extent that the \$120 million (\$86.6+\$33.4) increase is not approved on an interim basis, ATCO Electric's credit metrics will be negatively impacted as cash flow will not be received to cover increased expenses and therefore less cash available to cover interest payments. An increased level of interim rates will assist in mitigating these cash flow problems. As stated in ATCO Electric's 2011-2012 GTA, the credit metrics under the current treatment of CWIP and recovery of future tax would be significantly below the guidelines of an 'A' rated company.

Information relating to CU Inc.'s (ATCO Electric's) bond rating has been provided in the 2011-2012 GTA Module 2 Rebuttal Evidence. ATCO Electric is not asserting that the level of interim rates approved herein will lead to a change in the existing bond rating. Rather, the negative impact on cash flows, discussed above, will be another item that the rating agencies will consider as part of their assessments.

- (b) ATCO Electric receives its financing through its parent company CU Inc. The latest bond rating for CU Inc. is 'A' high (DBRS) or 'A' (S&P). Although ATCO Electric's credit metrics would be negatively impacted if interim rates are not approved, given the temporary nature of the interim rates it is unlikely that CU's bond rating would be impacted.

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Alberta Utilities Commission (AUC)
Round 1**

Received: November 18, 2010

AUC-AE-3

Reference: Application, page 7, lines 18-23

Issue/Sub-Issue: Transmission Access Payments

Quote: *"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."*

Request:

- (a) Please provide the latest forecast of TAP payments used for the scaling adjustment and indicate its date and source.
- (b) Please explain how AE will address future changes that may occur with the AESO tariff and result in differences from the TAP payments forecast used in the Application.

Response:

- (a) The latest forecast of TAP payments used for the scaling adjustment is \$168.6 M as set out in ATCO Electric's 2011-2012 GTA using AESO's 2010 proposed tariffs filed on March 5, 2010. Please refer to AUC-AE-03a Attachment 1 for the forecast TAP expense that was filed in the 2011-2012 GTA.
- (b) For the purpose of establishing 2011 interim rates, ATCO Electric is suggesting that it continue its use of the TAP deferral account whereby any changes in TAP payments as a result of new rates and rate structure from the AESO or differences between the actual and forecasted pool prices will be accumulated in the TAP deferral account and dispensed through a subsequent Rider G.

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

AUC-AE-03(a) Attachment 1

2011-2012 GTA: Year 2011
 Transmission Access Payments - Details

TOTAL
 Input section:

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
Ref:														
a	Number of equivalent PODs													
	127	127	127	127	127	127	127	127	127	127	127	127	129	
	Billing Capacity													
b	First 7.5 MW													
	781	778	782	777	777	777	777	777	777	777	777	777	791	9,349
c	Next 9.5 MW													
	496	488	493	489	488	490	502	502	500	501	503	531	5,983	
d	Next 23 MW													
	394	377	372	368	366	363	368	362	365	369	372	418	4,496	
e	Remaining													
	196	187	193	190	185	184	183	185	184	185	183	215	2,269	
f	Total													
	1,868	1,830	1,840	1,825	1,816	1,814	1,830	1,826	1,825	1,832	1,835	1,955	22,097	
g	Energy (MWh)													
	999,596	900,329	929,139	891,819	871,656	840,973	873,258	868,284	861,096	892,587	937,115	970,803	10,836,655	
h	Coincident Metered Demand													
	1,344	1,315	1,321	1,309	1,302	1,302	1,311	1,308	1,307	1,313	1,316	1,407	15,855	
i	Highest Metered Demand													
	1,734	1,671	1,676	1,565	1,529	1,546	1,560	1,561	1,570	1,598	1,649	1,825	19,484	
j	Pool price (\$) - D													
	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	
	Pool price (\$) - T													
	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	44.75	

(\$ in thousands)

Tariff		AESO proposed rate filed on March 16, 2010												
No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Bulk System Charge														
1	(i) (\$/MW/month)	\$ 2,265.00												
2	(ii) (\$/MWh)	\$ 0.82												
Local System Charge														
3	(i) (\$/MW/month)	\$ 1,006.00												
4	(ii) (\$/MWh)	\$ 0.59												
Point of Delivery Charge														
5	(i) First 7.5 MW (\$/MW/month)	\$ 4,762.00												
6	(ii) Next 9.5 MW (\$/MW/month)	\$ 1,757.00												
7	(iii) Next 23 MW (\$/MW/month)	\$ 1,065.00												
8	(iv) Remaining (\$/MW/month)	\$ 583.00												
9	(v) (\$/month)	\$ 7,030.00												
10	(vi) (\$/MWh)	\$ 0.29												
Operating Reserve Charge														
11	(i) Percentage	3.12%												
Voltage Control Charge														
12	(i) (\$/MWh)	\$ 0.40												
Other System Support Service Charge														
13	(i) (\$/MW/month)	\$ 59.00												

\$ 14,536 \$ 14,027 \$ 14,180 \$ 13,965 \$ 13,859 \$ 13,749 \$ 13,928 \$ 13,892 \$ 13,865 \$ 14,003 \$ 14,178 \$ 14,832 \$ 169,013

Credits Section:

UFLS Credit	\$ (35)	\$ (35)	\$ (35)	\$ (35)	\$ (35)	\$ (35)	\$ (35)	\$ (35)	\$ (35)	\$ (35)	\$ (35)	\$ (35)	\$ (35)	\$ (420)
Rider F - Balancing Pool Credit (\$/MWh)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Ridger G	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Rider C - True Up	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	\$ 14,501	\$ 13,992	\$ 14,145	\$ 13,930	\$ 13,824	\$ 13,714	\$ 13,893	\$ 13,857	\$ 13,830	\$ 13,968	\$ 14,143	\$ 14,797	\$	168,593

2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918

Information Responses To:
Alberta Utilities Commission (AUC)
Round 1

Received: November 18, 2010

AUC-AE-4

Reference: Application, page 7, lines 26-28

Issue/Sub-Issue: Supplemental Information

Quote: *“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.”*

Preamble: The Commission requires additional information related to alternate scenarios and their related rate impacts on customers.

Request:

Please provide supplementary information for each of the Distribution interim rate increase scenarios of 50 percent, 60 percent and 70 percent. This supplementary information, which should be in Word or Excel format to assist parties with their review, shall include the following for each scenario:

- i. 2011 Interim Distribution Tariff (Price Schedules);
- ii. Bill Comparison and Rate Impact Schedules;
- iii. Determination of Adjustment Factors Schedule (Scaling Factors); and
- iv. Update of Table 3 from Application showing proposed increases to revenue requirement

Response:

Please refer to AUC-AE-04 Attachments 1 to 12 for a breakdown of the supplementary information requested. Please see below for a Supplementary Information Attachment Index.

Supplementary Information Attachment Index			
Scenario	50% Increase Scenario	60% Increase Scenario	70% Increase Scenario
i	Attachment 01	Attachment 05	Attachment 09
ii	Attachment 02	Attachment 06	Attachment 10
iii	Attachment 03	Attachment 07	Attachment 11
iv	Attachment 04	Attachment 08	Attachment 12

PRICE SCHEDULE INDEX**RESIDENTIAL SERVICE**

Standard Residential Service Price Schedule D11

SMALL GENERAL SERVICE

Standard Small General Service Price Schedule D21

Small General Service - Energy Only Price Schedule D22

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

Irrigation Pumping Service Price Schedule D25

REA Irrigation Pumping Service Price Schedule D26

LARGE GENERAL SERVICE/INDUSTRIAL

Large General Service/Industrial - Distribution Connected Price Schedule D31

Large General Service/Industrial - Transmission Connected Price Schedule T31

Generator Interconnection and Standby Power - Distribution Connected Price Schedule D32

Transmission Opportunity Rate - Distribution Connected Price Schedule D33

Transmission Opportunity Rate - Transmission Connected Price Schedule T33

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

OILFIELD

Small Oilfield and Pumping Power Price Schedule D41

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

FARM SERVICE

REA Farm Service Price Schedule D51

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

Farm Service Price Schedule D56

LIGHTING SERVICE

Street Lighting Service Price Schedule D61

Private Lighting Service Price Schedule D63

PRICE OPTIONS

Idle Service Option F

Service for Non-Standard Transformation and Metering Configurations Option H

REA Distribution Price Credit Option P

PRICING ADJUSTMENTS (RIDERS)

Municipal Assessment Rider A-1

Balancing Pool Adjustment Rider B

Special Facilities Charge Rider E

Temporary Adjustment Rider G

Interim Adjustment Rider J

Interim RRT Adjustment Rider Q

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company. 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	66.45 ¢ / day	5.42 ¢ / kW.h
Service	25.81 ¢ / day	-
TOTAL PRICE	92.26 ¢ / day	7.31 ¢ / 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	-	18.18 ¢/kW/day	3.35 ¢ / kW.h	-
Service	33.26 ¢ / day	-	-	-
TOTAL PRICE	33.26 ¢ / day	28.80 ¢/kW/day	3.72 ¢ / 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	21.51 ¢ / kW.h	7.14 ¢ / kW.h
Service	-	-
TOTAL PRICE	22.02 ¢ / kW.h	7.65 ¢ / 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:

- the highest metered demand during the billing period;
- the estimated demand;
- if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;
- 5 kilowatts.

The minimum annual charge is 12 times the sum of:

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

Application

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

Availability

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

Price

Charges for service in any one billing 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	-	18.18 ¢/kW/day	3.35 ¢ / kW.h	-
Service	33.26 ¢ / day	-	-	-
TOTAL PRICE	33.26 ¢ / day	18.18 ¢/kW/day	3.35 ¢ / 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:

- the highest metered demand during the billing period;
- the estimated demand;
- if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;
- 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

- 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.
- 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.
- 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:

- the highest metered demand during the billing period;
- the estimated demand;
- if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;
- 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	14.55 ¢ /day	21.16 ¢/kW/day	18.60 ¢/kW/day	-
Service	\$2.2528 /day	-	0.68 ¢/kW/day	-
TOTAL PRICE	\$2.3983 /day	36.84 ¢/kW/day	35.50 ¢/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	1.43 ¢/kW/day	-	-
Service	9.74 ¢/kW/day	-	-
TOTAL PRICE	11.17 ¢/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	14.55 ¢ /day	21.16 ¢/kW/day	16.60 ¢/kW/day	-
Service	\$2.2528 /day	-	0.68 ¢/kW/day	-
TOTAL PRICE	\$2.3983 /day	36.84 ¢/kW/day	35.50 ¢/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.
- Telemetry is required for all points of service on this rate with demands greater than 2,500 kW, and any associated costs will be in addition to the charges in this rate.

Price

Charges for service in any one billing 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	14.55 ¢ /day	21.16 ¢/kW/day	16.60 ¢/kW/day	-	-
Service	\$2.2528 /day	-	0.68 ¢/kW/day	-	-
TOTAL PRICE	\$2.3982 /day + AESO DOS Rate	21.16 ¢/kW/day	17.28 ¢/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:	<input style="width: 95%;" type="text"/>		
Date of Request:	<input style="width: 95%;" type="text"/>		
Time of Request:	<input style="width: 95%;" type="text"/>		
1. OPPORTUNITY CONTRACT PERIOD:			
Start Date:	<input style="width: 60%;" type="text"/>	Start Time:	<input style="width: 20%;" type="text"/>
End Date:	<input style="width: 60%;" type="text"/>	End Time:	<input style="width: 20%;" type="text"/>
	Number of Hours in Contract Period:	<input style="width: 20%;" type="text"/>	Hours
2. TRANSMISSION OPPORTUNITY SERVICE OPTION:			
AESO "DEMAND OPPORTUNITY SERVICE":		DOS 7 Minutes:	<input style="width: 40%;" type="text"/>
		DOS 1 Hour:	<input style="width: 40%;" type="text"/>
		DOS Term:	<input style="width: 40%;" type="text"/>
3. OPPORTUNITY CONTRACT DEMAND:			
	<input style="width: 100px;" type="text"/>	kW	
4. BASE DEMAND:			
Large General Service/Industrial Price Schedule D31 Base Demand:		<input style="width: 100px;" type="text"/>	kW
Sum of Demands on all Opportunity Service Contracts:		<input style="width: 100px;" type="text"/>	kW
Total Base Demand:		<input style="width: 100px;" type="text"/>	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)



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

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

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

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

Availability

For Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from an isolated industrial area. 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	14.55 ¢ /day	21.16 ¢/kW/day	16.60 ¢/kW/day	-
Service	\$2.2528 /day	-	0.68 ¢/kW/day	-
TOTAL PRICE	\$2.3982 /day	21.16 ¢/kW/day	17.28 ¢/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	50.29 ¢ / day	46.72 ¢/kW/day	-
Service	88.52 ¢ / day	-	-
TOTAL PRICE	\$1.3881 / day	60.04 ¢/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	50.29 ¢ / day	46.72 ¢/kW/day
Service	88.52 ¢ / day	-
TOTAL PRICE	\$1.3881 / day	46.72 ¢/kW/day

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

- (a) The highest metered demand during the billing period;
- (b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the Distribution Contract Demand (DCD);
- (e) 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	-	8.66 ¢/kV.A/day	-
Service	29.43 ¢ / service / day	-	-
REA Specific Charges	See REA Tariff	-	-
Total Price	C₁ ¢ / service/ day	15.68 ¢/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	C₁ ¢ / service /day	D₁ ¢/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	24.91 ¢/service/day	-	-
TOTAL PRICE	24.91 ¢/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	26.11 ¢/service/day	11.38 ¢/kV.A/day	0.56 ¢ / kW.h
Service	29.43 ¢/service/day	-	-
TOTAL PRICE	55.54 ¢/service/day	18.40 ¢/kV.A/day	0.93 ¢ / kW.h

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

- (a) For breaker 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 breaker 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	24.71 ¢/fixture/day	0.021 ¢/watt/day
Service	12.92 ¢/fixture/day	-
TOTAL PRICE	37.63 ¢/fixture/day	0.040 ¢/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	39.83 ¢/fixture/day	0.021 ¢/watt/day
Service	12.92 ¢/fixture/day	-
TOTAL PRICE	52.75 ¢/fixture/day	0.040 ¢/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	13.11 ¢/fixture/day	0.006 ¢/watt/day
Service	12.92 ¢/fixture/day	-
TOTAL PRICE	26.03 ¢/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	26.22 ¢/fixture/day	0.021 ¢/watt/day
Service	12.92 ¢/fixture/day	-
TOTAL PRICE	39.14 ¢/fixture/day	0.040 ¢/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	17.14 ¢/fixture/day	0.021 ¢/watt/day
Service	12.92 ¢/fixture/day	-
TOTAL PRICE	30.06 ¢/fixture/day	0.040 ¢/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.

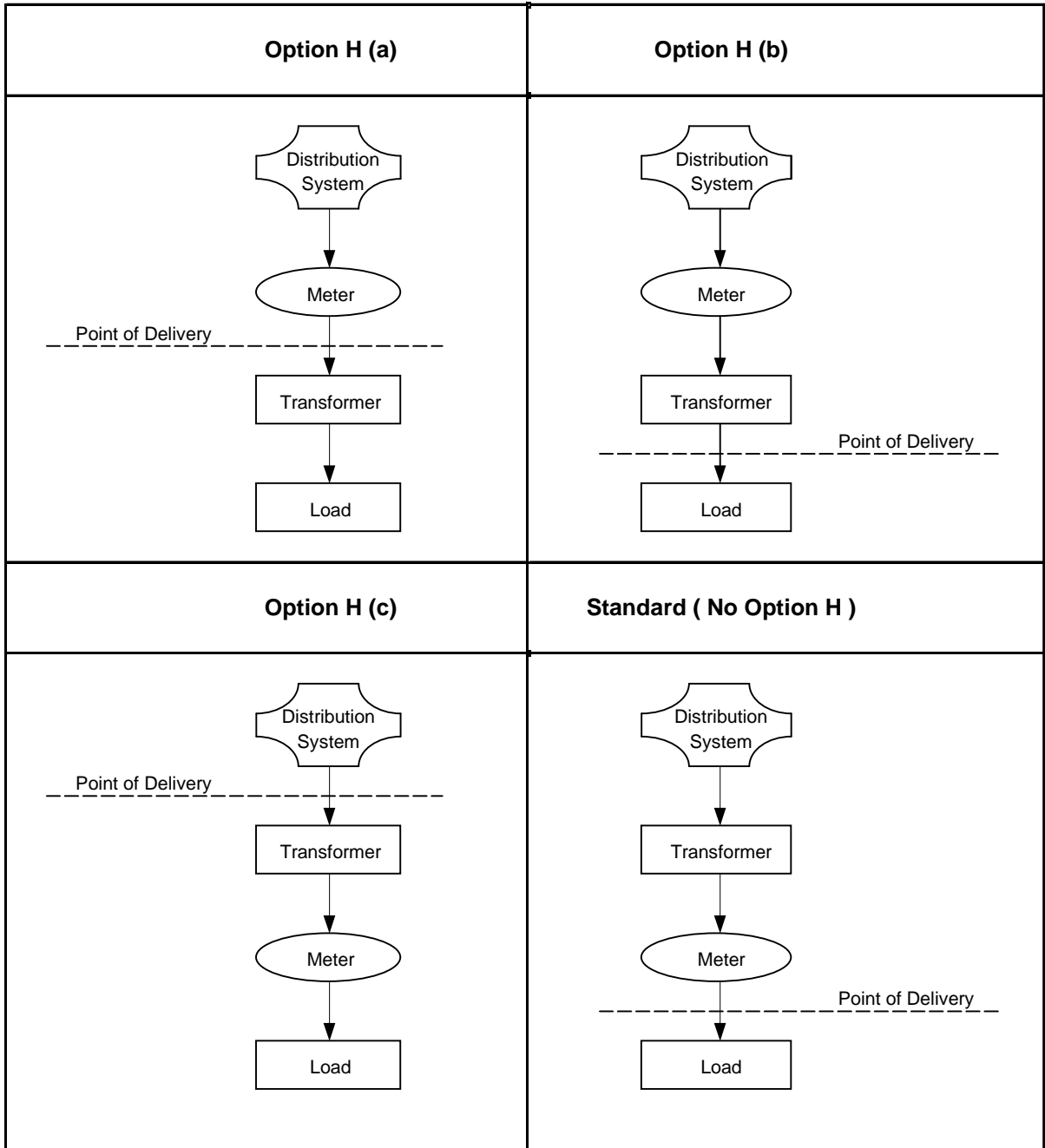
Availability

- 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.

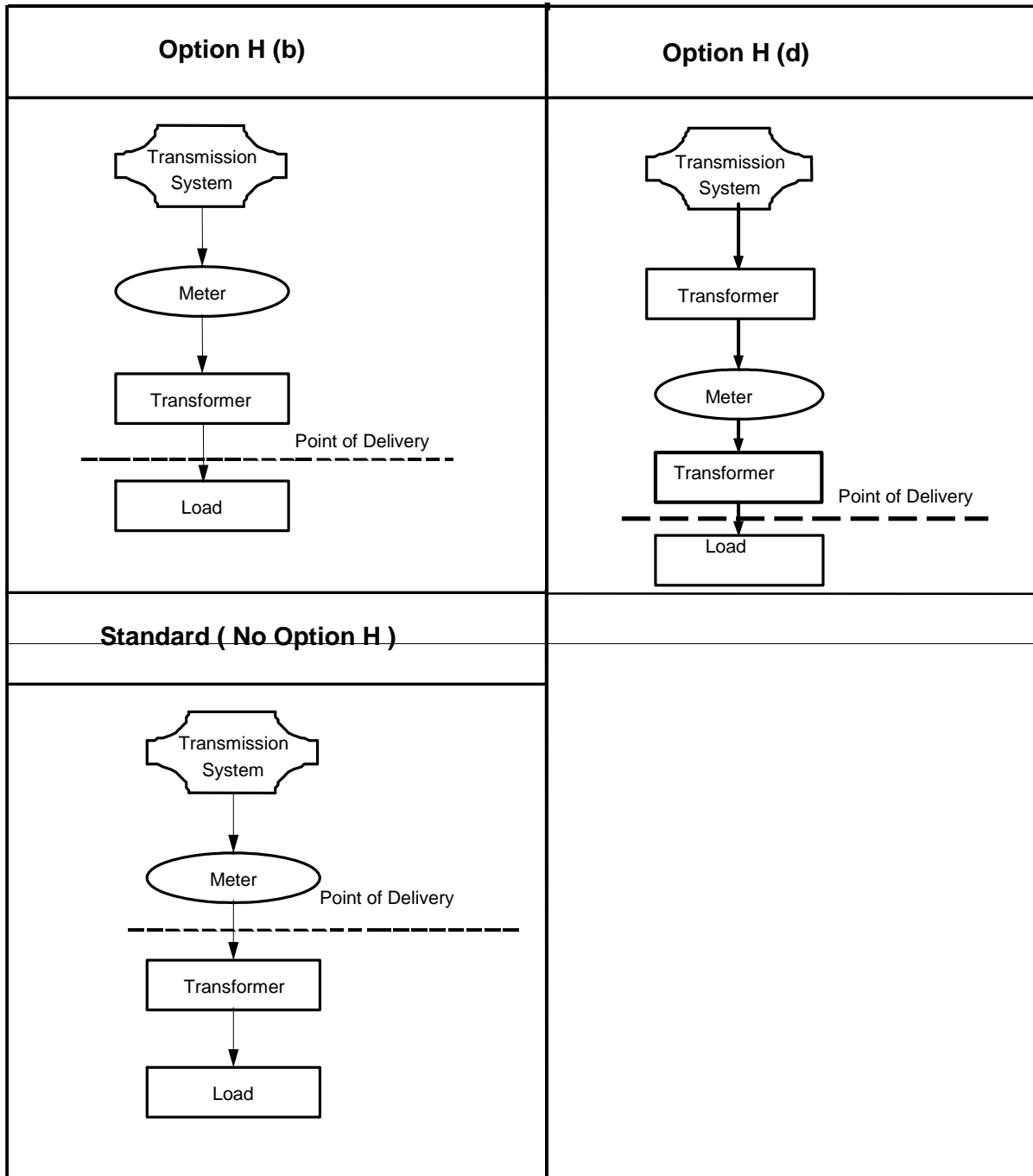
Price Adjustment

- (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 3.50 ¢/kW/day** of billing demand will be applied. This adjustment does not apply to customers connected directly to the transmission system who are exempt from the Distribution Charge on the applicable rate.
- (b) If primary or higher voltage delivery metering is desirable for the convenience of the Company, or to improve accessibility, etc., **demand and energy measurements will be reduced by 1%** so as to approximate secondary voltage delivery conditions.
- (c) If primary or higher voltage delivery is made to customer owned transformers, but metering is at secondary or utilization voltage for the Company's convenience, **demand and energy measurements will be increased by 1%** so as to approximate primary or transmission voltage delivery conditions and **a discount, as specified in (a)** shall apply.
- (d) Customers who are connected directly to the transmission system, but take service from the low side of a transformer (with primary side 25kV), and do not own or rent any necessary transformer(s), and are exempt from the Distribution Charge on the applicable rate, a **surcharge of 3.50 ¢/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	Empress 8+6	Jasper Nat'l Park 5	Sexsmith 7
Andrew 8+6	Fairview 8+6	Kinuso 8+6	Slave Lake 8+6
Beaverlodge 8+6	Falher 8+6	Kitscoty 8+6	Smoky Lake 8+6
Berwyn 8+6	Forestburg 8+6	Linden 8+6	Spirit River 8+6
Big Valley 8+6	Fort McMurray 7	Lloydminster 8+6	St Paul 8+6
Bonnyville 8+6	Fox Creek 8+6	Manning 7	Stettler 7+6
Botha 8+6	Gadsby 8+6	Mannville 8+6	Swan Hills 8+6
Carbon 7	Galahad 8+6	Marwayne 8+6	Three Hills 8+6
Castor 8+6	Girouxville 7	McLennan 7	Trochu 8+6
Cereal 7	Glendon 8+6	Minburn 8+6	Two Hills 8+6
Cold Lake 8+6	Grande Cache 8+6	Morrin 7	Valleyview 8+6
Consort 8+6	Grande Prairie 8+6	Mundare 6	Vegreville 8+6
Coronation 8+6	Grimshaw 8+6	Munson 8+6	Vermilion 8+6
Delburne 8+6	Halkirk 8+6	Myrnam 8+6	Veteran 8+6
Delia 8+6	Hanna 8+6	Nampa 7	Vilna 8+6
Derwent 8+6	Heisler 8+6	Oyen 8+6	Waskatenau 8+6
Dewberry 8+6	High Level 8+6	Paradise Valley 8+6	Wembley 7
Donalda 8+6	High Prairie 8+6	Peace River 8+6	Willingdon 8+6
Donnelly 8+6	Hines Creek 8+6	Radway (County 7) 8+6	Youngstown 7+6
Drumheller 8+6	Hythe 8+6	Rainbow Lake 8+6	
Elk Point 8+6	Innisfree 8+6	Rosalind 8+6	
Elnora 8+6	ID Jasper 7	Rycroft 8+6	

Table 2 – Category Numbers of Municipalities

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

Bonnyville Beach	County No. 27 Minburn	M.D. of Big Lake No. 125
Horseshoe Bay	County No. 29 Flagstaff	M.D. of Smoky R. No. 130
Lavoy	County No. 30 Lamont	M.D. of East Peace No. 131
Pelican Narrows	County No. 89 Lakeland	M.D. of Spirit River No. 133
Rochon Sands	M.D. of Badlands No. 07	M.D. of Peace No. 135
Wanham	M.D. of Greenview No. 16	M.D. of Fairview No. 136
Warspite	M.D. of Opportunity No. 17	I.D. No. 12 & ID No. 24
Whitesands	M.D. of Wood Buffalo No. 18	Allison Bay B219
County No. 01 Grande Pr.	M.D. of Birch Hills No. 19	Fort McMurray Band B352
County No. 06 Stettler	M.D. of Saddle Hills No. 20	Peavine N172
County No. 07 Thorhild	M.D. of Clear Hills No. 21	Gift Lake N173
County No. 13 Smoky Lake	M.D. of Northern Lights No. 22	East Prairie N174
County No. 16 Wheatland	M.D. of Mackenzie No. 23	Elizabeth N187
County No. 18 Paintearth	M.D. of Acadia No. 34	Fishing Lake N188
County No. 19 St. Paul	M.D. of Starland No. 47	Paddle Prairie N221
County No. 21 Two Hills	M.D. of Kneehill No. 48	Special Areas
County No. 22 Camrose	M.D. of Bonnyville No. 87	Sturgeon Lake I.R. #154
County No. 23 Red Deer	M.D. of Bonnyville Annexed No. 88	Whitefish Lake Band B924
County No. 24 Vermilion R.	M.D. of Lesser Slave River No. 124	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
Proceeding ID 918, No. 1606728

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

Rate Class	January 1, 2010				June 1, 2010				August 1, 2010				January 1, 2011			
	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	\$71.54	-\$2.17	-\$1.26	\$68.11
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	\$343.30	-\$6.50	-\$15.40	\$321.40
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	\$685.19	\$12.22	-\$34.97	\$662.45
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	\$434.40	-\$9.24	-\$18.75	\$406.41
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	\$48.73	\$1.65	-\$2.66	\$47.72
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	\$69.72	-\$0.20	-\$2.66	\$66.87
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	\$14.26	-\$0.29	-\$0.19	\$13.78
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	\$24,885.69	\$27.98	-\$2,044.00	\$22,869.66

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.1 - Example Rate Rider Effects: Residential Class - RRO Eligible

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Residential Class Consumption Levels Cost per Customer (\$/month)		
Row	Rate Component	Rate	300 kW.h per month	Typical 600 kW.h per month	1,200 kW.h per month	
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07139 /kW.h Energy Admin Fee \$ 7.95 /month	\$29.37	\$50.78	\$93.62	
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 Energy Charge \$ 0.0701 /kW.h	\$48.00	\$69.03	\$111.09	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00421 /kW.h Rider G -\$ 0.0100 /kW.h	-\$4.28	-\$8.55	-\$17.10	
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 Energy Admin Fee \$ 7.95 /month	\$30.35	\$52.76	\$97.57	
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 Energy Charge \$ 0.0706 /kW.h	\$48.29	\$69.47	\$111.83	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00421 /kW.h Rider G -\$ 0.0100 /kW.h	-\$4.28	-\$8.55	-\$17.10	
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 Energy Admin Fee \$ 7.95 /month	\$34.18	\$60.41	\$112.88	
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 Energy Charge \$ 0.0706 /kW.h	\$48.29	\$69.47	\$111.83	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G -\$ 0.00362 /kW.h	-\$1.72	-\$3.43	-\$6.86	
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 Energy Admin Fee \$ 7.95 /month	\$34.18	\$60.41	\$112.88	
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 \$ 0.9226 /day Energy Charge \$ 0.0731 /kW.h	\$49.61	\$71.54	\$115.41	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G -\$ 0.00362 /kW.h	-\$1.72	-\$3.43	-\$6.86	
27	Net DT Charges	Row 25 + Row 26	\$47.89	\$68.11	\$108.54	
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$82.08	\$128.52	\$221.42	
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference %	\$1.28 2%	\$2.42 2%	\$4.69 3%
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference %	\$6.39 9%	\$12.77 11%	\$25.55 13%
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference %	\$1.32 2%	\$2.07 2%	\$3.57 2%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

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)		
				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
Row	Rate Component	Rate				
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07037 /kW.h Energy Admin Fee \$ 8.46 /month	\$393.74	\$522.16	\$650.59	
2	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
3	2010 Energy Related Charge		\$393.74	\$522.16	\$650.59	
Row 1 + Row 2						
4	AE Interim DT Base Rates	Customer Charge \$ 0.3287 /day Energy Charge Blk 1 \$ 0.0357 /kW.h Energy Charge Blk 2 \$ 0.0048 /kW.h Demand Charge \$ 0.2612 /kW/day	\$246.38	\$325.22	\$404.06	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0021 /kW.h	-\$34.60	-\$46.14	-\$57.67	
6	Net DT Charges		\$211.78	\$279.09	\$346.39	
Row 4 + Row 5						
7	Combined Rate: January 1, 2010		\$605.51	\$801.25	\$996.98	
Row 3 + Row 6						
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07625 /kW.h Energy Admin Fee \$ 8.46 /month	\$425.93	\$565.09	\$704.24	
9	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
10	2010 Energy Related Charge		\$425.93	\$565.09	\$704.24	
Row 8 + Row 9						
11	AE Final DT Base Rates	Customer Charge \$ 0.3258 /day Energy Charge Blk 1 \$ 0.0370 /kW.h Energy Charge Blk 2 \$ 0.0042 /kW.h Demand Charge \$ 0.2703 /kW/day	\$252.80	\$333.81	\$414.82	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0021 /kW.h	-\$34.60	-\$46.14	-\$57.67	
13	Net DT Charges		\$218.20	\$287.68	\$357.15	
Row 11 + Row 12						
14	Predicted Combined Rate: June 1, 2010		\$644.13	\$852.76	\$1,061.40	
Row 10 + Row 13						
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08789 /kW.h Energy Admin Fee \$ 8.46 /month	\$489.66	\$650.06	\$810.46	
16	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
17	2010 Energy Related Charge		\$489.66	\$650.06	\$810.46	
Row 15 + Row 16						
18	AE Final DT Base Rates	Customer Charge \$ 0.3258 /day Energy Charge Blk 1 \$ 0.0370 /kW.h Energy Charge Blk 2 \$ 0.0042 /kW.h Demand Charge \$ 0.2703 /kW/day	\$252.80	\$333.81	\$414.82	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00089 /kW.h	-\$16.42	-\$21.90	-\$27.37	
20	Net DT Charges		\$236.38	\$311.92	\$387.45	
Row 18 + Row 19						
21	Predicted Combined Rate: August 1, 2010		\$726.04	\$961.97	\$1,197.91	
Row 17 + Row 20						
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08789 /kW.h Energy Admin Fee \$ 8.46 /month	\$489.66	\$650.06	\$810.46	
23	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
24	2011 Energy Related Charge		\$489.66	\$650.06	\$810.46	
Row 22 + Row 23						
25	AE Proposed DT Base Rates	Customer Charge \$ 0.3326 /day Energy Charge Blk 1 \$ 0.0371 /kW.h Energy Charge Blk 2 \$ 0.0037 /kW.h Demand Charge \$ 0.2880 /kW/day	\$259.97	\$343.30	\$426.63	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00089 /kW.h	-\$16.42	-\$21.90	-\$27.37	
27	Net DT Charges		\$243.54	\$321.40	\$399.25	
Row 25 + Row 26						
28	Predicted Combined Rate: January 1, 2011		\$733.20	\$971.46	\$1,209.71	
Row 24 + Row 27						
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference %	\$38.62 6%	\$51.52 6%	\$64.42 6%
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference %	\$81.91 13%	\$109.21 13%	\$136.51 13%
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference %	\$7.16 1%	\$9.48 1%	\$11.80 1%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

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 Energy Admin Fee \$ 8.46 /month	\$393.74	\$522.16	\$650.59	
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 Energy Charge Blk 1 \$ 0.0357 /kW.h Energy Charge Blk 2 \$ 0.0048 /kW.h Demand Charge \$ 0.2612 /kW/day	\$246.38	\$325.22	\$404.06	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0021 /kW.h	-\$34.60	-\$46.14	-\$57.67	
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 Energy Admin Fee \$ 8.46 /month	\$425.93	\$565.09	\$704.24	
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 Energy Charge Blk 1 \$ 0.0370 /kW.h Energy Charge Blk 2 \$ 0.0042 /kW.h Demand Charge \$ 0.2703 /kW/day	\$252.80	\$333.81	\$414.82	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0021 /kW.h	-\$34.60	-\$46.14	-\$57.67	
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 Energy Admin Fee \$ 8.46 /month	\$489.66	\$650.06	\$810.46	
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 Energy Charge Blk 1 \$ 0.0370 /kW.h Energy Charge Blk 2 \$ 0.0042 /kW.h Demand Charge \$ 0.2703 /kW/day	\$252.80	\$333.81	\$414.82	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00089 /kW.h	-\$16.42	-\$21.90	-\$27.37	
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 Energy Admin Fee \$ 8.46 /month	\$489.66	\$650.06	\$810.46	
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 \$ 0.3326 /day Energy Charge Blk 1 \$ 0.0371 /kW.h Energy Charge Blk 2 \$ 0.0037 /kW.h Demand Charge \$ 0.2880 /kW/day	\$259.97	\$343.30	\$426.63	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00089 /kW.h	-\$16.42	-\$21.90	-\$27.37	
27	Net DT Charges	Row 25 + Row 26	\$243.54	\$321.40	\$399.25	
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$733.20	\$971.46	\$1,209.71	
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference %	\$38.62 6%	\$51.52 6%	\$64.42 6%
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference %	\$81.91 13%	\$109.21 13%	\$136.51 13%
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference %	\$7.16 1%	\$9.48 1%	\$11.80 1%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.4 - Example Rate Rider Effects: Irrigation Pumping Service

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Irrigation Pumping Service Class		
			Consumption Levels Cost per Customer (\$/season)		
Row	Rate Component	Rate	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
Effective Date: January 1, 2010					
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07014 /kW.h	\$681.19	\$886.00	\$1,090.81
2	+/- RRO Deferral	Energy Admin Fee \$ 9.36 /month 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 Energy Charge \$ 0.0049 /kW.h Demand Charge \$ 0.2079 /kW/day	\$1,433.11	\$1,892.32	\$2,351.54
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00429 /kW.h Rider G -\$ 0.0042 /kW.h	-\$73.93	-\$98.58	-\$123.22
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
9	+/- RRO Deferral	Energy Admin Fee \$ 9.36 /month 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 Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 0.2145 /kW/day	\$1,465.69	\$1,937.28	\$2,408.86
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00429 /kW.h Rider G -\$ 0.0042 /kW.h	-\$73.93	-\$98.58	-\$123.22
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
16	+/- RRO Deferral	Energy Admin Fee \$ 9.36 /month 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 Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 0.2145 /kW/day	\$1,465.69	\$1,937.28	\$2,408.86
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00215 /kW.h Rider G -\$ 0.00266 /kW.h	-\$42.10	-\$56.14	-\$70.17
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
23	+/- RRO Deferral	Energy Admin Fee \$ 9.36 /month 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 Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 0.2709 /kW/day	\$1,840.34	\$2,430.84	\$3,021.34
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00215 /kW.h Rider G -\$ 0.00266 /kW.h	-\$42.10	-\$56.14	-\$70.17
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 3%	\$100.69 3%
Combined Rate (June 1, 2010 - August 1, 2010)		Row 21 vs Row 14	difference \$139.67 %	\$186.22 7%	\$232.78 7%
Combined Rate (August 1, 2010 - January 1, 2011)		Row 28 vs Row 21	difference \$374.65 %	\$493.56 17%	\$612.48 17%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.5 - Example Rate Rider Effects: REA Irrigation Pumping Service

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			REA Irrigation Pumping Service Class Consumption Levels Cost per Customer (\$/season)			
Row	Rate Component	Rate	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	
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07014 /kW.h Energy Admin Fee \$ 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		\$681.19	\$886.00	\$1,090.81	
Row 1 + Row 2						
4	AE Interim DT Base Rates	Customer Charge \$ 0.2592 /day Energy Charge \$ 0.0049 /kW.h Demand Charge \$ 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		\$803.20	\$1,052.45	\$1,301.69	
Row 4 + Row 5						
7	Combined Rate: January 1, 2010		\$1,484.40	\$1,938.45	\$2,392.51	
Row 3 + Row 6						
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07311 /kW.h Energy Admin Fee \$ 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		\$707.21	\$920.69	\$1,134.17	
Row 8 + Row 9						
11	AE Final DT Base Rates	Customer Charge \$ 0.2380 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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		\$868.53	\$1,141.06	\$1,413.59	
Row 11 + Row 12						
14	Predicted Combined Rate: June 1, 2010		\$1,575.74	\$2,061.75	\$2,547.76	
Row 10 + Row 13						
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08542 /kW.h Energy Admin Fee \$ 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		\$815.05	\$1,064.47	\$1,313.90	
Row 15 + Row 16						
18	AE Final DT Base Rates	Customer Charge \$ 0.2380 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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		\$900.36	\$1,183.50	\$1,466.64	
Row 18 + Row 19						
21	Predicted Combined Rate: August 1, 2010		\$1,715.40	\$2,247.97	\$2,780.54	
Row 17 + Row 20						
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08542 /kW.h Energy Admin Fee \$ 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		\$815.05	\$1,064.47	\$1,313.90	
Row 22 + Row 23						
25	AE Proposed DT Base Rates	Customer Charge \$ 0.3217 /day Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 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		\$1,090.66	\$1,431.26	\$1,771.86	
Row 25 + Row 26						
28	Predicted Combined Rate: January 1, 2011		\$1,905.70	\$2,495.73	\$3,085.76	
Row 24 + Row 27						
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%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

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 Energy Admin Fee \$ 18.03 /month	\$854.10	\$1,159.05	\$1,443.45	
2	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
3	2010 Energy Related Charge		\$854.10	\$1,159.05	\$1,443.45	
Row 1 + Row 2						
4	AE Interim DT Base Rates	Customer Charge \$ 2.3340 /day Energy Charge \$ 0.0048 /kW.h Demand Charge Blk 1 \$ 0.3186 /kW/day Demand Charge Blk 2 \$ 0.3051 /kW/day	\$606.48	\$627.84	\$733.78	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00420 /kW.h Rider G \$ 0.0018 /kW.h	-\$29.04	-\$39.63	-\$49.50	
6	Net DT Charges		\$577.44	\$588.21	\$684.28	
Row 4 + Row 5						
7	Combined Rate: January 1, 2010		\$1,431.54	\$1,747.27	\$2,127.73	
Row 3 + Row 6						
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07323 /kW.h Energy Admin Fee \$ 18.03 /month	\$911.44	\$1,237.31	\$1,541.21	
9	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
10	2010 Energy Related Charge		\$911.44	\$1,237.31	\$1,541.21	
Row 8 + Row 9						
11	AE Final DT Base Rates	Customer Charge \$ 2.3495 /day Energy Charge \$ 0.0042 /kW.h Demand Charge Blk 1 \$ 0.3434 /kW/day Demand Charge Blk 2 \$ 0.3275 /kW/day	\$636.83	\$655.52	\$765.66	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00420 /kW.h Rider G \$ 0.0018 /kW.h	-\$29.04	-\$39.63	-\$49.50	
13	Net DT Charges		\$607.79	\$615.89	\$716.16	
Row 11 + Row 12						
14	Predicted Combined Rate: June 1, 2010		\$1,519.23	\$1,853.20	\$2,257.37	
Row 10 + Row 13						
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08493 /kW.h Energy Admin Fee \$ 18.03 /month	\$1,054.18	\$1,432.11	\$1,784.57	
16	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
17	2010 Energy Related Charge		\$1,054.18	\$1,432.11	\$1,784.57	
Row 15 + Row 16						
18	AE Final DT Base Rates	Customer Charge \$ 2.3495 /day Energy Charge \$ 0.0042 /kW.h Demand Charge Blk 1 \$ 0.3434 /kW/day Demand Charge Blk 2 \$ 0.3275 /kW/day	\$636.83	\$655.52	\$765.66	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G \$ 0.00073 /kW.h	-\$16.67	-\$22.75	-\$28.42	
20	Net DT Charges		\$620.16	\$632.77	\$737.25	
Row 18 + Row 19						
21	Predicted Combined Rate: August 1, 2010		\$1,674.33	\$2,064.88	\$2,521.82	
Row 17 + Row 20						
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08493 /kW.h Energy Admin Fee \$ 18.03 /month	\$1,054.18	\$1,432.11	\$1,784.57	
23	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
24	2011 Energy Related Charge		\$1,054.18	\$1,432.11	\$1,784.57	
Row 22 + Row 23						
25	AE Proposed DT Base Rates	Customer Charge \$ 2.3982 /day Energy Charge \$ 0.0036 /kW.h Demand Charge Blk 1 \$ 0.3684 /kW/day Demand Charge Blk 2 \$ 0.3550 /kW/day	\$668.98	\$685.19	\$799.78	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G \$ 0.00073 /kW.h	-\$16.67	-\$22.75	-\$28.42	
27	Net DT Charges		\$652.31	\$662.45	\$771.36	
Row 25 + Row 26						
28	Predicted Combined Rate: January 1, 2011		\$1,706.49	\$2,094.56	\$2,555.93	
Row 24 + Row 27						
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	\$32.16	\$29.68	\$34.12
			%	2%	1%	1%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

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

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Large General Service Class Consumption Levels Cost per Customer (\$/month)		
				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
Row	Rate Component	Rate				
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		\$45,042.24	\$60,050.31	\$75,058.38	
	Row 1 + Row 2					
4	AE Interim DT Base Rates	Customer Charge \$ 2.3340 /day Energy Charge \$ 0.0048 /kW.h Demand Charge Blk 1 \$ 0.3186 /kW/day Demand Charge Blk 2 \$ 0.3051 /kW/day	\$17,155.62	\$22,783.32	\$28,411.02	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00420 /kW.h Rider G \$ 0.0018 /kW.h	-\$1,563.66	-\$2,084.88	-\$2,606.10	
6	Net DT Charges		\$15,591.96	\$20,698.44	\$25,804.92	
	Row 4 + Row 5					
7	Combined Rate: January 1, 2010		\$60,634.20	\$80,748.75	\$100,863.30	
	Row 3 + Row 6					
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		\$48,130.14	\$64,167.51	\$80,204.88	
	Row 8 + Row 9					
11	AE Final DT Base Rates	Customer Charge \$ 2.3495 /day Energy Charge \$ 0.0042 /kW.h Demand Charge Blk 1 \$ 0.3434 /kW/day Demand Charge Blk 2 \$ 0.3275 /kW/day	\$17,805.89	\$23,638.19	\$29,470.49	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00420 /kW.h Rider G \$ 0.0018 /kW.h	-\$1,563.66	-\$2,084.88	-\$2,606.10	
13	Net DT Charges		\$16,242.23	\$21,553.31	\$26,864.39	
	Row 11 + Row 12					
14	Predicted Combined Rate: June 1, 2010		\$64,372.37	\$85,720.82	\$107,069.27	
	Row 10 + Row 13					
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		\$55,817.04	\$74,416.71	\$93,016.38	
	Row 15 + Row 16					
18	AE Final DT Base Rates	Customer Charge \$ 2.3495 /day Energy Charge \$ 0.0042 /kW.h Demand Charge Blk 1 \$ 0.3434 /kW/day Demand Charge Blk 2 \$ 0.3275 /kW/day	\$17,805.89	\$23,638.19	\$29,470.49	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G \$ 0.00073 /kW.h	-\$897.62	-\$1,196.83	-\$1,496.03	
20	Net DT Charges		\$16,908.27	\$22,441.36	\$27,974.45	
	Row 18 + Row 19					
21	Predicted Combined Rate: August 1, 2010		\$72,725.31	\$96,858.07	\$120,990.83	
	Row 17 + Row 20					
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		\$55,817.04	\$74,416.71	\$93,016.38	
	Row 22 + Row 23					
25	AE Proposed DT Base Rates	Customer Charge \$ 2.3982 /day Energy Charge \$ 0.0036 /kW.h Demand Charge Blk 1 \$ 0.3684 /kW/day Demand Charge Blk 2 \$ 0.3550 /kW/day	\$18,640.94	\$24,763.57	\$30,886.20	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G \$ 0.00073 /kW.h	-\$897.62	-\$1,196.83	-\$1,496.03	
27	Net DT Charges		\$17,743.32	\$23,566.74	\$29,390.17	
	Row 25 + Row 26					
28	Predicted Combined Rate: January 1, 2011		\$73,560.36	\$97,983.45	\$122,406.55	
	Row 24 + Row 27					
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	\$835.06	\$1,125.39	\$1,415.72
			%	1%	1%	1%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.8 - Example Rate Rider Effects: Small Oilfield Class - RRO Eligible

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Small Oilfield Class Consumption Levels Cost per Customer (\$/month)		
Row	Rate Component	Rate	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 \$ 0.06807 /kW.h Energy Admin Fee \$ 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 \$ 1.3607 /day Energy Charge \$ 0.0049 /kW.h Demand Charge \$ 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 \$ 0.07236 /kW.h Energy Admin Fee \$ 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 \$ 1.3599 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 \$ 0.08452 /kW.h Energy Admin Fee \$ 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 \$ 1.3599 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 \$ 0.08452 /kW.h Energy Admin Fee \$ 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 \$ 1.3881 /day Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 0.6004 /kW/day	\$336.21	\$434.40	\$532.59
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	\$315.22	\$406.41	\$497.60
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$879.39	\$1,155.68	\$1,431.98
Comparisons					
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference \$33.44	\$44.60	\$55.76
			% 5%	5%	5%
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference \$105.81	\$141.08	\$176.35
			% 14%	14%	14%
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference \$9.13	\$11.90	\$14.66
			% 1%	1%	1%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.9 - Example Rate Rider Effects: Small Oilfield 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 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
Row	Rate Component	Rate				
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.06807 /kW.h Energy Admin Fee \$ 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 \$ 1.3607 /day Energy Charge \$ 0.0049 /kW.h Demand Charge \$ 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 \$ 0.07236 /kW.h Energy Admin Fee \$ 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 \$ 1.3599 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 \$ 0.08452 /kW.h Energy Admin Fee \$ 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 \$ 1.3599 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 \$ 0.08452 /kW.h Energy Admin Fee \$ 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 \$ 1.3881 /day Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 0.6004 /kW/day	\$336.21	\$434.40	\$532.59	
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	\$315.22	\$406.41	\$497.60	
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$879.39	\$1,155.68	\$1,431.98	
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference \$33.44 %	\$44.60 5%	\$55.76 5%	
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference \$105.81 %	\$141.08 14%	\$176.35 14%	
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference \$9.13 %	\$11.90 1%	\$14.66 1%	

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.10 - Example Rate Rider Effects: REA Farm Service Class (Pooled) - RRO Eligible

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				REA Farm Service Class Consumption Levels Cost per Customer (\$/month)		
Row	Rate Component	Rate		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
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07014 /kW.h Energy Admin Fee \$ 8.22 /month		\$61.18	\$96.25	\$131.32
2	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
3	2010 Energy Related Charge			\$61.18	\$96.25	\$131.32
Row 1 + Row 2						
4	AE Interim DT Base Rates	Customer Charge \$ 0.2916 /day Energy Charge \$ 0.0048 /kW.h Demand Charge \$ 0.1383 /kVA/day		\$43.49	\$45.89	\$48.29
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00425 /kW.h -\$ 0.0010 /kW.h		-\$3.93	-\$6.54	-\$9.14
6	Net DT Charges			\$39.56	\$39.35	\$39.15
Row 4 + Row 5						
7	Combined Rate: January 1, 2010			\$100.73	\$135.60	\$170.46
Row 3 + Row 6						
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07520 /kW.h Energy Admin Fee \$ 8.22 /month		\$65.00	\$102.60	\$140.20
9	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
10	2010 Energy Related Charge			\$65.00	\$102.60	\$140.20
Row 8 + Row 9						
11	AE Final DT Base Rates	Customer Charge \$ 0.2883 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 0.1458 /kVA/day		\$44.70	\$46.85	\$49.00
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00425 /kW.h -\$ 0.0010 /kW.h		-\$3.93	-\$6.54	-\$9.14
13	Net DT Charges			\$40.77	\$40.31	\$39.86
Row 11 + Row 12						
14	Predicted Combined Rate: June 1, 2010			\$105.76	\$142.91	\$180.05
Row 10 + Row 13						
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08824 /kW.h Energy Admin Fee \$ 8.22 /month		\$74.84	\$118.96	\$163.08
16	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
17	2010 Energy Related Charge			\$74.84	\$118.96	\$163.08
Row 15 + Row 16						
18	AE Final DT Base Rates	Customer Charge \$ 0.2883 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 0.1458 /kVA/day		\$44.70	\$46.85	\$49.00
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00212 /kW.h \$ 0.00132 /kW.h		-\$0.61	-\$1.01	-\$1.41
20	Net DT Charges			\$44.09	\$45.84	\$47.59
Row 18 + Row 19						
21	Predicted Combined Rate: August 1, 2010			\$118.94	\$164.80	\$210.67
Row 17 + Row 20						
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08824 /kW.h Energy Admin Fee \$ 8.22 /month		\$74.84	\$118.96	\$163.08
23	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
24	2011 Energy Related Charge			\$74.84	\$118.96	\$163.08
Row 22 + Row 23						
25	AE Proposed DT Base Rates	Customer Charge \$ 0.2943 /day Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 0.1568 /kVA/day		\$46.89	\$48.73	\$50.57
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00212 /kW.h \$ 0.00132 /kW.h		-\$0.61	-\$1.01	-\$1.41
27	Net DT Charges			\$46.29	\$47.72	\$49.16
Row 25 + Row 26						
28	Predicted Combined Rate: January 1, 2011			\$121.13	\$166.69	\$212.24
Row 24 + Row 27						
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	\$2.19	\$1.88	\$1.57
			%	2%	1%	1%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.11 - Example Rate Rider Effects: Farm 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				REA Farm Service Class Consumption Levels Cost per Customer (\$/month)		
Row	Rate Component	Rate		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
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07014 /kW.h Energy Admin Fee \$ 8.22 /month		\$61.18	\$96.25	\$131.32
2	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
3	2010 Energy Related Charge			\$61.18	\$96.25	\$131.32
Row 1 + Row 2						
4	AE Interim DT Base Rates	Customer Charge \$ 0.5299 /day Energy Charge \$ 0.0095 /kW.h Demand Charge \$ 0.1680 /kVA/day		\$60.87	\$65.62	\$70.37
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00425 /kW.h -\$ 0.0037 /kW.h		-\$6.00	-\$9.98	-\$13.95
6	Net DT Charges			\$54.87	\$55.64	\$56.42
Row 4 + Row 5						
7	Combined Rate: January 1, 2010			\$116.04	\$151.89	\$187.73
Row 3 + Row 6						
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07520 /kW.h Energy Admin Fee \$ 8.22 /month		\$65.00	\$102.60	\$140.20
9	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
10	2010 Energy Related Charge			\$65.00	\$102.60	\$140.20
Row 8 + Row 9						
11	AE Final DT Base Rates	Customer Charge \$ 0.5441 /day Energy Charge \$ 0.0098 /kW.h Demand Charge \$ 0.1724 /kVA/day		\$62.51	\$67.41	\$72.31
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00425 /kW.h -\$ 0.0037 /kW.h		-\$6.00	-\$9.98	-\$13.95
13	Net DT Charges			\$56.51	\$57.43	\$58.36
Row 11 + Row 12						
14	Predicted Combined Rate: June 1, 2010			\$121.51	\$160.03	\$198.56
Row 10 + Row 13						
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08824 /kW.h Energy Admin Fee \$ 8.22 /month		\$74.84	\$118.96	\$163.08
16	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
17	2010 Energy Related Charge			\$74.84	\$118.96	\$163.08
Row 15 + Row 16						
18	AE Final DT Base Rates	Customer Charge \$ 0.5441 /day Energy Charge \$ 0.0098 /kW.h Demand Charge \$ 0.1724 /kVA/day		\$62.51	\$67.41	\$72.31
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00212 /kW.h -\$ 0.00016 /kW.h		-\$1.72	-\$2.86	-\$3.99
20	Net DT Charges			\$60.79	\$64.56	\$68.32
Row 18 + Row 19						
21	Predicted Combined Rate: August 1, 2010			\$135.63	\$183.52	\$231.40
Row 17 + Row 20						
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08824 /kW.h Energy Admin Fee \$ 8.22 /month		\$74.84	\$118.96	\$163.08
23	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
24	2011 Energy Related Charge			\$74.84	\$118.96	\$163.08
Row 22 + Row 23						
25	AE Proposed DT Base Rates	Customer Charge \$ 0.5554 /day Energy Charge \$ 0.0093 /kW.h Demand Charge \$ 0.1840 /kVA/day		\$65.08	\$69.72	\$74.37
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00212 /kW.h -\$ 0.00016 /kW.h		-\$1.72	-\$2.86	-\$3.99
27	Net DT Charges			\$63.36	\$66.87	\$70.37
Row 25 + Row 26						
28	Predicted Combined Rate: January 1, 2011			\$138.20	\$185.83	\$233.46
Row 24 + Row 27						
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	\$2.57	\$2.31	\$2.06
			%	2%	1%	1%

**ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728**

Appendix B.12 - Example Rate Rider Effects: Street Light Service Class D61 Option A

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Street Light Service Class Consumption Levels Cost per Customer (\$/month)		
				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
Row	Rate Component	Rate				
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.05837 /kW.h Energy Admin Fee \$ 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 \$ 0.3075 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 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 -\$ 0.00419 /kW.h Rider G -\$ 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 \$ 0.04120 /kW.h Energy Admin Fee \$ 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 \$ 0.3054 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 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 -\$ 0.00419 /kW.h Rider G -\$ 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 \$ 0.05392 /kW.h Energy Admin Fee \$ 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 \$ 0.3054 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 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 -\$ 0.00209 /kW.h Rider G -\$ 0.0007 /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 \$ 0.05392 /kW.h Energy Admin Fee \$ 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 \$ 0.3840 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 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 -\$ 0.00209 /kW.h Rider G -\$ 0.0007 /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%

**ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728**

Appendix B.13 - Example Rate Rider Effects: Private Lighting Service Class D63 Option A

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Private Street Light Service Class		
				Consumption Levels Cost per Customer (\$/month)		
Row	Rate Component	Rate	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	
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.05837 /kW.h Energy Admin Fee \$ 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 \$ 0.3668 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 0.0004 /W/day	\$12.08	\$13.70	\$15.32	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0007 /W/day	-\$2.19	-\$5.47	-\$8.75	
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 Energy Admin Fee \$ 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 \$ 0.3686 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 0.0004 /W/day	\$12.20	\$13.91	\$15.62	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0007 /W/day	-\$2.19	-\$5.47	-\$8.75	
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 Energy Admin Fee \$ 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 \$ 0.3686 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 0.0004 /W/day	\$12.20	\$13.91	\$15.62	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00004 /W/day	-\$0.19	-\$0.48	-\$0.77	
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 Energy Admin Fee \$ 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 \$ 0.3762 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 0.0004 /W/day	\$12.48	\$14.26	\$16.05	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00004 /W/day	-\$0.19	-\$0.48	-\$0.77	
27	Net DT Charges	Row 25 + Row 26	\$12.29	\$13.78	\$15.28	
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$16.78	\$21.14	\$25.44	
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference %	-\$0.49 -3%	-\$1.31 -8%	-\$2.11 -12%
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference %	\$2.44 17%	\$6.11 42%	\$9.77 64%
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference %	\$0.28 2%	\$0.35 2%	\$0.43 2%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No 1606728

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

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Large General Service Class Consumption Levels Cost per Customer (\$/month)			
Note: Assume coincident metered demand equals to 50% of the metered demand				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	
Row	Rate Component	Rate					
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		
2	+/- RRO Deferral	Energy Admin Fee \$ 18.03 /month RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00		
3	2010 Energy Related Charge	Pool Price \$57.30	\$52,546.28	\$70,055.69	\$87,565.11		
		Row 1 + Row 2					
4	AE and AESO Rates	Customer Charge \$ 0.0000 /day Energy Charge \$ 0.0045 /kW.h Demand Charge Blk 1 \$ 0.15 /kW/day Demand Charge Blk 2 \$ 0.06 /kW/day	\$20,483.59	\$24,528.62	\$28,573.65		
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge (1st 7.5MW) \$ 3.96 /kW/month POD Charge fixed \$ 7,030.00 /month Balancing Pool Refund Rider -\$ 0.00400 /kW.h Rider G -\$ 0.0004 /kW.h	-\$3,349.61	-\$4,466.14	-\$5,582.68		
6	Net DT Charges		\$17,133.99	\$20,062.48	\$22,990.98		
		Row 4 + Row 5					
7	Combined Rate: January 1, 2010		\$69,680.26	\$90,118.17	\$110,556.08		
		Row 3 + Row 6					
Effective Date: June 1, 2010							
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07323 /kW.h Energy Admin Fee \$ 18.03 /month	\$56,148.83	\$74,859.09	\$93,569.36		
9	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00		
10	2010 Energy Related Charge	Pool Price \$57.30	\$56,148.83	\$74,859.09	\$93,569.36		
		Row 8 + Row 9					
11	AE and AESO Rates	Customer Charge \$ 0.0000 /day Energy Charge \$ 0.0045 /kW.h Demand Charge Blk 1 \$ 0.17 /kW/day Demand Charge Blk 2 \$ 0.06 /kW/day	\$20,806.09	\$24,851.12	\$28,896.15		
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge (1st 7.5MW) \$ 3.96 /kW/month POD Charge fixed \$ 7,030.00 /month Balancing Pool Refund Rider -\$ 0.00400 /kW.h Rider G -\$ 0.0004 /kW.h	-\$3,349.61	-\$4,466.14	-\$5,582.68		
13	Net DT Charges		\$17,456.49	\$20,384.98	\$23,313.48		
		Row 11 + Row 12					
14	Predicted Combined Rate: June 1, 2010		\$73,605.31	\$95,244.07	\$116,882.83		
		Row 10 + Row 13					
Effective Date: August 1, 2010							
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08493 /kW.h Energy Admin Fee \$ 18.03 /month	\$65,116.88	\$86,816.49	\$108,516.11		
16	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00		
17	2010 Energy Related Charge	Pool Price \$57.30	\$65,116.88	\$86,816.49	\$108,516.11		
		Row 15 + Row 16					
18	AE and AESO Rates	Customer Charge \$ 0.0000 /day Energy Charge \$ 0.0045 /kW.h Demand Charge Blk 1 \$ 0.17 /kW/day Demand Charge Blk 2 \$ 0.06 /kW/day	\$20,806.09	\$24,851.12	\$28,896.15		
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge (1st 7.5MW) \$ 3.96 /kW/month POD Charge fixed \$ 7,030.00 /month Balancing Pool Refund Rider -\$ 0.00200 /kW.h Rider G \$ 0.00003 /kW.h	-\$1,512.02	-\$2,016.02	-\$2,520.03		
20	Net DT Charges		\$19,294.07	\$22,835.10	\$26,376.12		
		Row 18 + Row 19					
21	Predicted Combined Rate: August 1, 2010		\$84,410.95	\$109,651.59	\$134,892.23		
		Row 17 + Row 20					
Effective Date: January 1, 2011							
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08493 /kW.h Energy Admin Fee \$ 18.03 /month	\$65,116.88	\$86,816.49	\$108,516.11		
23	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00		
24	2011 Energy Related Charge	Pool Price \$57.30	\$65,116.88	\$86,816.49	\$108,516.11		
		Row 22 + Row 23					
25	AE and AESO Rates	Customer Charge \$ 0.0000 /day Energy Charge \$ 0.0045 /kW.h Demand Charge Blk 1 \$ 0.17 /kW/day Demand Charge Blk 2 \$ 0.06 /kW/day	\$20,840.66	\$24,885.69	\$28,930.72		
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge (1st 7.5MW) \$ 3.96 /kW/month POD Charge fixed \$ 7,030.00 /month Balancing Pool Refund Rider -\$ 0.00200 /kW.h Rider G \$ 0.00003 /kW.h	-\$1,512.02	-\$2,016.02	-\$2,520.03		
27	Net DT Charges		\$19,328.64	\$22,869.66	\$26,410.69		
		Row 25 + Row 26					
28	Predicted Combined Rate: January 1, 2011		\$84,445.51	\$109,686.15	\$134,926.79		
		Row 24 + Row 27					
Comparisons							
Combined Rate (January 1, 2010 - June 1, 2010)		Row 14 vs Row 7		difference %	\$3,925.05 6%	\$5,125.90 6%	\$6,326.75 6%
Combined Rate (June 1, 2010 - August 1, 2010)		Row 21 vs Row 14		difference %	\$10,805.64 15%	\$14,407.52 15%	\$18,009.39 15%
Combined Rate (August 1, 2010 - January 1, 2011)		Row 28 vs Row 21		difference %	\$34.57 0%	\$34.57 0%	\$34.57 0%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Energy Rates Used in Appendix B-1 to B-14

	Admin. Charges	Cost of Energy for			
	Fixed (\$ / Day)	January 2010 (\$ / kWh)	June 2010 (\$ / kWh)	August 2010 (\$ / kWh)	January 2011 (\$ / 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

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

	A	B	C	D	E	F	G	H	I	J
1	D Tariff Rates									
2	2011 proposed interim									
3	(Oct 18,2010)									
4	D11									
5										
6		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
7	T				1.89 ¢/kW.h	0.00 ¢/kW.h				
8	D	66.45 ¢/day			5.42 ¢/kW.h	0.00 ¢/kW.h		0.00 ¢/kV.A/day		
9	S	25.81 ¢/day								
10	Total	92.26 ¢/day			7.31 ¢/kW.h	0.00 ¢/kW.h		0.00 ¢/kV.A/day		
11										
12										
13	D21									
14										
15		Customer	Demand 1	Demand 2	Energy 1	Energy 2	Option H(a)	PF	Option P	
16	T		10.62 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
17	D		18.18 ¢/kW/day		3.35 ¢/kW.h	0.00 ¢/kW.h	-3.50 ¢/kW/day	0.00 ¢/kV.A/day		
18	S	33.26 ¢/day								
19	Total	33.26 ¢/day	28.80 ¢/kW/day		3.71 ¢/kW.h	0.37 ¢/kW.h		0.00 ¢/kV.A/day	46%	
20										
21										
22	D22									
23										
24		Customer	Demand 1	Demand 2	Energy 1	Energy 2	Option H(a)	PF	Option P	
25	T				0.51 ¢/kW.h	0.51 ¢/kW.h				
26	D				21.51 ¢/kW.h	7.14 ¢/kW.h	-3.50 ¢/kW/day	0.00 ¢/kV.A/day		
27	S									
28	Total	0.00 ¢/day	0.00 ¢/kW/day	0.00 ¢/kW/day	22.03 ¢/kW.h	7.65 ¢/kW.h		0.00 ¢/kV.A/day	46%	
29										
30										
31	D25									
32										
33		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
34	T		11.00 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
35	D		16.09 ¢/kW/day		0.00 ¢/kW.h	0.00 ¢/kW.h		0.00 ¢/kV.A/day		
36	S	32.17 ¢/day								
37	Total	32.17 ¢/day	27.09 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h		0.00 ¢/kV.A/day		
38										
39										
40	D26									
41										
42		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
43	T		11.00 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
44	D		5.07 ¢/kW/day		0.00 ¢/kW.h	0.00 ¢/kW.h		0.00 ¢/kV.A/day		
45	S	32.17 ¢/day								
46	Total	32.17 ¢/day	16.06 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h		0.00 ¢/kV.A/day		
47										
48										
49	D31									
50										
51		Customer	Demand 1	Demand 2	Energy 1	Energy 2	Option H(a)	PF	Option P	Option H(b)
52	T		15.68 ¢/kW/day	18.22 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h				
53	D	14.55 ¢/day	21.16 ¢/kW/day	16.60 ¢/kW/day			-3.50 ¢/kW/day	20.17 ¢/kV.A/day		-1.00%
54	S	225.28 ¢/day		0.68 ¢/kW/day						
55	Total	239.82 ¢/day	36.84 ¢/kW/day	35.50 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h		20.17 ¢/kV.A/day	33%	
56										
57										
58	T31 and T33									
59										
60		Customer	Demand 1	Demand 2	Energy 1	Energy 2	Option H(d)	PF		
61	T									
62	d		1.43 ¢/kW/day				3.50 ¢/kW/day	20.17 ¢/kV.A/day		
63	s		9.74 ¢/kW/day							
64	Total	0.00 ¢/day	11.17 ¢/kW/day	0.00 ¢/kW/day	0.00 ¢/kW.h	0.00 ¢/kW.h		20.17 ¢/kV.A/day		
65										
66										
67	D32									
68										
69		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
70	T		15.68 ¢/kW/day	18.22 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h				
71	D	14.55 ¢/day	21.16 ¢/kW/day	16.60 ¢/kW/day				20.17 ¢/kV.A/day		
72	S	225.28 ¢/day		0.68 ¢/kW/day						
73	Total	239.82 ¢/day	36.84 ¢/kW/day	35.50 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h		20.17 ¢/kV.A/day		
74										
75										

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

	A	B	C	D	E	F	G	H	I	J
1	D Tariff Rates									
	2011 proposed interim (Oct 18,2010)									
76	D33									
77										
78		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
79	T		15.68 ¢/kW/day	18.22 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h		should be avg. DOS rate		
80	D	14.55 ¢/day	21.16 ¢/kW/day	16.60 ¢/kW/day				20.17 ¢/kV.A/day		
81	S	225.28 ¢/day		0.68 ¢/kW/day						
82	Total	239.82 ¢/day	36.84 ¢/kW/day	35.50 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h		20.17 ¢/kV.A/day		
83										
84										
85	T33									
86										
87		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
88	T									
89	d		1.43 ¢/kW/day					20.17 ¢/kV.A/day		
90	s		9.74 ¢/kW/day							
91	Total	0.00 ¢/day	11.17 ¢/kW/day	0.00 ¢/kW/day	0.00 ¢/kW.h	0.00 ¢/kW.h		20.17 ¢/kV.A/day		
92										
93										
94	D41									
95										
96		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
97	T		13.32 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
98	D	50.29 ¢/day	46.72 ¢/kW/day					44.59 ¢/kV.A/day		
99	S	88.52 ¢/day								
100	Total	138.81 ¢/day	60.04 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h		44.59 ¢/kV.A/day		
101										
102										
103	D51									
104										
105		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
106	T		7.02 ¢/kV.A/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
107	D (O&M Pool)		8.66 ¢/kV.A/day					0.00 ¢/kV.A/day		
108	S	29.43 ¢/day								
109	Total	29.43 ¢/day	15.68 ¢/kV.A/day		0.37 ¢/kW.h	0.37 ¢/kW.h		0.00 ¢/kV.A/day		
110										
111										
112	D52									
113										
114		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
115	T		7.02 ¢/kV.A/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
116	D							0.00 ¢/kV.A/day		
117	S	24.91 ¢/day								
118	Total	24.91 ¢/day	7.02 ¢/kV.A/day		0.37 ¢/kW.h	0.37 ¢/kW.h		0.00 ¢/kV.A/day		
119										
120										
121	D56									
122										
123		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
124	T		7.02 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
125	D	26.11 ¢/day	11.38 ¢/kW/day		0.56 ¢/kW.h	0.56 ¢/kW.h		0.00 ¢/kV.A/day		
126	S	29.43 ¢/day								
127	Total	55.54 ¢/day	18.40 ¢/kW/day		0.93 ¢/kW.h	0.93 ¢/kW.h		0.00 ¢/kV.A/day		
128										
129										
130	D61									
131										
132		Customer	Demand 1							
133	T		0.017 ¢/W/day							
134	D - Option A	31.15 ¢/fixture/day	0.031 ¢/W/day							
135	D - Option B	85.51 ¢/fixture/day	0.031 ¢/W/day							
136	D - Option C	41.11 ¢/fixture/day	0.031 ¢/W/day							
137	D - Option D									
138	D - Option E	31.15 ¢/fixture/day	0.031 ¢/W/day							
139	S	7.25 ¢/fixture/day								
140	Total									
141										
142										
143	D63									
144										
145		Customer	Demand 1							
146	T		0.019 ¢/W/day							
147	D - Option A	24.71 ¢/fixture/day	0.021 ¢/W/day							
148	D - Option B	39.83 ¢/fixture/day	0.021 ¢/W/day							
149	D - Option C	13.11 ¢/fixture/day	0.006 ¢/W/day							
150	D - Option D	26.22 ¢/fixture/day	0.021 ¢/W/day							
151	D - Option E	17.14 ¢/fixture/day	0.021 ¢/W/day							
152	S	12.92 ¢/fixture/day								
153	Total									

**ATCO Electric
2011 Interim Tariff Application
Proceeding 918, No. 1606728**

Determination of Adjustment Factors (for Rates Jan. 1 - Dec. 31, 2011) Updated for Amended 2010 Final Tariff Application

Table 1									Table 2				
Scaling Factor Determination									Breakdown of Transmission Rate				
All Revenue in \$'000's									All Revenue in \$'000's				
Year	Column No.	Scenario	(A)	(B)	(C)	(D)	(E)		Total	Based on 2010 Final Rate Application			
			Trans Demand Revenue	Trans Energy Revenue	Trans Demand Revenue	Trans Energy Revenue	Dist Revenue	Power Factor		Demand Related Portion	Energy Related Portion	Total Trans Revenue	
Before Scaling													
2011		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)						D11	14,240	4,533	18,774
		Adj for D61	(88)	88						D61	227	88	315
		Adj for D63	(14)	14						D63	35	14	48
	(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	285,948	5,408	459,949				
	(3)	Scaling Factor	1.151720	0.863227	1.000000	1.000000	1.020730	1.000	1.037628				
		D25 &D26					1.351695		1.250000				
	D61					1.257405		1.250000					
After Scaling													
2011		12 mo. 2010 Final rates after scaling	90,536	48,210	23,459	5,980	276,228	5,408	449,821				
		D25 &D26	60	10			129		200				
		D61	338				9,591		9,929				
		Adj for D11	16,401	(16,401)						D11	16,401	3,913	20,314.33933
		Adj for D61	(76)	76						D61	261	76	337.73300
		Adj for D63	(12)	12						D63	40	12	51.92197
	(4)	Total	107,248	31,907	23,459	5,980	285,948	5,408	459,949				
										(F)			
										Factored Future Costs for 2011			
										Scaling Factor			

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) to 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.

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

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 Proposed RR \$ million
Transmission	\$336.6	\$86.6	(\$54.3)	\$32.2	37%	\$282.2
Distribution	\$493.6	\$33.4	(\$16.7)	\$16.7	50% *	\$476.9

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

PRICE SCHEDULE INDEX**RESIDENTIAL SERVICE**

Standard Residential Service Price Schedule D11

SMALL GENERAL SERVICE

Standard Small General Service Price Schedule D21

Small General Service - Energy Only Price Schedule D22

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

Irrigation Pumping Service Price Schedule D25

REA Irrigation Pumping Service Price Schedule D26

LARGE GENERAL SERVICE/INDUSTRIAL

Large General Service/Industrial - Distribution Connected Price Schedule D31

Large General Service/Industrial - Transmission Connected Price Schedule T31

Generator Interconnection and Standby Power - Distribution Connected Price Schedule D32

Transmission Opportunity Rate - Distribution Connected Price Schedule D33

Transmission Opportunity Rate - Transmission Connected Price Schedule T33

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

OILFIELD

Small Oilfield and Pumping Power Price Schedule D41

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

FARM SERVICE

REA Farm Service Price Schedule D51

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

Farm Service Price Schedule D56

LIGHTING SERVICE

Street Lighting Service Price Schedule D61

Private Lighting Service Price Schedule D63

PRICE OPTIONS

Idle Service Option F

Service for Non-Standard Transformation and Metering Configurations Option H

REA Distribution Price Credit Option P

PRICING ADJUSTMENTS (RIDERS)

Municipal Assessment Rider A-1

Balancing Pool Adjustment Rider B

Special Facilities Charge Rider E

Temporary Adjustment Rider G

Interim Adjustment Rider J

Interim RRT Adjustment Rider Q

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company. 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	67.25 ¢ / day	5.48 ¢ / kW.h
Service	26.12 ¢ / day	-
TOTAL PRICE	93.37 ¢ / day	7.37 ¢ / 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	-	18.40 ¢/kW/day	3.39 ¢ / kW.h	-
Service	33.66 ¢ / day	-	-	-
TOTAL PRICE	33.66 ¢ / day	29.02 ¢/kW/day	3.76 ¢ / 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	21.77 ¢ / kW.h	7.22 ¢ / kW.h
Service	-	-
TOTAL PRICE	22.28 ¢ / kW.h	7.73 ¢ / 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:

- the highest metered demand during the billing period;
- the estimated demand;
- if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;
- 5 kilowatts.

The minimum annual charge is 12 times the sum of:

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

Application

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

Availability

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

Price

Charges for service in any one billing 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	-	18.40 ¢/kW/day	3.39 ¢ / kW.h	-
Service	33.66 ¢ / day	-	-	-
TOTAL PRICE	33.66 ¢ / day	18.40 ¢/kW/day	3.75 ¢ / 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:

- the highest metered demand during the billing period;
- the estimated demand;
- if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;
- 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

- 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.
- 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.
- 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	14.72 ¢ /day	21.41 ¢/kW/day	16.80 ¢/kW/day	-
Service	\$2.2800 /day	-	0.69 ¢/kW/day	-
TOTAL PRICE	\$2.4272 /day	37.09 ¢/kW/day	35.71 ¢/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	1.45 ¢/kW/day	-	-
Service	9.86 ¢/kW/day	-	-
TOTAL PRICE	11.31 ¢/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	14.72 ¢ /day	21.41 ¢/kW/day	16.80 ¢/kW/day	-
Service	\$2.2800 /day	-	0.69 ¢/kW/day	-
TOTAL PRICE	\$2.4272 /day	37.09 ¢/kW/day	35.71 ¢/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.
- Telemetry is required for all points of service on this rate with demands greater than 2,500 kW, and any associated costs will be in addition to the charges in this rate.

Price

Charges for service in any one billing 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	14.72 ¢ /day	21.41 ¢/kW/day	16.80 ¢/kW/day	-	-
Service	\$2.2800 /day	-	0.69 ¢/kW/day	-	-
TOTAL PRICE	\$2.4272 /day + AESO DOS Rate	37.09 ¢/kW/day	17.49 ¢/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)

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.
- Telemetry is required for all points of service on this rate with demands greater than 2,500 kW, and any associated costs will be in addition to the charges in this rate.

Price

Charges for service in any one billing 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)



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

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

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

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

Availability

For Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from an isolated industrial area. 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	14.72 ¢ /day	21.41 ¢/kW/day	16.80 ¢/kW/day	-
Service	\$2.2800 /day	-	0.69 ¢/kW/day	-
TOTAL PRICE	\$2.4272 /day	21.41 ¢/kW/day	17.49 ¢/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	50.90 ¢ / day	47.28 ¢/kW/day	-
Service	89.59 ¢ / day	-	-
TOTAL PRICE	\$1.4049 / day	60.61 ¢/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	50.90 ¢ / day	47.28 ¢/kW/day
Service	89.59 ¢ / day	-
TOTAL PRICE	\$1.4049 / day	47.28 ¢/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	-	8.77 ¢/kV.A/day	-
Service	29.79 ¢ / service / day	-	-
REA Specific Charges	See REA Tariff	-	-
Total Price	C₁ ¢ / 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	C₁ ¢ / service /day	D₁ ¢/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	25.21 ¢/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	26.43 ¢/service/day	11.52 ¢/kV.A/day	0.57 ¢ / kW.h
Service	29.79 ¢/service/day	-	-
TOTAL PRICE	56.22 ¢/service/day	18.54 ¢/kV.A/day	0.94 ¢ / kW.h

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

- (a) For breaker 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 breaker 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	25.01 ¢/fixture/day	0.021 ¢/watt/day
Service	13.07 ¢/fixture/day	-
TOTAL PRICE	38.08 ¢/fixture/day	0.040 ¢/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	40.32 ¢/fixture/day	0.021 ¢/watt/day
Service	13.07 ¢/fixture/day	-
TOTAL PRICE	53.39 ¢/fixture/day	0.040 ¢/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	13.27 ¢/fixture/day	0.006 ¢/watt/day
Service	13.07 ¢/fixture/day	-
TOTAL PRICE	26.34 ¢/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	26.54 ¢/fixture/day	0.021 ¢/watt/day
Service	13.07 ¢/fixture/day	-
TOTAL PRICE	39.61 ¢/fixture/day	0.040 ¢/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	17.35 ¢/fixture/day	0.021 ¢/watt/day
Service	13.07 ¢/fixture/day	-
TOTAL PRICE	30.42 ¢/fixture/day	0.040 ¢/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.

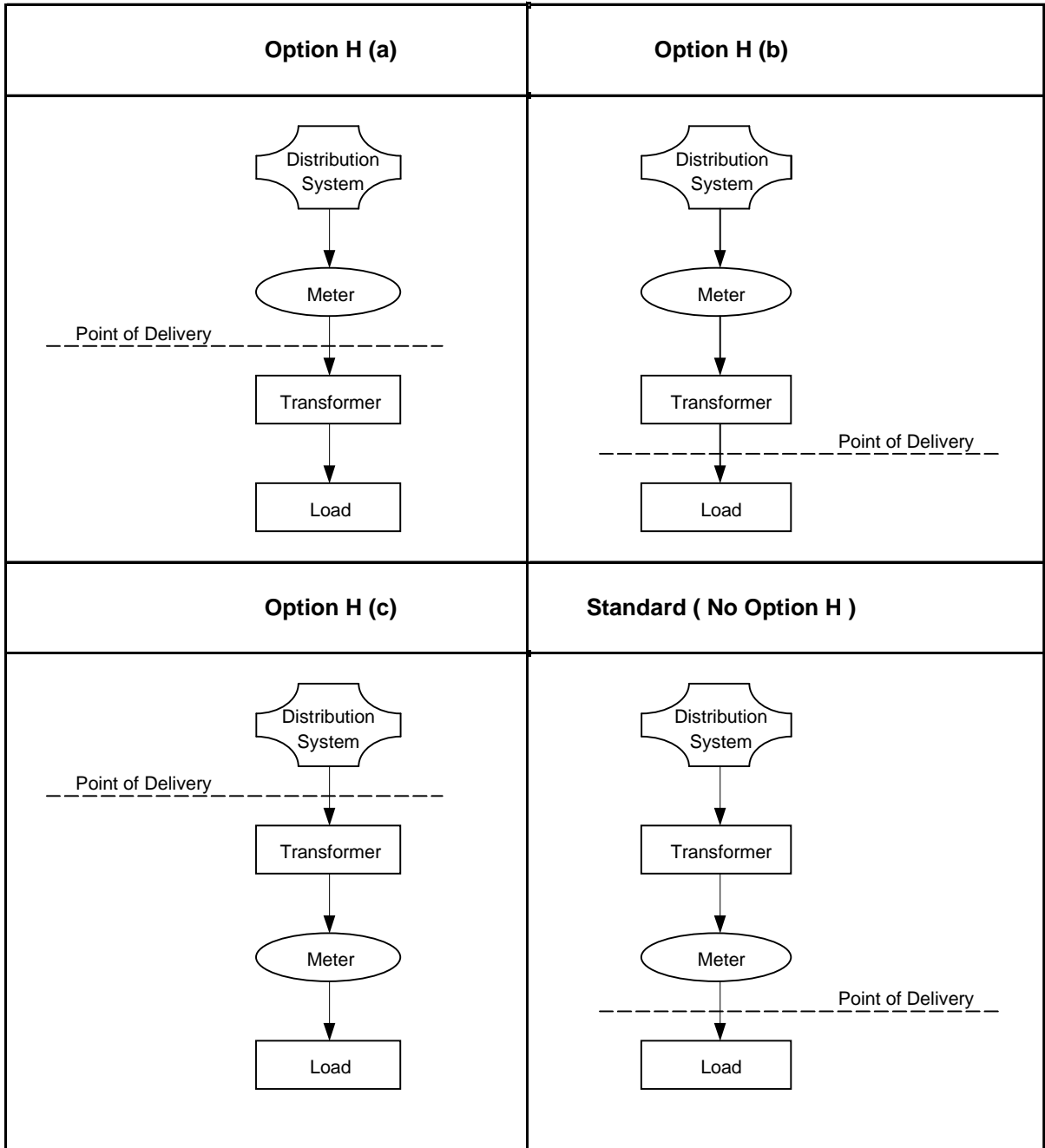
Availability

- 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.

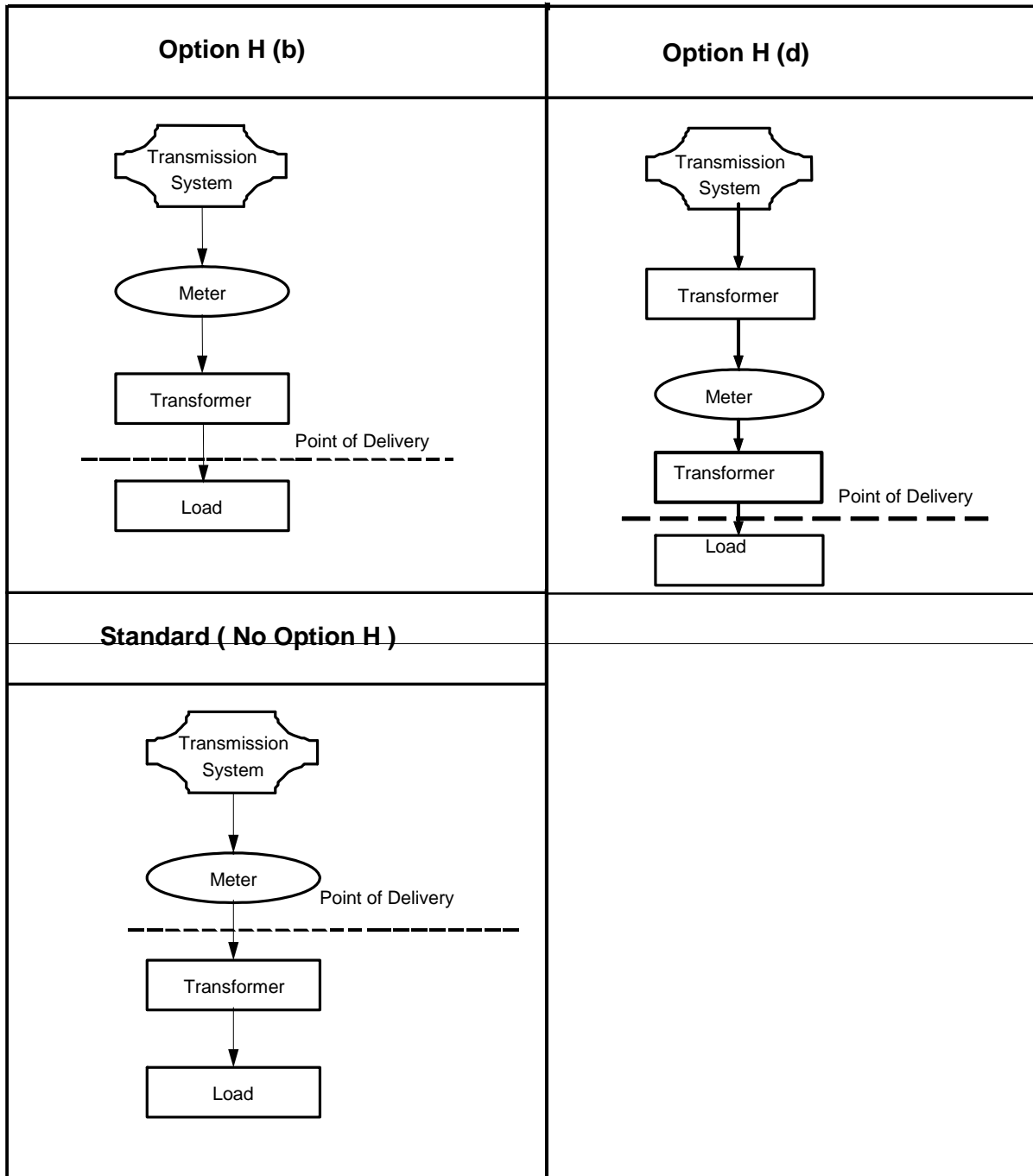
Price Adjustment

- (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 3.54 ¢/kW/day** of billing demand will be applied. This adjustment does not apply to customers connected directly to the transmission system who are exempt from the Distribution Charge on the applicable rate.
- (b) If primary or higher voltage delivery metering is desirable for the convenience of the Company, or to improve accessibility, etc., **demand and energy measurements will be reduced by 1%** so as to approximate secondary voltage delivery conditions.
- (c) If primary or higher voltage delivery is made to customer owned transformers, but metering is at secondary or utilization voltage for the Company's convenience, **demand and energy measurements will be increased by 1%** so as to approximate primary or transmission voltage delivery conditions and **a discount, as specified in (a)** shall apply.
- (d) Customers who are connected directly to the transmission system, but take service from the low side of a transformer (with primary side 25kV), and do not own or rent any necessary transformer(s), and are exempt from the Distribution Charge on the applicable rate, a **surcharge of 3.54 ¢/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	Empress 8+6	Jasper Nat'l Park 5	Sexsmith 7
Andrew 8+6	Fairview 8+6	Kinuso 8+6	Slave Lake 8+6
Beaverlodge 8+6	Falher 8+6	Kitscoty 8+6	Smoky Lake 8+6
Berwyn 8+6	Forestburg 8+6	Linden 8+6	Spirit River 8+6
Big Valley 8+6	Fort McMurray 7	Lloydminster 8+6	St Paul 8+6
Bonnyville 8+6	Fox Creek 8+6	Manning 7	Stettler 7+6
Botha 8+6	Gadsby 8+6	Mannville 8+6	Swan Hills 8+6
Carbon 7	Galahad 8+6	Marwayne 8+6	Three Hills 8+6
Castor 8+6	Girouxville 7	McLennan 7	Trochu 8+6
Cereal 7	Glendon 8+6	Minburn 8+6	Two Hills 8+6
Cold Lake 8+6	Grande Cache 8+6	Morrin 7	Valleyview 8+6
Consort 8+6	Grande Prairie 8+6	Mundare 6	Vegreville 8+6
Coronation 8+6	Grimshaw 8+6	Munson 8+6	Vermilion 8+6
Delburne 8+6	Halkirk 8+6	Myrnam 8+6	Veteran 8+6
Delia 8+6	Hanna 8+6	Nampa 7	Vilna 8+6
Derwent 8+6	Heisler 8+6	Oyen 8+6	Waskatenau 8+6
Dewberry 8+6	High Level 8+6	Paradise Valley 8+6	Wembley 7
Donalda 8+6	High Prairie 8+6	Peace River 8+6	Willingdon 8+6
Donnelly 8+6	Hines Creek 8+6	Radway (County 7) 8+6	Youngstown 7+6
Drumheller 8+6	Hythe 8+6	Rainbow Lake 8+6	
Elk Point 8+6	Innisfree 8+6	Rosalind 8+6	
Elnora 8+6	ID Jasper 7	Rycroft 8+6	

Table 2 – Category Numbers of Municipalities

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

Bonnyville Beach	County No. 27 Minburn	M.D. of Big Lake No. 125
Horseshoe Bay	County No. 29 Flagstaff	M.D. of Smoky R. No. 130
Lavoy	County No. 30 Lamont	M.D. of East Peace No. 131
Pelican Narrows	County No. 89 Lakeland	M.D. of Spirit River No. 133
Rochon Sands	M.D. of Badlands No. 07	M.D. of Peace No. 135
Wanham	M.D. of Greenview No. 16	M.D. of Fairview No. 136
Warspite	M.D. of Opportunity No. 17	I.D. No. 12 & ID No. 24
Whitesands	M.D. of Wood Buffalo No. 18	Allison Bay B219
County No. 01 Grande Pr.	M.D. of Birch Hills No. 19	Fort McMurray Band B352
County No. 06 Stettler	M.D. of Saddle Hills No. 20	Peavine N172
County No. 07 Thorhild	M.D. of Clear Hills No. 21	Gift Lake N173
County No. 13 Smoky Lake	M.D. of Northern Lights No. 22	East Prairie N174
County No. 16 Wheatland	M.D. of Mackenzie No. 23	Elizabeth N187
County No. 18 Paintearth	M.D. of Acadia No. 34	Fishing Lake N188
County No. 19 St. Paul	M.D. of Starland No. 47	Paddle Prairie N221
County No. 21 Two Hills	M.D. of Kneehill No. 48	Special Areas
County No. 22 Camrose	M.D. of Bonnyville No. 87	Sturgeon Lake I.R. #154
County No. 23 Red Deer	M.D. of Bonnyville Annexed No. 88	Whitefish Lake Band B924
County No. 24 Vermilion R.	M.D. of Lesser Slave River No. 124	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
Proceeding ID 918, No. 1606728

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

Rate Class	January 1, 2010				June 1, 2010				August 1, 2010				January 1, 2011			
	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	\$72.27	-\$2.17	-\$1.26	\$68.84
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	\$346.35	-\$6.50	-\$15.40	\$324.45
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	\$689.90	\$12.22	-\$34.97	\$667.15
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	\$438.29	-\$9.24	-\$18.75	\$410.30
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	\$49.07	\$1.65	-\$2.66	\$48.07
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	\$70.32	-\$0.20	-\$2.66	\$67.46
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	\$14.42	-\$0.29	-\$0.19	\$13.94
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	\$24,905.92	\$27.98	-\$2,044.00	\$22,889.90

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.1 - Example Rate Rider Effects: Residential Class - RRO Eligible

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Residential Class Consumption Levels Cost per Customer (\$/month)		
Row	Rate Component	Rate		300 kW.h per month	Typical 600 kW.h per month	1,200 kW.h per month
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			\$29.37	\$50.78	\$93.62
	Row 1 + Row 2					
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			\$43.73	\$60.48	\$93.99
	Row 4 + Row 5					
7	Combined Rate: January 1, 2010			\$73.09	\$111.26	\$187.61
	Row 3 + Row 6					
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			\$30.35	\$52.76	\$97.57
	Row 8 + Row 9					
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			\$44.02	\$60.92	\$94.73
	Row 11 + Row 12					
14	Predicted Combined Rate: June 1, 2010			\$74.37	\$113.68	\$192.30
	Row 10 + Row 13					
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			\$34.18	\$60.41	\$112.88
	Row 15 + Row 16					
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			\$46.58	\$66.04	\$104.97
	Row 18 + Row 19					
21	Predicted Combined Rate: August 1, 2010			\$80.76	\$126.46	\$217.85
	Row 17 + Row 20					
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			\$34.18	\$60.41	\$112.88
	Row 22 + Row 23					
25	AE Proposed DT Base Rates	Customer Charge	\$ 0.9337 /day	\$50.14	\$72.27	\$116.53
		Energy Charge	\$ 0.0738 /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			\$48.42	\$68.84	\$109.66
	Row 25 + Row 26					
28	Predicted Combined Rate: January 1, 2011			\$82.61	\$129.25	\$222.54
	Row 24 + Row 27					
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	\$1.85	\$2.79	\$4.69
			%	2%	2%	2%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

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 Energy Admin Fee \$ 8.46 /month	\$393.74	\$522.16	\$650.59	
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 Energy Charge Blk 1 \$ 0.0357 /kW.h Energy Charge Blk 2 \$ 0.0048 /kW.h Demand Charge \$ 0.2612 /kW/day	\$246.38	\$325.22	\$404.06	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0021 /kW.h	-\$34.60	-\$46.14	-\$57.67	
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 Energy Admin Fee \$ 8.46 /month	\$425.93	\$565.09	\$704.24	
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 Energy Charge Blk 1 \$ 0.0370 /kW.h Energy Charge Blk 2 \$ 0.0042 /kW.h Demand Charge \$ 0.2703 /kW/day	\$252.80	\$333.81	\$414.82	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0021 /kW.h	-\$34.60	-\$46.14	-\$57.67	
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 Energy Admin Fee \$ 8.46 /month	\$489.66	\$650.06	\$810.46	
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 Energy Charge Blk 1 \$ 0.0370 /kW.h Energy Charge Blk 2 \$ 0.0042 /kW.h Demand Charge \$ 0.2703 /kW/day	\$252.80	\$333.81	\$414.82	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00089 /kW.h	-\$16.42	-\$21.90	-\$27.37	
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 Energy Admin Fee \$ 8.46 /month	\$489.66	\$650.06	\$810.46	
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 \$ 0.3366 /day Energy Charge Blk 1 \$ 0.0375 /kW.h Energy Charge Blk 2 \$ 0.0037 /kW.h Demand Charge \$ 0.2902 /kW/day	\$262.29	\$346.35	\$430.41	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00089 /kW.h	-\$16.42	-\$21.90	-\$27.37	
27	Net DT Charges	Row 25 + Row 26	\$245.86	\$324.45	\$403.04	
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$735.52	\$974.51	\$1,213.50	
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference %	\$38.62 6%	\$51.52 6%	\$64.42 6%
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference %	\$81.91 13%	\$109.21 13%	\$136.51 13%
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference %	\$9.48 1%	\$12.54 1%	\$15.59 1%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

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)		
				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
Row	Rate Component	Rate				
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07037 /kW.h Energy Admin Fee \$ 8.46 /month	\$393.74	\$522.16	\$650.59	
2	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
3	2010 Energy Related Charge		\$393.74	\$522.16	\$650.59	
		Row 1 + Row 2				
4	AE Interim DT Base Rates	Customer Charge \$ 0.3287 /day Energy Charge Blk 1 \$ 0.0357 /kW.h Energy Charge Blk 2 \$ 0.0048 /kW.h Demand Charge \$ 0.2612 /kW/day	\$246.38	\$325.22	\$404.06	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0021 /kW.h	-\$34.60	-\$46.14	-\$57.67	
6	Net DT Charges		\$211.78	\$279.09	\$346.39	
		Row 4 + Row 5				
7	Combined Rate: January 1, 2010		\$605.51	\$801.25	\$996.98	
		Row 3 + Row 6				
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07625 /kW.h Energy Admin Fee \$ 8.46 /month	\$425.93	\$565.09	\$704.24	
9	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
10	2010 Energy Related Charge		\$425.93	\$565.09	\$704.24	
		Row 8 + Row 9				
11	AE Final DT Base Rates	Customer Charge \$ 0.3258 /day Energy Charge Blk 1 \$ 0.0370 /kW.h Energy Charge Blk 2 \$ 0.0042 /kW.h Demand Charge \$ 0.2703 /kW/day	\$252.80	\$333.81	\$414.82	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0021 /kW.h	-\$34.60	-\$46.14	-\$57.67	
13	Net DT Charges		\$218.20	\$287.68	\$357.15	
		Row 11 + Row 12				
14	Predicted Combined Rate: June 1, 2010		\$644.13	\$852.76	\$1,061.40	
		Row 10 + Row 13				
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08789 /kW.h Energy Admin Fee \$ 8.46 /month	\$489.66	\$650.06	\$810.46	
16	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
17	2010 Energy Related Charge		\$489.66	\$650.06	\$810.46	
		Row 15 + Row 16				
18	AE Final DT Base Rates	Customer Charge \$ 0.3258 /day Energy Charge Blk 1 \$ 0.0370 /kW.h Energy Charge Blk 2 \$ 0.0042 /kW.h Demand Charge \$ 0.2703 /kW/day	\$252.80	\$333.81	\$414.82	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00089 /kW.h	-\$16.42	-\$21.90	-\$27.37	
20	Net DT Charges		\$236.38	\$311.92	\$387.45	
		Row 18 + Row 19				
21	Predicted Combined Rate: August 1, 2010		\$726.04	\$961.97	\$1,197.91	
		Row 17 + Row 20				
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08789 /kW.h Energy Admin Fee \$ 8.46 /month	\$489.66	\$650.06	\$810.46	
23	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
24	2011 Energy Related Charge		\$489.66	\$650.06	\$810.46	
		Row 22 + Row 23				
25	AE Proposed DT Base Rates	Customer Charge \$ 0.3366 /day Energy Charge Blk 1 \$ 0.0375 /kW.h Energy Charge Blk 2 \$ 0.0037 /kW.h Demand Charge \$ 0.2902 /kW/day	\$262.29	\$346.35	\$430.41	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00089 /kW.h	-\$16.42	-\$21.90	-\$27.37	
27	Net DT Charges		\$245.86	\$324.45	\$403.04	
		Row 25 + Row 26				
28	Predicted Combined Rate: January 1, 2011		\$735.52	\$974.51	\$1,213.50	
		Row 24 + Row 27				
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	\$9.48	\$12.54	\$15.59
			%	1%	1%	1%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.4 - Example Rate Rider Effects: Irrigation Pumping Service

GST not included

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

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.5 - Example Rate Rider Effects: REA Irrigation Pumping Service

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				REA Irrigation Pumping Service Class Consumption Levels Cost per Customer (\$/season)		
Row	Rate Component	Rate	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	
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07014 /kW.h Energy Admin Fee \$ 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		\$681.19	\$886.00	\$1,090.81	
		Row 1 + Row 2				
4	AE Interim DT Base Rates	Customer Charge \$ 0.2592 /day Energy Charge \$ 0.0049 /kW.h Demand Charge \$ 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		\$803.20	\$1,052.45	\$1,301.69	
		Row 4 + Row 5				
7	Combined Rate: January 1, 2010		\$1,484.40	\$1,938.45	\$2,392.51	
		Row 3 + Row 6				
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07311 /kW.h Energy Admin Fee \$ 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		\$707.21	\$920.69	\$1,134.17	
		Row 8 + Row 9				
11	AE Final DT Base Rates	Customer Charge \$ 0.2380 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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		\$868.53	\$1,141.06	\$1,413.59	
		Row 11 + Row 12				
14	Predicted Combined Rate: June 1, 2010		\$1,575.74	\$2,061.75	\$2,547.76	
		Row 10 + Row 13				
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08542 /kW.h Energy Admin Fee \$ 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		\$815.05	\$1,064.47	\$1,313.90	
		Row 15 + Row 16				
18	AE Final DT Base Rates	Customer Charge \$ 0.2380 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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		\$900.36	\$1,183.50	\$1,466.64	
		Row 18 + Row 19				
21	Predicted Combined Rate: August 1, 2010		\$1,715.40	\$2,247.97	\$2,780.54	
		Row 17 + Row 20				
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08542 /kW.h Energy Admin Fee \$ 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		\$815.05	\$1,064.47	\$1,313.90	
		Row 22 + Row 23				
25	AE Proposed DT Base Rates	Customer Charge \$ 0.3217 /day Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 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		\$1,090.66	\$1,431.26	\$1,771.86	
		Row 25 + Row 26				
28	Predicted Combined Rate: January 1, 2011		\$1,905.70	\$2,495.73	\$3,085.76	
		Row 24 + Row 27				
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%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

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 Energy Admin Fee \$ 18.03 /month	\$854.10	\$1,159.05	\$1,443.45	
2	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
3	2010 Energy Related Charge		\$854.10	\$1,159.05	\$1,443.45	
Row 1 + Row 2						
4	AE Interim DT Base Rates	Customer Charge \$ 2.3340 /day Energy Charge \$ 0.0048 /kW.h Demand Charge Blk 1 \$ 0.3186 /kW/day Demand Charge Blk 2 \$ 0.3051 /kW/day	\$606.48	\$627.84	\$733.78	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00420 /kW.h Rider G \$ 0.0018 /kW.h	-\$29.04	-\$39.63	-\$49.50	
6	Net DT Charges		\$577.44	\$588.21	\$684.28	
Row 4 + Row 5						
7	Combined Rate: January 1, 2010		\$1,431.54	\$1,747.27	\$2,127.73	
Row 3 + Row 6						
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07323 /kW.h Energy Admin Fee \$ 18.03 /month	\$911.44	\$1,237.31	\$1,541.21	
9	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
10	2010 Energy Related Charge		\$911.44	\$1,237.31	\$1,541.21	
Row 8 + Row 9						
11	AE Final DT Base Rates	Customer Charge \$ 2.3495 /day Energy Charge \$ 0.0042 /kW.h Demand Charge Blk 1 \$ 0.3434 /kW/day Demand Charge Blk 2 \$ 0.3275 /kW/day	\$636.83	\$655.52	\$765.66	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00420 /kW.h Rider G \$ 0.0018 /kW.h	-\$29.04	-\$39.63	-\$49.50	
13	Net DT Charges		\$607.79	\$615.89	\$716.16	
Row 11 + Row 12						
14	Predicted Combined Rate: June 1, 2010		\$1,519.23	\$1,853.20	\$2,257.37	
Row 10 + Row 13						
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08493 /kW.h Energy Admin Fee \$ 18.03 /month	\$1,054.18	\$1,432.11	\$1,784.57	
16	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
17	2010 Energy Related Charge		\$1,054.18	\$1,432.11	\$1,784.57	
Row 15 + Row 16						
18	AE Final DT Base Rates	Customer Charge \$ 2.3495 /day Energy Charge \$ 0.0042 /kW.h Demand Charge Blk 1 \$ 0.3434 /kW/day Demand Charge Blk 2 \$ 0.3275 /kW/day	\$636.83	\$655.52	\$765.66	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G \$ 0.00073 /kW.h	-\$16.67	-\$22.75	-\$28.42	
20	Net DT Charges		\$620.16	\$632.77	\$737.25	
Row 18 + Row 19						
21	Predicted Combined Rate: August 1, 2010		\$1,674.33	\$2,064.88	\$2,521.82	
Row 17 + Row 20						
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08493 /kW.h Energy Admin Fee \$ 18.03 /month	\$1,054.18	\$1,432.11	\$1,784.57	
23	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
24	2011 Energy Related Charge		\$1,054.18	\$1,432.11	\$1,784.57	
Row 22 + Row 23						
25	AE Proposed DT Base Rates	Customer Charge \$ 2.4272 /day Energy Charge \$ 0.0036 /kW.h Demand Charge Blk 1 \$ 0.3709 /kW/day Demand Charge Blk 2 \$ 0.3571 /kW/day	\$673.68	\$689.90	\$805.17	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G \$ 0.00073 /kW.h	-\$16.67	-\$22.75	-\$28.42	
27	Net DT Charges		\$657.02	\$667.15	\$776.75	
Row 25 + Row 26						
28	Predicted Combined Rate: January 1, 2011		\$1,711.19	\$2,099.26	\$2,561.33	
Row 24 + Row 27						
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	\$36.86	\$34.38	\$39.51
			%	2%	2%	2%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

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

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Large General Service Class Consumption Levels Cost per Customer (\$/month)		
				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
Row	Rate Component	Rate				
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.06853 /kW.h Energy Admin Fee \$ 18.03 /month	\$45,042.24	\$60,050.31	\$75,058.38	
2	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
3	2010 Energy Related Charge		\$45,042.24	\$60,050.31	\$75,058.38	
		Row 1 + Row 2				
4	AE Interim DT Base Rates	Customer Charge \$ 2.3340 /day Energy Charge \$ 0.0048 /kW.h Demand Charge Blk 1 \$ 0.3186 /kW/day Demand Charge Blk 2 \$ 0.3051 /kW/day	\$17,155.62	\$22,783.32	\$28,411.02	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00420 /kW.h Rider G \$ 0.0018 /kW.h	-\$1,563.66	-\$2,084.88	-\$2,606.10	
6	Net DT Charges		\$15,591.96	\$20,698.44	\$25,804.92	
		Row 4 + Row 5				
7	Combined Rate: January 1, 2010		\$60,634.20	\$80,748.75	\$100,863.30	
		Row 3 + Row 6				
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07323 /kW.h Energy Admin Fee \$ 18.03 /month	\$48,130.14	\$64,167.51	\$80,204.88	
9	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
10	2010 Energy Related Charge		\$48,130.14	\$64,167.51	\$80,204.88	
		Row 8 + Row 9				
11	AE Final DT Base Rates	Customer Charge \$ 2.3495 /day Energy Charge \$ 0.0042 /kW.h Demand Charge Blk 1 \$ 0.3434 /kW/day Demand Charge Blk 2 \$ 0.3275 /kW/day	\$17,805.89	\$23,638.19	\$29,470.49	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00420 /kW.h Rider G \$ 0.0018 /kW.h	-\$1,563.66	-\$2,084.88	-\$2,606.10	
13	Net DT Charges		\$16,242.23	\$21,553.31	\$26,864.39	
		Row 11 + Row 12				
14	Predicted Combined Rate: June 1, 2010		\$64,372.37	\$85,720.82	\$107,069.27	
		Row 10 + Row 13				
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08493 /kW.h Energy Admin Fee \$ 18.03 /month	\$55,817.04	\$74,416.71	\$93,016.38	
16	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
17	2010 Energy Related Charge		\$55,817.04	\$74,416.71	\$93,016.38	
		Row 15 + Row 16				
18	AE Final DT Base Rates	Customer Charge \$ 2.3495 /day Energy Charge \$ 0.0042 /kW.h Demand Charge Blk 1 \$ 0.3434 /kW/day Demand Charge Blk 2 \$ 0.3275 /kW/day	\$17,805.89	\$23,638.19	\$29,470.49	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G \$ 0.00073 /kW.h	-\$897.62	-\$1,196.83	-\$1,496.03	
20	Net DT Charges		\$16,908.27	\$22,441.36	\$27,974.45	
		Row 18 + Row 19				
21	Predicted Combined Rate: August 1, 2010		\$72,725.31	\$96,858.07	\$120,990.83	
		Row 17 + Row 20				
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08493 /kW.h Energy Admin Fee \$ 18.03 /month	\$55,817.04	\$74,416.71	\$93,016.38	
23	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
24	2011 Energy Related Charge		\$55,817.04	\$74,416.71	\$93,016.38	
		Row 22 + Row 23				
25	AE Proposed DT Base Rates	Customer Charge \$ 2.4272 /day Energy Charge \$ 0.0036 /kW.h Demand Charge Blk 1 \$ 0.3709 /kW/day Demand Charge Blk 2 \$ 0.3571 /kW/day	\$18,742.74	\$24,896.67	\$31,050.60	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G \$ 0.00073 /kW.h	-\$897.62	-\$1,196.83	-\$1,496.03	
27	Net DT Charges		\$17,845.12	\$23,699.84	\$29,554.57	
		Row 25 + Row 26				
28	Predicted Combined Rate: January 1, 2011		\$73,662.16	\$98,116.55	\$122,570.95	
		Row 24 + Row 27				
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference %	\$3,738.17 6%	\$4,972.07 6%	\$6,205.97 6%
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference %	\$8,352.94 13%	\$11,137.25 13%	\$13,921.57 13%
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference %	\$936.85 1%	\$1,258.49 1%	\$1,580.12 1%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.8 - Example Rate Rider Effects: Small Oilfield Class - RRO Eligible

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge			Small Oilfield Class Consumption Levels Cost per Customer (\$/month)		
			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
Row	Rate Component	Rate			
Effective Date: January 1, 2010					
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.06807 /kW.h Energy Admin Fee \$ 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 \$ 1.3607 /day Energy Charge \$ 0.0049 /kW.h Demand Charge \$ 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 \$ 0.07236 /kW.h Energy Admin Fee \$ 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 \$ 1.3599 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 \$ 0.08452 /kW.h Energy Admin Fee \$ 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 \$ 1.3599 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 \$ 0.08452 /kW.h Energy Admin Fee \$ 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 \$ 1.4049 /day Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 0.6061 /kW/day	\$339.25	\$438.29	\$537.32
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	\$318.26	\$410.30	\$502.34
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$882.44	\$1,159.57	\$1,436.71
Comparisons					
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference \$33.44 %	\$44.60 5%	\$55.76 5%
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference \$105.81 %	\$141.08 14%	\$176.35 14%
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference \$12.17 %	\$15.78 1%	\$19.39 1%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.9 - Example Rate Rider Effects: Small Oilfield 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 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
Row	Rate Component	Rate				
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.06807 /kW.h Energy Admin Fee \$ 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 \$ 1.3607 /day Energy Charge \$ 0.0049 /kW.h Demand Charge \$ 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 \$ 0.07236 /kW.h Energy Admin Fee \$ 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 \$ 1.3599 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 \$ 0.08452 /kW.h Energy Admin Fee \$ 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 \$ 1.3599 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 \$ 0.08452 /kW.h Energy Admin Fee \$ 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 \$ 1.4049 /day Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 0.6061 /kW/day	\$339.25	\$438.29	\$537.32	
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	\$318.26	\$410.30	\$502.34	
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$882.44	\$1,159.57	\$1,436.71	
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference \$33.44 %	\$44.60 5%	\$55.76 5%	
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference \$105.81 %	\$141.08 14%	\$176.35 14%	
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference \$12.17 %	\$15.78 1%	\$19.39 1%	

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.10 - Example Rate Rider Effects: REA Farm Service Class (Pooled) - RRO Eligible

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				REA Farm Service Class Consumption Levels Cost per Customer (\$/month)		
Row	Rate Component	Rate		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
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07014 /kW.h Energy Admin Fee \$ 8.22 /month		\$61.18	\$96.25	\$131.32
2	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
3	2010 Energy Related Charge			\$61.18	\$96.25	\$131.32
Row 1 + Row 2						
4	AE Interim DT Base Rates	Customer Charge \$ 0.2916 /day Energy Charge \$ 0.0048 /kW.h Demand Charge \$ 0.1383 /kVA/day		\$43.49	\$45.89	\$48.29
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00425 /kW.h -\$ 0.0010 /kW.h		-\$3.93	-\$6.54	-\$9.14
6	Net DT Charges			\$39.56	\$39.35	\$39.15
Row 4 + Row 5						
7	Combined Rate: January 1, 2010			\$100.73	\$135.60	\$170.46
Row 3 + Row 6						
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07520 /kW.h Energy Admin Fee \$ 8.22 /month		\$65.00	\$102.60	\$140.20
9	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
10	2010 Energy Related Charge			\$65.00	\$102.60	\$140.20
Row 8 + Row 9						
11	AE Final DT Base Rates	Customer Charge \$ 0.2883 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 0.1458 /kVA/day		\$44.70	\$46.85	\$49.00
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00425 /kW.h -\$ 0.0010 /kW.h		-\$3.93	-\$6.54	-\$9.14
13	Net DT Charges			\$40.77	\$40.31	\$39.86
Row 11 + Row 12						
14	Predicted Combined Rate: June 1, 2010			\$105.76	\$142.91	\$180.05
Row 10 + Row 13						
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08824 /kW.h Energy Admin Fee \$ 8.22 /month		\$74.84	\$118.96	\$163.08
16	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
17	2010 Energy Related Charge			\$74.84	\$118.96	\$163.08
Row 15 + Row 16						
18	AE Final DT Base Rates	Customer Charge \$ 0.2883 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 0.1458 /kVA/day		\$44.70	\$46.85	\$49.00
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00212 /kW.h \$ 0.00132 /kW.h		-\$0.61	-\$1.01	-\$1.41
20	Net DT Charges			\$44.09	\$45.84	\$47.59
Row 18 + Row 19						
21	Predicted Combined Rate: August 1, 2010			\$118.94	\$164.80	\$210.67
Row 17 + Row 20						
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08824 /kW.h Energy Admin Fee \$ 8.22 /month		\$74.84	\$118.96	\$163.08
23	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
24	2011 Energy Related Charge			\$74.84	\$118.96	\$163.08
Row 22 + Row 23						
25	AE Proposed DT Base Rates	Customer Charge \$ 0.2979 /day Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 0.1579 /kVA/day		\$47.23	\$49.07	\$50.91
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00212 /kW.h \$ 0.00132 /kW.h		-\$0.61	-\$1.01	-\$1.41
27	Net DT Charges			\$46.63	\$48.07	\$49.50
Row 25 + Row 26						
28	Predicted Combined Rate: January 1, 2011			\$121.47	\$167.03	\$212.58
Row 24 + Row 27						
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	\$2.53	\$2.22	\$1.91
			%	2%	1%	1%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.11 - Example Rate Rider Effects: Farm 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				REA Farm Service Class Consumption Levels Cost per Customer (\$/month)		
Row	Rate Component	Rate	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	
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07014 /kW.h Energy Admin Fee \$ 8.22 /month	\$61.18	\$96.25	\$131.32	
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 Energy Charge \$ 0.0095 /kW.h Demand Charge \$ 0.1680 /kVA/day	\$60.87	\$65.62	\$70.37	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00425 /kW.h -\$ 0.0037 /kW.h	-\$6.00	-\$9.98	-\$13.95	
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 Energy Admin Fee \$ 8.22 /month	\$65.00	\$102.60	\$140.20	
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 Energy Charge \$ 0.0098 /kW.h Demand Charge \$ 0.1724 /kVA/day	\$62.51	\$67.41	\$72.31	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00425 /kW.h -\$ 0.0037 /kW.h	-\$6.00	-\$9.98	-\$13.95	
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 Energy Admin Fee \$ 8.22 /month	\$74.84	\$118.96	\$163.08	
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 Energy Charge \$ 0.0098 /kW.h Demand Charge \$ 0.1724 /kVA/day	\$62.51	\$67.41	\$72.31	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00212 /kW.h -\$ 0.00016 /kW.h	-\$1.72	-\$2.86	-\$3.99	
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 Energy Admin Fee \$ 8.22 /month	\$74.84	\$118.96	\$163.08	
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 \$ 0.5621 /day Energy Charge \$ 0.0094 /kW.h Demand Charge \$ 0.1854 /kVA/day	\$65.64	\$70.32	\$75.00	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00212 /kW.h -\$ 0.00016 /kW.h	-\$1.72	-\$2.86	-\$3.99	
27	Net DT Charges	Row 25 + Row 26	\$63.92	\$67.46	\$71.00	
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$138.76	\$186.42	\$234.09	
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference \$5.46 %	\$8.14 5%	\$10.82 6%	
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference \$14.13 %	\$23.49 12%	\$32.84 17%	
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference \$3.13 %	\$2.91 2%	\$2.69 1%	

**ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728**

Appendix B.12 - Example Rate Rider Effects: Street Light Service Class D61 Option A

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Street Light Service Class Consumption Levels Cost per Customer (\$/month)		
				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
Row	Rate Component	Rate				
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.05837 /kW.h Energy Admin Fee \$ 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 \$ 0.3075 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 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 -\$ 0.00419 /kW.h Rider G -\$ 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 \$ 0.04120 /kW.h Energy Admin Fee \$ 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 \$ 0.3054 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 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 -\$ 0.00419 /kW.h Rider G -\$ 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 \$ 0.05392 /kW.h Energy Admin Fee \$ 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 \$ 0.3054 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 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 -\$ 0.00209 /kW.h Rider G -\$ 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 \$ 0.05392 /kW.h Energy Admin Fee \$ 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 \$ 0.3840 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 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 -\$ 0.00209 /kW.h Rider G -\$ 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%

**ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728**

Appendix B.13 - Example Rate Rider Effects: Private Lighting Service Class D63 Option A

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Private Street Light Service Class		
				Consumption Levels Cost per Customer (\$/month)		
Row	Rate Component	Rate	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	
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.05837 /kW.h Energy Admin Fee \$ 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 \$ 0.3668 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 0.0004 /W/day	\$12.08	\$13.70	\$15.32	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0007 /W/day	-\$2.19	-\$5.47	-\$8.75	
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 Energy Admin Fee \$ 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 \$ 0.3686 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 0.0004 /W/day	\$12.20	\$13.91	\$15.62	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0007 /W/day	-\$2.19	-\$5.47	-\$8.75	
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 Energy Admin Fee \$ 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 \$ 0.3686 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 0.0004 /W/day	\$12.20	\$13.91	\$15.62	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.0004 /W/day	-\$0.19	-\$0.48	-\$0.77	
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 Energy Admin Fee \$ 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 \$ 0.3808 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 0.0004 /W/day	\$12.62	\$14.42	\$16.21	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.0004 /W/day	-\$0.19	-\$0.48	-\$0.77	
27	Net DT Charges	Row 25 + Row 26	\$12.43	\$13.94	\$15.45	
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$16.93	\$21.29	\$25.61	
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	\$0.42	\$0.51	\$0.60
			%	3%	2%	2%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

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

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Large General Service Class Consumption Levels Cost per Customer (\$/month)		
Note: Assume coincident metered demand equals to 50% of the metered demand				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
Row	Rate Component	Rate				
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
2	+/- RRO Deferral	Energy Admin Fee	\$ 18.03 /month			
		RRO Deferral	\$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00
3	2010 Energy Related Charge	Pool Price	\$57.30	\$52,546.28	\$70,055.69	\$87,565.11
		Row 1 + Row 2				
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			
		POD Charge (1st 7.5MW)	\$ 3.96 /kW/month			
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge fixed	\$ 7,030.00 /month	-\$3,349.61	-\$4,466.14	-\$5,582.68
		Balancing Pool Refund Rider	-\$ 0.0040 /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
9	+/- RRO Deferral	Energy Admin Fee	\$ 18.03 /month			
		RRO Deferral	\$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00
10	2010 Energy Related Charge	Pool Price	\$57.30	\$56,148.83	\$74,859.09	\$93,569.36
		Row 8 + Row 9				
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			
		POD Charge (1st 7.5MW)	\$ 3.96 /kW/month			
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge fixed	\$ 7,030.00 /month	-\$3,349.61	-\$4,466.14	-\$5,582.68
		Balancing Pool Refund Rider	-\$ 0.0040 /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
16	+/- RRO Deferral	Energy Admin Fee	\$ 18.03 /month			
		RRO Deferral	\$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00
17	2010 Energy Related Charge	Pool Price	\$57.30	\$65,116.88	\$86,816.49	\$108,516.11
		Row 15 + Row 16				
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			
		POD Charge (1st 7.5MW)	\$ 3.96 /kW/month			
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge fixed	\$ 7,030.00 /month	-\$1,512.02	-\$2,016.02	-\$2,520.03
		Balancing Pool Refund Rider	-\$ 0.0020 /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
23	+/- RRO Deferral	Energy Admin Fee	\$ 18.03 /month			
		RRO Deferral	\$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00
24	2011 Energy Related Charge	Pool Price	\$57.30	\$65,116.88	\$86,816.49	\$108,516.11
		Row 22 + Row 23				
25	AE and AESO Rates	Customer Charge	\$ 0.0000 /day	\$20,860.89	\$24,905.92	\$28,950.95
		Energy Charge	\$ 0.0045 /kW.h			
		Demand Charge Blk 1	\$ 0.17 /kW/day			
		Demand Charge Blk 2	\$ 0.06 /kW/day			
		POD Charge (1st 7.5MW)	\$ 3.96 /kW/month			
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge fixed	\$ 7,030.00 /month	-\$1,512.02	-\$2,016.02	-\$2,520.03
		Balancing Pool Refund Rider	-\$ 0.0020 /kW.h			
		Rider G	\$ 0.00003 /kW.h			
27	Net DT Charges	Row 25 + Row 26		\$19,348.87	\$22,889.90	\$26,430.92
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27		\$84,465.75	\$109,706.39	\$134,947.03
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7		difference %	\$3,925.05 6%	\$5,125.90 6%
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14		difference %	\$10,805.64 15%	\$14,407.52 15%
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21		difference %	\$54.80 0%	\$54.80 0%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Energy Rates Used in Appendix B-1 to B-14

	Admin. Charges	Cost of Energy for			
	Fixed (\$ / Day)	January 2010 (\$ / kWh)	June 2010 (\$ / kWh)	August 2010 (\$ / kWh)	January 2011 (\$ / 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

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

	A	B	C	D	E	F	G	H	I	J
1	D Tariff Rates									
2	2011 proposed interim									
3	(Oct 18,2010)									
4	D11									
5										
6		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
7	T				1.89 ¢/kW.h	0.00 ¢/kW.h				
8	D	67.25 ¢/day			5.48 ¢/kW.h	0.00 ¢/kW.h		0.00 ¢/kV.A/day		
9	S	26.12 ¢/day								
10	Total	93.37 ¢/day			7.38 ¢/kW.h	0.00 ¢/kW.h		0.00 ¢/kV.A/day		
11										
12										
13	D21									
14										
15		Customer	Demand 1	Demand 2	Energy 1	Energy 2	Option H(a)	PF	Option P	
16	T		10.62 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
17	D		18.40 ¢/kW/day		3.39 ¢/kW.h	0.00 ¢/kW.h	-3.54 ¢/kW/day	0.00 ¢/kV.A/day		
18	S	33.66 ¢/day								
19	Total	33.66 ¢/day	29.02 ¢/kW/day		3.75 ¢/kW.h	0.37 ¢/kW.h		0.00 ¢/kV.A/day	46%	
20										
21										
22	D22									
23										
24		Customer	Demand 1	Demand 2	Energy 1	Energy 2	Option H(a)	PF	Option P	
25	T				0.51 ¢/kW.h	0.51 ¢/kW.h				
26	D				21.77 ¢/kW.h	7.22 ¢/kW.h	-3.54 ¢/kW/day	0.00 ¢/kV.A/day		
27	S									
28	Total	0.00 ¢/day	0.00 ¢/kW/day	0.00 ¢/kW/day	22.29 ¢/kW.h	7.73 ¢/kW.h		0.00 ¢/kV.A/day	46%	
29										
30										
31	D25									
32										
33		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
34	T		11.00 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
35	D		16.09 ¢/kW/day		0.00 ¢/kW.h	0.00 ¢/kW.h		0.00 ¢/kV.A/day		
36	S	32.17 ¢/day								
37	Total	32.17 ¢/day	27.09 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h		0.00 ¢/kV.A/day		
38										
39										
40	D26									
41										
42		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
43	T		11.00 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
44	D		5.07 ¢/kW/day		0.00 ¢/kW.h	0.00 ¢/kW.h		0.00 ¢/kV.A/day		
45	S	32.17 ¢/day								
46	Total	32.17 ¢/day	16.06 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h		0.00 ¢/kV.A/day		
47										
48										
49	D31									
50										
51		Customer	Demand 1	Demand 2	Energy 1	Energy 2	Option H(a)	PF	Option P	Option H(b)
52	T		15.68 ¢/kW/day	18.22 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h				
53	D	14.72 ¢/day	21.41 ¢/kW/day	16.80 ¢/kW/day			-3.54 ¢/kW/day	20.17 ¢/kV.A/day		-1.00%
54	S	228.00 ¢/day		0.69 ¢/kW/day						
55	Total	242.72 ¢/day	37.09 ¢/kW/day	35.71 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h		20.17 ¢/kV.A/day	33%	
56										
57										
58	T31 and T33									
59										
60		Customer	Demand 1	Demand 2	Energy 1	Energy 2	Option H(d)	PF		
61	T									
62	d		1.45 ¢/kW/day				3.54 ¢/kW/day	20.17 ¢/kV.A/day		
63	s		9.86 ¢/kW/day							
64	Total	0.00 ¢/day	11.31 ¢/kW/day	0.00 ¢/kW/day	0.00 ¢/kW.h	0.00 ¢/kW.h		20.17 ¢/kV.A/day		
65										
66										
67	D32									
68										
69		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
70	T		15.68 ¢/kW/day	18.22 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h				
71	D	14.72 ¢/day	21.41 ¢/kW/day	16.80 ¢/kW/day				20.17 ¢/kV.A/day		
72	S	228.00 ¢/day		0.69 ¢/kW/day						
73	Total	242.72 ¢/day	37.09 ¢/kW/day	35.71 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h		20.17 ¢/kV.A/day		
74										
75										

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

	A	B	C	D	E	F	G	H	I	J
1	D Tariff Rates									
	2011 proposed interim (Oct 18,2010)									
76	D33									
77										
78		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
79	T		15.68 ¢/kW/day	18.22 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h		should be avg. DOS rate		
80	D	14.72 ¢/day	21.41 ¢/kW/day	16.80 ¢/kW/day				20.17 ¢/kV.A/day		
81	S	228.00 ¢/day		0.69 ¢/kW/day						
82	Total	242.72 ¢/day	37.09 ¢/kW/day	35.71 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h		20.17 ¢/kV.A/day		
83										
84										
85	T33									
86										
87		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
88	T									
89	d		1.45 ¢/kW/day					20.17 ¢/kV.A/day		
90	s		9.86 ¢/kW/day							
91	Total	0.00 ¢/day	11.31 ¢/kW/day	0.00 ¢/kW/day	0.00 ¢/kW.h	0.00 ¢/kW.h		20.17 ¢/kV.A/day		
92										
93										
94	D41									
95										
96		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
97	T		13.32 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
98	D	50.90 ¢/day	47.28 ¢/kW/day					44.59 ¢/kV.A/day		
99	S	89.59 ¢/day								
100	Total	140.49 ¢/day	60.61 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h		44.59 ¢/kV.A/day		
101										
102										
103	D51									
104										
105		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
106	T		7.02 ¢/kV.A/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
107	D (O&M Pool)		8.77 ¢/kV.A/day					0.00 ¢/kV.A/day		
108	S	29.79 ¢/day								
109	Total	29.79 ¢/day	15.79 ¢/kV.A/day		0.37 ¢/kW.h	0.37 ¢/kW.h		0.00 ¢/kV.A/day		
110										
111										
112	D52									
113										
114		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
115	T		7.02 ¢/kV.A/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
116	D							0.00 ¢/kV.A/day		
117	S	25.21 ¢/day								
118	Total	25.21 ¢/day	7.02 ¢/kV.A/day		0.37 ¢/kW.h	0.37 ¢/kW.h		0.00 ¢/kV.A/day		
119										
120										
121	D56									
122										
123		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
124	T		7.02 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
125	D	26.43 ¢/day	11.52 ¢/kW/day		0.57 ¢/kW.h	0.57 ¢/kW.h		0.00 ¢/kV.A/day		
126	S	29.79 ¢/day								
127	Total	56.21 ¢/day	18.54 ¢/kW/day		0.94 ¢/kW.h	0.94 ¢/kW.h		0.00 ¢/kV.A/day		
128										
129										
130	D61									
131										
132		Customer	Demand 1							
133	T		0.017 ¢/W/day							
134	D - Option A	31.15 ¢/fixture/day	0.031 ¢/W/day							
135	D - Option B	85.51 ¢/fixture/day	0.031 ¢/W/day							
136	D - Option C	41.11 ¢/fixture/day	0.031 ¢/W/day							
137	D - Option D									
138	D - Option E	31.15 ¢/fixture/day	0.031 ¢/W/day							
139	S	7.25 ¢/fixture/day								
140	Total									
141										
142										
143	D63									
144										
145		Customer	Demand 1							
146	T		0.019 ¢/W/day							
147	D - Option A	25.01 ¢/fixture/day	0.021 ¢/W/day							
148	D - Option B	40.32 ¢/fixture/day	0.021 ¢/W/day							
149	D - Option C	13.27 ¢/fixture/day	0.006 ¢/W/day							
150	D - Option D	26.54 ¢/fixture/day	0.021 ¢/W/day							
151	D - Option E	17.35 ¢/fixture/day	0.021 ¢/W/day							
152	S	13.07 ¢/fixture/day								
153	Total									

Determination of Adjustment Factors (for Rates Jan. 1 - Dec. 31, 2011) Updated for Amended 2010 Final Tariff Application

Table 1									Table 2					
Scaling Factor Determination									Breakdown of Transmission Rate					
All Revenue in \$'000's									All Revenue in \$'000's					
Year	Column No.	Scenario	(A)	(B)	(C)	(D)	(E)		Based on 2010 Final Rate Application					
			Trans Demand Revenue	Trans Energy Revenue	Trans Demand Revenue T31	Trans Energy Revenue T31	Dist Revenue	Power Factor	Total	Demand Related Portion	Energy Related Portion	Total Trans Revenue		
Before Scaling														
2011		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)						D11	14,240	4,533	18,774	
		Adj for D61	(88)	88						D61	227	88	315	
		Adj for D63	(14)	14						D63	35	14	48	
	(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	289,283	5,408	463,285					
	(3)	Scaling Factor	1.151720	0.863227	1.000000	1.000000	1.033057	1.000	1.045154					
		D25 &D26					1.351695		1.250000					
	D61					1.257405		1.250000						
After Scaling														
2011		12 mo. 2010 Final rates after scaling	90,536	48,210	23,459	5,980	279,563	5,408	453,157					
		D25 &D26	60	10			129		200					
		D61	338				9,591		9,929					
		Adj for D11	16,401	(16,401)						D11	16,401	3,913	20,314.33933	1.082057
		Adj for D61	(76)	76						D61	261	76	337.73300	1.070896
		Adj for D63	(12)	12						D63	40	12	51.92197	1.071095
	(4)	Total	107,248	31,907	23,459	5,980	289,283	5,408	463,285					
										(F)				
										Factored Future Costs for 2011				
										Scaling Factor				

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 b 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.

**ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728**

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 Proposed RR \$ million
Transmission	\$336.6	\$86.6	(\$54.3)	\$32.2	37%	\$282.2
Distribution	\$493.6	\$33.4	(\$13.3)	\$20.0	60% *	\$480.2

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

PRICE SCHEDULE INDEX**RESIDENTIAL SERVICE**

Standard Residential Service Price Schedule D11

SMALL GENERAL SERVICE

Standard Small General Service Price Schedule D21

Small General Service - Energy Only Price Schedule D22

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

Irrigation Pumping Service Price Schedule D25

REA Irrigation Pumping Service Price Schedule D26

LARGE GENERAL SERVICE/INDUSTRIAL

Large General Service/Industrial - Distribution Connected Price Schedule D31

Large General Service/Industrial - Transmission Connected Price Schedule T31

Generator Interconnection and Standby Power - Distribution Connected Price Schedule D32

Transmission Opportunity Rate - Distribution Connected Price Schedule D33

Transmission Opportunity Rate - Transmission Connected Price Schedule T33

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

OILFIELD

Small Oilfield and Pumping Power Price Schedule D41

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

FARM SERVICE

REA Farm Service Price Schedule D51

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

Farm Service Price Schedule D56

LIGHTING SERVICE

Street Lighting Service Price Schedule D61

Private Lighting Service Price Schedule D63

PRICE OPTIONS

Idle Service Option F

Service for Non-Standard Transformation and Metering Configurations Option H

REA Distribution Price Credit Option P

PRICING ADJUSTMENTS (RIDERS)

Municipal Assessment Rider A-1

Balancing Pool Adjustment Rider B

Special Facilities Charge Rider E

Temporary Adjustment Rider G

Interim Adjustment Rider J

Interim RRT Adjustment Rider Q

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company. 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	68.05 ¢ / day	5.55 ¢ / kW.h
Service	26.43 ¢ / day	-
TOTAL PRICE	94.48 ¢ / day	7.44 ¢ / 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	-	18.62 ¢/kW/day	3.43 ¢ / kW.h	-
Service	34.06 ¢ / day	-	-	-
TOTAL PRICE	34.06 ¢ / day	29.24 ¢/kW/day	3.80 ¢ / 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	22.03 ¢ / kW.h	7.31 ¢ / kW.h
Service	-	-
TOTAL PRICE	22.55 ¢ / kW.h	7.82 ¢ / 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)

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	-	18.62 ¢/kW/day	3.43 ¢ / kW.h	-
Service	34.06 ¢ / day	-	-	-
TOTAL PRICE	34.06 ¢ / day	18.62 ¢/kW/day	3.43 ¢ / 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:

- the highest metered demand during the billing period;
- the estimated demand;
- if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;
- 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

- 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.
- 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.
- 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	14.90 ¢ /day	21.67 ¢/kW/day	17.00 ¢/kW/day	-
Service	\$2.3072 /day	-	0.70 ¢/kW/day	-
TOTAL PRICE	\$2.4561 /day	37.35 ¢/kW/day	35.92 ¢/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	1.46 ¢/kW/day	-	-
Service	9.98 ¢/kW/day	-	-
TOTAL PRICE	11.44 ¢/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	14.90 ¢ /day	21.67 ¢/kW/day	17.00 ¢/kW/day	-
Service	\$2.3072 /day	-	0.70 ¢/kW/day	-
TOTAL PRICE	\$2.4561 /day	37.35 ¢/kW/day	35.92 ¢/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.
- Telemetry is required for all points of service on this rate with demands greater than 2,500 kW, and any associated costs will be in addition to the charges in this rate.

Price

Charges for service in any one billing 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	14.90 ¢ /day	21.67 ¢/kW/day	17.00 ¢/kW/day	-	-
Service	\$2.3072 /day	-	0.70 ¢/kW/day	-	-
TOTAL PRICE	\$2.4562 /day + AESO DOS Rate	21.67 ¢/kW/day	17.70 ¢/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)

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)



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

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

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

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

Availability

For Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from an isolated industrial area. 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	14.90 ¢ /day	21.67 ¢/kW/day	17.00 ¢/kW/day	-
Service	\$2.3072 /day	-	0.70 ¢/kW/day	-
TOTAL PRICE	\$2.4562 /day	21.67 ¢/kW/day	17.70 ¢/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	51.51 ¢ / day	47.85 ¢/kW/day	-
Service	90.66 ¢ / day	-	-
TOTAL PRICE	\$1.4216 / day	61.17 ¢/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	51.51 ¢ / day	47.85 ¢/kW/day
Service	90.66 ¢ / day	-
TOTAL PRICE	\$1.4216 / day	47.85 ¢/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	-	8.87 ¢/kV.A/day	-
Service	30.14 ¢ / service / day	-	-
REA Specific Charges	See REA Tariff	-	-
Total Price	C₁ ¢ / 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	C₁ ¢ / service /day	D₁ ¢/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	25.51 ¢/service/day	-	-
TOTAL PRICE	25.51 ¢/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	26.74 ¢/service/day	11.66 ¢/kV.A/day	0.57 ¢ / kW.h
Service	30.14 ¢/service/day	-	-
TOTAL PRICE	56.88 ¢/service/day	18.68 ¢/kV.A/day	0.94 ¢ / 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	25.30 ¢/fixture/day	0.022 ¢/watt/day
Service	13.23 ¢/fixture/day	-
TOTAL PRICE	38.53 ¢/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	40.80 ¢/fixture/day	0.022 ¢/watt/day
Service	13.23 ¢/fixture/day	-
TOTAL PRICE	54.03 ¢/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	13.43 ¢/fixture/day	0.006 ¢/watt/day
Service	13.23 ¢/fixture/day	-
TOTAL PRICE	26.66 ¢/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	26.85 ¢/fixture/day	0.022 ¢/watt/day
Service	13.23 ¢/fixture/day	-
TOTAL PRICE	40.08 ¢/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	17.56 ¢/fixture/day	0.022 ¢/watt/day
Service	13.23 ¢/fixture/day	-
TOTAL PRICE	30.79 ¢/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.

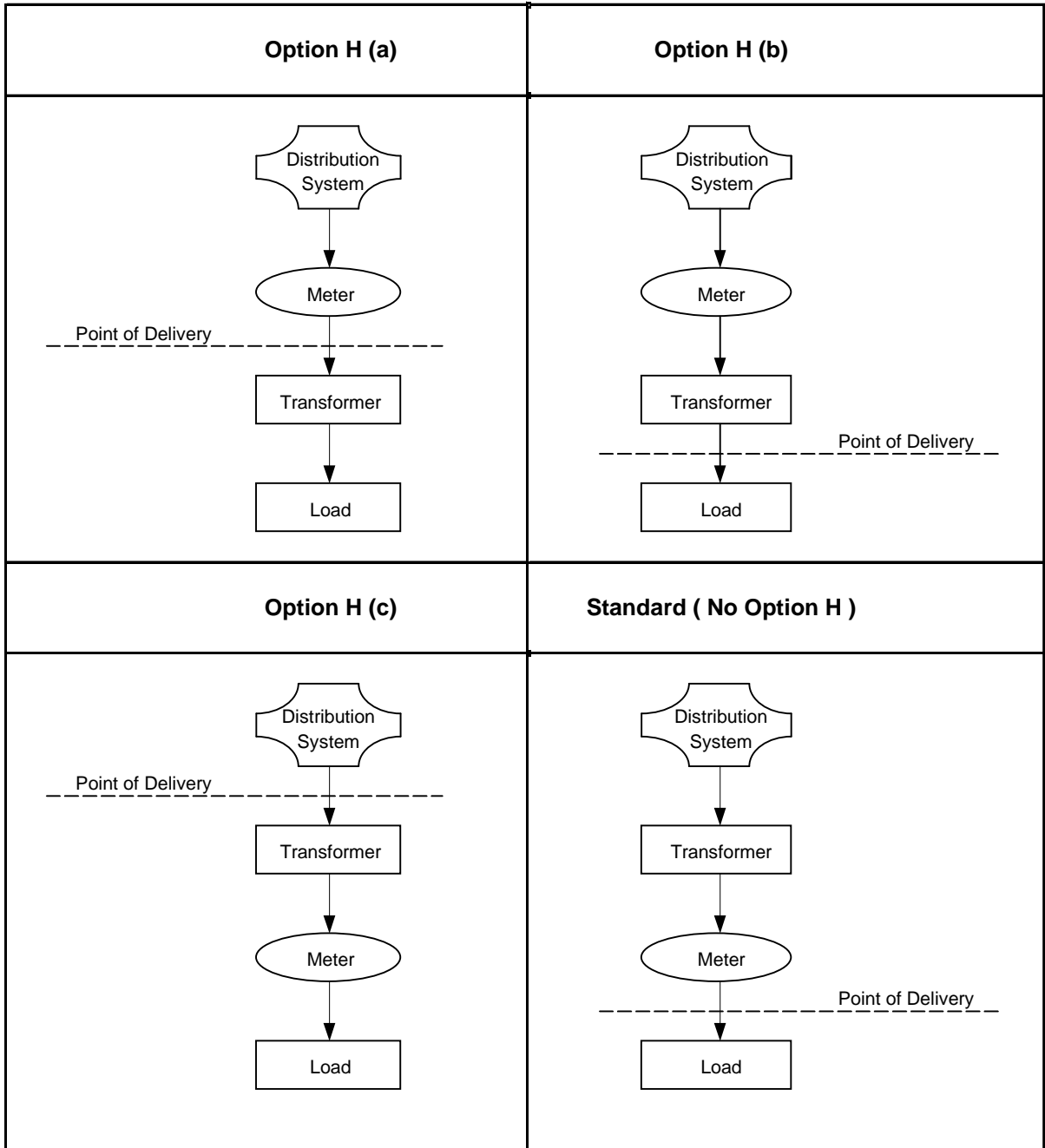
Availability

- 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.

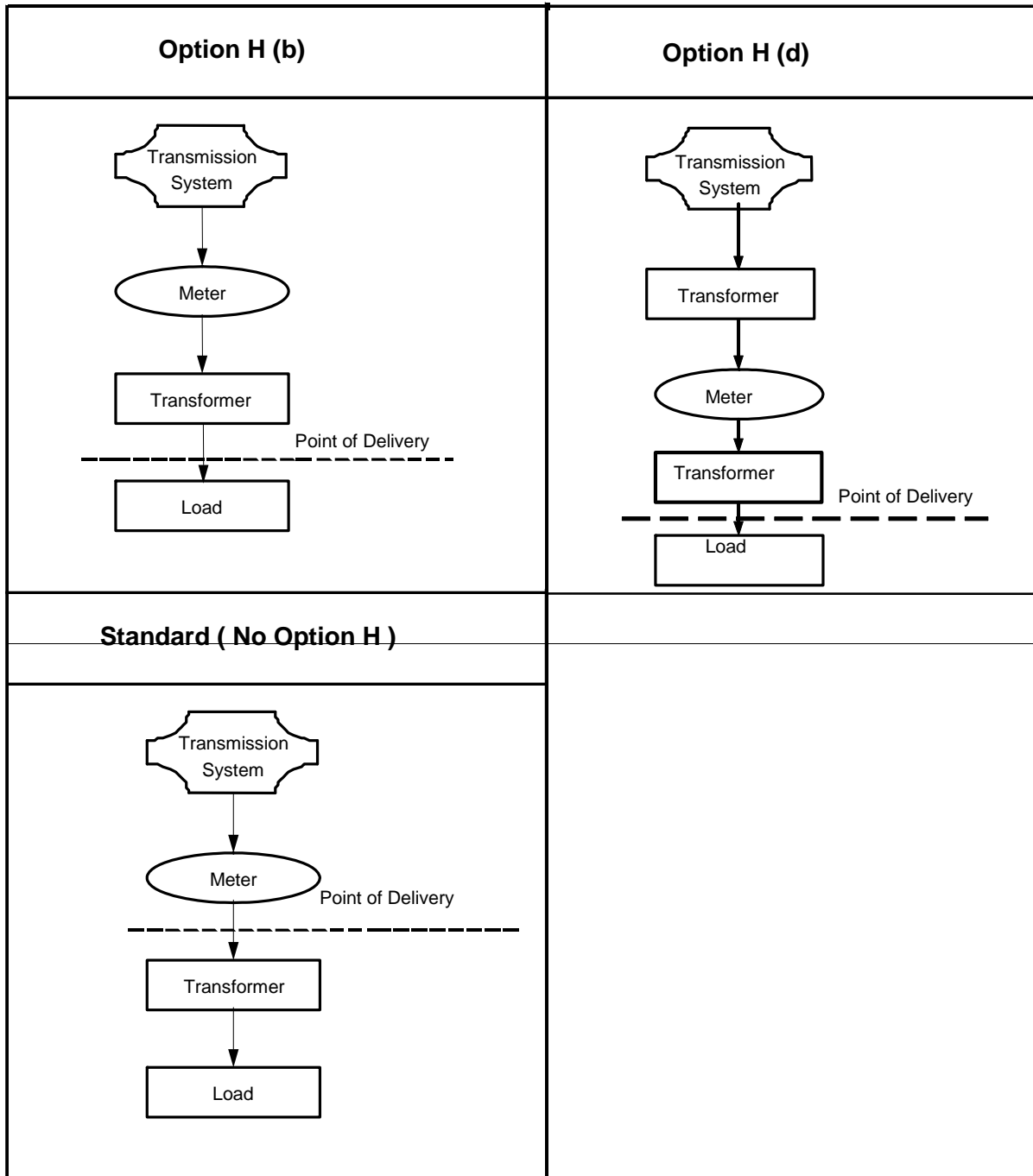
Price Adjustment

- (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 3.58 ¢/kW/day** of billing demand will be applied. This adjustment does not apply to customers connected directly to the transmission system who are exempt from the Distribution Charge on the applicable rate.
- (b) If primary or higher voltage delivery metering is desirable for the convenience of the Company, or to improve accessibility, etc., **demand and energy measurements will be reduced by 1%** so as to approximate secondary voltage delivery conditions.
- (c) If primary or higher voltage delivery is made to customer owned transformers, but metering is at secondary or utilization voltage for the Company's convenience, **demand and energy measurements will be increased by 1%** so as to approximate primary or transmission voltage delivery conditions and **a discount, as specified in (a)** shall apply.
- (d) Customers who are connected directly to the transmission system, but take service from the low side of a transformer (with primary side 25kV), and do not own or rent any necessary transformer(s), and are exempt from the Distribution Charge on the applicable rate, a **surcharge of 3.58 ¢/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	Empress 8+6	Jasper Nat'l Park 5	Sexsmith 7
Andrew 8+6	Fairview 8+6	Kinuso 8+6	Slave Lake 8+6
Beaverlodge 8+6	Falher 8+6	Kitscoty 8+6	Smoky Lake 8+6
Berwyn 8+6	Forestburg 8+6	Linden 8+6	Spirit River 8+6
Big Valley 8+6	Fort McMurray 7	Lloydminster 8+6	St Paul 8+6
Bonnyville 8+6	Fox Creek 8+6	Manning 7	Stettler 7+6
Botha 8+6	Gadsby 8+6	Mannville 8+6	Swan Hills 8+6
Carbon 7	Galahad 8+6	Marwayne 8+6	Three Hills 8+6
Castor 8+6	Girouxville 7	McLennan 7	Trochu 8+6
Cereal 7	Glendon 8+6	Minburn 8+6	Two Hills 8+6
Cold Lake 8+6	Grande Cache 8+6	Morrin 7	Valleyview 8+6
Consort 8+6	Grande Prairie 8+6	Mundare 6	Vegreville 8+6
Coronation 8+6	Grimshaw 8+6	Munson 8+6	Vermilion 8+6
Delburne 8+6	Halkirk 8+6	Myrnam 8+6	Veteran 8+6
Delia 8+6	Hanna 8+6	Nampa 7	Vilna 8+6
Derwent 8+6	Heisler 8+6	Oyen 8+6	Waskatenau 8+6
Dewberry 8+6	High Level 8+6	Paradise Valley 8+6	Wembley 7
Donalda 8+6	High Prairie 8+6	Peace River 8+6	Willingdon 8+6
Donnelly 8+6	Hines Creek 8+6	Radway (County 7) 8+6	Youngstown 7+6
Drumheller 8+6	Hythe 8+6	Rainbow Lake 8+6	
Elk Point 8+6	Innisfree 8+6	Rosalind 8+6	
Elnora 8+6	ID Jasper 7	Rycroft 8+6	

Table 2 – Category Numbers of Municipalities

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

Bonnyville Beach	County No. 27 Minburn	M.D. of Big Lake No. 125
Horseshoe Bay	County No. 29 Flagstaff	M.D. of Smoky R. No. 130
Lavoy	County No. 30 Lamont	M.D. of East Peace No. 131
Pelican Narrows	County No. 89 Lakeland	M.D. of Spirit River No. 133
Rochon Sands	M.D. of Badlands No. 07	M.D. of Peace No. 135
Wanham	M.D. of Greenview No. 16	M.D. of Fairview No. 136
Warspite	M.D. of Opportunity No. 17	I.D. No. 12 & ID No. 24
Whitesands	M.D. of Wood Buffalo No. 18	Allison Bay B219
County No. 01 Grande Pr.	M.D. of Birch Hills No. 19	Fort McMurray Band B352
County No. 06 Stettler	M.D. of Saddle Hills No. 20	Peavine N172
County No. 07 Thorhild	M.D. of Clear Hills No. 21	Gift Lake N173
County No. 13 Smoky Lake	M.D. of Northern Lights No. 22	East Prairie N174
County No. 16 Wheatland	M.D. of Mackenzie No. 23	Elizabeth N187
County No. 18 Paintearth	M.D. of Acadia No. 34	Fishing Lake N188
County No. 19 St. Paul	M.D. of Starland No. 47	Paddle Prairie N221
County No. 21 Two Hills	M.D. of Kneehill No. 48	Special Areas
County No. 22 Camrose	M.D. of Bonnyville No. 87	Sturgeon Lake I.R. #154
County No. 23 Red Deer	M.D. of Bonnyville Annexed No. 88	Whitefish Lake Band B924
County No. 24 Vermilion R.	M.D. of Lesser Slave River No. 124	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
Proceeding ID 918, No. 1606728**

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

Rate Class	January 1, 2010				June 1, 2010				August 1, 2010				January 1, 2011			
	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	\$73.00	-\$2.17	-\$1.26	\$69.56
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	\$349.40	-\$6.50	-\$15.40	\$327.51
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	\$694.60	\$12.22	-\$34.97	\$671.85
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	\$442.18	-\$9.24	-\$18.75	\$414.19
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	\$49.42	\$1.65	-\$2.66	\$48.41
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	\$70.91	-\$0.20	-\$2.66	\$68.06
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	\$14.57	-\$0.29	-\$0.19	\$14.09
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	\$24,926.16	\$27.98	-\$2,044.00	\$22,910.13

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.1 - Example Rate Rider Effects: Residential Class - RRO Eligible

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Residential Class Consumption Levels Cost per Customer (\$/month)		
				300 kW.h per month	Typical 600 kW.h per month	1,200 kW.h per month
Row	Rate Component	Rate				
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			\$29.37	\$50.78	\$93.62
		Row 1 + Row 2				
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			\$43.73	\$60.48	\$93.99
		Row 4 + Row 5				
7	Combined Rate: January 1, 2010			\$73.09	\$111.26	\$187.61
		Row 3 + Row 6				
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			\$30.35	\$52.76	\$97.57
		Row 8 + Row 9				
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			\$44.02	\$60.92	\$94.73
		Row 11 + Row 12				
14	Predicted Combined Rate: June 1, 2010			\$74.37	\$113.68	\$192.30
		Row 10 + Row 13				
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			\$34.18	\$60.41	\$112.88
		Row 15 + Row 16				
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			\$46.58	\$66.04	\$104.97
		Row 18 + Row 19				
21	Predicted Combined Rate: August 1, 2010			\$80.76	\$126.46	\$217.85
		Row 17 + Row 20				
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			\$34.18	\$60.41	\$112.88
		Row 22 + Row 23				
25	AE Proposed DT Base Rates	Customer Charge	\$ 0.9449 /day	\$50.67	\$73.00	\$117.64
		Energy Charge	\$ 0.0744 /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			\$48.95	\$69.56	\$110.78
		Row 25 + Row 26				
28	Predicted Combined Rate: January 1, 2011			\$83.14	\$129.98	\$223.66
		Row 24 + Row 27				
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	\$2.38	\$3.52	\$5.81
			%	3%	3%	3%

**ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728**

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		\$393.74	\$522.16	\$650.59
		Row 1 + Row 2			
4	AE Interim DT Base Rates	Customer Charge \$ 0.3287 /day Energy Charge Blk 1 \$ 0.0357 /kW.h Energy Charge Blk 2 \$ 0.0048 /kW.h	\$246.38	\$325.22	\$404.06
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge \$ 0.2612 /kW/day Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0021 /kW.h	-\$34.60	-\$46.14	-\$57.67
6	Net DT Charges		\$211.78	\$279.09	\$346.39
		Row 4 + Row 5			
7	Combined Rate: January 1, 2010		\$605.51	\$801.25	\$996.98
		Row 3 + Row 6			
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		\$425.93	\$565.09	\$704.24
		Row 8 + Row 9			
11	AE Final DT Base Rates	Customer Charge \$ 0.3258 /day Energy Charge Blk 1 \$ 0.0370 /kW.h Energy Charge Blk 2 \$ 0.0042 /kW.h	\$252.80	\$333.81	\$414.82
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge \$ 0.2703 /kW/day Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0021 /kW.h	-\$34.60	-\$46.14	-\$57.67
13	Net DT Charges		\$218.20	\$287.68	\$357.15
		Row 11 + Row 12			
14	Predicted Combined Rate: June 1, 2010		\$644.13	\$852.76	\$1,061.40
		Row 10 + Row 13			
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		\$489.66	\$650.06	\$810.46
		Row 15 + Row 16			
18	AE Final DT Base Rates	Customer Charge \$ 0.3258 /day Energy Charge Blk 1 \$ 0.0370 /kW.h Energy Charge Blk 2 \$ 0.0042 /kW.h	\$252.80	\$333.81	\$414.82
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge \$ 0.2703 /kW/day Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00089 /kW.h	-\$16.42	-\$21.90	-\$27.37
20	Net DT Charges		\$236.38	\$311.92	\$387.45
		Row 18 + Row 19			
21	Predicted Combined Rate: August 1, 2010		\$726.04	\$961.97	\$1,197.91
		Row 17 + Row 20			
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		\$489.66	\$650.06	\$810.46
		Row 22 + Row 23			
25	AE Proposed DT Base Rates	Customer Charge \$ 0.3406 /day Energy Charge Blk 1 \$ 0.0379 /kW.h Energy Charge Blk 2 \$ 0.0037 /kW.h	\$264.61	\$349.40	\$434.20
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge \$ 0.2924 /kW/day Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00089 /kW.h	-\$16.42	-\$21.90	-\$27.37
27	Net DT Charges		\$248.18	\$327.51	\$406.83
		Row 25 + Row 26			
28	Predicted Combined Rate: January 1, 2011		\$737.84	\$977.56	\$1,217.29
		Row 24 + Row 27			
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 \$11.80	\$15.59	\$19.38
			% 2%	2%	2%

**ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728**

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		\$393.74	\$522.16	\$650.59	
Row 1 + Row 2						
4	AE Interim DT Base Rates	Customer Charge \$ 0.3287 /day Energy Charge Blk 1 \$ 0.0357 /kW.h Energy Charge Blk 2 \$ 0.0048 /kW.h	\$246.38	\$325.22	\$404.06	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge \$ 0.2612 /kW/day Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0021 /kW.h	-\$34.60	-\$46.14	-\$57.67	
6	Net DT Charges		\$211.78	\$279.09	\$346.39	
Row 4 + Row 5						
7	Combined Rate: January 1, 2010		\$605.51	\$801.25	\$996.98	
Row 3 + Row 6						
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		\$425.93	\$565.09	\$704.24	
Row 8 + Row 9						
11	AE Final DT Base Rates	Customer Charge \$ 0.3258 /day Energy Charge Blk 1 \$ 0.0370 /kW.h Energy Charge Blk 2 \$ 0.0042 /kW.h	\$252.80	\$333.81	\$414.82	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge \$ 0.2703 /kW/day Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0021 /kW.h	-\$34.60	-\$46.14	-\$57.67	
13	Net DT Charges		\$218.20	\$287.68	\$357.15	
Row 11 + Row 12						
14	Predicted Combined Rate: June 1, 2010		\$644.13	\$852.76	\$1,061.40	
Row 10 + Row 13						
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		\$489.66	\$650.06	\$810.46	
Row 15 + Row 16						
18	AE Final DT Base Rates	Customer Charge \$ 0.3258 /day Energy Charge Blk 1 \$ 0.0370 /kW.h Energy Charge Blk 2 \$ 0.0042 /kW.h	\$252.80	\$333.81	\$414.82	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge \$ 0.2703 /kW/day Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00089 /kW.h	-\$16.42	-\$21.90	-\$27.37	
20	Net DT Charges		\$236.38	\$311.92	\$387.45	
Row 18 + Row 19						
21	Predicted Combined Rate: August 1, 2010		\$726.04	\$961.97	\$1,197.91	
Row 17 + Row 20						
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		\$489.66	\$650.06	\$810.46	
Row 22 + Row 23						
25	AE Proposed DT Base Rates	Customer Charge \$ 0.3406 /day Energy Charge Blk 1 \$ 0.0379 /kW.h Energy Charge Blk 2 \$ 0.0037 /kW.h	\$264.61	\$349.40	\$434.20	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Demand Charge \$ 0.2924 /kW/day Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00089 /kW.h	-\$16.42	-\$21.90	-\$27.37	
27	Net DT Charges		\$248.18	\$327.51	\$406.83	
Row 25 + Row 26						
28	Predicted Combined Rate: January 1, 2011		\$737.84	\$977.56	\$1,217.29	
Row 24 + Row 27						
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference %	\$38.62 6%	\$51.52 6%	\$64.42 6%
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference %	\$81.91 13%	\$109.21 13%	\$136.51 13%
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference %	\$11.80 2%	\$15.59 2%	\$19.38 2%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

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	
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07014 /kW.h Energy Admin Fee \$ 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 \$ 0.2592 /day Energy Charge \$ 0.0049 /kW.h Demand Charge \$ 0.2079 /kW/day	\$1,433.11	\$1,892.32	\$2,351.54	
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	\$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 Energy Admin Fee \$ 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 \$ 0.2380 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 0.2145 /kW/day	\$1,465.69	\$1,937.28	\$2,408.86	
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	\$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 Energy Admin Fee \$ 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 \$ 0.2380 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 0.2145 /kW/day	\$1,465.69	\$1,937.28	\$2,408.86	
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	\$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 Energy Admin Fee \$ 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 \$ 0.3217 /day Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 0.2709 /kW/day	\$1,840.34	\$2,430.84	\$3,021.34	
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	\$1,798.24	\$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%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.5 - Example Rate Rider Effects: REA Irrigation Pumping Service

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				REA Irrigation Pumping Service Class		
				Consumption Levels Cost per Customer (\$/season)		
Row	Rate Component	Rate	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	
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07014 /kW.h Energy Admin Fee \$ 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		\$681.19	\$886.00	\$1,090.81	
		Row 1 + Row 2				
4	AE Interim DT Base Rates	Customer Charge \$ 0.2592 /day Energy Charge \$ 0.0049 /kW.h Demand Charge \$ 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 -\$ 0.00429 /kW.h Rider G -\$ 0.0042 /kW.h	-\$73.93	-\$98.58	-\$123.22	
6	Net DT Charges		\$803.20	\$1,052.45	\$1,301.69	
		Row 4 + Row 5				
7	Combined Rate: January 1, 2010		\$1,484.40	\$1,938.45	\$2,392.51	
		Row 3 + Row 6				
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07311 /kW.h Energy Admin Fee \$ 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		\$707.21	\$920.69	\$1,134.17	
		Row 8 + Row 9				
11	AE Final DT Base Rates	Customer Charge \$ 0.2380 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 -\$ 0.00429 /kW.h Rider G -\$ 0.0042 /kW.h	-\$73.93	-\$98.58	-\$123.22	
13	Net DT Charges		\$868.53	\$1,141.06	\$1,413.59	
		Row 11 + Row 12				
14	Predicted Combined Rate: June 1, 2010		\$1,575.74	\$2,061.75	\$2,547.76	
		Row 10 + Row 13				
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08542 /kW.h Energy Admin Fee \$ 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		\$815.05	\$1,064.47	\$1,313.90	
		Row 15 + Row 16				
18	AE Final DT Base Rates	Customer Charge \$ 0.2380 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 -\$ 0.00215 /kW.h Rider G -\$ 0.00266 /kW.h	-\$42.10	-\$56.14	-\$70.17	
20	Net DT Charges		\$900.36	\$1,183.50	\$1,466.64	
		Row 18 + Row 19				
21	Predicted Combined Rate: August 1, 2010		\$1,715.40	\$2,247.97	\$2,780.54	
		Row 17 + Row 20				
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08542 /kW.h Energy Admin Fee \$ 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		\$815.05	\$1,064.47	\$1,313.90	
		Row 22 + Row 23				
25	AE Proposed DT Base Rates	Customer Charge \$ 0.3217 /day Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 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 -\$ 0.00215 /kW.h Rider G -\$ 0.00266 /kW.h	-\$42.10	-\$56.14	-\$70.17	
27	Net DT Charges		\$1,090.66	\$1,431.26	\$1,771.86	
		Row 25 + Row 26				
28	Predicted Combined Rate: January 1, 2011		\$1,905.70	\$2,495.73	\$3,085.76	
		Row 24 + Row 27				
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7				
			difference %	\$91.34 6%	\$123.30 6%	
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14				
			difference %	\$139.67 9%	\$186.22 9%	
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21				
			difference %	\$190.30 11%	\$247.76 11%	

**ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728**

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 Energy Admin Fee \$ 18.03 /month	\$854.10	\$1,159.05	\$1,443.45	
2	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
3	2010 Energy Related Charge		\$854.10	\$1,159.05	\$1,443.45	
		Row 1 + Row 2				
4	AE Interim DT Base Rates	Customer Charge \$ 2.3340 /day Energy Charge \$ 0.0048 /kW.h Demand Charge Blk 1 \$ 0.3186 /kW/day Demand Charge Blk 2 \$ 0.3051 /kW/day	\$606.48	\$627.84	\$733.78	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00420 /kW.h Rider G \$ 0.0018 /kW.h	-\$29.04	-\$39.63	-\$49.50	
6	Net DT Charges		\$577.44	\$588.21	\$684.28	
		Row 4 + Row 5				
7	Combined Rate: January 1, 2010		\$1,431.54	\$1,747.27	\$2,127.73	
		Row 3 + Row 6				
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07323 /kW.h Energy Admin Fee \$ 18.03 /month	\$911.44	\$1,237.31	\$1,541.21	
9	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
10	2010 Energy Related Charge		\$911.44	\$1,237.31	\$1,541.21	
		Row 8 + Row 9				
11	AE Final DT Base Rates	Customer Charge \$ 2.3495 /day Energy Charge \$ 0.0042 /kW.h Demand Charge Blk 1 \$ 0.3434 /kW/day Demand Charge Blk 2 \$ 0.3275 /kW/day	\$636.83	\$655.52	\$765.66	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00420 /kW.h Rider G \$ 0.0018 /kW.h	-\$29.04	-\$39.63	-\$49.50	
13	Net DT Charges		\$607.79	\$615.89	\$716.16	
		Row 11 + Row 12				
14	Predicted Combined Rate: June 1, 2010		\$1,519.23	\$1,853.20	\$2,257.37	
		Row 10 + Row 13				
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08493 /kW.h Energy Admin Fee \$ 18.03 /month	\$1,054.18	\$1,432.11	\$1,784.57	
16	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
17	2010 Energy Related Charge		\$1,054.18	\$1,432.11	\$1,784.57	
		Row 15 + Row 16				
18	AE Final DT Base Rates	Customer Charge \$ 2.3495 /day Energy Charge \$ 0.0042 /kW.h Demand Charge Blk 1 \$ 0.3434 /kW/day Demand Charge Blk 2 \$ 0.3275 /kW/day	\$636.83	\$655.52	\$765.66	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G \$ 0.00073 /kW.h	-\$16.67	-\$22.75	-\$28.42	
20	Net DT Charges		\$620.16	\$632.77	\$737.25	
		Row 18 + Row 19				
21	Predicted Combined Rate: August 1, 2010		\$1,674.33	\$2,064.88	\$2,521.82	
		Row 17 + Row 20				
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08493 /kW.h Energy Admin Fee \$ 18.03 /month	\$1,054.18	\$1,432.11	\$1,784.57	
23	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h	\$0.00	\$0.00	\$0.00	
24	2011 Energy Related Charge		\$1,054.18	\$1,432.11	\$1,784.57	
		Row 22 + Row 23				
25	AE Proposed DT Base Rates	Customer Charge \$ 2.4561 /day Energy Charge \$ 0.0036 /kW.h Demand Charge Blk 1 \$ 0.3735 /kW/day Demand Charge Blk 2 \$ 0.3592 /kW/day	\$678.39	\$694.60	\$810.56	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G \$ 0.00073 /kW.h	-\$16.67	-\$22.75	-\$28.42	
27	Net DT Charges		\$661.72	\$671.85	\$782.14	
		Row 25 + Row 26				
28	Predicted Combined Rate: January 1, 2011		\$1,715.89	\$2,103.96	\$2,566.72	
		Row 24 + Row 27				
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference %	\$87.68 6%	\$105.93 6%	\$129.64 6%
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference %	\$155.11 10%	\$211.68 11%	\$264.45 12%
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference %	\$41.56 2%	\$39.08 2%	\$44.90 2%

**ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728**

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

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Large General Service Class Consumption Levels Cost per Customer (\$/month)		
Row	Rate Component	Rate	Rate	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
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.06853 /kW.h Energy Admin Fee \$ 18.03 /month		\$45,042.24	\$60,050.31	\$75,058.38
2	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
3	2010 Energy Related Charge			\$45,042.24	\$60,050.31	\$75,058.38
Row 1 + Row 2						
4	AE Interim DT Base Rates	Customer Charge \$ 2.3340 /day Energy Charge \$ 0.0048 /kW.h Demand Charge Blk 1 \$ 0.3186 /kW/day Demand Charge Blk 2 \$ 0.3051 /kW/day Balancing Pool Refund Rider -\$ 0.00420 /kW.h Rider G \$ 0.0018 /kW.h		\$17,155.62	\$22,783.32	\$28,411.02
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)			-\$1,563.66	-\$2,084.88	-\$2,606.10
6	Net DT Charges			\$15,591.96	\$20,698.44	\$25,804.92
Row 4 + Row 5						
7	Combined Rate: January 1, 2010			\$60,634.20	\$80,748.75	\$100,863.30
Row 3 + Row 6						
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07323 /kW.h Energy Admin Fee \$ 18.03 /month		\$48,130.14	\$64,167.51	\$80,204.88
9	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
10	2010 Energy Related Charge			\$48,130.14	\$64,167.51	\$80,204.88
Row 8 + Row 9						
11	AE Final DT Base Rates	Customer Charge \$ 2.3495 /day Energy Charge \$ 0.0042 /kW.h Demand Charge Blk 1 \$ 0.3434 /kW/day Demand Charge Blk 2 \$ 0.3275 /kW/day Balancing Pool Refund Rider -\$ 0.00420 /kW.h Rider G \$ 0.0018 /kW.h		\$17,805.89	\$23,638.19	\$29,470.49
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)			-\$1,563.66	-\$2,084.88	-\$2,606.10
13	Net DT Charges			\$16,242.23	\$21,553.31	\$26,864.39
Row 11 + Row 12						
14	Predicted Combined Rate: June 1, 2010			\$64,372.37	\$85,720.82	\$107,069.27
Row 10 + Row 13						
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08493 /kW.h Energy Admin Fee \$ 18.03 /month		\$55,817.04	\$74,416.71	\$93,016.38
16	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
17	2010 Energy Related Charge			\$55,817.04	\$74,416.71	\$93,016.38
Row 15 + Row 16						
18	AE Final DT Base Rates	Customer Charge \$ 2.3495 /day Energy Charge \$ 0.0042 /kW.h Demand Charge Blk 1 \$ 0.3434 /kW/day Demand Charge Blk 2 \$ 0.3275 /kW/day Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G \$ 0.00073 /kW.h		\$17,805.89	\$23,638.19	\$29,470.49
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)			-\$897.62	-\$1,196.83	-\$1,496.03
20	Net DT Charges			\$16,908.27	\$22,441.36	\$27,974.45
Row 18 + Row 19						
21	Predicted Combined Rate: August 1, 2010			\$72,725.31	\$96,858.07	\$120,990.83
Row 17 + Row 20						
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08493 /kW.h Energy Admin Fee \$ 18.03 /month		\$55,817.04	\$74,416.71	\$93,016.38
23	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
24	2011 Energy Related Charge			\$55,817.04	\$74,416.71	\$93,016.38
Row 22 + Row 23						
25	AE Proposed DT Base Rates	Customer Charge \$ 2.4561 /day Energy Charge \$ 0.0036 /kW.h Demand Charge Blk 1 \$ 0.3735 /kW/day Demand Charge Blk 2 \$ 0.3592 /kW/day Balancing Pool Refund Rider -\$ 0.00210 /kW.h Rider G \$ 0.00073 /kW.h		\$18,844.54	\$25,029.77	\$31,215.00
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)			-\$897.62	-\$1,196.83	-\$1,496.03
27	Net DT Charges			\$17,946.92	\$23,832.94	\$29,718.97
Row 25 + Row 26						
28	Predicted Combined Rate: January 1, 2011			\$73,763.96	\$98,249.65	\$122,735.35
Row 24 + Row 27						
Comparisons						
Combined Rate (January 1, 2010 - June 1, 2010)		Row 14 vs Row 7	difference %	\$3,738.17 6%	\$4,972.07 6%	\$6,205.97 6%
Combined Rate (June 1, 2010 - August 1, 2010)		Row 21 vs Row 14	difference %	\$8,352.94 13%	\$11,137.25 13%	\$13,921.57 13%
Combined Rate (August 1, 2010 - January 1, 2011)		Row 28 vs Row 21	difference %	\$1,038.65 1%	\$1,391.58 1%	\$1,744.52 1%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.8 - Example Rate Rider Effects: Small Oilfield Class - RRO Eligible

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Small Oilfield Class Consumption Levels Cost per Customer (\$/month)		
				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
Row	Rate Component	Rate				
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.06807 /kW.h Energy Admin Fee \$ 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 \$ 1.3607 /day Energy Charge \$ 0.0049 /kW.h Demand Charge \$ 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 \$ 0.07236 /kW.h Energy Admin Fee \$ 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 \$ 1.3599 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 \$ 0.08452 /kW.h Energy Admin Fee \$ 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 \$ 1.3599 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 \$ 0.08452 /kW.h Energy Admin Fee \$ 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 \$ 1.4216 /day Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 0.6117 /kW/day	\$342.29	\$442.18	\$542.06	
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	\$321.30	\$414.19	\$507.07	
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$885.48	\$1,163.46	\$1,441.44	
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference \$33.44 %	\$44.60 5%	\$55.76 5%	
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference \$105.81 %	\$141.08 14%	\$176.35 14%	
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference \$15.22 %	\$19.67 2%	\$24.13 2%	

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.9 - Example Rate Rider Effects: Small Oilfield 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 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
Row	Rate Component	Rate				
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.06807 /kW.h Energy Admin Fee \$ 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 \$ 1.3607 /day Energy Charge \$ 0.0049 /kW.h Demand Charge \$ 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 \$ 0.07236 /kW.h Energy Admin Fee \$ 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 \$ 1.3599 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 \$ 0.08452 /kW.h Energy Admin Fee \$ 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 \$ 1.3599 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 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 \$ 0.08452 /kW.h Energy Admin Fee \$ 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 \$ 1.4216 /day Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 0.6117 /kW/day	\$342.29	\$442.18	\$542.06	
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	\$321.30	\$414.19	\$507.07	
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$885.48	\$1,163.46	\$1,441.44	
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference \$33.44 %	\$44.60 5%	\$55.76 5%	
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference \$105.81 %	\$141.08 14%	\$176.35 14%	
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference \$15.22 %	\$19.67 2%	\$24.13 2%	

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.10 - Example Rate Rider Effects: REA Farm Service Class (Pooled) - RRO Eligible

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				REA Farm Service Class Consumption Levels Cost per Customer (\$/month)		
Row	Rate Component	Rate		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
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07014 /kW.h Energy Admin Fee \$ 8.22 /month		\$61.18	\$96.25	\$131.32
2	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
3	2010 Energy Related Charge			\$61.18	\$96.25	\$131.32
Row 1 + Row 2						
4	AE Interim DT Base Rates	Customer Charge \$ 0.2916 /day Energy Charge \$ 0.0048 /kW.h Demand Charge \$ 0.1383 /kVA/day		\$43.49	\$45.89	\$48.29
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00425 /kW.h -\$ 0.0010 /kW.h		-\$3.93	-\$6.54	-\$9.14
6	Net DT Charges			\$39.56	\$39.35	\$39.15
Row 4 + Row 5						
7	Combined Rate: January 1, 2010			\$100.73	\$135.60	\$170.46
Row 3 + Row 6						
Effective Date: June 1, 2010						
8	Forecast Energy Rate: June 1, 2010	Energy Charge \$ 0.07520 /kW.h Energy Admin Fee \$ 8.22 /month		\$65.00	\$102.60	\$140.20
9	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
10	2010 Energy Related Charge			\$65.00	\$102.60	\$140.20
Row 8 + Row 9						
11	AE Final DT Base Rates	Customer Charge \$ 0.2883 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 0.1458 /kVA/day		\$44.70	\$46.85	\$49.00
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00425 /kW.h -\$ 0.0010 /kW.h		-\$3.93	-\$6.54	-\$9.14
13	Net DT Charges			\$40.77	\$40.31	\$39.86
Row 11 + Row 12						
14	Predicted Combined Rate: June 1, 2010			\$105.76	\$142.91	\$180.05
Row 10 + Row 13						
Effective Date: August 1, 2010						
15	Forecast Energy Rate: August 1, 2010	Energy Charge \$ 0.08824 /kW.h Energy Admin Fee \$ 8.22 /month		\$74.84	\$118.96	\$163.08
16	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
17	2010 Energy Related Charge			\$74.84	\$118.96	\$163.08
Row 15 + Row 16						
18	AE Final DT Base Rates	Customer Charge \$ 0.2883 /day Energy Charge \$ 0.0043 /kW.h Demand Charge \$ 0.1458 /kVA/day		\$44.70	\$46.85	\$49.00
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00212 /kW.h \$ 0.00132 /kW.h		-\$0.61	-\$1.01	-\$1.41
20	Net DT Charges			\$44.09	\$45.84	\$47.59
Row 18 + Row 19						
21	Predicted Combined Rate: August 1, 2010			\$118.94	\$164.80	\$210.67
Row 17 + Row 20						
Effective Date: January 1, 2011						
22	Forecast Energy Rate: January 1, 2011	Energy Charge \$ 0.08824 /kW.h Energy Admin Fee \$ 8.22 /month		\$74.84	\$118.96	\$163.08
23	+/- RRO Deferral	RRO Deferral \$ 0.0000 /kW.h		\$0.00	\$0.00	\$0.00
24	2011 Energy Related Charge			\$74.84	\$118.96	\$163.08
Row 22 + Row 23						
25	AE Proposed DT Base Rates	Customer Charge \$ 0.3014 /day Energy Charge \$ 0.0037 /kW.h Demand Charge \$ 0.1589 /kVA/day		\$47.58	\$49.42	\$51.25
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00212 /kW.h \$ 0.00132 /kW.h		-\$0.61	-\$1.01	-\$1.41
27	Net DT Charges			\$46.97	\$48.41	\$49.85
Row 25 + Row 26						
28	Predicted Combined Rate: January 1, 2011			\$121.81	\$167.37	\$212.93
Row 24 + Row 27						
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	\$2.88	\$2.56	\$2.25
			%	2%	2%	1%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Appendix B.11 - Example Rate Rider Effects: Farm 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				REA Farm Service Class Consumption Levels Cost per Customer (\$/month)		
Row	Rate Component	Rate	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	
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.07014 /kW.h Energy Admin Fee \$ 8.22 /month	\$61.18	\$96.25	\$131.32	
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 Energy Charge \$ 0.0095 /kW.h Demand Charge \$ 0.1680 /kVA/day	\$60.87	\$65.62	\$70.37	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00425 /kW.h -\$ 0.0037 /kW.h	-\$6.00	-\$9.98	-\$13.95	
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 Energy Admin Fee \$ 8.22 /month	\$65.00	\$102.60	\$140.20	
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 Energy Charge \$ 0.0098 /kW.h Demand Charge \$ 0.1724 /kVA/day	\$62.51	\$67.41	\$72.31	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00425 /kW.h -\$ 0.0037 /kW.h	-\$6.00	-\$9.98	-\$13.95	
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 Energy Admin Fee \$ 8.22 /month	\$74.84	\$118.96	\$163.08	
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 Energy Charge \$ 0.0098 /kW.h Demand Charge \$ 0.1724 /kVA/day	\$62.51	\$67.41	\$72.31	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00212 /kW.h -\$ 0.00016 /kW.h	-\$1.72	-\$2.86	-\$3.99	
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 Energy Admin Fee \$ 8.22 /month	\$74.84	\$118.96	\$163.08	
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 \$ 0.5688 /day Energy Charge \$ 0.0094 /kW.h Demand Charge \$ 0.1868 /kVA/day	\$66.20	\$70.91	\$75.63	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider G -\$ 0.00212 /kW.h -\$ 0.00016 /kW.h	-\$1.72	-\$2.86	-\$3.99	
27	Net DT Charges	Row 25 + Row 26	\$64.48	\$68.06	\$71.63	
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$139.32	\$187.02	\$234.71	
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference \$5.46 %	\$8.14 5%	\$10.82 6%	
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference \$14.13 %	\$23.49 12%	\$32.84 17%	
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference \$3.69 %	\$3.50 2%	\$3.32 1%	

**ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728**

Appendix B.12 - Example Rate Rider Effects: Street Light Service Class D61 Option A

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Street Light Service Class Consumption Levels Cost per Customer (\$/month)		
				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
Row	Rate Component	Rate				
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.05837 /kW.h Energy Admin Fee \$ 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 \$ 0.3075 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 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 -\$ 0.00419 /kW.h Rider G -\$ 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 \$ 0.04120 /kW.h Energy Admin Fee \$ 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 \$ 0.3054 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 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 -\$ 0.00419 /kW.h Rider G -\$ 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 \$ 0.05392 /kW.h Energy Admin Fee \$ 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 \$ 0.3054 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 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 -\$ 0.00209 /kW.h Rider G -\$ 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 \$ 0.05392 /kW.h Energy Admin Fee \$ 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 \$ 0.3840 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 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 -\$ 0.00209 /kW.h Rider G -\$ 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%

**ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728**

Appendix B.13 - Example Rate Rider Effects: Private Lighting Service Class D63 Option A

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Private Street Light Service Class		
				Consumption Levels Cost per Customer (\$/month)		
Row	Rate Component	Rate	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	
Effective Date: January 1, 2010						
1	Energy Rate: January 1, 2010	Energy Charge \$ 0.05837 /kW.h Energy Admin Fee \$ 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 \$ 0.3668 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 0.0004 /W/day	\$12.08	\$13.70	\$15.32	
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0007 /W/day	-\$2.19	-\$5.47	-\$8.75	
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 Energy Admin Fee \$ 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 \$ 0.3686 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 0.0004 /W/day	\$12.20	\$13.91	\$15.62	
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00422 /kW.h Rider G -\$ 0.0007 /W/day	-\$2.19	-\$5.47	-\$8.75	
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 Energy Admin Fee \$ 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 \$ 0.3686 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 0.0004 /W/day	\$12.20	\$13.91	\$15.62	
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00004 /W/day	-\$0.19	-\$0.48	-\$0.77	
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 Energy Admin Fee \$ 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 \$ 0.3853 /day Energy Charge \$ 0.0000 /kW.h Demand Charge \$ 0.0004 /W/day	\$12.77	\$14.57	\$16.38	
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider -\$ 0.00211 /kW.h Rider G -\$ 0.00004 /W/day	-\$0.19	-\$0.48	-\$0.77	
27	Net DT Charges	Row 25 + Row 26	\$12.57	\$14.09	\$15.62	
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27	\$17.07	\$21.45	\$25.77	
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7	difference %	-\$0.49 -3%	-\$1.31 -8%	-\$2.11 -12%
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14	difference %	\$2.44 17%	\$6.11 42%	\$9.77 64%
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21	difference %	\$0.57 3%	\$0.67 3%	\$0.76 3%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

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

GST not included

Includes Cost of Energy in Effective Rate Schedules at the Time or Flow-Through Charge Amount or Forecast of Energy Charge				Large General Service Class Consumption Levels Cost per Customer (\$/month)		
Note: Assume coincident metered demand equals to 50% of the metered demand				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
Row	Rate Component	Rate				
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			
		POD Charge (1st 7.5MW)	\$ 3.96 /kW/month			
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge fixed	\$ 7,030.00 /month	-\$3,349.61	-\$4,466.14	-\$5,582.68
		Balancing Pool Refund Rider	-\$ 0.0040 /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			
		POD Charge (1st 7.5MW)	\$ 3.96 /kW/month			
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge fixed	\$ 7,030.00 /month	-\$3,349.61	-\$4,466.14	-\$5,582.68
		Balancing Pool Refund Rider	-\$ 0.0040 /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			
		POD Charge (1st 7.5MW)	\$ 3.96 /kW/month			
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge fixed	\$ 7,030.00 /month	-\$1,512.02	-\$2,016.02	-\$2,520.03
		Balancing Pool Refund Rider	-\$ 0.0020 /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	\$20,881.13	\$24,926.16	\$28,971.19
		Energy Charge	\$ 0.0045 /kW.h			
		Demand Charge Blk 1	\$ 0.18 /kW/day			
		Demand Charge Blk 2	\$ 0.06 /kW/day			
		POD Charge (1st 7.5MW)	\$ 3.96 /kW/month			
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	POD Charge fixed	\$ 7,030.00 /month	-\$1,512.02	-\$2,016.02	-\$2,520.03
		Balancing Pool Refund Rider	-\$ 0.0020 /kW.h			
		Rider G	\$ 0.00003 /kW.h			
27	Net DT Charges	Row 25 + Row 26		\$19,369.11	\$22,910.13	\$26,451.16
28	Predicted Combined Rate: January 1, 2011	Row 24 + Row 27		\$84,485.98	\$109,726.62	\$134,967.26
Comparisons						
	Combined Rate (January 1, 2010 - June 1, 2010)	Row 14 vs Row 7		difference %	\$3,925.05 6%	\$5,125.90 6%
	Combined Rate (June 1, 2010 - August 1, 2010)	Row 21 vs Row 14		difference %	\$10,805.64 15%	\$14,407.52 15%
	Combined Rate (August 1, 2010 - January 1, 2011)	Row 28 vs Row 21		difference %	\$75.04 0%	\$75.04 0%

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

AUC-AE-04 Attachment 10

Appendix B-15
 Bill Comparisons - Rate Impact
 Page 16 of 18

Energy Rates Used in Appendix B-1 to B-14

	Admin. Charges	Cost of Energy for			
	Fixed (\$ / Day)	January 2010 (\$ / kWh)	June 2010 (\$ / kWh)	August 2010 (\$ / kWh)	January 2011 (\$ / 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

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

	A	B	C	D	E	F	G	H	I	J
1	D Tariff Rates									
	2011 proposed interim (Oct 18,2010)									
76	D33									
77										
78		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
79	T		15.68 ¢/kW/day	18.22 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h		should be avg. DOS rate		
80	D	14.90 ¢/day	21.67 ¢/kW/day	17.00 ¢/kW/day				20.17 ¢/kV.A/day		
81	S	230.72 ¢/day		0.70 ¢/kW/day						
82	Total	245.61 ¢/day	37.35 ¢/kW/day	35.92 ¢/kW/day	0.36 ¢/kW.h	0.36 ¢/kW.h		20.17 ¢/kV.A/day		
83										
84										
85	T33									
86										
87		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
88	T									
89	d		1.46 ¢/kW/day					20.17 ¢/kV.A/day		
90	s		9.98 ¢/kW/day							
91	Total	0.00 ¢/day	11.44 ¢/kW/day	0.00 ¢/kW/day	0.00 ¢/kW.h	0.00 ¢/kW.h		20.17 ¢/kV.A/day		
92										
93										
94	D41									
95										
96		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
97	T		13.32 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
98	D	51.51 ¢/day	47.85 ¢/kW/day					44.59 ¢/kV.A/day		
99	S	90.66 ¢/day								
100	Total	142.16 ¢/day	61.17 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h		44.59 ¢/kV.A/day		
101										
102										
103	D51									
104										
105		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
106	T		7.02 ¢/kV.A/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
107	D (O&M Pool)		8.87 ¢/kV.A/day					0.00 ¢/kV.A/day		
108	S	30.14 ¢/day								
109	Total	30.14 ¢/day	15.89 ¢/kV.A/day		0.37 ¢/kW.h	0.37 ¢/kW.h		0.00 ¢/kV.A/day		
110										
111										
112	D52									
113										
114		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
115	T		7.02 ¢/kV.A/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
116	D							0.00 ¢/kV.A/day		
117	S	25.51 ¢/day								
118	Total	25.51 ¢/day	7.02 ¢/kV.A/day		0.37 ¢/kW.h	0.37 ¢/kW.h		0.00 ¢/kV.A/day		
119										
120										
121	D56									
122										
123		Customer	Demand 1	Demand 2	Energy 1	Energy 2		PF		
124	T		7.02 ¢/kW/day		0.37 ¢/kW.h	0.37 ¢/kW.h				
125	D	26.74 ¢/day	11.66 ¢/kW/day		0.57 ¢/kW.h	0.57 ¢/kW.h		0.00 ¢/kV.A/day		
126	S	30.14 ¢/day								
127	Total	56.88 ¢/day	18.68 ¢/kW/day		0.94 ¢/kW.h	0.94 ¢/kW.h		0.00 ¢/kV.A/day		
128										
129										
130	D61									
131										
132		Customer	Demand 1							
133	T		0.017 ¢/W/day							
134	D - Option A	31.15 ¢/fixture/day	0.031 ¢/W/day							
135	D - Option B	85.51 ¢/fixture/day	0.031 ¢/W/day							
136	D - Option C	41.11 ¢/fixture/day	0.031 ¢/W/day							
137	D - Option D									
138	D - Option E	31.15 ¢/fixture/day	0.031 ¢/W/day							
139	S	7.25 ¢/fixture/day								
140	Total									
141										
142										
143	D63									
144										
145		Customer	Demand 1							
146	T		0.019 ¢/W/day							
147	D - Option A	25.30 ¢/fixture/day	0.022 ¢/W/day							
148	D - Option B	40.80 ¢/fixture/day	0.022 ¢/W/day							
149	D - Option C	13.43 ¢/fixture/day	0.006 ¢/W/day							
150	D - Option D	26.85 ¢/fixture/day	0.022 ¢/W/day							
151	D - Option E	17.56 ¢/fixture/day	0.022 ¢/W/day							
152	S	13.23 ¢/fixture/day								
153	Total									

ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728

Determination of Adjustment Factors (for Rates Jan. 1 - Dec. 31, 2011) Updated for Amended 2010 Final Tariff Application

Table 1									Table 2					
Scaling Factor Determination									Breakdown of Transmission Rate					
All Revenue in \$'000's									All Revenue in \$'000's					
Year	Column No.	Scenario	(A)	(B)	(C)	(D)	(E)		Total	Based on 2010 Final Rate Application				
			Trans Demand Revenue	Trans Energy Revenue	Trans Demand Revenue T31	Trans Energy Revenue T31	Dist Revenue	Power Factor		Demand Related Portion	Energy Related Portion	Total Trans Revenue		
Before Scaling														
2011		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)						D11	14,240	4,533	18,774	
		Adj for D61	(88)	88						D61	227	88	315	
		Adj for D63	(14)	14						D63	35	14	48	
	(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	292,619	5,408	466,621					
	(3)	Scaling Factor	1.151720	0.863227	1.000000	1.000000	1.045384	1.000	1.052680					
		D25 & D26					1.351695		1.250000					
	D61					1.257405		1.250000						
After Scaling														
2011		12 mo. 2010 Final rates after scaling	90,536	48,210	23,459	5,980	282,899	5,408	456,493					
		D25 & D26	60	10			129		200					
		D61	338				9,591		9,929					
		Adj for D11	16,401	(16,401)						D11	16,401	3,913	20,314.33933	1.082057
		Adj for D61	(76)	76						D61	261	76	337.73300	1.070896
		Adj for D63	(12)	12						D63	40	12	51.92197	1.071095
(4)	Total	107,248	31,907	23,459	5,980	292,619	5,408	466,621					(E)	
									Factored Future Costs for 2011					
									Scaling Factor					

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.

**ATCO Electric
2011 Interim Tariff Application
Proceeding ID 918, No. 1606728**

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 Proposed RR \$ million
Transmission	\$336.6	\$86.6	(\$54.3)	\$32.2	37%	\$282.2
Distribution	\$493.6	\$33.4	(\$10.0)	\$23.4	70% *	\$483.5

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

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Alberta Utilities Commission (AUC)
Round 1**

Received: November 18, 2010

AUC-AE-5

Reference: Application, page 9, lines 22-25

Issue/Sub-Issue: Proposed Revision Method for AE Rider B – Balancing Pool Adjustment

Quote: *“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.”*

Preamble: The Commission requires further information.

Request:

- (a) Please explain what methodology and process would be followed under AE’s proposal, including the communication of rate schedule changes to customers/parties.
- (b) Please identify and explain what timing deadline under AE’s proposed method would be required to “still allow” AE to properly test and implement a change to Rider B resulting from a change to the AESO Rider F – Balancing Pool Consumer Allocation Rider, given that the Commission would still need to approve the AESO Rider F change.
- (c) Please discuss whether AE has received any indication at the present time that the AESO Rider F may be changing effective January 1, 2011, and identify the source.

Response:

- (a) Under this proposal, ATCO Electric would submit a letter and rate change sheet to the AUC upon notification from the AESO that the Balancing Pool Consumer Allocation Rider has changed. ATCO Electric would reference its 2011 Interim Tariff Application and request that the Rider B be approved as part of the 2011 Interim Tariffs effective January 1, 2011. If the Balancing Pool Consumer Allocation Rider does not occur until after January 1, ATCO Electric would file a separate Application seeking approval to amend its Rider B.
- (b) As with this 2011 Interim Tariff Application, ATCO Electric would require an AUC decision by December 15, 2010, to properly test and implement a change to Rider B effective for January 1, 2011.
- (c) On November 22, 2010, the Balancing Pool announced that the allocation to power consumers will be set at \$2.00 per MWh. Notwithstanding, there has not yet been any notification from the AESO regarding its Rider F amounts effective January 1, 2011. Upon notification of AESO's Rider F application for 2011, ATCO Electric will, in turn, file an application to the AUC requesting approval of its Balancing Pool Consumer Allocation Rider B amounts effective January 1, 2011.

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Alberta Utilities Commission (AUC)
Round 1**

Received: November 18, 2010

AUC-AE-6

Reference: Application, Appendix B-1 and Notice – Summary of Rate Impact to Typical Bills

Issue/Sub-Issue: Differences in Bill Impact Comparison Information

Preamble: The Commission requires additional information.

Request:

- (a) Please reconcile and explain the differences shown for each rate class for the August 1, 2010 and the January 1, 2011 bill impact information and confirm which source of information is correct.
- (b) If Appendix B-1 should be revised, please provide updated information.

Response:

- (a) The difference between the rate impact set out in Appendix B-1 and the rate impact illustrated in the Notice is based on the estimated retail rates assumed for the period. The retail rates shown in Appendix B-1 include administration charges (i.e., the fixed component of the energy charge) that a typical customer might see on its bill. The information provided in the Notice was intended to illustrate a typical 'energy' price for the assumed period as energy charges may vary between retail providers. ATCO Electric has updated the rate impact information provided in the Notice to match the rate impact information provided in Appendix B-1.

- (b) Below is the Summary of Rate Impact to Typical Bills from the Notice revised to show consistent energy charges (both fixed and variable) as set out in Appendix B-1.

Summary of Rate Impact to Typical Bills

		<u>August 1, 2010</u>	<u>January 1, 2011</u>	<u>\$ Impact</u>	<u>% Impact</u>
D11 Residential @ 600 kWh	Total wires	\$ 66.04	\$ 71.02	\$ 4.98	8%
	Retail	\$ 60.41	\$ 60.41	\$ -	0%
	Total Bill	\$ 126.46	\$ 131.43	\$ 4.98	4%
D21 Commercial 20 kW; 7,300 kWh	Total wires	\$ 311.92	\$ 333.61	\$ 21.70	7%
	Retail	\$ 650.06	\$ 650.06	\$ -	0%
	Total Bill	\$ 961.97	\$ 983.67	\$ 21.70	2%
D25 Irrigation 40 kW; 11,680 kWh	Total wires	\$ 263.71	\$ 332.90	\$ 69.19	26%
	Retail	\$ 149.23	\$ 149.23	\$ -	0%
	Total Bill	\$ 412.94	\$ 482.13	\$ 69.19	17%
D31 Industrial 50 kW; 16,650 kWh	Total wires	\$ 632.77	\$ 681.25	\$ 48.49	8%
	Retail	\$ 1,432.11	\$ 1,432.11	\$ -	0%
	Total Bill	\$ 2,064.88	\$ 2,113.37	\$ 48.49	2%
D41 Oilfield 20 kW; 8,760 kWh	Total wires	\$ 394.51	\$ 421.96	\$ 27.45	7%
	Retail	\$ 749.28	\$ 749.28	\$ -	0%
	Total Bill	\$ 1,143.79	\$ 1,171.24	\$ 27.45	2%
D51 REA Pooled 7.5 kVA; 1,255 kWh	Total wires	\$ 45.84	\$ 49.09	\$ 3.25	7%
	Retail	\$ 118.96	\$ 118.96	\$ -	0%
	Total Bill	\$ 164.80	\$ 168.05	\$ 3.25	2%
D56 Farm 7.5 kVA; 1,255 kWh	Total wires	\$ 64.56	\$ 69.25	\$ 4.69	7%
	Retail	\$ 118.96	\$ 118.96	\$ -	0%
	Total Bill	\$ 183.52	\$ 188.21	\$ 4.69	3%
D61 Street Lights 250 Watts	Total wires	\$ 11.55	\$ 14.47	\$ 2.91	25%
	Retail	\$ 7.35	\$ 7.35	\$ -	0%
	Total Bill	\$ 18.91	\$ 21.82	\$ 2.91	15%
D63 Private Lights 250 Watts	Total wires	\$ 13.43	\$ 14.40	\$ 0.98	7%
	Retail	\$ 7.35	\$ 7.35	\$ -	0%
	Total Bill	\$ 20.78	\$ 21.76	\$ 0.98	5%
T31 T Connect 2 MW; 1,022 MWh	Total wires	\$ 22,835.10	\$ 22,950.60	\$ 115.51	1%
	Retail	\$ 86,816.49	\$ 86,816.49	\$ -	0%
	Total Bill	\$ 109,651.59	\$ 109,767.09	\$ 115.51	0%



Submitted Via Email DDS

November 23, 2010

Alberta Utilities Commission
#400, 425-1st Street S.W.
Calgary, Alberta
T2P 3L8

Attention: David Cherniwchan
Application Officer

Dear Sir:

RE: ATCO Electric Ltd. – 2011 Interim Tariff Application
Application No. 1606728, Proceeding ID 918

Responses to CCA's Information Requests

Please find attached ATCO Electric's responses to the CCA's Information Requests with respect to its 2011 Interim Tariff Application.

This information has been uploaded onto the AUC Electronic Application System.

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

Sincerely,

Original Signed by Nick Palladino

Nick Palladino, P.Eng.
Manager, Pricing

NP/by
Att.

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Consumers' Coalition of Alberta (CCA)
Round 1**

Received: November 18, 2010

CCA-AE-1

Topic: General

Reference: Nov 2, 2011 Interim Tariff Application

Preamble: Additional information is needed to better understand the timing of AE's 2011 interim rate application.

Requests:

- (a) Please explain the decision to file this Application on November 2, 2011. Please include in this response why AE could not have filed this Application either before the start of the oral hearing (e.g. after the IR response date) or soon after the hearing, when the oral record was completed other than for Module 2.
- (b) What is the proposed period of recovery of the 2011 proposed interim rates?

Response:

- (a) The filing date of this Application is consistent with ATCO Electric's previous interim tariff applications, which have been filed between October 31 and November 8. The filing date is also influenced by the amount of time typically required to process this type of application and have approvals in place for a January 1, 2011 implementation. Since ATCO Electric has not proposed to deviate from its Commission approved method to establish interim tariffs, ATCO Electric was of the view that filing this Application on November 2 would not have posed any concerns with the Commission or interested parties. Also, in order to help determine the proposed level of reduction in the proposed revenue requirement increase for establishing interim rates for 2011, ATCO Electric waited until the close of the oral record from the 2011-2012 GTA, which was October 25.

- (b) ATCO Electric is proposing to make the interim rates effective January 1, 2011. ATCO Electric does not expect a decision on the final approved 2011 revenue requirement from the 2011-2012 GTA until the second quarter of 2011, and final 2011 rates from the 2011 Phase II Application until the fourth quarter of 2011. As a result, in an effort to reduce the number of rate changes in a given period, ATCO Electric anticipates that the 2011 interim rates will remain in place for the 2011 calendar year. As noted in the 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.

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Consumers' Coalition of Alberta (CCA)
Round 1**

Received: November 18, 2010

CCA-AE-2

Topic: Requested level of interim rate increase

Reference: 2011 Interim Rate Application, Section 1.1, page 1; Page 6, Tables 1-3

Preamble: 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.

Requests:

- (a) Please provide a summary of the percent of forecast revenue deficiencies approved by the AUC in its recent interim rate decisions.

Response:

- (a) Below is a table summarizing the percent of forecast revenue deficiencies approved by the AUC in recent ATCO Electric interim rate decisions.

**ATCO Electric
Interim Rate Increases
Applied vs Approved**

		Distribution			Transmission		
		Rate Increase			Rate Increase		
		Applied \$M	Approved \$M	Percentage	Applied \$M	Approved \$M	Percentage
1	2006	62.0	62.0	100%	10.4	5.2	50%
1	2007	13.1	6.6	50%	10.8	5.4	50%
2	2008	n/a	n/a	n/a	n/a	n/a	n/a
1	2009	62.9	42.2	67%	30.4	15.2	50%
2	2010	n/a	n/a	n/a	n/a	n/a	n/a

Notes:

¹ These years are based on Scaling approach - applied vs approved increases are not applicable (n/a) for these years.

² These years are based on implementation of Phase II tariffs.

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Consumers' Coalition of Alberta (CCA)
Round 1**

Received: November 18, 2010

CCA-AE-3

Topic: Quantum and Timing of Proposed Interim Rate increases

Reference: 2011 Interim Rate Application, Section 1.1, page 3

Preamble:

AE states:

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. [Page 3, L1-9]

Further information is needed in respect of the foregoing.

Requests:

- (a) Should the AUC (i) deny the 2011 Interim Application (ii) approve say 50% of the requested increases, please provide an assessment of the such a denial on each of the following:
- (i) Ability to provide safe and reliable service;
 - (ii) AE's cash flows;
 - (iii) Financial integrity of the company – including requirement to borrow additional funds (and whether short or long term), credit metrics and credit ratings;
 - (iv) Impact of level of customer service;

- (v) Impact on rate stability and;
 - (vi) Any other factors.
- (b) Should the AUC approve the Application as filed, please explain and provide full details of how such an approval will impact cash flows and credit ratings in 2010.
- (c) Please provide an estimate of the earliest date when AE expects a decision from AUC in respect of AE's Phase 1 2011-2012 GTA ID. 650.
- (d) Please explain why it would not be reasonable for the AUC to consider an application for 2011 interim rates after it releases the AE 2011-2012 GTA ID.650.
- (e) Assuming an AUC Decision re ID. 650 is released soon after Q1-2011, and further interim rates are subsequently approved to be in effect say, July 1, 2011, please confirm AE will be able to record revenues from this decision in its 2011 financials and therefore, (i) there should be no impact on credit ratings (ii) there is little or no inter-generational inequity to the extent 2011 costs are collected in 2011 (iii) should AUC approves AE's application for FIT and CWIP in Rate Base as filed, AE will have accelerated collection of these amounts i.e. effective July 1, 2011 vs. the alternative which is to reflect these amounts as part of a 2011-2012 Final Rates Application, which as noted by AE on page 1 (Lines 17-18) may not be decided on by the AUC until Q4-2011.

Response:

- (a) With respect to parts (ii) and (iii), please refer to AUC-AE-2. With respect to parts (i), (iv) and (v), ATCO Electric is of the view that, while it is difficult to assess the potential impacts specifically related to the level of customer service support and the ability to provide safe and reliable service arising from any reduction in the forecast target revenue requirement, the Phase I GTA provides the detail bases to support ATCO Electric's applied for rate increases. As noted in response to CCA-AE-1, ATCO Electric anticipates that the interim rates will remain in place for the full 2011 calendar year. As such, it is important to reflect the best forecast of 2011 rates in the levels approved by the AUC on an interim basis. It is simply not reasonable for ATCO Electric to defer recovery of forecasted costs for the test period. Any significant reduction in the interim rates would also result in the approved rates not sending the proper price signals to customers.

ATCO Electric would point to the initial 2009 interim tariff application, Decision 2008-134, as an example whereby the Commission initially approved recovery of only 25% of the proposed revenue requirement increase for Distribution. ATCO Electric submitted that the approved increase would result in a significant revenue shortfall, impact ATCO Electric's ability to begin recovering its forecasted costs for the test period, and further exacerbate customer rate increases in 2010. As a result, ATCO Electric filed a further interim tariff

application to address the matters related to intergenerational equity so that price signals to customers would be more reflective of the costs ATCO Electric was forecasted to incur linking the collection of rate revenue to when the costs are incurred. The AUC subsequently revised the level of interim rates.

- (b) Please refer to AUC-AE-2.
- (c) Please refer to UCA-AE-1.
- (d) ATCO Electric is anticipating a final Decision (including compliance Decisions) on its 2011-2012 GTA in the second quarter of 2011 (for both Modules 1 and 2). Allowing process time for an interim tariff application would result in interim rates effective sometime in the third quarter of 2011. Consistent with previous interim tariff applications, a key objective of interim rates is to design and implement such rates so that appropriate price signals are sent to customers now, ensuring there is a strong link between rate revenue and when the costs are incurred. Delaying the interim tariff application until later in 2011 does not address the concerns herein including part (a) above. Delaying the implementation of interim rates would also depart from the Commission's previously approved interim tariff applications.
- (e) Please refer to AUC-AE-2 and CCA-AE-3(a-d).

2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918

Information Responses To:
Consumers' Coalition of Alberta (CCA)
Round 1

Received: November 18, 2010

CCA-AE-4

Topic: Contentious Issues

Reference: 2011 Interim Rate Application, Section 2.0

Preamble: 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. [Page 4, L7-12] {Emphasis added}

Requests:

- (a) Please provide the basis of this statement that there are no contentious cost drivers with respect to the 2011 Transmission Revenue Requirement. Include in this response, AE interpretation of contentious issues versus debatable issues.
- (b) Please confirm it is AE's view that with respect to Transmission, other than issues related to FIT and CWIP in Rate Base, all other issues identified in intervener evidence and cross examination by both the AUC and interveners are not contentious or subject to debate, and that the AUC will reject en masse all such submissions.

Response:

- (a) ATCO Electric based this statement on its assessment that intervener evidence in ATCO Electric's 2011-2012 GTA respecting transmission issues did not recommend major reductions in forecast 2011 revenue requirement. ATCO Electric does not consider there is a difference between contentious issues and debatable issues. The key point for the interim application is that the module 2 issues are recognized as contentious by ATCO Electric. They have not

yet been tested before the Commission and their impact has been excluded from the revenue requirement requested in the interim application.

- (b) At the time of the interim application ATCO Electric recognized that interveners would likely make some recommendations in argument to lower the applied for revenue requirement. However, ATCO Electric considers it has fully supported its applied for revenue requirement and does not forecast material disallowances.

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Consumers' Coalition of Alberta (CCA)
Round 1**

Received: November 18, 2010

CCA-AE-5

Topic: Contentious Issues

Reference: 2011 Interim Rate Application, Section 2.0

Preamble: 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. [Page 4, L7-12]

Requests:

- (a) Please provide the basis for the statement that with respect to Distribution, there are no contentious issues which should be removed by the AUC for purposes of 2011 interim rates. Please provide this response in light of the fact that intervenors have addressed several issues in evidence and cross examination and indicate if it is AE's view that all these issues are not contentious or subject to debate, and that the AUC will reject en masse all such submissions
- (b) Page 4: L19: Please provide support for the statement that "based on previously approved Interim Tariff Applications and final approved revenue requirements" a recovery equal to 90% of the requested rate increase is reasonable for an Interim rate increase.
- (c) In AE's views, please describe the issues which are represented by the 10% proposed reduction in the shortfall or the requested 2011 distribution rate increase.
- (d) Has AE done an assessment of the total of the changes proposed by intervenors in filed evidence? If so, please provide AE's calculations in this regard in order to provide the AUC some context with respect to potential issues at debate or contentious issues.

Response:

(a)-(c)

Please refer to AUC-AE-1(a) and (b).

(d) ATCO Electric has not conducted any detailed assessment of the total changes proposed by interveners in filed evidence from the 2011-2012 GTA. The approach ATCO Electric has taken to establish interim rates for 2011 is consistent with the approach taken in previous interim tariff applications. The process to establish interim rates is not predicated on a detailed assessment of what the Commission might ultimately disallow in the Phase I Application. It is based on arriving at a reasonable balance between recognizing that some disallowance may occur in the Phase I while still allowing ATCO Electric the opportunity to begin collecting its forecasted costs set out in the test year. It is an opportunity to ensure a link between rate revenue and costs, sending the correct price signals to customers, thereby avoiding intergenerational equity issues to the extent possible.

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Consumers' Coalition of Alberta (CCA)
Round 1**

Received: November 18, 2010

CCA-AE-6

Topic: Rate Design - Scaling Method

Reference: 2011 Interim Rate Application, Section 2.2

Preamble: Further understanding is needed in respect of AE's proposed scaling method to design of interim rates.

Requests:

- (a) Page 7, L2-3: AE states its scaling approach was "first introduced in ATCO Electric's 2005-2006 GTA." Please confirm AE has been using this approach since in the design of interim rates and explain what method(s) were used by AE prior to the scaling method.
 - (a) Please indicate if AE's scaling method, or a similar approach, is employed by any of the other utilities in Alberta.
- (b) Page 7, L6-7: Please provide the basis for the statement the scaling method will minimize "the fluctuations in customer rates as much as possible."
- (c) App B: Please provide a computation of the % increase in rates effective Jan 1, 2011 to the rates currently in place for each rate class, and explain why, for example, Industrial Rate 31 proposed rate increase on Jan 1, 2011 of 4.6% [\$24,966/24,851] is significantly higher than say the proposed Residential rate increase of 7.2% [74.45/69.47].
- (d) One of the general public interest factors established by the AUC is to consider "may be appropriate to apply the interim rider on an across-the-board basis." [Decision 2009-024, page 2]. Please provide a computation of the 2011 interim rates using a simple "across-the-board" method and provide pros and cons of this method as compared to AE's scaling method.
- (e) To AE's knowledge, what other methods have been approved by the AUC (and its predecessors) in the design of interim rates.

- (f) To the extent the scaling approach relies on the most recently approved 2010 final rates (per Decision 2010-205), please confirm the scaling approach for 2011 interim rates simply attempts to mimic the 2010 final rate design and does not reflect (directionally or otherwise) whatever changes AE may file in its 2011-2012 Phase 2 GTA, expected to be filed imminently i.e. in Q4-2010.
- (g) Considering the anticipated 2011-2012 Phase 2 GTA will be filed imminently, please explain why it would not be reasonable to await this filing to design the 2011 interim rates.
- (h) Please explain and discuss the impact of the scaling method on the revenue to cost ratios, both in the aggregate and by component (Fixed Charge, Demand and Energy) to be filed in the 2011-2012 Phase 2 GTA.
- (i) Page 8, L4: Please provide the results of the scaling approach assuming the AUC approves 50% of the amounts proposed in this 2011 Interim Rate Application.
- (j) Attachment 1 Note (1) states: "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." Please explain (i) which transmission COSS is being referred to and (ii) what factors led to the adjustment to revenues between Demand and energy components.
- (k) Attachment 1: Please reconcile the "Target" D&T revenues to the data shown on Table 3.

Response:

- (a) Confirmed. ATCO Electric has been using the scaling approach since the 2005-2006 GTA. Prior to the 2005-2006 GTA, in years where a full Phase II was not available, interim rates were normally a carry forward of existing rates until subsequent final rates were approved. It is important to point out that ATCO Electric is facing different cost pressures now compared to the period when interim rates were a carry forward of existing approved rates. In addition the timeframe prior to the 2005-2006 GTA represents years where ATCO Electric had different rate structures. For example, during the period 2001 to 2004, in addition to Transmission and Distribution service, ATCO Electric also provided an energy rate through the Regulated Rate Option Tariff. Prior to 2001 and deregulation of the generation business unit, ATCO Electric had bundled rates including Generation, Transmission and Distribution.
 - (a) Another Alberta utility that uses a similar scaling method approach in its interim filing applications is FortisAlberta Inc.

- (b) The basis for the statement is that final rates for 2011 will not be approved until the fourth quarter of 2011. The scaling approach has been approved by the Commission as an effective mechanism to allow ATCO Electric to begin collecting its forecast costs in a timely manner at the beginning of 2011. This approach to scaling and setting interim rates also allows for a more streamlined transition to final rates and helps reduce rate shock to customers. Also, please refer to CCA-AE-3(a).
- (c) Please see Table CCA-AE-6 Table 1 for the Comparison of Base Rates of Typical Customers between existing rates and rates proposed for January 1, 2011. In general, distribution component of the rates increase by 7.0% while the transmission component varies by rate class depending on demand-energy mix of the transmission charge. The exceptions for the distribution charge are irrigation rates (D25 & D36) and Street Light Rates (D31), which are proposed to increase overall by 25%. The reason why Industrial Rate T31 proposed increase (0.46%) is significantly lower than the Residential D11 proposed increase (7.2%) is due to the transmission component of Industrial Rate T31. Since the transmission component of Rate T31 is a flow through of the AESO, there is no change in the transmission component for T31 (as noted by the 0% in CCA-AE6 Table 1 and the scaling factor of 1.00 in columns C and D in line 3 of 02_AE_2011_Interim_Attachment_1_Scaled rates.xls).

CCA-AE-6 Table 1
Comparison of Base Rates of Typical Customers

Rate Class	August 1, 2010			January 1, 2011			Percentage Increase		
	Trans.	Dist.	Total	Trans.	Dist.	Total	Trans.	Dist.	Total
D11	10.50	58.97	69.47	11.34	63.11	74.45	8.0%	7.0%	7.2%
D21	85.98	247.83	333.81	90.73	264.78	355.51	5.5%	6.8%	6.5%
D25	867.70	1069.58	1937.28	984.82	1446.02	2430.84	13.5%	35.2%	25.5%
D26	867.70	371.94	1239.64	984.82	502.58	1487.40	13.5%	35.1%	20.0%
D31-50 kW	274.08	381.44	655.52	295.14	408.86	704.00	7.7%	7.2%	7.4%
D31-2 MW	12839.70	10798.49	23638.19	13704.60	11591.37	25295.97	6.7%	7.3%	7.0%
D41	107.09	315.42	422.51	112.33	337.62	449.95	4.9%	7.0%	6.5%
D51	19.10	27.75	46.85	20.44	29.66	50.10	7.0%	6.9%	6.9%
D56	19.10	48.31	67.41	20.44	51.67	72.11	7.0%	7.0%	7.0%
D61	1.20	11.04	12.24	1.28	13.88	15.15	6.3%	25.7%	23.8%
D63	1.28	12.64	13.91	1.43	13.46	14.88	11.8%	6.5%	7.0%
T31	23210.12	1641.00	24851.12	23210.13	1756.50	24966.63	0.0%	7.0%	0.5%

- (d) The “across-the-board” scaling factor would be 1.067731 (please refer to the scaling factor of 1.067731 in line 3 of 02_AE_2011_Interim_Attachment_1_Scaled rates.xls: \$473,293k/\$443,270k). It is also important to point out that as noted in part (c) above, ATCO Electric is required to increase the distribution charge for the irrigation rates (D25 & D36) and Street Light Rates (D31) by 25% as a result of the negotiated settlement terms arising from the 2010 Phase II Application. An increase of 25% is required in order to bring revenue-to-cost ratios in these rate classes to within a band of 95% to 105%.

Some of the pros of using the same across-the-board scaling factor include ease of calculation, a more straightforward interim tariff application, and ease of implementation.

Some of the cons of using an “across-the-board” scaling factor include not flowing through properly the AESO rates dollar for dollar to direct connect T31 customers, issues with addressing revenue to cost ratios for the irrigation D25 & D26 and light D61 rate class (as discussed above) and a greater misalignment in true-ups between interim and final rates amongst customer classes.

- (e) Please refer to the response provided under part (a) above.
- (f) Confirmed.
- (g) Although ATCO Electric's 2011-2012 Phase II DTA will be filed fourth quarter 2010, a decision on final 2011 rates is not expected 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. Please refer to CCA-AE-1(a) and CCA-AE-3(d).
- (h) ATCO Electric is in the process of finalizing its 2011-2012 Phase II DTA, to be filed in the fourth quarter of 2010. As such, finalized costs, in aggregate and by component, are not available, currently, to address impacts of the scaling method on the revenue to cost ratios in the 2010-2012 Phase II DTA.
- (i) Please refer to AUC-AE-4 for AUC requested scenarios of 50%, 60% and 70% recovery of GTA proposed revenue requirement increase.
- (j) Please see the following:
 - (i) The transmission COSS being referred to is the 2010 transmission COSS.
 - (ii) The transmission cost components are based on demand and energy. The recovery of these costs is through the energy charge for D11 and demand charge for D61 and D63. ATCO Electric has always been consistent in handling the transmission component of these rates with this methodology.

(k) Please see Table CCA-AE-6 Table 2 Reconciliation of "Target" D&T revenues as shown on Table 3.

CCA-AE-6 Table 2
Reconciliation of "Target" D&T Revenues as shown on Table 3

	A	B	C	E=B+C	F=E/B % Recovery of GTA	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	Proposed RR Increase \$ million	2011 Interim Tariff Proposed RR \$ million
Transmission (TFO)	336.6	86.6	(54.3)	32.3	37%	282.3
Distribution						
TAP	168.6	9.5	0.0	9.5	100%	168.6
Dist.	308.0	23.9	(3.3)	20.6	86%	304.7
Sub-Total	476.6	33.4	(3.3)	30.0	90%	473.3
Fran. Fee	16.9	0.0	0.0	0	-	16.9
Total	493.6	33.4	(3.3)	30.0	90%	490.2

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Consumers' Coalition of Alberta (CCA)
Round 1**

Received: November 18, 2010

CCA-AE-7

Topic: ATCO Electric's Rider B – Balancing Pool Adjustment

Reference: 2011 Interim Rate Application, Section 2.4, page 9

Preamble:

Further understanding is needed in respect of the following statement:

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.

Requests:

- (a) Since AESO's Rider F is calculated on the substation POD and AE's Rider B is based on the readings at the customer meter, please quantify the difference and explain by way of an example, how AE adjusts this difference for each customer class.
- (b) Please indicate if there is a difference in the computation of AE's Rider B for Direct Connect customers. For example, is there a flow-through of the AESO's Rider G for these customers?

Response:

- (a) ATCO Electric's Rider B – Balancing Pool Adjustment is designed to include a portion related to distribution losses required to lessen the amount of any future true-ups. For example, in the 2010 Rider G, the amount ATCO Electric refunded to customers was \$67.285 M while the AESO refunded \$66.782 M resulting in a relatively immaterial net collection of \$0.503 M. This amount was allocated to customer rate classes based on the original amount refunded, with the exception of direct connect T31 customers.
- (b) There is no difference in the computation of ATCO Electric's Rider B Direct Connect T31 customers. Namely, as these customers are a flow-through there is no true-up required in the Rider G applications.



Submitted Via Email DDS

November 23, 2010

Alberta Utilities Commission
#400, 425-1st Street S.W.
Calgary, Alberta
T2P 3L8

Attention: David Cherniwchan
Application Officer

Dear Sir:

RE: ATCO Electric Ltd. – 2011 Interim Tariff Application
Application No. 1606728, Proceeding ID 918

Responses to UCA's Information Requests

Please find attached ATCO Electric's responses to the UCA's Information Requests with respect to its 2011 Interim Tariff Application.

This information has been uploaded onto the AUC Electronic Application System.

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

Sincerely,

Original Signed by Nick Palladino

Nick Palladino, P.Eng.
Manager, Pricing

NP/by
Att.

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Utilities Consumer Advocate (UCA)
Round 1**

Received: November 18, 2010

UCA-AE-1

Topic: Timing of Phase 1 Decision

Reference: Exhibit 0001.00, AE Application, page 2, lines 25 and 26

Preamble: AE makes reference to its 2011-2012 GTA. The UCA requires an understanding of the timing for the GTA

Request:

- (a) Please provide the dates for Argument and Reply Argument for the first module of the AE 2011-2012 GTA, proceeding 1606228, Application 650.
- (b) Based on an estimate of 90 days for the Commission to render a Decision, please provide the projected date for such decision for the first module of the AE 2011-2012 GTA Application No. 1606228, Proceeding ID #650.

Response:

(a)-(b)

The filing date for Argument was November 19th, 2010 and Reply Argument is to be submitted on December 10th, 2010. It is ATCO Electric's understanding that the Commission will issue a single Decision that deals with both Module 1 and Module 2 issues. As such, such a decision will not be rendered until approximately 90 days after the completion of Module 2 Reply Argument. The date for such argument has not been set at this point.

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Utilities Consumer Advocate (UCA)
Round 1**

Received: November 18, 2010

UCA-AE-2

Topic: Transmission Cost Increases

Reference: Exhibit 0001.00, AE Application, page 2, lines 9-17

Preamble: AE has indicated:

“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.” The UCA requires an understanding of the impacts of the various reasons for increased costs.

Request:

- (a) For 2011, please provide a summary of the increases in Transmission costs that includes and identifies:
- (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.
- (b) Please reconcile the sum of the costs in (a) above to the increase in Transmission Revenue for 2011 from the AE 2010-2011 GTA, Application No. 1606228, Proceeding ID #650.

Response:

(a)-(b)

Please refer to UCA-AE-02 Attachment 1.

ATCO Electric
2011-2012 General Tariff Application
Analysis of Rate Increase

Line No.	Description	Ref.	2011 Revenue Requirement (1)	O & U Filing Adjustments Page 2	2011 Revenue Requirement
1	BASE - 2010 Approved Revenue requirement		250.0	-	250.0
2	Growth in Sales		-	-	-
3	2010 Approved Revenue requirement - adjusted for growth in sales	S. 3-1	250.0	-	250.0
4	Fuel		(1.3)	-	(1.3)
5	O&M and Revenue offsets		10.3	(2.5)	7.8
6	Rate base		39.3	(10.3)	29.0
7	CWIP in rate base		41.2	5.5	46.7 (2)
8	Pension - cash basis		7.2	(0.5)	6.7
9	Financing		(3.2)	(2.1)	(5.3)
10	Lower Federal Tax rate		(0.7)		(0.7)
11	Lower/(higher) tax deductions		(3.6)	0.2	(3.3)
12	Federal Future Tax - Transmission		11.0	(3.9)	7.1 (2)
13		S. 3-1	<u>100.1</u>	<u>(13.5)</u>	<u>86.6</u>
14			<u>40.0%</u>		<u>34.6%</u>
15	2011-2012 GTA Revenue requirement	S. 3-1	<u>350.1</u>		<u>336.6</u>

Note 1 - Amounts provided in Section 3 Attachment 2

Note 2 - Differences from Table 1 is a result of a further detailed review of the O&U filing, where as Table 1 was an estimate.

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Utilities Consumer Advocate (UCA)
Round 1**

Received: November 18, 2010

UCA-AE-3

Topic: Distribution Cost Increases

Reference: Exhibit 0001.00, AE Application, page 2, lines 19-24

Preamble: AE has indicated:

“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.”

The UCA requires an understanding of the impacts of the various reasons for increased costs.

Request:

- (a) For 2011, please provide a summary of the increases in Transmission costs that includes and identifies:
- (i) increases in return on rate base (return, income taxes and depreciation) associated with increases in rate base;
 - (ii) impact of pension contributions;
 - (iii) operating cost increases largely attributable to:
 - 1) inflationary costs;
 - 2) added labour to support ongoing technology initiatives and increased number of customers;
 - 3) system related costs; and
 - 4) high growth and aging infrastructure; and

- (iv) increased return on rate base (return, income taxes and depreciation) due to rate base additions,
- (b) Please reconcile the sum of the costs in (a) above to the increase in Distribution Revenue for 2011 from the AE 2010-2011 GTA, Application No. 1606228, Proceeding ID #650.

Response:

(a)-(b)

Please refer to UCA-AE-03 Attachment 1.

ATCO Electric
2011-2012 General Tariff Application
Analysis of Rate Increase
(\$ Millions)

Line No.	Description	Ref.	2011 Revenue Requirement (1)	O & U Filing Adjustments Sch 1 pg 2	2011 O&U Revenue Requirement
1	BASE - 2010 Approved Revenue requirement		439.6	-	439.6
2	Growth in Sales		20.6	-	20.6
3	2010 Approved Revenue requirement - adjusted for growth in sales	S. 12-1	460.2	-	460.2
4	COGS/Distribution Property Taxes over increased sales growth		3.7	-	3.7
5	O&M and Revenue offsets		11.6	(2.2)	9.4
6	Rate base		16.6	0.1	16.7
7	CWIP in rate base		-		-
8	Pension - cash basis		9.7	(1.1)	8.6
9	Financing		(1.8)	(1.2)	(3.0)
10	Lower Federal Tax rate		(0.7)		(0.7)
11	Lower/(higher) tax deductions		(2.0)	0.7	(1.3)
12		S. 12-1	<u>37.1</u>	<u>(3.7)</u>	<u>33.4</u>
13			<u>8.1%</u>		<u>7.2%</u>
14	2011-2012 GTA Revenue requirement	S. 12-1	<u>497.3</u>		<u>493.6</u>

2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918

Information Responses To:
Utilities Consumer Advocate (UCA)
Round 1

Received: November 18, 2010

UCA-AE-4

Topic: Prior Decisions

Reference: Exhibit 0001.00, AE Application, page 4, lines 1 and 2

Preamble: AE mentions

Request:

- (a) Please provide the increase requested in the last AE GTA, Application No. 1578371, Proceeding ID #86 for 2009 for each of Transmission and Distribution, and the approved interim increase related to 2009 from Decision 2008-134 for each of Transmission and Distribution.
- (b) In response to (a), above, please provide the approved interim increase both the dollar value and percentage of the requested amount for each of Transmission and Distribution.

Response:

- (a) The 2009 Transmission and Distribution requested and approved rate increases in Decision 2008-134 and updated in Decision 2009-046 are as follows:

	Requested GTA Rate Increase	(\$M) Approved Interim Rate Increase (Effective Jan. – Dec. 2009)	Updated Approved Interim Rate Increase (Effective May – Dec. 2009)
Transmission	31.7	15.2 (Decision 2008-134)	Did not change.
Distribution	62.9	11.1 (Decision 2008-134)	Additional 31.1 (Decision 2009-046)

- (b) Please refer to CCA-AE-2.

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Utilities Consumer Advocate (UCA)
Round 1**

Received: November 18, 2010

UCA-AE-5

Topic: Distribution Scaling Factors

Reference: Exhibit 0001.00, AE Application, page 8, Table 4

Preamble: AE provides a table that summarizes the scaling factors for each rate. All Distribution rates are proposed to be scaling factors of 1.07 except D25, D26, and D61. The D25 and D26 scaling factor is 1.352 and the D61 scaling factor is proposed to be 1.257.

Request:

- (a) Please fully explain why AE is not using a uniform scaling factor for all rates.
- (b) When AE designs rates, does AE employ rate caps to mitigate rate increases? Please fully explain.
- (c) Please provide the Distribution portion of Table 4 using a uniform scaling factor.

Response:

- (a) With respect to scaling of the 'Distribution' function, in accordance with the negotiated terms set out in ATCO Electric's 2010 Phase II and approved by the Commission in Decision 2009-231, ATCO Electric is required to transition rates for Irrigation D25 & D26 and Light D61 customers to within a 95% to 105% revenue to cost ratio band over a 5 year time frame. This results in a maximum rate increase of 25% on an annual basis to these rate classes. In order to do this, the distribution scaling factors for these rate classes are higher than the scaling factors for the remaining rate classes.
- (b) ATCO Electric does not address revenue to cost ratios for purposes of scaling and, therefore, rate caps are not utilized to mitigate rate increases. The exception, as explained in part (a) above, is with respect to the Irrigation and Street Light customer classes whereby rate increases capped to 25% have been introduced to bring these rate classes within the 95% to 105% revenue to cost

ratio over a 5 year time frame. It is also important to note that the requested increase in the proposed distribution revenue requirement for 2011 compared to revenue on existing rates is 7.2%, as set out in ATCO Electric's 2011-2012 GTA. ATCO Electric is of the view that the impact arising from the proposed revenue requirement increase from the 2011-2012 GTA is below 10%, which has generally been used in the past as a rate cap guideline. As a result, with the exception of the rate design matter associated with Irrigation and Street Light customers as noted above, rate cap issues are not relevant in this Application.

- (c) A uniform scaling factor for the distribution portion of Table 4 would be 1.103880 (please refer to sum of Line 2, Distribution Revenue and Power Factor divided by sum of Line 1, Distribution Revenue and Power Factor of 02_AE_2011_Interim_Attachment_1_Scaled rates.xls: \$304,699k / \$283,749k). Please see below for the updated Table 4. Also, please refer to CCA-AE-6(d) for a discussion as to the reasons why a uniform scaling factor approach is not reasonable for this Application.

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

Rate Class	Transmission Access		Distribution		
	Demand	Energy	Customer	Demand	Energy
D11			1.104	1.104	1.104
D25 & D26			1.104	1.104	1.104
D61			1.104	1.104	1.104
D63			1.104	1.104	1.104
T31			1.104	1.104	1.104
Others			1.104	1.104	1.104

**2011 Interim Tariff Application
Application No. 1606728
Proceeding ID. 918**

**Information Responses To:
Utilities Consumer Advocate (UCA)
Round 1**

Received: November 18, 2010

UCA-AE-6

Topic: Transmission Scaling Factors

Reference: Exhibit 0001.00, AE Application, page 8, Table 4

Preamble: AE provides a table that summarizes the scaling factors for each rate. Different scaling factors are being proposed for most rates. For the energy component of D25 & D 26, and for Others, the scaling factor is less than 1.

Request:

- (a) Please fully explain why AE is not using a uniform scaling factor for all rates.
- (b) Please explain why AE used a scaling factor of less than one for D11 (Energy), and Other (Energy).
- (c) When AE designs rates, does AE employ rate caps to mitigate rate increases? Please fully explain.
- (d) Please provide the Transmission portion of Table 4 using a uniform scaling factor.

Response:

- (a) With respect to scaling of the 'Transmission' function, Direct Connect T31 customers are flowed through directly the AESO Transmission Access Payments (TAP) and, therefore, this rate class has a scaling factor of 1.0. The residential D11 rate class does not have a demand component and the light D61 & D63 rate classes do not have an Energy component and, so, the scaling factors for these customers are different from the other rate classes to compensate for differences in rate structures.

- (b) Please see (a) above.
- (c) TAP amounts from the AESO are flowed through and recovered 100% from ATCO Electric's customers and, therefore, rate caps are not utilized to mitigate rate increases.
- (d) A uniform scaling factor for the transmission portion of Table 4 would be 1.05687 (please refer to sum of Line 2, columns A through D divided by sum of Line 1, columns A through D of 02_AE_2011_Interim_Attachment_1_Scaled rates.xls: \$168,593k / \$159,521k). Please see below for the updated Table 4.

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

Rate Class	Transmission Access		Distribution		
	Demand	Energy	Customer	Demand	Energy
D11	N/A	1.057			
D25 & D26	1.057	1.057			
D61	1.057	N/A			
D63	1.057	N/A			
T31	1.057	1.057			
Others	1.057	1.057			

Please note that as the T31 rate class is a flow through of the AESO tariffs, ATCO Electric finds it inappropriate to apply a uniform scaling factor to this rate class.