### ALBERTA ENERGY AND UTILITIES BOARD

### **DECISION E95102**

re:

### ALBERTA POWER LIMITED

In the matter of the Phase II portion of a general rate application by Alberta Power Limited for an increase in the rates, charges or schedules for electric light, power or energy furnished to its customers in Alberta.

### BEFORE:

B. T. McManus Q.C. Presiding Member

A. Calista Barfett

Member

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: Mr. J. A. Bryan, Q.C. Bryan & Company

For the Industrial Power Consumers : Mr. A. L. McLarty Association of Alberta

Milner Fenerty

For the Alberta Federation of REAs Ltd.

: Mr. K. L. Sisson Sisson, Warren, Sinclair

For the Alberta Association of Municipal Districts and Counties : Mr. P. G. Sully, Q.C. Brownlee Fryett

For the Public Institutional Consumers of Alberta

: Ms. Nancy McKenzie Ackroyd, Piasta, Roth & Day

For the Independent Power Producers Society of Alberta : Mr. L. L. Manning Parlee McLaws

For the Alberta Cogenerators Council

: Mr. R. D. Secord Ackroyd, Piasta, Roth & Day

For Canadian Forest Products Limited

: Mr. L. L. Manning Parlee McLaws

For the Consumers Coalition of Alberta

: Mr. J. B. Wachowich Wachowich & Company

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#### WITNESSES

For Alberta Power Limited

: Mr. Richard Stout Manager, Rates and Cost of Service

: Ms. Heidi Kirrmaier, P.Eng. Regulatory/Rates Specialist

: Mr. Pat Garvin Manager of Marketing and Industrial Sales

: Mr. Warren Frost, P.Eng. Supervising Engineer Pricing

: Mr. John Walker Supervisor Cost of Service

For the Alberta Federation of REAs Ltd. and the Alberta Association of Municipal Districts and Counties : Mr. W. B. Marcus JBS Energy, Inc.

For the Industrial Power Consumers Association of Alberta : Dr. Alan Rosenburg Consultant Drazen-Brubaker & Associates Ltd.

For the Alberta Cogenerators Council

: Dr. Michael Schmidt Consultant Drazen-Brubaker & Associates Ltd.

For the Independent Power Producers Society of Alberta

: Mr. Robert D. Knecht Industrial Economics, Incorporated

: Mr. Guido Bachmann Chairman of IPPSA and V.P. Northland Power

: Mr. Ross Keating V.P. Electric Energy Division, Canada Hydro Developers Inc.

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### WITNESSES

For the Consumers Coalition of Alberta : Mr. Bruce R. Oliver

Revilo Hill Associates, Inc.

#### **ABBREVIATIONS**

AAMDC Alberta Association of Municipal Districts and Counties

ACC Alberta Cogenerators Council

AEUB Act Alberta Energy and Utilities Board Act

AIS Alberta Integrated System

APL Alberta Power Limited

Board or AEUB Alberta Energy and Utilities Board
Canfor Canadian Forest Products Limited

CCA Consumers Coalition of Alberta

COS Cost of Service

COSS Cost of Service Study

ECOSS Embedded Cost of Service Study
EEMA Electric Energy Marketing Agency

EMS Export Market Service

ERCB Energy Resources Conservation Board

ESR Electric Service Regulations
GRA General Rate Application

IPCAA Industrial Power Consumers Association of Alberta

IPP Independent Power Producers

IPPSA Independent Power Producers Society of Alberta

MI Municipal Intervenors
NCP Non-Coincident Peak

NUL Northwestern Utilities Limited
O&M Operating and Maintenance

PICA Public Institutional Consumers of Alberta

PUB Public Utilities Board

PUB Act Public Utilities Board Act

REA Alberta Federation of REAs Ltd.
SaskPower Saskatchewan Power Corporation
TransAlta TransAlta Utilities Corporation

WESCUP Westcoast Energy Inc./Canadian Utilities Power

### REFERENCES

ORDER / DECISION / REPORT NO.	DATE	PARTICULARS
E90082	December 21, 1990	TransAlta Utilities Corporation (Decision - 1991 Rate Rider - EEMA Flow-Through)
E91074	December 13, 1991	Alberta Power Limited, Edmonton Power and TransAlta Utilities Corporation (Decision - EEMA 1990 Adjustment, 1992 Forecast)
E91095	December 13, 1991	Alberta Power Limited (Decision - 1991 GRA - Phase I)
E93035	May 25, 1993	Alberta Power Limited (Decision - 1991/1992 GRA - Phase II)
E93068	October 8, 1993	Alberta Power Limited (Decision - 1991/1992 GRA, Phase II - Vary Decision E93035)
E93069	October 8, 1993	Alberta Power Limited (Decision - Test year 1993)
E93082	October 29, 1993	Alberta Power Limited (Order - Vary Decision E93068)
E94034	June 17, 1994	Alberta Power Limited (Decision - 1992 GRA, Phase II)
E94076	November 4, 1994	TransAlta Utilities Corporation (Decision - Network and Generation Services)
E94084	December 22, 1994	Northwestern Utilities Limited (Decision - 1994 GRA, Phase II)
E95021	March 2, 1995	Alberta Power Limited (Decision - EEMA Flow-Through Rider)
E95048	April 24, 1995	City of Red Deer and Northwestern Utilities Limited (Decision - Amend Special Franchise Contract)
E95059	May 31, 1995	City of Edmonton and Northwestern Utilities Limited (Decision - Amend Rate Rider "A")

### 1. INTRODUCTION

The Phase II portion of the Alberta Power Limited (APL) General Rate Application (GRA) was filed with the Public Utilities Board (the PUB) on July 11, 1994. The Lieutenant Governor in Council ordered that the Alberta Energy and Utilities Board Act c.A-19.5, S.A. 1994 (AEUB Act) be proclaimed in force on February 15, 1995. The AEUB Act brings together the Energy Resources Conservation Board (the ERCB) and the PUB. Section 8 of the AEUB Act states:

- "8(1) All matters that may be dealt with by the ERCB or the PUB under any enactment or as otherwise provided by law shall be dealt with by the Board and are within the exclusive jurisdiction of the Board.
- (2) If on the coming into force of this Act any matter is before the ERCB or the PUB,
  - (a) the matter shall be continued before or by the Board, and
  - (b) the members of the ERCB and the PUB dealing with the matter shall continue to deal with it in their capacity as members of the Board."

In the above quote and in all references hereinafter found "Board" means the Alberta Energy and Utilities Board.

### Pursuant to the above:

- (a) this matter has been continued before the division of the PUB previously assigned to deal with it; and
- (b) this Decision is issued as a Decision of the Board.

### 1. INTRODUCTION

APL filed a GRA on September 9, 1992 with the PUB for approval to change existing rates, charges or schedules for electric light, power or energy furnished by APL to its customers in Alberta for the 1993 test year.

In Decision E93035 dated May 25, 1993, the Board determined the rates, tolls and charges for APL which were designed to recover APL's approved 1992 revenue requirement. Decision E93035 approved interim industrial services rates and final Rates 11, 12, 18, 21, 25, 35, 41, 51, 52, 56, 61 and 63 and final riders D, E, F, M, N, S, T and U. The interim industrial service rates were Rates 31, 32, 36, 37 and 38 and Riders B, H, I, and L which were in existence when APL's GRA for the 1993 test year was filed on September 9, 1992.

In Decision E93069 dated October 8, 1993, the Board determined APL's rate base, fair return on rate base and total electric utility revenue requirement for the 1993 test year. In Decision E93068 dated October 8, 1993 (as varied by Order E93082 dated October 29, 1993), the Board varied Decision E93035 by adjusting Rider G to give effect in APL's rates to, inter alia, APL's 1993 revenue deficiency as determined in Decision E93069.

In Decision E94034 dated June 17, 1994, the Board approved, effective July 1, 1994, revised interim industrial Rates 30, 31, 32, 33A, 33B, 34, 36 and 38 and Riders G and I which, when combined with the rates approved in Decision E93035, were forecast to collect an amount very close to APL's approved 1993 revenue requirement.

### 1. INTRODUCTION

APL provided its 1993 Phase II filing (the Application) to the Board on July 11, 1994. Public hearings related to the Application were held in Edmonton from November 28 to December 2, 1994. The applicant and intervenors were required to provide written argument on December 22, 1994 and written reply on January 18, 1995. Intervenors filing submissions were the Municipal Intervenors (the MI), the Industrial Power Consumers Association of Alberta (IPCAA), the Alberta Federation of REAs Ltd. (REA), the Alberta Association of Municipal Districts and Counties (AAMDC), the Public Institutional Consumers of Alberta (PICA), the Alberta Cogenerators Council (ACC), the Independent Power Producers Society of Alberta (IPPSA), Canadian Forest Products Limited (Canfor), the Consumers Coalition of Alberta (CCA) and TransAlta Utilities Corporation (TransAlta).

This Decision fixes rates, tolls and charges forecast to generate total revenues approximately equal to the total 1993 Electric Utility Revenue Requirement approved by the Board in Decision E93069. The Decision sets forth the positions of interested parties and provides reasons for the Board's findings.

#### 2. SALES AND REVENUE FORECASTS

APL indicated that the rate schedules it proposed had been designed to recover the 1993 revenue requirement as determined by the Board in Decision E93069.

### MI

The MI noted that APL included no revenue from Rates 30, 32, 34 and 38 in its billing determinants for 1993 and submitted that APL should include a forecast of revenues from those rates in future filings or provide evidence why it is not appropriate to forecast any such revenues. (Argument, p.47)

#### REA/AAMDC

The REA/AAMDC supported the MI's position and submitted that the revenue and contribution to fixed costs from Rates 30, 32, 34 and 38 were increasing and that in future forecasts APL should utilize those revenues to offset firm customer rates.

The REA/AAMDC also agreed with other intervenors that APL should be required to account for power factor penalty revenue. (Reply, p.3)

### PICA

PICA noted that, unless customers install corrective equipment to improve their power factors, penalty revenues are forecast to increase from \$240,400 in 1994 to \$479,500 in 1995. PICA also noted that, while APL indicated the penalty

#### 2. SALES AND REVENUE FORECASTS

revenues would not be realized due to customers' corrective actions, APL would avoid the costs which lower power factors cause the system to incur. PICA submitted that, in the absence of estimated reductions in operating costs associated with the power factor correction, APL should be directed to recognize the forecast increase in penalty revenues for 1995. (Argument, p.1)

### CCA

The CCA submitted that the imposition of increased power factor charges must necessarily produce either increased revenues or decreased costs of service or some combination thereof, thereby reducing the revenues that APL needs to recover through other rates and charges. Under APL's proposal none of the cost savings or increased revenues would flow to APL's customers until a future GRA. The CCA submitted that, since in the absence of corrective actions by customers the proposed charges would generate an additional \$240,000 in 1995 and \$550,000 in 1996, APL's other rates should be lowered to reflect those amounts. (Argument, p.27)

### APL

In response to CCA and PICA, APL submitted that the evidence presented indicated definite cost savings only in the long run since power factor improvement "...will liberate more capacity on the rest of the system and allow us to defer future expansion costs." (Tr. p.856) APL submitted that its survey of other utilities in Canada, including TransAlta, indicated that the experience of these utilities supported APL's conclusion that an increase in the

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### 2. SALES AND REVENUE FORECASTS

penalty would not result in additional revenue since the penalty will provide significant incentive to customers to install corrective equipment. (Reply, p.23)

### Board Findings

The Board considers it appropriate for APL to propose rates to collect its approved 1993 revenue requirement. The Board is not convinced at this time that any additional cost reductions or revenues relating to imposition of the power factor penalties should be factored into the rates proposed. While the Board expects that some revenue or cost saving will arise over time, the Board has no specific indication of the significance or timing of the revenues or cost savings other than that provided by APL. APL indicated that cost savings would only arise in the long run and in the shorter term that the increase in penalty revenues would be insignificant due to customer corrective actions.

The Board notes that APL had less than one year's experience with partial requirement rates at the time the Application was prepared. However, the Board expects that APL will provide in its next Phase II proceeding a forecast of revenues or a detailed explanation as to why no revenues arise from Rates 30, 32, 34, and 38.

### (a) General

APL indicated that its cost of service study (COSS) utilizes the same methodology as its 1992 COSS, with two exceptions. Firstly, instead of allocating distribution additions partly on the basis of incremental customer additions, forecast distribution assets are allocated based on forecast 1993 customers and class non-coincident peak (NCP). Secondly, customers served from the primary distribution level are no longer allocated costs associated with the secondary distribution level.

Several modifications to APL's COSS were proposed by intervenors. Acceptance of the modifications would change the revenue to cost ratios arising from APL's COSS. The following provides a summary of the resultant revenue to cost ratios which are discussed in the Decision.

# 3. COST OF SERVICE(a) General

### Revenue to Cost on Proposed Rates

Line <u>No.</u>	Rate Schedule	APL	REA/AAMDC Schedule 1 Marcus Evidence	PICA Attachment 1 (Argument)
1	Residential Rate 11	99%	101%	101%
2	Residential Rate 18	<b>85</b> %	87%	<b>86</b> %
3	General Service Rate 21	103%	102%	104%
	Irrigation Rate 25	68%	<b>64</b> %	<b>68</b> %
4 5	Industrial Rate 31	101%	100%	100%
6	Industrial Rate 36 -			
	Husky Rainbow Lake	87%	87%	<b>83</b> %
7	Oilfield Rate 41	112%	116%	<b>113</b> %
8	REA Farm Service Rate 51	103%	103%	105%
9	Farm Service Rate 56	84%	90%	<b>85</b> %
10	Street Light Rate 61	86%	<b>78</b> %	<b>87</b> %
11	Sentinel Light Rate 63	89%	93%	90%
12	Total Company	100%	100%	100%

### (b) Classification of Distribution Assets

The cost of distribution plant was classified into demand and customer related costs in order to recognize the separate functions of providing service to customers and meeting individual customer's peak demands. APL classified its primary distribution assets entirely to demand. Secondary assets were classified to customer and demand with the customer component deemed to vary with the weighted forecast number of 1993 customers and the demand component deemed to vary with the forecast 1993 NCP demand of each rate class.

APL indicated that, typically, the zero intercept and the minimum size of facilities method are used to determine the customer component. APL indicated that it had classified the costs of its secondary distribution facilities as customer or demand related based upon a judgement of what a correct minimum size/zero intercept study would produce.

In Decision E93035 the Board considered that an objective study should be preferable to subjective assessments for the purposes of classifying distribution costs to demand and customer. The Board directed APL to conduct zero intercept studies related to its distribution assets, ensuring that the analysis was based on the relationship between capacity and cost. APL was directed to present the results of the studies at the time of its next GRA, including any rationale APL might have for deviating from the results of the studies in its COSS.

### (b) Classification of Distribution Assets

APL provided an analysis of the zero intercept studies which it performed based on trending replacement cost to reflect its asset records. (BR.APL-1) The reasonableness check APL provided indicated that a minimum size/zero intercept study based upon APL's historical asset records did not yield rational results. For Poles, Towers and Fixtures, the study indicated that the actual APL system must consist of something less than the minimum that APL would construct. For underground conductors, the study indicated the existence of a conductor more costly than any that APL uses.

Mr. Marcus, on behalf of the REA/AAMDC, stated that APL should use its zero intercept studies as adjusted by him for inflation. The adjustments increased the revenue to cost ratios of the Rate 56 farm class by reducing the portion of distribution plant classified as customer related. Mr. Marcus concluded that the adjustments also justified a recommendation that the pooled farm REA operating and maintenance (O&M) rate be reduced by 6.7%. Revenue to cost ratios which Mr. Marcus filed in his evidence are referenced in Section 4(a) hereof.

#### MI

The MI submitted that the zero intercept studies, as adjusted by Mr. Marcus, provided a minimum system cost which was 79% of net book value, rather than \$5 million greater than book value as APL's unadjusted study indicated.

In argument, the MI also provided another approach to estimating the customer component of the total distribution asset, utilizing strictly current replacement costs. The MI submitted that its approach would eliminate any errors in

### (b) Classification of Distribution Assets

assumptions regarding the weighted age, construction price index or prorated depreciation. The MI calculated a customer component of 30% for secondary distribution assets, using only 30 foot poles priced at \$465 each, and a customer component of 23% with 45 foot poles at \$610. The MI submitted that, while the approach assumed no changes in system design or function over time, it provided independent support for Mr. Marcus' customer component of 23% (Exhibit 55) and APL's preliminary zero intercept analysis customer component of 30%.

The MI noted that APL had indicated, in its revised response to BR-APL.1(b), that the zero intercept based regression does a reasonably good job of describing the cost/size relationship and reflects the Board's directions. The MI submitted that Mr. Marcus's adjusted revenue to cost ratios (Exhibit 56) should be used in evaluating APL's rate design. (Argument, p.3)

### **IPCAA**

IPCAA submitted that a number of reasons were provided by APL for not incorporating the results of its zero intercept studies into the COSS (Tr. pp.260-261, 265) and these reasons were not disputed (Reply, p.4). IPCAA submitted that "speculations" as to how APL's study might be adjusted were in no sense established as correct on the evidence. (Argument, p.17)

### REA/AAMDC

The REA/AAMDC submitted that APL had not responded fully to submissions that the zero intercept study data, as adjusted by Mr. Marcus, was adequate

### (b) Classification of Distribution Assets

to incorporate into APL's COSS. The REA/AAMDC submitted that there was sufficient evidence on the record to support the use of the zero intercept study and the Board should require APL to incorporate it. (Argument, p.11)

### PICA

PICA submitted that given the deficiencies and shortcomings APL described in its current zero intercept analysis, the method APL proposed for allocation of customer and demand costs should be approved for this proceeding. However, PICA further submitted that APL should be directed to carry out a survey, using sampling methods, to determine the size and age of historical distribution assets and to use the survey results to provide a zero intercept study for distribution assets at APL's next GRA. (Argument, p.4).

### CCA

The CCA submitted that only meters and service lines were clearly customer related distribution system assets and that other distribution system investments not funded by customer contributions could be classified as demand related. The CCA noted that the zero intercept study by Mr. Marcus suggested that 23% of APL's investment in poles, towers and fixtures should be classified as customer related. The CCA submitted that regression analysis indicated that the customer related investment in those assets may be between 16% and 30% of the total cost of those facilities. The CCA also submitted that, considering the inconclusive results of APL's analysis and other parties' assessments, the reliability of APL's cost of service (COS) results was insufficient to warrant use of a plus or minus 5% band as a measure of the acceptability of revenue to

### (b) Classification of Distribution Assets

cost ratios. The CCA submitted that the Board should encourage APL's further investigation and development of supporting data for its methods in its next GRA. (Argument, p.7)

The CCA further submitted that, in light of the overstatement of customer related costs, the residential customers should not face any rate increase in this rate case. (Reply, p.8)

### APL

APL indicated that a minimum size approach was appropriate when the relationship between cost and capacity, required for the zero intercept approach, is not present. APL submitted that the minimum size approach was appropriate for Poles, Towers and Fixtures, since there was no relationship between size and the demand that can be served and since legislation requires that certain clearances be met. (Reply, p.8)

Despite the REA's statement to the contrary, APL submitted that its distribution price index in its zero intercept approach did account for the increase in pole prices since 1990. APL submitted that results from use of the replacement cost method are distorted unless specific inflation factors for each type of asset are available and even then it may be impossible to accurately reflect historical cost since APL's asset records show only the average facility age, while assets are of various ages. (Reply, p.9)

### (b) Classification of Distribution Assets

APL agreed with the REA/AAMDC that the costs of some underground conductors included in the 1992 study were incorrectly excluded from the 1993 study. APL indicated, however, that the problem identified would remain even if the 1992 study were used, since the result would imply use of the most expensive conductor throughout APL's system. (Reply, p.10)

APL submitted that no intervenor adequately refuted APL's claim that minimum size/zero intercept studies performed using APL asset records resulted in irrational results. APL considered invalid the REA/AAMDC's use of an inflation factor to generate rational results, since arbitrary adjustments do not solve the problem of having inadequate data. APL submitted that the minimum size/zero intercept results were unusable and that the Board should approve the classification of costs to demand and customer as filed. (Reply, p.11)

### Board Findings

The Board previously directed APL to provide an objective study, considering that the study should be preferable to subjective assessments for the purposes of classifying distribution costs to demand and customer. However, the Board notes that in this proceeding the study, performed using APL's current asset records, resulted in "irrational" results unless subjectively adjusted, due to the inadequacy of those records for use in a zero intercept study. The Board considers, therefore, that all of the methods of classification of distribution assets suggested in this proceeding require reasoned judgement. In view of the shortcomings indicated in the studies supplied by intervenors, the Board

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## ALBERTA ENERGY AND UTILITIES BOARD

- 3. COST OF SERVICE
- (b) Classification of Distribution Assets

considers the classification of costs to demand and customer as filed by APL to be more appropriate for use in this proceeding.

### (c) Allocation of Distribution Assets

APL allocated 1991 distribution assets to rate schedules based on forecast 1993 customers and class NCPs, instead of allocating distribution additions partly on the basis of a rate class' forecast incremental customer additions, as was done in past GRAs. APL stated that the method used in past GRAs had incorrectly mixed average embedded costs allocation with incremental or marginal cost allocation.

APL indicated that the 1993 forecast distribution assets were then prorated to rate schedules based on the 1991 actual distribution assets allocations. APL also indicated that an adjustment was made to recognize the portion of primary distribution assets deemed upstream for Electric Energy Marketing Agency (EEMA) purposes.

### MI

The MI submitted that the two year lag, between 1991 actual and 1993 forecast date, resulted in over-allocation of costs to rate classes which grew at a slower than average rate and under-allocation to classes which grew faster. The MI submitted that, preferably, the forecast gross distribution assets should first be split between rural and non-rural categories and then allocated on the basis of the forecast NCPs and number of customers, or, at least, the data lag should be reduced to no more than one year.

- 3. COST OF SERVICE
- (c) Allocation of Distribution Assets

### **IPCAA**

IPCAA submitted that the argument that APL's allocation method was unfair, since the farm class' share of energy and demand has declined in recent years as capital costs have risen, ran counter to two important principles. Firstly, it was well accepted that costs should not be distinguished to customers on the basis of vintage. Secondly, all customers in a rate class do not use vintage assets equally since some increase or reduce their use of electricity over time. IPCAA submitted that the decision to abandon the cost averaging, which the REA/AAMDC endorsed, and move to incremental cost causation, should be predicated on more than "mere suspicion". IPCAA submitted that expansion tends to benefit all customers and that any "philosophical leanings" held by APL and affecting cost over-allocation to Rate 56, must be further tested. (Argument, p.2)

### REA/AAMDC

The REA/AAMDC recommended that the marginal cost allocation method used previously be continued, since the proportion of customer related cost allocated on an incremental basis was small. An additional benefit would be the reduction of what the REA/AAMDC submitted was the over allocation of cost to the Farm rate class.

Given the very different growth rates of the various rate classes, the REA/AAMDC supported the MI's proposal that in future COS studies APL should be directed to first split forecast gross distribution assets between rural

### (c) Allocation of Distribution Assets

and non-rural categories, and then to allocate them on the basis of forecast NCPs and number of customers. (Reply, p.4)

### **PICA**

PICA agreed with APL that distribution plant additions should be allocated to customer classes based on an average cost per unit basis, since it was consistent with the principle of averaging all vintages for an embedded ECOSS. Then, if APL's classification between customer and demand is appropriate, vintage differences alone would not result, at subsequent GRA's, in significant swings of costs allocated between rate classes.

### APL

APL noted that the marginal approach to cost allocation violates the averaging concept and leads to an inequity in that classes forecast to be fast growing in test years receive above average increases and classes which actually grow faster between GRAs will see no such increases.

APL submitted that the use of forecast test years in GRAs makes it impossible to reduce the data lag as the MI's recommend. However, APL indicated that it would investigate the MI suggestion that forecast distribution assets be split into rural and non-rural prior to allocation to rate classes. (Reply, p.13)

### Board Findings

The Board considers that the change in COS methodology made by APL is appropriate since averaging distribution assets across vintages should be more

### (c) Allocation of Distribution Assets

consistent with the principle of averaging all vintages of customers and should also minimize rate instability between GRAs. The Board expects that APL will complete a study of the results of splitting forecast distribution assets into rural and non-rural prior to allocation to rate classes and, if appropriate, incorporate the results of this study in its next Phase II filing.

### (d) Rural/Non-Rural Split of Secondary Distribution Assets

APL indicated that it had segregated the secondary distribution system into rural and non-rural components to recognize the cost differences in supplying rural versus non-rural customers. APL stated that it classified distribution assets on the basis of the whether they were constructed to serve rural or non-rural customers and that it did not make changes to the classifications to reflect subsequent changes in customer mix.

#### REA/AAMDC

The REA/AAMDC noted that APL agrees that it appears that the current COS over-allocates distribution asset costs to farm rate classes since APL does not reclassify the assets from rural to non-rural when an urban area annexes a rural area. The REA/AAMDC submitted that APL tried to minimize the effect, but the accuracy of the split between rural and non-rural customers should be established to ensure fair allocation to farm customers. (Argument, p.12)

#### MI

While the MI "took no exception to" the REA/AAMDC recommendation, the MI noted that APL also made no change in classification if a distribution line classified as non-rural was tapped into by rural customers. The MI submitted that any analysis of distribution assets should involve all changes in use and not just those related to annexation situations. (Reply, p.1)

- 3. COST OF SERVICE
- (d) Rural/Non-Rural Split of Secondary Distribution Assets

### APL

APL submitted that, while its accounting system was not designed to track assets to perfectly mirror usage, it accurately recorded the usage of the majority of the assets. The COSS could not be expected to accurately allocate the minority of costs associated with exceptions. (Argument, p.14) APL noted that, while its preliminary analysis indicated some inaccuracies in the asset records, it could not yet provide the magnitude of those inaccuracies. APL agreed that further work was necessary to identify and quantify problems with the asset records and to identify an appropriate solution. (Reply, p.5)

### **Board Findings**

The Board considers APL's accounting system should track the usage of as high a portion of its assets as reasonably possible, thereby allowing the COSS to allocate most of APL's costs accurately. The Board notes that, while APL suspected the effect of the inaccuracies in asset records to be small, APL agreed that to clarify the effect further work was necessary. The Board expects that APL will complete a study of its asset records, report on the magnitude of inaccuracies and propose any corrections required in its next Phase II filing.

### (e) Allocation of Secondary Distribution Costs

Primary customers are large customers who take service at 25 kV. APL indicated that primary distribution serves a transmission function whereby energy is transferred from a transmission substation to a load center by numbered primary distribution lines. Secondary distribution distributes energy throughout an area on unnumbered 25 kV lines, but does not serve any distribution level. APL indicated that customers served from the primary distribution level would no longer be allocated costs associated with the secondary distribution level.

### REA/AAMDC

The REA/AAMDC submitted that APL's proposed change was the "antithesis" of the averaging concept. The REA/AAMDC submitted that there was no difference in service from primary or secondary distribution lines and that some primary customers took service from secondary distribution lines.

The REA/AAMDC also submitted that the costs of 25 kV lines for REA's and other farm rate classes were allocated upstream and therefore farm customers should not be allocated any further 25 kV distribution costs in the downstream cost allocation process. (Argument, p.9)

#### PICA

PICA noted that APL was unable to separately identify the costs of 25 kV unnumbered lines. PICA submitted that, since some primary customers may be

### (e) Allocation of Secondary Distribution Costs

connected by unnumbered lines, little weight should be accorded the methodology change proposed by APL. (Argument, p.8)

### **IPCAA**

In response to the position of the REA/AAMDC, IPCAA submitted that the averaging concept requires that similar customers not have their costs distinguished by virtue of asset vintages, since costs caused by similar customers will likely be similar over time. IPCAA submitted that the averaging concept had nothing to do with charging customers for the costs of facilities they do not use. (Reply, p.3)

### APL

APL acknowledged that some primary customers were served from secondary distribution lines, but considered that the large individual loads of primary customers made it likely that the majority were served from primary lines. APL noted that primary distribution customers' loads were each individually large enough to be considered load centers. APL submitted that the most reasonable approach was to allocate only primary distribution costs to primary customers. (Reply, pp.11-12)

APL noted that its intent was to allocate upstream only the portion of those 25 kV lines which connect the Farm load system with the transmission system. The costs of other 25 kV lines distributing energy into the farming areas remained downstream. APL submitted that the REA's assumption, that all 25 kV costs associated with the Farm rate class were allocated upstream, was

### ALBERTA ENERGY AND UTILITIES BOARD

- 3. COST OF SERVICE
- (e) Allocation of Secondary Distribution Costs

incorrect. APL submitted that the Farm rate class was correctly allocated a portion of downstream 25 kV costs. (Reply, p.12)

### Board Findings

Considering the size of primary loads, the Board will accept, for the purposes of this Decision, APL's position that most primary loads are served by primary distribution lines. However, considering that APL has acknowledged that at least some primary loads are served off of secondary distribution lines, the Board expects APL to complete a study of its distribution lines to determine whether some portion of the cost of secondary lines should be allocated to primary customers. APL is expected to incorporate the results of the study in its next Phase II filing.

### (f) Calculation and Allocation of the 1993 EEMA Flow-Through

### **PICA**

PICA submitted that APL's treatment of the 1993 EEMA flow-through distorted the results of the COSS. The \$17.788 million flow-through, which reflects the change in transfer payments by rate class from 1992 to 1993, was allocated to rate classes on the basis of revenues per class rather than costs per class. As included in Section 4(a) of this Decision, PICA set out the revenue/cost ratios which would arise from allocation by cost (Argument, pp.3-4 and Attachment 1).

#### REA/AAMDC

The REA/AAMDC agreed with PICA that APL's use of the EEMA rider revenue to allocate the EEMA flow-through amount to rate classes did not reflect cost causation. The REA/AAMDC recommended that the Board allocate the 1993 EEMA flow-through amount based on 1993 costs rather than revenues. (Reply, p.4)

### <u>CCA</u>

The CCA submitted that APL should allocate the 1993 EEMA flow-through amounts based on 1993 costs rather than the 1993 EEMA flow-through rider revenue. (Reply, p.7)

- COST OF SERVICE
- Calculation and Allocation of the 1993 EEMA Flow-Through (f)

### Board Findings

While the Board considers that the modification to the COSS suggested by PICA may be appropriate from a technical point of view, the Board notes that the change in revenue to cost ratios arising from the adjustment would be small, and in no case larger than 2%. The Board does not consider that such a change should cause it to vary its findings, set out in the sections which follow, wherein the Board considers that in the circumstances of this Application an across-the-board average rate increase is appropriate for most The Board recognizes the COS to be only one factor to be considered rates. in rate design and further recognizes that the revenue to cost ratio for a customer class is a moving target that depends on the changing average revenues per customer, the average costs per customer and the changing cost characteristics of the AIS.

#### (a) Principles of Rate Design

APL stated that its rates were designed taking into consideration the following eight rate design criteria. These criteria establish that rates should:

- (1) Recover the total revenue requirement including required increases in revenue, together with the allocation of this revenue increase to each class of customer.
- (2) Recognize the level and structure of existing rates and their historical development. Major modifications to rate levels and structures should be made gradually.
- (3) Recognize the value of service provided, specifically, competition with alternative sources of energy services and the price sensitivity of different consumer groups.
- (4) Recover the COS as determined by cost studies. Bearing in mind an increased emphasis on criteria number (3) and that the cost of future facilities required to provide service should be recognized.
- (5) Be comparable with rate levels, structures and policies of other utilities, especially those adjoining APL's service territory.
- (6) Avoid undue discrimination between and within customer classes.
- (7) Promote efficient and cost effective usage of power and discourage wasteful or inefficient usage.
- (8) Promote ease of understanding and acceptance by customers, as well as ease of administration and economy of billing.

## (a) Principles of Rate Design

APL indicated in Exhibit 30 which of these criteria were used in designing each particular rate and also supplied the weight given to each criteria in each rate's design.

#### MI

The MI submitted that there was insufficient evidence before the Board to justify other than an across-the-board increase for all customer classes (Argument, p.45). Using Mr. Marcus' methodology in Schedule 1 of Exhibit 56, the MI calculated that the revenue to cost ratio for APL's proposed Rate 31 would be about 100% and less than "APL's targeted 101%" (Argument, p.24). The MI also submitted that APL had not justified a below average increase for Rate 31 by relying on "APL's experience" regarding Rate 31's price sensitivity (Tr. p.283). The MI recommended that an average increase of 4.7% be applied to Rate 31, thereby providing sufficient additional revenue to allow all other rate classes to also receive only the average increase.

#### <u>IPCAA</u>

IPCAA submitted that, other than for an average increase, APL's approach to rate design is incapable of any analysis, verification or replication. IPCAA submitted that the Board should clearly indicate to APL that the broad, general and nebulous approach to rate design advanced by APL in this proceeding is not reasonable. (Argument, p.4)

IPCAA considered that the argument that the revenue to cost ratio of Rate 31 should be 100% ignored any rate design consideration other than the COS.

## (a) Principles of Rate Design

The MI position, that Rate 31 should receive the average increase to reduce the increase of Rate 11 to the average, was also unreasonable since it would result in a Rate 11 revenue to cost ratio even further below unity. (Reply, p.8)

#### REA/AAMDC

The REA/AAMDC submitted that, if the Board accepted their proposal to increase the allocation of secondary distribution costs to demand and reduce the customer portion, the revenue to cost ratio of Rate 31 would be below 100%. The REA/AAMDC noted that, even if APL had retained the cost allocation methodology approved in Decision E93035, then an across-the-board increase would have yielded a 101% revenue to cost ratio for Rate 31, which was the ratio APL considered appropriate. Furthermore, the REA/AAMDC submitted that an average increase would not adversely effect Rate 31 customers, since they were already paying the higher rate due to the existing interim across-the-board increase of Rider G. Finally, the REA/AAMDC submitted that the evidence before the Board did not warrant a below average increase for Rate 31 and the average increase should be applied. (Argument, p.17)

## **PICA**

PICA noted that Rate 31 could be divided into three approximately equal revenue sub groups; small (less than 500 kW), medium (consumption between 500 kW and 10 MW) and large (over 10 MW), with each subgroup generating revenue higher than from any other APL rate class. PICA noted that Exhibit 52 indicated that pursuant to APL's proposal, small Rate 31 customers

### (a) Principles of Rate Design

would receive a below average increase of 3.6%, medium customers an above average increase of 5.6% and large customers an average increase of 4.7%. PICA also noted that MI.APL-28 (Revised) indicated revenue to cost ratios of 107.65% for customers under 2 MW and 94.11% for customers over 2 MW. noted as well that those revenue to cost ratios had deteriorated since the previous rate hearing when the corresponding ratios were about 105% and 98% Given the deterioration in revenue to cost ratios for over and (Tr. p.296). under 2 MW customers, PICA submitted that the Rate 31 second demand block should remain at \$14.70/kW/month and the third demand block should be raised, per Exhibit 75, to maintain revenue neutrality for Rate 31 as a whole PICA and to provide medium customers with about an average increase. submitted that, if competitive factors provided justification for under recovery from large customers, all customers should pay for foregone revenues, not just the small and medium size Rate 31 customers. (Argument, p.16)

#### CCA

The CCA submitted that APL had failed to provide compelling evidence to support the appropriateness of a less than average increase for Rate 31. The CCA also submitted that, if the Board finds discounts appropriate on the basis of competition from alternate energy, the Board should require the company to absorb 30% of the differential between forecast costs and revenues for the class to provide the company incentives to maximize revenue and to recognize that rate discounts reduce risks to shareholders. (Reply, pp.20-21)

## (a) Principles of Rate Design

The CCA submitted that since APL's COS did not specifically address or account for costs imposed on the system by industrial customers' low power factor operations, the cost to serve large industrial customers was understated and the costs to serve residential and small commercial customers was overstated.

#### Board Findings

The Board agrees that each of the eight rate design criteria considered by APL in the design of the proposed rates is important in certain circumstances. The Board also agrees with APL that the weighting of each criterion should vary depending on the particular circumstances of each rate class, and that judgment must be exercised to obtain an appropriate balance among the objectives of the criteria.

The Board considers that the record of this proceeding indicates that APL considered most of the criteria in the design of each of the rates it proposed. The Board notes that there were no major plant additions forecast for the 1993 test year; nor was there any significant change in rate design philosophy proposed by APL for 1993. As a result no significant inter-class rate rebalancing was required, and none was proposed by APL. Therefore, the Board is not persuaded by IPCAA's arguments that APL's approach was unreasonable in the circumstances. The Board considers that APL, generally speaking, has applied the criteria appropriately in the design of its proposed rates.

### (a) Principles of Rate Design

In light of the lack of any demonstrated need for rate rebalancing, the Board considers that rate stability, acceptability by customers and fairness to customers are the most important criteria to be considered in the design of rates for the 1993 test year. An average across-the-board increase in rates would generally best meet those criteria. However, the Board also considers that it is generally important, when a customer class is out of tolerance, that some move is made in the direction of the target range. Therefore, the Board considers that, for the purposes of this Decision, an approximate average across-the-board increase in the revenues recovered from each rate class is appropriate, with certain minor adjustments made for specific rate classes.

The Board is not convinced by submissions that competitive forces, or any other criteria, currently provide sufficient reason for a lower than average increase for Rate 31. The Board notes that, if revenue from Rate 31 is increased by the same percentage of about 4.9% as that from other rate classes (i.e. an average across-the-board increase), then APL will recover its total 1993 revenue requirement on a forecast basis. (See Appendix 1)

The reasons for the Board's specific adjustments to APL's proposed rates are set out in Section 5 of this Decision.

## (b) Partial Requirements Rate Design Philosophy

APL noted that some services in the partial requirement rate package, such as system support and standby, had been components of former full service rates and are delivered using common facilities whose costs were and are fully allocated to full requirement rate categories.

In Decision E94034, the Board considered that the evolution of APL's partial requirement rates should continue in an effort to develop fair rates which will reflect an appropriate apportionment of system costs and benefits amongst all customers, since all customers, by their interconnection to the system, cause system costs to be incurred and system benefits to be available.

The Board considered that the ability of the system to offer partial requirement rates which are lower than full requirement rates is a valuable system benefit. The Board noted that it was not possible, at the time Decision E94034 was released, to separate the cost to produce certain operating benefits, or alternatively the cost of partial requirement services, because those benefits are intrinsic to any large electric system's physical characteristics and the existing ECOSS had evolved to allocate costs to full requirement customers. The Board considered that it would be equitable for all customers who produce those valuable benefits to share in a portion of their value. The Board accepted APL's position that the benefits being received by present partial requirement customers would generally exceed those benefits being received by the system as a result of the existence of the partial requirement customers. The Board

# (b) Partial Requirements Rate Design Philosphy

considered that offering partial requirement services at reduced prices compared to full requirement rates in effect ensures that a portion of the value of system operating benefits is received by partial requirement customers.

The Board considered that, since the electric system presently provides more benefits to partial requirement customers than it receives from them, it would not be inappropriate, at that time, for partial requirement rates to be set to exceed the rates determined by the present ECOSS. Partial requirement customers would then provide a contribution towards fixed system costs. The Board noted that, if the number of partial requirement customers grew, the stabilization and capacity capabilities of their class may increase and provide offsetting benefits to the system at some point in the future.

Based on APL's definition of services, the Board considered that APL had valued services appropriately. Generally the value of standby power is higher than maintenance power, which in turn is higher than supplemental power which is the same as other firm power sales. All are of higher value than economy energy. Interruptible power is lower in value than firm power. Economy energy is the lowest value power and should be used only by customers for whom power priced under any other rate would not be economically competitive.

The Board considered that, as APL proposed, those relative market or economic value rankings should be combined with appropriate transitions to embedded cost rates to serve as an appropriate aid in the design and setting

# (b) Partial Requirements Rate Design Philosphy

of rates for any service which could not be appropriately determined using the ECOSS. The Board was generally satisfied that the rates proposed by APL in its industrial rates basket were at the appropriate level considering the value and economic ranking of the services provided under the rates. The Board did not consider that the embedded cost and hence the revenue to cost ratio of each partial requirement service were the most significant design criteria for the purposes of that Decision.

#### **PICA**

While PICA supported APL's partial requirements rate design philosophy, PICA considered that in future GRAs time of use price signals would allow more efficient utilization of the system. PICA submitted that the Board should direct APL to look at time of use price signals as a refinement to its firm partial requirements rates.

## Board Findings

The Board examined submissions by IPCAA, IPPSA and the ACC that modifications should be made to APL's partial requirement rates. However, the Board continues to consider that APL's partial requirement rate design is appropriate. The Board was not persuaded by any evidence or argument adduced at this proceeding that there is any need for any change in the findings, in Decision E94034 as outlined above, regarding partial requirements rate design. Therefore, the Board considers that an across-the-board increase in partial requirement rates is appropriate at this time with the minor

## ALBERTA ENERGY AND UTILITIES BOARD

- 4. RATE DESIGN
- (b) Partial Requirements Rate Design Philosphy

adjustments indicated for specific rate classes in the Individual Rates, Tolls and Charges portion of this Decision.

## (a) General

In the Application the average rate increase proposed by APL was 4.72% on rates excluding all riders or 0.0% on rates including all riders (existing interim Rider G had been set at 4.88% to allow APL to collect its 1993 revenue requirement on a forecast basis). The rate increases proposed by APL and forecast revenue recovery were provided in Schedule 4.3.1 of Tab 2 as follows:

Proposed Rate Increases Over Existing Rate								
			(\$000's)					
		Revenue on Existing Rates	Revenue on Proposed Rates		Revenue on Existing Rates	Revenue on Proposed Rates		
Line	Rate Schedule	Including	Including	*	Excluding	Excluding	*	
No.	Rate Schedule	all Riders (Rider G=4.88%	all Riders (Rider G=0%)	Increase	all Riders	all Riders	Increase	
		•	,					
1	Residential Rate 11	61,952	62,203	0.4%	57,114	60,149	5.3%	
2	Residential Rate 18	3,532	3,545	0.4%	3,320	3,496	5.3%	
3	REA Farm Service Rate 51	13,462	13,535	0.5%	12,836	13,535	5.4%	
4	Farm Service Rate 56	21,177	21,270	0.4%	20,193	21,271	5.3%	
5	General Service Rate 21	48,940	49,258	0.6%	45,183	47,671	5.5%	
6	Irrigation Rate 25 and 26	117	118	1.0%	111	118	5.9%	
7	Industrial Rate 31	216,209	215,406	-0.4%	206,426	215,396	4.3%	
8	Rate 33 Reserve Energy	9,008	<b>8,9</b> 09	-1.1%	5,569	5,569	0.0%	
9	Rate 35 WESCUP	2,717	2,717	0.0%	2,707	2,707	0.0%	
10	Rate 36 Husky Rainbow Lake	7,302	7,276	-0.3%	6,962	7,276	4.5%	
12	Oilfield Rate 41	30,566	30,764	0.6%	29,030	30,645	5.6%	
13	Street Light Rate 61	3,219	3,237	0.5%	2,976	3,130	5.2%	
14	Space Light Rate 63	760	764	0.5%	708	746	5.4%	
15	Total	418,961	419,001	0.0%	393,134	411,709	4.7%	

As can be seen in the above table APL proposed to increase revenue on most rates by a maximum of 1.0% (over existing rates including Rider G). APL

#### (a) General

proposed that Rate 31, Rate 33 and Rate 36 (which is based on Rate 31) would recover slightly less revenue than on existing rates.

The Board's specific changes to APL's proposed rates and the reasons for the changes are set out in this section of the Decision. The revenue cost ratios resulting from APL's rate proposals and COS proposals are shown in Appendix 1. Also shown in Appendix 1 are the Board revenue to cost ratios for the rates approved by the Board.

## (b) Residential Rate 11 and Rate 12

APL proposed a 5.3% increase in average Rate 11 billings, which was slightly higher than the 4.7% average increase, and would result in a revenue to cost ratio of 99%. APL proposed no increase in the fixed charges of residential Rate 11 but an increase of 6.82% in energy charges resulting in an increase from 7.04¢/kWh to 7.52¢/kWh.

APL proposed elimination of Rate 12 (residential time-of-use option) as there were no customers on the rate. The time-of-use pilot project was proposed and approved in APL's 1991/1992 GRA. APL noted that customers indicated that the savings did not justify the change in consumption behavior.

#### MI

The MI noted that Mr. Marcus' adjusted zero intercept studies indicated a revenue to cost ratio of 100.6% for APL's proposed Rate 11. The MI supported the evidence of Mr. Marcus and further noted that APL had proposed a less than average increase for Rate 31 and was not moving Rate 56 above the revenue to cost ratio of 83%. The MI submitted that, although APL's expressed intent was to apply the same average increase of 4.7% to all classes, Rate 11 customers received an increase of 5.3%, while the increase for Rate 31 was below average. The resulting revenue to cost ratio for Rate 11 would be 99%, while APL had chosen not to bring certain other rates within the 95% to 105% Board approved tolerance level. The MI submitted that the evidence filed

## (b) Residential Rate 11 and Rate 12

by APL did not justify more than an average increase for Rate 11 customers under those circumstances.

#### CCA

The CCA submitted that given evidence concerning over allocation to the customer related components and that APL's residential revenue-to-cost ratio was higher than that of most utilities (Tr. p.394), the increase faced by Rate 11 customers should be tempered. The CCA submitted that the revenue to cost ratios of Rates 18, 25, 36, 56, 61 and 63 should be increased to mitigate the rate increase faced by Rate 11 customers.

The CCA also submitted that the Rate 11 fixed charge recovers a significant proportion of APL's revenue requirement, which effectively reduces the risk that the shareholders must bear. Customers under Rate 11 generally have no distribution options for receipt of their electrical energy. The CCA further submitted that a relatively high customer charge does not promote efficient use of electrical energy in APL's service area, since a higher fixed charge and a lower energy charge conveys the inappropriate pricing signal that conservation is not desirable.

The CCA submitted that Rate 12 should remain in place to ensure future conservation of natural resources and that the design of Rate 12 could be revisited in a future GRA.

#### (b) Residential Rate 11 and Rate 12

#### APL

APL noted that there were no objections to the proposed Rate 11 at the Hearing and requested that Rate 11 be approved by the Board as proposed.

In response to the CCA's concern about the level of the fixed charge component of Rate 11, APL stated that the fixed charge collects only a portion of the customer costs allocated to Rate 11. Those costs were related to distribution poles, overhead and underground line and various administrative expenses, all of which vary with the number of customers served rather than with demand or energy considerations. APL noted that the proposed fixed charge component would only collect 72% of the customer costs allocated to Rate 11, whereas the proposed energy charge component collects 138% of the allocated energy costs. APL submitted that, therefore, the claim of the CCA that the fixed charge level is driven by a desire to limit shareholder risk is unfounded and incorrect. Furthermore, the proposed residential energy rate provides more than an adequate signal for customers to conserve energy.

#### Board Findings

The Board accepts that Rate 12 should be eliminated since there are no customers willing to take service under the rate and the Board generally considers rate offerings should be as simple as reasonably possible. If residential time of use rates are requested by APL's customers in the future, the new rates can be set at appropriate levels at that time.

#### (b) Residential Rate 11 and Rate 12

The Board notes that APL's fixed charge collects 72% of the customer costs allocated to Rate 11. The Board considers that the level of APL's fixed charge component is not inappropriately high. Therefore, in light of the Board's findings that an average across-the-board increase in rates is appropriate in this Decision, the Board will accept APL's proposal of no increase in the fixed charge of residential Rate 11, but decrease APL's proposed energy charge from 7.52 ¢/kWh to 7.48 ¢/kWh.

## (c) Residential Rate 18

While APL proposed a 5.3% increase in average Rate 11 billings, the Company proposed to maintain Rate 18 (the residential rate for Lloydminster) at a lower rate than Rate 11 so as to be comparable to Saskatchewan Power Corporation's (SaskPower) residential rate in an effort to retain the Lloydminster franchise and the revenues associated with it. APL indicated that the Lloydminster franchise agreement would expire on October 31, 1996 and, therefore, comparability with SaskPower was a dominant rate criterion.

#### MI

In response to CCA submissions expressing concern regarding "below cost charges for service to Rate 18," the MI noted that the average Rate 18 residential customer (consuming 600 kWh/month) would be billed only 2.33% less than the average Rate 11 customer. The MI noted that only the cost of serving 13,711 residential customers within the Lloydminster district was available. The cost to serve the 5,716 Rate 18 customers in the City of Lloydminster could not be broken out and therefore a revenue cost ratio was not known.

The MI submitted that, at any rate, competitive pressures justified the rate differential. SaskPower's rate was some 6.3% lower than Rate 18 for the average customer and APL indicated that if the Lloydminster franchise were lost, APL would have stranded investment to the year 2000 and beyond. The MI considered that it "would, therefore, be inappropriate to attempt to

#### (c) Residential Rate 18

separately identify the costs for Rate 18 simply because a separate rate has been struck due to competitive pressures from SaskPower." (Argument, p.11.)

In reply the MI submitted that the CCA concerns regarding Rate 18 completely ignored the fact that there is no specific evidence as to the specific costs of serving City of Lloydminster residential customers, and that Rate 18 was not based on COS criteria.

The MI took issue with a number of the submissions of the CCA with respect to COS, rate differentials and stranded costs, and noted that no other intervenors were opposed to the implementation of the proposed Rate 18. The MI agreed with the REA/AAMDC that the discount is at a "nominal level" and "almost symbolic at this time." The MI agreed with the recommendation of the REA/AAMDC that APL should develop a more accurate COSS by using a single residential class, rather than dividing the class between Rates 11 and 18.

Finally, the MI stated that the CCA's submission that APL should be required to absorb 30% of "foregone revenue" should be considered by the Board as patently unfair, since retaining the Lloydminster load is in the best interests of APL's other customers.

#### REA/AAMDC

The REA/AAMDC submitted that the \$90,000 discount to Lloydminster customers was nominal and also reasonable, if required to compete with SaskPower. The

## (c) Residential Rate 18

REA/AAMDC noted that the difference in Rate 11 and 18 costs was within the range of the costs which are "geographically averaged" for Rate 11. (Argument p.19)

The REA/AAMDC noted that, for the COSS, Rate 18 data is aggregated with Rate 11 data from 37 communities in the Lloydminster district distorting comparisons of Rate 11 and 18. The REA/AAMDC submitted that APL should provide an aggregate COS for a single residential class including Rate 18 customers and then derive a rate for Lloydminster through a rider applied to Rate 11.

#### **PICA**

In argument PICA noted that Rate 11 has historically been higher than SaskPower's residential rate. Consequently, to limit the potential impacts of competition from SaskPower, Rate 18 was designed to produce a net differential of 10% or less. PICA noted that proposed rates for Rate 18 result in a revenue cost ratio of 85% compared to 99% for Rate 11.

PICA indicated that it considered Rate 18 to be a load retention rate since it is set significantly below average cost, to generate a certain amount of contribution towards fixed costs and to avoid stranded investment in the short to medium term. PICA agreed with the CCA that it is economically inefficient to continue providing service under Rate 18 if long run revenues are expected to be insufficient to cover long run average costs. However, there was no

#### (c) Residential Rate 18

evidence in these proceedings indicating long run marginal costs for Rate 18 are less than average embedded costs.

PICA also submitted there was insufficient evidence in the proceedings to make an assessment of the risk of stranded investment resulting from potential loss of the Lloydminster franchise. PICA recommended that APL be directed to identify and quantify the cost of facilities that could be stranded and how the risk would change over time. PICA also suggested that APL should propose options for moving Rate 18 to full average cost recovery in the long term as the risk decreases.

PICA submitted that it did not oppose the approval of Rate 18 as proposed.

#### CCA

In argument the CCA stated that APL's COS analysis indicated that the Company's service to residential customers in the Lloydminster franchise area (Rate 18) did not recover its full costs of service at either existing or proposed rate levels. The analysis also suggested that the costs of serving those customers were greater than the costs of serving APL's other (Rate 11) residential customers.

The CCA noted that existing rates recover only 79% of the costs of serving Rate 18 customers and that proposed rates will recover only 84%. The CCA submitted that the revenue to cost ratio for Rate 18 is clearly not within the

## (c) Residential Rate 18

95% to 105% range previously used by the Board to judge the acceptability of cost recovery levels for individual rate classes.

The CCA noted that APL's rationale for maintaining Rate 18 at a level below COS reflects a concern that its charges for service may not be competitive with those of SaskPower. However, the CCA submitted that APL has not demonstrated that its rates exceed those which SaskPower could offer. APL has offered no assessment of the extent to which SaskPower would be required to upgrade existing transmission facilities or to acquire additional generation capacity so as to provide expanded service in Lloydminster. The CCA submitted that APL had not met its burden of proof with respect to the need for continued subsidization of service to Rate 18 customers, and that charges for these customers should be set at least equal to those proposed for Rate 11.

The CCA submitted that if the Board considers that competition from SaskPower is sufficient to justify APL's concerns regarding retention of service to the Lloydminster area, then the Board must assess whether the long-term subsidization of service to the area is in the best interests of the Company's other ratepayers.

The CCA further submitted that, should the Board conclude that below cost charges for Rate 18 are warranted to protect against potential loss of the Lloydminster franchise, the Board should take steps to ensure that APL has appropriate incentives to maximize the revenues derived from customers in the area. Such incentives should be designed to require APL to absorb a

#### (c) Residential Rate 18

percentage of the rate discounts, thereby ensuring that APL does not discount the rates any more than is necessary to retain the service.

In reply argument the CCA referred to comments made by Mr. Bruce Oliver in his testimony on behalf of the CCA, wherein he stated that APL appears in this instance to be facing a long-run form of competition rather than short-run competition. He indicated that in the short-run a supplier is better off if it obtains some contribution to its fixed COS by means of marginal pricing. However, marginal rates should not be offered in the long term. A supplier should discontinue provision of a service if it concludes that its long-run revenue from provision of the service will not be sufficient to recover its long-run average cost. The CCA submitted that in this situation, a supplier should be able to obtain a better long-run return through alternative investments.

The CCA agreed with the recommendation of the REA/AAMDC that a more accurate COSS should be developed, but did not agree that this would be achieved by combining rate classes 11 and 18 into a single residential class. The CCA felt that this would lead to higher rates and lower revenue to cost ratios for Rate 11.

The CCA submitted that the issue of postage stamp rates should not be confused with the issue of load retention rates, and stated that Rate 18 is a load retention rate that results in subsidization of uneconomic sales by all other customers. The CCA noted APL's assertion that the discounted present value

### (c) Residential Rate 18

of the annual rate discount for Rate 18 would be \$400,000. However, the CCA considered that since Rate 18 was established in 1974, it would be more appropriate to calculate the present value of the discount from that date. Therefore, according to the CCA, the resulting amount of approximately \$2.7 million is the economic cost to APL's other customers.

The CCA considered it unreasonable to use marginal rates in the long run, since other customers pay higher costs to subsidize those marginal rate customers. If the Lloydminster load would have been shed by the system and replaced by additional growth supplied by Lloydminster transmission and generation assets, rates would have been minimized for all other customers.

The CCA noted that significant plant had been built and entered into rate base since 1974. Therefore, continuing to offer Rate 18 to Lloydminster customers violated APL's stated load retention rate criteria since the criteria state that a load retention rate will terminate at the time new generation or transmission capacity is required.

The CCA considered that if discounted Rate 18 should remain in place, the discounts should be reflected in the energy charge and not in the customer charge. This would allow residential Rate 18 customers to change their consumption patterns to minimize their bills.

The CCA agreed with the MI that there is no specific COS information regarding Rate 18 customers in the City of Lloydminster. The CCA felt that

#### (c) Residential Rate 18

re-enforced the testimony of Mr. Oliver that there was no justification for a difference in Rates 11 and 18.

The CCA referred to load retention criteria previously submitted on behalf of the City of Red Deer at the recent TransAlta Load Retention hearing. The CCA submitted that certain of those criteria supported the position that APL's Rate 18 should have been subject to a time limit instead of being allowed to continue in place for in excess of 20 years. The CCA further submitted that those criteria appeared to support the CCA's view that foregone revenues should be apportioned between the shareholders of the utility and its customers. The CCA further noted that the REA/AAMDC, in argument submitted to the TransAlta hearing, also supported such apportionment.

### APL

APL stated that the primary constraint on Rate 18 has been the rate levels, structures and policies of SaskPower. The primary concern was that if APL rate levels became significantly higher than those offered by SaskPower, customer dissatisfaction might lead to loss of the Lloydminster franchise. Rate 18 has historically been set at a level no more than 10% higher than SaskPower's residential rate level.

APL noted that, like the Rate 18 revenue to cost ratio, the revenue to cost ratios of some other communities of similar size would also be above or below the 95% to 105% target range. Costs determined for a municipality or region may vary significantly from the average determined for the entire rate class.

#### (c) Residential Rate 18

Such differences are primarily attributable to the vintage of the facilities installed and communities like Lloydminster, which have experienced periods of recent high growth, can be expected to have lower than average revenue to cost ratios. Therefore, APL submitted that undue weight should not be placed on the absolute level of the Rate 18 revenue to cost ratio.

Referring to the CCA's concern that the magnitude of potential stranded investment had not been defined, APL submitted that the magnitude would be much greater than the magnitude of the rate discount provided.

APL disagreed with the CCA's view that any discount for Lloydminster should be reflected in the energy charge. APL submitted that maintaining the fixed charge at the current monthly level of \$10.60 and increasing the energy charge addressed customers' concerns and APL's objective of eventually merging Rates 11 and 18, since the energy charges of 7.52¢/kWh are now identical. APL submitted that Rate 18 should be approved as proposed.

In Reply APL agreed with the recommendation of the REA/AAMDC for development of a more accurate COSS using a single rate class rather than dividing the class between Rate 11 and Rate 18.

APL stated that Rate 18 should be considered part of the larger Rate 11 residential rate class and that Rate 18 was classified separately solely for rate design purposes. However, the classification resulted in the need for a separate COSS. If APL were to include all costs of serving residential

#### (c) Residential Rate 18

customers in all franchise areas, the costs allocated to current Rate 18 based on forecast sales would be \$3,691,000. Rate 18 as currently proposed will collect \$3,558,000. The revenue to cost ratio of 96% which would arise from such a methodology change is within the range approved by the Board.

APL further submitted that providing a subsidy to Rate 18 that ensures the continuation of the Lloydminster franchise is prudent in light of the costs that would be stranded if the franchise were lost to SaskPower. The loss of the franchise would result in the other customers absorbing the demand costs now paid for by the Lloydminster customers. APL calculated that the annual demand costs allocated to Lloydminster customers would be in excess of \$5 million (Exhibit 89 indicated that the 1993 EEMA demand estimate for Lloydminster was 25.75 MW and the EEMA demand cost was in excess of \$200/kW). Those annual demand costs are an order of magnitude greater than the present value of a perpetual subsidy annuity of \$40,000. Therefore, loss of the Lloydminster franchise for a single year would be more expensive than subsidizing Rate 18 forever.

#### Board Findings

The Board notes APL's submissions that the revenue to cost ratios of certain other communities served under Rate 11 would similarly be lower than 95% if their costs were isolated. The Board also notes that Lloydminster's revenue to cost ratio would be 96% if the costs to serve all residential customers in all franchise areas were averaged. The Board further notes APL's concern that, if its charges for service are not competitive with those of SaskPower, APL may

#### (c) Residential Rate 18

lose its franchise, thereby stranding significant investment for a number of years at a very high cost relative to the level of the Lloydminster "subsidy". Considering these factors the Board concludes that the level of Rate 18 proposed by APL is appropriate.

In light of the Board's findings that an average across-the-board increase in rates is appropriate in this Decision, the Board will accept APL's proposal of no increase in the fixed charges of residential Rate 18, but decrease APL's proposed energy charge from 7.52¢/kWh to 7.48¢/kWh.

The Board considers that the CCA proposal that shareholders should be required to subsidize a portion of the subsidy to Lloydminster would be unfair, since retaining the Lloydminster load is in the best interests of all of APL's other customers. The Board also finds little merit in the CCA's other arguments.

### (d) Small General Service Rate 21

APL proposed an increase of 5.4% in revenues from customers served under Rate 21, which was slightly higher than the 4.88% existing Rider "G". APL also proposed three extra options for Rate 21 customers. One was Rate 21A, an energy only option for smaller customers with very low consumption levels, who often do not understand demand charges and ratchets employed in Rate 21B. A second option was Option H which provides a credit for Rate 21 customers served at primary or transmission voltages and which was structured and set at the same level as existing Option H for Rate 31 customers. A third option was Option T (off peak demand) which allows customers to purchase power at 10% of the demand charge for the portion of off-peak demand that exceeds the on-peak demand, providing the customer pays for the installation of approved time-of-use metering and satisfies other Option T qualifications.

The proposed change in demand charge for Rate 21 was as follows:

	Existing	Proposed					
For all billing demand over 2000 kW:	\$3.89	\$4.05/kW					
The proposed changes in energy charges for Rate 31 were:							
For the first 200 kWh/kW of billing demand:	7.17	7.60¢/kWh					
For energy in excess of 200 kWh/kW:	3.22	<b>3.4</b> 0¢/kWh					

## (d) Small General Service Rate 21

#### CCA

The CCA stated that it had no objection to the implementation of an energy only option for small service Rate 21 customers provided that any risk in revenue loss that may be applicable to this option remains within the small general service category.

The CCA also contended that deficient power factor customers should be required to pay a charge which is reflective of the costs that they impose on other APL customers. The CCA submitted that a deficient power factor charge should be associated with Rates 21, 25 and 26 for customers found to have a power factor less than 90%. The CCA also submitted that APL should require customers to install corrective equipment if they are found to have a power factor less than 90%. The CCA suggested that APL could, on a sample basis, conduct power factor tests on an "economically viable" basis as an alternative to installing expensive metering devises to measure the power factor for billing purposes.

## **Board Findings**

In light of the Board's findings that an average across-the-board increase in rates is appropriate in this Decision the Board will accept APL's proposed fixed charge of \$5.04/kWh for Rate 21, but will decrease the proposed energy charges as follows:

## ALBERTA ENERGY AND UTILITIES BOARD

## 5. INDIVIDUAL RATES, TOLLS OR CHARGES

## (d) Small General Service Rate 21

	Proposed by APL	Board Approved
For the first 200 kWh/kW of billing demand:	7.60	7.53¢/kWh
For energy in excess of 200 kWh/kW:	3.40	3.38¢/kWh

The Board approves Option H since Rate 21 customers served at primary or transmission voltages should be entitled to an Option H which is structured and set at the same level as the existing Option H for Rate 31 customers. The Board also approves Option T for Rate 21, providing the reasons for its findings in this regard in the section entitled Option T. The Board considers that the other changes to Rate 21 proposed by APL are justified for the reasons supplied by APL.

#### (e) Irrigation Rate 25 and Rate 26 (REA) - Irrigation Pumping Service

APL proposed an above average increase for Rates 25 and 26 of 5.9% which would result in a revenue to cost ratio of 68%. APL considered that since further increases would result in rate levels higher than TransAlta's, no further revenue to cost improvement could be presently made.

APL also proposed that Rate 25 and 26 be applicable to all separately metered irrigation pumping services which are less than 150 kW, whether or not they are bona-fide farming operations, thereby minimizing intrusion into customers' operations. APL also proposed that, for Rates 25 and 26, as for Rates 31 and 41, it would estimate non-metered service demand as HP Nameplate multiplied by 0.76 or as kW Nameplate. This proposal was explained in BR-APL.4.

#### **IPCAA**

IPCAA stated that it had no objection to the specific rate proposed by APL for Rate 25. However, IPCAA submitted that the proposed rate was not well supported by APL's stated rate design criteria. IPCAA noted that APL's rate design criteria included value of service and comparability to other utilities. IPCAA contended that the use of these criteria should have resulted in an above average increase for Rate 25.

#### CCA

The CCA contended that deficient power factor customers should be required to pay a charge which is reflective of the costs that they impose on other APL

# (e) Irrigation Rate 25 and Rate 26 (REA) - Irrigation Pumping Service

customers. The CCA submitted that a deficient power factor charge should be associated with Rates 21, 25 and 26 for customers found to have a power factor less than 90%. The CCA also submitted that APL should require customers to install corrective equipment if they are found to have a power factor less than 90%. The CCA suggested that APL could conduct power factor tests on a sample basis as an alternative to installing expensive metering devices.

### Board Findings

The Board accepts APL's proposed increase of 5.9% which would result in a revenue to cost ratio of 68% for Rates 25 and 26. The Board notes that APL considered that no further revenue to cost improvement could be presently since further increases would result in rate levels higher than The Board generally considers that it is important, when a customer class is out of tolerance, to make a definite move in the direction of the target range (95%-105% revenue to cost ratio) to ensure that the rates remain just, reasonable and non-discriminatory. classes among customer However, the Board will approve APL's proposed 5.9% increase in light of Board's findings that the levels and TransAlta's rate across-the-board increase in rates is appropriate for most other rates in this The Board considers that any further increase above the 5.9% proposed by APL would be inappropriate at this time.

The Board agrees in principle with APL that for standard full requirement rates intrusion into customers' operations should be minimized. Therefore, the

## (e) Irrigation Rate 25 and Rate 26 (REA) - Irrigation Pumping Service

Board approves APL's proposal that Rates 25 and 26 be applicable to all separately metered irrigation pumping services which are less than 150 kW, whether or not they are bona-fide farming operations. The Board also approves APL's proposal to estimate non-metered service demand as HP Nameplate multiplied by 0.76 or as kW Nameplate (as explained in BR-APL.4) and as is the case for Rates 31 and 41, to better reflect actual demand for Rates 25 and 26.

The Board considers that CCA's submission that APL could conduct power factor testing economically is speculative and without evidentiary basis.

## (f) System Support Minimum Rate 30

APL proposed an increase of 4.9% to Rate 30. APL noted that the proposed level was very close to the equivalent TransAlta rate approved in Decision E94076, dated November 4, 1994.

System support is the "real time" continual balancing of power flows and electric system voltage and frequency control which is provided by interconnection to the integrated electrical system. APL indicated that Rate 30 was required to ensure compensation to the system for system support services in circumstances where no charge mechanism would otherwise be available. APL noted that even partial requirement customers who could provide all of their own load remain connected to the system to obtain the stability their electrical equipment requires and to avoid loss of production or the capital and operating costs required to provide the stability and backup necessary to run independently of the system. Such customers could receive significant operating benefits at no charge, since standard utility practice is to record demands by integrating energy over a 15 minute interval or longer, and since interval transient power flows that change rapidly or reverse direction within that time could register a low or zero reading.

In its 1992 Phase II filing APL indicated that Rate 30 was designed considering both value to the customer and an estimate of the cost of providing the service. The estimate recognized that fixed generation costs are incurred to provide load following and control of system frequency and that a minimum transmission

## (f) System Support Minimum Rate 30

system is required for partial requirement customer interconnection to various utility generators.

In Decision E94034, the Board noted that only those customers who are not billed an amount greater than the minimum monthly system support under another rate would be charged the minimum standby rate. APL therefore considered that only customers who do not use such services, but remain connected to the system, should be charged. The Board considered that APL's suggested level for Rate 30 had been logically developed and was an appropriate starting point for minimum system support in APL's partial requirements rate package.

#### MI

The MI noted from Decision E94034 that only customers who are not billed an amount greater than the minimum monthly support charge and who remain connected to the system would be charged Rate 30. The Board stated in the Decision that partial requirement customers should compensate the system for a portion of the benefits they receive from it. The MI supported the approval of Rate 30 as filed by APL.

#### **IPCAA**

IPCAA considered that APL should eliminate Rate 30 and caution customers that they will be expected to bear costs they cause. IPCAA considered that value of service was the major basis for design of this rate and that the rate was a practical discouragement to potential self-generating customers. IPCAA

#### (f) System Support Minimum Rate 30

submitted that if Rate 30 were to be continued, the Board should direct that the rate be designed as a cost based rate.

#### ACC

The ACC submitted that Rate 30 was unnecessary since industrial customers would likely be taking other service and would thus already be paying for contract demand. They should not have to pay an additional demand charge.

#### APL

APL noted that the cost basis of Rate 30 was provided in APL's 1991/92 Phase II filing and approved by the Board in Decision E94034. APL proposed to increase the rate by about the average increase. APL also noted the evidence that Rate 30 is a minimum charge and, therefore, customers at current consumption levels would not be subject to an additional demand charge through the application of Rate 30 (Tr. pp.900-901). APL submitted that Rate 30 must be in place to signal customers that they will be charged if connected to the system for the benefits of system stabilization.

#### Board Findings

The Board considered the submissions by IPCAA and the ACC that modifications should be made to Rate 30, however, the Board continues to take the view that APL's partial requirement rate design, including Rate 30, is appropriate. The Board was not persuaded by evidence or argument at this proceeding that there is any need for a change in its findings, in Decision E94034 as outlined above, regarding Rate 30. Therefore, the Board finds that

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
  (f) System Support Minimum Rate 30

increase APL proposed to Rate 30, consistent with the 4.9% the across-the-board increase to rates generally, is appropriate at this time.

## 5. INDIVIDUAL RATES, TOLLS OR CHARGES

# (g) Large General Service/Industrial Rate 31

Large general service and industrial customers are served under Rate Schedule APL proposed an increase in revenue of 4.3% from Rate 31 customers. 31. APL also proposed that billing demand for non-metered service be estimated as HP Nameplate multiplied by 0.76 or as kW Nameplate (as explained in BR-APL.4) for services which are not demand metered, in order to account for the difference which usually occurs between the sizing of equipment and the actual connected load.

The proposed demand charges for Rate 31 were:

	Existing	Proposed
For the first 500 kW of billing demand:	\$17.10	\$16.88/kW
For the next 1500 kW of billing demand:	\$14.70	\$15.11/kW
For all billing demand over 2000 kW:	\$12.22	\$11.56/kW

The proposed energy charges for Rate 31 were:

For the first 400 kWh/kW of billing demand:	1.70	1.93¢/kWh
For energy in excess of 400 kWh/kW:	1.20	1.50¢/kWh

APL stated that the difference between demand blocks was reduced in percentage terms to move towards a two block demand charge reflecting the two basic service functions of transmission and distribution.

## (g) Large General Service/Industrial Rate 31

APL explained that the large increase in the trailing step energy block (in excess of 400 kWh/kW of billing demand) from 1.2¢/kWh to 1.5¢/kWh was to reflect current estimates of average Alberta Integrated System (AIS) incremental energy costs. APL noted that the energy tailblock level of 400 kWh/kW was established to encourage high load factor usage and that the rate provides an economic signal which corresponds to the short run marginal cost of AIS energy, thereby promoting efficient energy consumption decisions.

APL considered that a 90% power factor was an acceptable target for customer loads. Low customer power factors could result in increased system losses and reduced carrying capacity of transmission and distribution facilities, while customer power factors exceeding 90% may result in unacceptably high system voltages and voltage control problems. APL indicated that it had not quantified the costs of power factor correction, since it would be difficult and the resources required were not available. However, APL considered that current penalty charges for each kVA in excess of 1.11 times measured kW demand were not high enough and resulted in customers choosing to pay penalties rather than installing corrective equipment. APL noted that its penalties were about 10 times lower than comparable power factor penalties of other Canadian utilities (Application, Tab 3(D), Schedule 31PF).

APL proposed the phase-in, over a five year period, of a new power factor correction penalty structure in line with those of other Canadian utilities. APL proposed a charge for deficient power factor equal to a percentage (the Percentage) of the trailing step demand charge as applied to the difference

# (g) Large General Service/Industrial Rate 31

between the highest metered kVA demand and 111 percent of the highest metered demand in the same billing period. The Percentage would be 25% in 1995, 40% in 1996, 55% in 1997, 70% in 1998 and 85% in 1999.

APL revised its phase-in proposal in its Reply, requesting that the Board increase the existing penalty of \$1.46 per kVA by 4.88% (the level of existing Rider G) to \$1.53 per kVA for the balance of 1995, with implementation of APL's proposed power factor structure effective January 1, 1996 rather than January 1, 1995.

#### MI

Using Mr. Marcus' methodology in Schedule 1, Exhibit 56, the MI calculated that the revenue to cost ratio for APL's proposed Rate 31 would be about 100% and less than "APL's targeted 101%" (Argument, p.24). The MI also submitted that APL had not justified a below average increase for Rate 31 by merely relying on "APL's experience" regarding Rate 31's price sensitivity (Tr. p.283). The MI recommended that an average increase of 4.7% be applied to Rate 31, which would provide sufficient revenue to allow all other rate classes to also receive only the average increase originally intended by APL.

Respecting intra-class subsidization, the MI noted that APL's revised response to MI-APL.28 indicated that the revenue to cost ratio for the Rate 31 under 2,000 kW sub-class was 108% and the ratio for the over 2000 kW sub-class was 94%. Each had moved further from 100% since the last Phase II when they were 105% and 98%, respectively. The MI submitted that the over 2000 kW block

# (g) Large General Service/Industrial Rate 31

should be maintained at \$12.22 per kW and that APL should be directed to provide COS identification of the revenue to cost ratios for each of the three demand blocks (100 kW, 500 kW and over 2000 kW) to facilitate elimination of cross-subsidization of large customers.

Respecting runout rates, the MI noted that demand charges recover only 79% of demand costs allocated to Rate 31 and submitted that shortfalls should be recovered from both energy blocks, including high load factor customers. The MI also submitted that it was inappropriate for IPCAA's witnesses to "mix" 1995 average incremental costs with 1993 embedded costs when "APL has meticulously utilized 1993 forecast costs for the COS and rate design purposes throughout its filing". (Argument, pp.28-29) The MI further noted that TransAlta's runout rate was based on 1992 incremental energy costs. The MI submitted that the 1.50¢/kWh was, if anything, too low to recover average off-peak incremental costs during 1993.

Noting the 94% revenue to cost ratio for the over 2,000 kW demand block customers, the MI submitted that, if a reduction in the run out rate were found appropriate, any replacement revenues required should be recovered from the over 2,000 kW customers.

The MI noted that industrial contracts were generally for a five year initial term with a one year rolling renewal, while franchise agreements were for 10 years. The MI submitted that all contracts and renewal periods should consider the time the system would require to absorb the loss of the

## (g) Large General Service/Industrial Rate 31

contracted load. The MI recommended that the Board direct APL to address the appropriateness of one year rolling renewals and differences between the terms of franchise agreements and industrial contracts at its next Phase II.

#### **IPCAA**

IPCAA considered that the argument, that the revenue to cost ratio of Rate 31 should be 100%, ignored any rate design consideration other than COS. The MI position that Rate 31 should receive the average increase to reduce the increase to Rate 11 was also unreasonable according to IPCAA, since it would result in a Rate 11 revenue to cost ratio even further below unity.

IPCAA noted that the incremental cost of energy for off peak hours is much lower than the system incremental cost of 1.64¢/kWh and that significant run out consumption occurs in the off peak hours, since run out energy consumption does not begin until a customer's load factor exceeds 55%. IPCAA also noted that the 1995 AIS forecast hourly load indicated that the cost for an incremental kWh is less than 1.4¢/kWh for 2500 of the year's hours and sometimes less than the current run out rate of 1.2¢/kWh. IPCAA submitted that a run out charge of 1.41¢/kWh (equal to the corresponding block of TransAlta's Rate 790) more reasonably balanced the various factors APL considered in its proposed 1.5¢/kWh run out charge. IPCAA further submitted that it was important that APL's rate be consistent with TransAlta's, since industries in each service area compete and since it was appropriate to ensure that the equalized costs of demand and energy out of EEMA continued to benefit APL's customers as intended.

# (g) Large General Service/Industrial Rate 31

Respecting intra-class subsidization, IPCAA noted that there are intra-class subsidies within every rate class, since all customers do not make use of the same facilities or vintage of facilities and since all customers are not equally distant from the integrated generation and transmission system. Even individual revenue to cost ratios for like sized communities could be expected to vary above and below the target range (i.e. 95% - 105%) (APL Argument, p.21). IPCAA submitted that there was a multitude of different customers in each class and, in absolute terms, at least as many differences in the costs caused by them. IPCAA submitted that PICA's division of Rate 31 was arbitrary and that a sound and rational basis should be identified before any division occurs, lest the concept of inter-class averaging be defeated. IPCAA noted that while PICA's divisions reflected Rate 31 demand blocks, they ignored energy block divisions and other possible distinctions.

Respecting power factor correction, IPCAA submitted that, in the event area power factor correction is less costly than individual customer correction, APL should be required to effect the area correction and charge the costs to the customer.

#### REA/AAMDC

The REA/AAMDC submitted that if the Board accepted their proposal to increase the allocation of secondary distribution costs to demand and reduce the customer portion, the revenue to cost ratio of Rate 31 would be below 100%. The REA/AAMDC noted that, if APL had retained the cost allocation methodology approved in Decision E93035, an across-the-board increase would

## (g) Large General Service/Industrial Rate 31

have yielded a 101% revenue to cost ratio for Rate 31, which was the ratio APL considered appropriate. The REA/AAMDC submitted that an average increase would not adversely affect Rate 31 customers since they were already paying the higher rate through the existing interim across-the-board increase of Rider G. Finally, the REA/AAMDC submitted that the evidence before the Board did not warrant a below average increase for Rate 31 and the average increase should be applied.

Respecting runout rates, the REA/AAMDC submitted that it was critical that Rate 31 customers be given a price above the short-run marginal energy cost The REA/AAMDC supported to prevent subsidization from other customers. APL's proposal to increase the tailblock energy charge, noting that the forecast incremental cost was in excess of 2.0¢/kWh in vears after 1995 (IPCAA.APL-17) and the actual off-peak incremental cost in 1993 exceeded 1.7¢/kWh (IPCAA.APL-15). The REA/AAMDC submitted that APL's tailblock rate should also be adopted to signal the expected rise in marginal costs over the remainder of the decade, when no new coal generation is to be built. (Argument, pp.19-20)

The REA/AAMDC also supported APL's "expressed intent" (Tr. p.558) to extend contract length requirements to protect the significant investments APL is required to make to serve large industrial loads.

# 5. INDIVIDUAL RATES, TOLLS OR CHARGES

# (g) Large General Service/Industrial Rate 31

## **PICA**

PICA submitted that Rate 31 should be divided into three approximately equal revenue sub-groups: small (less than 500 kW), medium (consumption between 500 kW and 10 MW) and large (over 10 MW), with each sub group generating revenue higher than from any other APL rate class. PICA noted that with this split the small sub group would have 67% of its customers at load factors greater than 50%, while the large sub group would have 96% of its customers at load factors greater than 50% (Tr. p.612). PICA questioned APL's assurances that the structure of Rate 31 compensates for any diversity in size and load factors within the rate class, noting that MI.APL-28 (Revised) Exhibit 89) indicated revenue to cost ratios of 107.65% for customers under 2 (MW and 94.11% for customers over 2 MW. PICA further noted that the revenue to cost ratios had deteriorated since the previous rate hearing when the corresponding ratios were about 105% and 98% (Tr. p.296).

PICA noted APL's indications that there was merit in further evaluation of the groups within Rate 31 (Tr. p.611) and submitted that the Board should direct APL to provide cost studies to help evaluate any cross-subsidies among the proposed small, medium and large customer sub groups. PICA further submitted that APL should be directed to demonstrate that the tilt in Rate 31 favoring large customers does not result in rates below the long run marginal cost of serving those customers.

PICA noted from Exhibit 52 that under APL's proposal small Rate 31 customers would receive a below average increase of 3.6%, medium customers an above

# (g) Large General Service/Industrial Rate 31

average increase of 5.6% and large customers an average increase of 4.7%. Given the deterioration in revenue to cost ratios for both over and under 2 MW customers, PICA submitted that the Rate 31 second demand block should remain at \$14.70/kW/month and the third demand block should be raised per Exhibit 75 to maintain revenue neutrality for Rate 31 as a whole and provide medium customers with about an average increase. PICA submitted that avoidance of undue discrimination amongst customers within Rate 31 should override APL's concern that the change would make the potential transition to a two demand block rate more difficult in the next Phase II. PICA also submitted that if competitive factors were justification for under recovery from large customers, all customers should pay for foregone revenues, not just small and medium size Rate 31 customers.

In response to APL's submission that arbitrary and unfair rate changes might result from splitting Rate 31, PICA submitted that designing rate blocks or splitting the rate having regard to the electrical parameters such as demand and load factor, which are indicators of homogeneity within a rate class, would be fair and equitable to all present Rate 31 customers. PICA also questioned APL's submissions that the design of Rate 31 was appropriate in light of other rate design criteria. PICA submitted that its alternative rate design also takes into account historical development of the rate, while recovering rate class costs more fairly. PICA submitted that APL had not provided evidence that the Rate 31 tail block provided price signals to encourage economically efficient use, of the marginal cost APL no information on since has (PICA.APL-18(b)). PICA recommended that APL be directed to demonstrate at

# 5. INDIVIDUAL RATES, TOLLS OR CHARGES

# (g) Large General Service/Industrial Rate 31

marginal costs. PICA submitted that the timing of rate applications (TransAlta's last Phase II was for 1992) was not reason for not correcting APL's intra-class disparities, given that 80% of APL's and TransAlta's costs are costs out of EEMA and TransAlta's rates might be found similarly tilted in favor of large customers. (Reply, pp.2-4)

PICA submitted that the tailblock demand charge should be increased so as to achieve the revenue to cost ratio of 101.66% for over 2MW customers as initially premised by APL in its proposed structure for Rate 31. (Reply, pp.4-5)

#### Canfor

Canfor submitted that APL should be required to carry out and provide to customers a meaningful analysis of the costs imposed on the system by low power factor customers before APL is allowed to recover such costs from customers. Canfor submitted that such an analysis should indicate the level of costs imposed on the system and if possible identify by rate class customers imposing the costs. If the Board approves penalties prior to provision of the analysis, those penalties should be subject to the analysis being provided within a reasonable time.

Canfor also submitted that six months notice should be provided prior to implementation of power factor penalties.

# (g) Large General Service/Industrial Rate 31

Canfor encouraged APL to consider other alternatives to power factor penalties, such as taking efficient and cost-effective corrective actions itself and instituting a program to educate and advise customers when it is more economic to make corrections on the customers' sites.

#### CCA

The CCA submitted that APL had failed to provide compelling evidence in support of the necessity and appropriateness of a less than average increase for Rate 31. The CCA also submitted that, if the Board finds discounts appropriate on the basis of competition from alternate energy, the Board should require the company to absorb 30% of the differential between forecast costs and revenues for the class to provide the incentive to maximize revenue and to recognize that rate discounts reduce risks to shareholders. (Reply, pp.20-21)

The CCA submitted that since APL's COS does not specifically address or account for costs imposed on the system by industrial customers' low power factor operations, the cost to serve large industrial customers is understated and the costs to serve residential and small commercial customers is overstated.

The CCA also submitted that it would be appropriate to amend Rate schedules 21, 25 and 26 to state that APL "shall" require a customer to install corrective equipment if its power factor is less than 90% or, alternatively, pay a charge reflective of the costs its low power factor imposes on the system. The CCA submitted that customers' power factors should be tested on a sample basis to

## (g) Large General Service/Industrial Rate 31

provide an economically viable alternative to installing expensive metering devices.

# APL

APL submitted that PICA's suggestion of subdividing Rate 31 into more rate classes could have drawbacks, since customers with load sizes slightly above or below the arbitrary cut-off points established may experience unfair step changes between the rates. APL agreed that there was some indication that Rate 31 customers consuming less than 2MW are subsidizing larger load Rate 31 customers. However, APL considered Rate 31 appropriate in light of other rate design criteria, including historical development of the rate, recovery of rate class costs, price signals to encourage economically efficient use, comparability to neighboring utilities and competitiveness to other energy sources. (Argument, pp.36-37)

In response to IPCAA's position that the incremental energy costs seen by tailblock customers was lower than 15 mills, APL submitted that the calculations of IPCAA's witness, Dr. Rosenberg, indicated that over 6000 of the hours in 1995 (69%) would be supplied by units with incremental costs in excess of 14 mills. APL submitted that, at any rate, off-peak customers should make some contribution to the fixed costs of the facilities they are using. APL further submitted that there is no evidence to support the notion that a customer's tailblock usage occurs exclusively during the off-peak periods. APL noted that the differential between incremental energy costs during all hours

## (g) Large General Service/Industrial Rate 31

(18.9 \$/MWh) and off-peak hours (17.9 \$/MWh) (IPCAA-APL.15 and 17) is not as significant as claimed by IPCAA.

APL noted that AIS average incremental energy costs were 1.89¢/kWh in 1993 and 1.924¢/kWh in 1994 and forecast to be 1.642¢/kWh in 1995 (with Genesee 1) and 2.075¢/kWh in 1996 (IPCAA-APL.17). APL submitted that while these calculations supported a tailblock energy rate in excess of the 1.5¢/kWh it proposed, APL did not increase the rate further in the interests of rate stability to customers.

In response to IPCAA's position that APL should provide power factor correction equipment where required and charge the customer accordingly, APL submitted that it was more efficient from the system's perspective for the customer to correct the problem close to the source i.e. at the customer's motor.

In Reply, APL supported Canfor's recommendation that a notice period precede the increase in power factor penalties. APL proposed that the proposed power factor penalty structure and levels be effective January 1, 1996 and that the power factor penalty charge be \$1.53 per kVA for the balance of 1995 (the 4.88% average increase applied to the existing penalty of \$1.46 per kVA).

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (g) Large General Service/Industrial Rate 31

#### Board Findings

Considering that the level of the AIS average incremental energy costs are forecast to be 1.642¢/kWh in 1995 (with Genesee 1) and 2.075¢/kWh in 1996 (IPCAA-APL.17), the Board accepts that the tailblock energy rate should be increased to the 1.5¢/kWh proposed by APL. Acknowledging the importance of rate stability, the Board considers that any further increase in the rate would be inappropriate at this time.

The Board is not convinced by APL's or IPCAA's submissions that competitive forces currently provide sufficient reason for a lower than average increase for Rate 31 customers. Therefore, the Board considers that an increase in Rate 31 approximately equal to the across-the-board average is appropriate for this Decision.

Further, the Board recognizes the shift in intra class revenue to cost ratios and notes that under APL's proposal the large increase in tailblock energy rate has been mitigated by the decrease from \$12.22/kW to \$11.56/kW in the rate for billing demand over 2,000 kW. The Board is not convinced by submissions regarding competitive forces or other factors that large customers should not see a greater portion of the increase in the runout block rate. The costs to serve these large customers (i.e. the runout rate) have increased. Therefore, the Board will increase the rate for billing demand over 2,000 kW proposed by APL to increase revenue recovery from Rate 31 appropriately.

# 5. INDIVIDUAL RATES, TOLLS OR CHARGES

# (g) Large General Service/Industrial Rate 31

The demand charges for Rate 31 approved by the Board are:

	Proposed by APL	Board Approved
For the first 500 kW of billing demand:	\$16.88	\$16.88/kW
For the next 1500 kW of billing demand:	\$15.11	\$15.11/kW
For all billing demand over 2000 kW:	\$11.56	\$11.79/kW

The energy charges for Rate 31 approved by the Board are:

	Proposed	Board
	by APL	<u>Approved</u>
For the first 400 kWh/kW of billing demand:	1.93	1.93¢/kWh
For energy in excess of 400 kWh/kW:	1.50	1.50¢/kWh

The Board also approves APL's proposal to estimate non-metered service demand as HP Nameplate multiplied by 0.76 or as kW Nameplate (as explained in BR-APL.4), to better reflect actual demand for Rates 25 and 26, as with Rates 31 and 41.

The Board considers that the low level of APL's power factor correction penalties in comparison to other utilities may result in customers paying the penalties rather than taking corrective measures. Increased system losses and reduced carrying capacity of transmission and distribution facilities arise when power factors are low. Therefore, the Board will approve the phase in, over a five year period, of APL's proposed power factor correction penalty structure commencing January 1, 1996.

# 5. INDIVIDUAL RATES, TOLLS OR CHARGES

# (h) Rate 31A - New Gas Compression Load

APL proposed Rate 31A as a new rate to attract new gas compression load which desired a strictly energy based rate and which was not using electricity extensively, primarily because of the demand and ratchet charges in existing Rate 31. Under Rate 31A gas compression customers would be able to pay in proportion to their monthly energy consumption, with no fixed charge for peak demand, and to better match costs with gas revenues. The explicit demand charge would be replaced with a minimum energy amount.

APL was targeting 10 MW of incremental load for this rate and proposed allowing subscription over a 2 year period only to new load. Initial subscription would be for a maximum of 5 years. APL forecast no significant difference in revenues arising from Rate 31A compared to subscription under Rate 31 and would assess the extent of any variance to determine whether the rate should be applicable to existing customers and other market segments.

APL filed the new Rate 31A for acknowledgement on September 6, 1995 in order that the rate could be implemented on an interim basis effective October 1, 1995 to meet the fall and winter construction season of its customers. The Board accepted the filing as a "filing for acknowledgement" by letter dated September 11, 1995.

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (h) Rate 31A New Gas Compression Load

#### **IPCAA**

IPCAA considered that the rate should also be available to any existing customers who qualify, to avoid discrimination by denying existing customers the prospect of discounts offered to new customers. IPCAA considered that it was apparent that APL was uncertain whether Rate 31A would provide a discount relative to Rate 31, since APL wished to restrict Rate 31A by offering it initially only to new customers and for a term of only 5 years.

#### REA/AAMDC

The REA/AAMDC, noting a discounted rate proposed for retention of a TransAlta gas compression load, submitted that the Board should ensure that firm service customers would not be asked to similarly subsidize APL gas compression load, by requiring APL to bear any risk of non-recovery of facility investment needed to service such loads.

#### CCA

The CCA expressed concern that, without firm longer term contracts, APL might at some point be pressured into adopting discounted load retention rates to the detriment of other customers.

#### APL

APL submitted that offering Rate 31A only to new or incremental loads would allow for load growth that would not occur on standard rates, as did Rate 33, thereby better utilizing existing AIS capacity for the benefit of all customers. Rate 31 is restructured as a concession to help "make the sale", while for

# (h) Rate 31A - New Gas Compression Load

Rate Rate 33 the price is discounted. For such "load enhancement rates" APL submitted that it was critical that a concession be made only to loads which require it and which would not materialize on any other rate. Otherwise, all other customers would be worse off as a result of the sale. APL noted that throughout North America demand and ratchet charges were still considered to be the fairest method of recovering demand related generation and transmission costs and providing price signals that, by keeping load factors up and costs down, encourage economic efficiency. APL indicated that Rate 31A was a special option which was not appropriate for rate design in general, but which would have less impact than a rate discount. Therefore, APL proposed that only new gas compression load should qualify for Rate 31A. (Reply, pp.25-26)

#### Board Findings

The Board approves Rate 31A for new or incremental loads to allow for load growth that APL indicates would not occur on standard rates. The Board accepts that better utilization of existing AIS capacity for the benefit of all customers is the goal of the rate and that therefore the concession should be made only to the loads which require it and which would not materialize on any other rate. If the rate does result in a discount from current rates, as IPCAA suggested it might, allowing the concession to other than new or incremental loads would risk making all customers not eligible for the rate worse off as a result of the sales. After APL gains experience with the rate, the company will have the information to weigh benefits and costs so as to determine if customers already on other rates should be allowed on Rate 31A.

#### 5. INDIVIDUAL RATES, TOLLS OR CHARGES

## (i) Rates 32A, 32B, 34A and 34B - Standby Power

APL indicated that it had maintained the existing structure of Rates 32A and 32B, which the Board approved in Decision E94034, and applied the average increase of about 4.7% to the components of the rates. Rates 34A and 34B are interruptible standby rates. APL indicated in its rate proposal that because they are Class II interruptible rates, they should not receive the average increase applied to firm rates and should remain at the levels established in Decision E94034.

Rate 32 is a standby power rate originally designed only to meet the standby power needs of self-generating customers. When APL proposed the rate at its 1992 Phase II, APL indicated that the transition to Rate 31 was a primary consideration in a redesigned Rate 32 because standby service can be difficult to distinguish from supplementary service and the two merge as effective load factor increases. Rate 32A was for customers whose standby load factor would be less than 3.0%, i.e. self-generators and customers who have no self generation, but infrequently experience demand excursions significantly higher Rate 32B would be most economical for than their normal demand. self-generators who expected to require system standby power for between 3% and 15% of the time. Users with load factors greater than 15% (i.e. high enough to be considered as supplemental power users) would find Rate 31 was the lowest rate in APL's industrial rate basket.

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (i) Rates 32A, 32B, 34A and 34B Standby Power

## MI

The MI considered that APL's Exhibit 56 indicated that APL's standby rates were lower than TransAlta's up to about a 10% load factor. The MI considered that ACC's suggestion that APL adopt TransAlta's rate implied that ACC expected utilizing standby at a significantly higher load factor. The MI submitted Rate 33 or Rate 31 would be more appropriate for such usage and supported Rate 32 as designed.

#### ACC

The ACC submitted that APL should provide the same firm standby service rate as proposed by TransAlta and should consider a stochastic approach in the future. Additionally, exporting independent power producers (IPP) should not be charged for both export transmission demand and firm standby transmission service demand.

#### APL

APL submitted that Exhibit 54 indicated that the levels of its Rates 32A and 32B were very comparable to TransAlta's Rates 820 and 830. APL indicated that, unlike APL's customers who have access to both partial and full requirement rates, TransAlta's customers must categorize themselves as partial requirement customers to utilize network services rates. Furthermore, TransAlta's partial requirements customers may only use network services rates. APL submitted that the current structure of Rate 32 allowed layering and a combination of full service and partial requirement rates in a non-discriminatory manner, which is the foundation to APL's approach to industrial rate design. Adoption of

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (i) Rates 32A, 32B, 34A and 34B Standby Power

TransAlta's rate structure for standby services would be fundamentally incompatible with APL's approach.

## Board Findings

Although the Board examined submissions by the ACC that modifications should be made to APL's proposed standby rates, the Board continues to consider that APL's partial requirement rate design, including its standby rates, is appropriate. The Board was not persuaded by any evidence or argument at this proceeding that there is any need for a change at this time to its findings, in Decision E94034, regarding standby rates. Therefore, the Board considers that an across-the-board increase as proposed by APL of about 4.9% to Rates 32A and 32B is appropriate at this time.

# (j) Rate 33 - Reserve Energy

APL indicated that it proposed no changes to Rate 33 as approved in Decision E94034. Rate 33 was designed to take advantage of temporary market opportunities when the AIS has low cost capacity available. Rate 33 allows for consumption in circumstances when APL is convinced that the customer would not have purchased energy at standard higher revenue rates for incremental production or when it would otherwise be economically attractive to self-generate. The rate is only available if APL determines that there is sufficient system generation and transmission capacity and energy available. This rate, therefore, allows the AIS to more fully utilize existing capacity. The rate schedule defines normal demand and normal load factor to minimize the loss of energy sales at the Company's standard rate. Reserve energy usage is interruptible and available short term (less than 11 days) under Rate 33A and long term (11 days or longer) under Rate 33B.

#### MI

The MI submitted that sales under Rate 33 should be rigorously tested to ensure that they would not be economically viable under any other rate lest other customers be required to make up cannibalized revenue. The MI submitted that customers who wished to use Rate 33 should be required to open their books to APL to the extent necessary to ensure that no cannibalization occurs and to maximize the contribution above marginal costs made by Rate 33 sales.

## (j) Rate 33 - Reserve Energy

The MI were concerned that, while APL indicated that most Rate 33 users could provide 8 to 12 hours notice, APL responded to customer pressure requesting notice of one hour or less by compromising at a 4 hours notice provision when the rate was set. The MI submitted that some customers would be able to trip their plant loads instantaneously with lost generation, provide the 4 hours notice and then use Rate 33 effectively as standby. The MI submitted that cogenerators and self generators should be required to provide a record of their outages to APL to ensure that Rate 33 is not used for standby.

The MI considered that APL had not adequately explained why Rate 33 sales over the four test years 1990 through 1993 have exceeded forecast by about 65% and recommended that the Board direct APL to provide at its next GRA detailed reasons for the variance from forecast from 1990 to 1993. (Argument, pp.37-38)

#### **IPCAA**

IPCAA submitted that when a customer can demonstrate that it can provide its own backup or that it is more economic for it to reduce load than to incur APL's standby charges, APL should provide Rate 33 energy. Otherwise both APL and the customer lose, since APL will lose Rate 33 sales and the customer will incur higher costs than under Rate 33.

#### REA/AAMDC

The REA/AAMDC supported the positions advanced by the MI.

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (j) Rate 33 Reserve Energy

## **ACC**

The ACC submitted that qualification for Rate 33 should not require that customers divulge profitability information to APL. Instead qualification should be tied to incremental consumption. Also the "take or pay" provisions should be eliminated since they could inhibit customer's utilization of this opportunity-driven rate.

#### APL

APL indicated that it would investigate a customer's profitability only at its request, when the customer qualifies for use of Rate 33 because it is going out of business or because the market prices for its product will not support higher rates.

APL indicated that careful analysis, documentation and monitoring of the usage of this "discounted" rate is conducted by APL to distinguish genuine qualifications from mere negotiating positions and to ensure that the required special conditions outlined in MI-APL-12 are applied on a case by case basis.

APL indicated that it shared the MI concerns that 4 hours notice before a customer can be served under Rate 33 might be insufficient notice to distinguish between standby and reserve energy usage. While APL considered that it would be too intrusive to meter its customers' generators, APL indicated that self generating and co-generating customers agreed to provide a history of forced outages (frequency and duration) for their on-site generation to assist APL in the administration of standby events. APL indicated that it would

## (j) Rate 33 - Reserve Energy

continue to monitor on a case by case basis and propose an increase in the notice period, if 4 hours proves insufficient to prevent cannibalization.

In regard to APL's opportunity to earn extra return from Rate 33 sales which have been higher than forecast, APL noted that variances from forecast could go either way for any rate, including rates with much larger margins than Rate 33. Additionally APL submitted that many of the Rate 33 sales had displaced sales forecast to be made on rate schedules producing higher revenues and leading to an negative revenue variance from forecast.

APL also submitted that there was no evidence that the "take or pay" (Rate 33A) or "minimum load factor" (Rate 33B) provisions in Rate 33 act as barriers to customer use since customer acceptance and use of Rate 33 has increased steadily since its introduction in 1990 (MI-APL-12). APL indicated that discussions with customers made it clear that they preferred arrangements where a slightly higher premium would avoid frequent economic interruption. Such arrangements required that APL reserve the energy contracted for the customer and that the customer be obligated to purchase a minimum amount of that energy (take or pay). APL indicated that the "reserve charge" built in a customer incentive for improving actual load factors and simplified the billing of layered rates.

## Board Findings

The Board expects that the concerns expressed by the REA/AAMDC and the MI regarding cannibalization would be shared by APL, since APL is regulated

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (j) Rate 33 Reserve Energy

on a forecast test year basis and any unpredicted cannibalization by bid energy sales of forecast sales in another higher rate class would result in lower than forecast revenues for APL. The Board considers that APL must be given some flexibility in negotiating with reserve energy customers to ensure that benefits are maximized for customers who do not receive the discounts available to customers who are able to qualify for Rate 33. The Board anticipates that APL will maximize revenues from all sources including Rate 33 and that such revenues will serve as a base for future test year forecasts. The Board expects that APL will continue to use its actual experience in the application of this rate in order to effect any necessary modifications and refinements in notice periods and other factors so that benefits resulting from availability of low cost system capacity will continue to be shared.

#### (k) Rate 35 - WESCUP

Since Westcoast Energy Inc./Canadian Utilities Power (WESCUP) was a Class II interruptible customer similar to Rate 33 customers, APL proposed no change in WESCUP's rate.

The Board, in Decision E91095, dated December 13, 1991, recognized the WESCUP sale as unique in that WESCUP was reselling the electricity as opposed to consuming it within Alberta. In recognition of the uniqueness of the sale the Board determined that other AIS customers should not subsidize the sale and further that WESCUP should provide a fair contribution to fixed costs. In Decision E93035 the Board considered that the WESCUP sale was essentially the same as any Class II interruptible energy sale except for the reselling of electricity to out of province customers, a unique attribute accounted for through the requirement that the rate to WESCUP recover incremental costs. The Board considered that, although the contribution provided by Rate 33 customers will vary based on individual contracts, a fair contribution for WESCUP would be the average Rate 33 contribution. WESCUP would then be treated in a manner similar to class II customers. The Board adjusted APL's charges to WESCUP to reflect its findings.

#### **IPCAA**

IPCAA noted several differences between WESCUP and Rate 33 customers.

Rate 33 customers operating at a lower load factor than 75% would see an

#### (k) Rate 35 - WESCUP

increase in energy costs, whereas WESCUP would not. Rate 33 was subject to the vagaries of the export market or other conditions, while WESCUP had a long term arrangement under which considerable confidence exists that the energy will be provided. WESCUP's suggestion that higher rates would make service uneconomic (Tr. p.342) was not verified by APL, as it would have been for Rate 33 customers, but rather by Canadian Utilities, a party with a material interest (Tr. p.343).

IPCAA considered it inconsistent that WESCUP should receive no increase while Rate 30, which was based on value of service and a theoretical notion of cost should receive an average increase. IPCAA submitted that based on the above WESCUP's rate should be increased by the average increase applied to rates for consumers in Alberta.

#### REA/AAMDC

The REA/AAMDC noted that, since WESCUP purchases energy at a fixed rate, as the marginal cost of AIS energy increases the contribution to fixed costs made by WESCUP decreases. Since, in Decision E93035, the Board indicated that WESCUP should make a fair contribution to fixed costs and the contribution was 8 to 10 mills per kWh, the REA/AAMDC submitted that the Board should require the future contribution to be at 9 mills per kWh. The REA/AAMDC noted APL's indication that it could negotiate a contribution to fixed costs that ensured the margin was maintained if variable costs of production fluctuated. The REA/AAMDC recommended that the Board direct APL to do so.

#### 5. INDIVIDUAL RATES, TOLLS OR CHARGES

#### (k) Rate 35 - WESCUP

#### APL

APL submitted that the costs of serving WESCUP, which is Class II interruptible, were based on entirely different principles than those used to determine the costs of firm embedded cost based rate classes. APL submitted that the WESCUP rate recovers all of the cost of the dedicated facilities, incremental losses and average incremental production costs incurred to serve WESCUP as the Board considered appropriate in Decision E93035 and makes a reasonable contribution to fixed costs to the benefit of other rate classes.

In Decision E93035, the Board ruled that a reasonable contribution to fixed costs from Rate 35 would be of similar magnitude to the margin on Rate 33 sales which are also Class II interruptible sales. APL noted that, on Rate 33 sales, the forecast margin in 1993 was 6 mills and the actual margins have ranged from 2.4 mills to 8.3 mills from 1990 to 1993 (MI-ALP-12) with individual sales varying far more than the averages. APL indicated that the proposed Rate 35 contributes 4.3 mills and submitted that was "well within the normal range of Rate 33 margins". (Reply, pp.33-34)

APL agreed with IPCAA that, since WESCUP's rate is set by the Board, WESCUP is not subject to the vagaries of the export market or other conditions influencing Rate 33 levels. However, APL noted that WESCUP could not benefit from market "lows" as Rate 33 customers might.

APL submitted that since Rate 35 includes an explicit demand charge which is applied to the greater of WESCUP's metered demand or contract minimum

#### (k) Rate 35 - WESCUP

demand, WESCUP's rate varied with load factor like other Rate 33 customers whose rates increase as their load factors decrease due to the reserve charge.

# Board Findings

The Board, after reviewing the submissions in this proceeding, remains of the view that WESCUP is similar to other Rate 33 customers, other than in its reselling of electricity to customers outside Alberta, which is accounted for by requiring that Rate 35 recover incremental costs. Therefore, the Board considers that, consistent with Decision E93035, the contribution per kWh from Rate 35 should be set so as to be approximately equivalent to the average contribution per kWh from Rate 33. The average forecast contribution for 1993 was 6 mills while WESCUP's contribution was forecast to be 4.3 mills. Therefore, the Board will increase the Energy Charge proposed by APL by about 1.7 mills. The Board will approve a Rate 35 Energy Charge of 2.03¢/kW.

# 5. INDIVIDUAL RATES, TOLLS OR CHARGES

# (1) Rate 36 - Rainbow Processing Plant

APL proposed to continue to keep Rate 36 (Rainbow Lake Gas Processing Plant) equivalent to Rate 31 and therefore modified Rate 36 identically to Rate 31.

# Board Findings

The Board remains convinced, consistent with its findings in Decision E91074, that Rate 36 should be consistent with Rate 31. Therefore, the Board will approve Rate 36 so as to reflect the provisions of Rate 31 approved in this Decision.

## (m) Rate 38 - Maintenance Energy

APL proposed to increase Rate 38 by 4.9% (the existing Rider G level) since it was a firm energy service.

Rate 38 was available to be scheduled in advance by customers served under a long term contract under Rates 31, 32, 33 or 34 to allow them to perform maintenance or testing or to serve other load which was not part of their day to day operations. APL proposed shortening notice provisions for subscription to the firm rate by half, to be at least equal to the requested usage period and not less than 24 hours. The shortened notice would make it easier for non generators to use the rate for abnormally high demand, short term process testing.

## ACC

The ACC submitted that since the provision of Rate 38 energy places a minimal demand on utility capacity because the maintenance is scheduled in advance, Rate 40 should have a minimal or no demand charge.

# APL

In response to the ACC, APL noted that Rate 38 is an energy only rate and does not contain a demand component.

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (m) Rate 38 Maintenance Energy

## **Board Findings**

The Board examined submissions by the ACC that modifications should be made to APL's proposed Rate 38. The Board continues to consider that APL's partial requirement rate design, including its Rate 38, is appropriate. The Board was not persuaded by any evidence or argument adduced at this proceeding that there is any need for a change to its findings, in Decision E94034, regarding Rate 38. Therefore, the Board considers that an across-the-board increase as proposed by APL of 4.9% to Rate 38 is appropriate at this time.

## (n) Rate 39 - Export Market Service

APL proposed a new rate, Rate 39 (Export Market Service (EMS)), to allow IPPs to export their power to jurisdictions outside Alberta without causing economic harm to retail customers within Alberta. APL proposed that Rate 39 should, initially, be restricted to the first 100 MW contracted provincially since any major increase in transmission capital requirements might place significant upward pressure on retail rates. The rate for long term EMS contracts was based on the embedded costs of transmission and distribution that are allocated to the larger General Service Class (Rate 31). When APL deems that sufficient temporary transmission capacity is available, Rate 39B would allow short term (less than 5 years) EMS contracts at 50% of the Rate 39 to recognize that no additional system investment is necessary as in the case of Class II economy energy sales. APL stated that the short term export Rate Rate 39(B) would be available for customers who can satisfy conditions similar to a Class II interruptible customer.

The Rate covers the two types of IPP contracts APL envisioned as realistic. A firm power contract, where the IPP would have a delivery contract specifying the power transfer level within each 10 minute interval and a firm energy contract, where the IPP would have a delivery contract specifying only that a firm quantity of energy will be transferred each month.

When an IPP's power or energy does not match that which was contracted for under Rates 39 or 39B, over any 15 minute metering interval for firm power

# (n) Rate 39 - Export Market Service

contracts, or over the month for firm energy contracts, economic settlements would apply as follows:

- (1) Excess energy produced by the IPP would be treated as inadvertent energy and the IPP would be compensated at the run-out energy block of Rate Schedule 31 (i.e. 1.5¢/kWh).
- (2) (a) Where the IPP has a firm power contract, any deficiency in power would be treated as standby or supplemental power delivery by APL and charged to the IPP on Rates 32A or 32B as nominated by the IPP and discounted by 45%.
  - (b) Where the IPP has a firm energy contract, any monthly deficiency from the scheduled energy will be treated as temporary firm energy usage and charged to the IPP accordingly on Rate 38 (i.e. 5.25¢/kWh).

#### MI

The MI submitted that Alberta rate payers should not be exposed to unfavourable impacts of unlimited export sales, nor should APL be required to provide standby service to exporters at less than the value of that service.

With respect to recommendations that the 100 MW cap be eliminated, the MI submitted that the Board should place more weight on APL's expertise as to

#### (n) Rate 39 - Export Market Service

whether the AIS is capable of supporting more than 100 MW of EMS at this time without any detrimental impact on in-province rate payers.

The MI also noted IPPSA's proposal that IPPs pay only the system marginal running costs for under deliveries was based on the existence of excess AIS capacity. MI submitted that it would be unfair for one customer class to purchase firm standby service based on the existence of excess capacity while other classes are required to bear the cost of such capacity. Also, rather than, as IPPSA proposed, having APL demonstrate that exporters may be abusing the design of the Rate 39, MI submitted it was more appropriate to protect other customers while first gaining experience, to determine whether under deliveries were truly inadvertent and unbiased energy flows.

In Reply, the MI submitted that IPPSA had changed its original position in argument when it did not address the delivery issue and proposed that APL's rate include a ±5% balancing allowance as in TransAlta's Rate 820. The MI submitted that since this position was not addressed by IPPSA in evidence or during the hearing it constituted new evidence in argument and should not be given any consideration.

The MI submitted that they supported Rate 39 as filed by APL.

#### **IPCAA**

IPCAA generally supported APL's export rate proposal.

# (n) Rate 39 - Export Market Service

However, IPCAA submitted that customers should be allowed to use Rate 39B as long as no capital investment is required by APL and there is sufficient transmission capacity available. IPCAA submitted that "no rate should have as its foundation the maximization of benefits for other customers or customer classes." (Argument, p.16)

IPCAA noted that under the proposed Rate 39 imbalance treatment, production by IPP in excess of scheduled deliveries would be treated as inadvertent energy priced at 1.5¢/kWh while deficient power, would be treated as standby priced IPCAA submitted that APL supported the imbalance up to 14.3¢/kWh. treatment based on a hypothetical structure for IPP contracts which painted a picture favourable to the point APL seeks to advance. IPCAA's submitted that APL's approach to dealing with imbalances was not justified on actual experience, which has demonstrated that the same imbalance issues have been accommodated amicably and in a symmetrical fashion between utilities. submitted that symmetry resulted since utilities could not bring regulatory power to bear on one another so as to impose an unreasonable relationship. IPCAA submitted that the asymmetrical treatment of imbalances proposed by APL was symptomatic of an approach consistent with preservation of the utility monopoly and that no conscientious effort had been made to establish a practical and useable export rate.

IPCAA submitted that Rate 39 imbalances should be settled at an AIS pool price as indicated by Dr. Rosenberg and that APL should establish measures to deal with customers abusing system rights if required. (Argument,

#### (n) Rate 39 - Export Market Service

pp.16-17) In Reply, IPCAA noted that the MI had suggested with respect to this issue that it may be more appropriate to first gain some experience to determine whether under deliveries were truly inadvertent and unbiased energy flows. IPCAA disagreed with this suggestion on the basis that the imposition of provisions predicated on the assumption that abuses will occur will only contribute to ensuring that no experience will ever be obtained.

#### REA/AAMDC

The REA/AAMDC noted that a large portion of the arguments submitted by intervenors dealt with issues around the level and basis for the partial requirement rates and the export service rates. The REA/AAMDC supported the design and level of the rates proposed by APL.

#### PICA

PICA noted APL's position with respect to Imbalance Provisions and disagreed with the recommendations of Dr. Rosenburg in his evidence on behalf of IPCAA. PICA submitted that charging under deliveries at the AIS Pool price as proposed by Dr. Rosenburg assumes the pool price already reflects some kind of capacity costs, whereas current pool prices reflect only the incremental cost of electricity. PICA submitted that APL's proposal for charging under deliveries of power at the standby rate adjusted for transmission costs would be appropriate since it would recover both energy and standby capacity costs.

With respect to under deliveries of firm energy, PICA agreed that APL's proposal to charge firm energy under deliveries at the temporary firm energy

# ALBERTA ENERGY AND UTILITIES BOARD

# 5. INDIVIDUAL RATES, TOLLS OR CHARGES

# (n) Rate 39 - Export Market Service

rate would be reasonable since it was consistent with the costs associated with APL's contractual obligation to deliver a certain amount of firm energy within a contracted time period.

PICA noted that differences in rate design philosophy resulted in APL's charges for EMS being significantly higher than TransAlta's under certain assumptions, due primarily to TransAlta allowing a plus or minus 5% tolerance for imbalances on rates 820 and 830. Under other assumptions, APL's proposed charges for overuse are lower than TransAlta's. PICA submitted that APL should be directed to monitor the costs associated with overuse, and propose refinements to the imbalance penalties as needed based on its experience over time.

#### **IPPSA**

IPPSA noted that APL proposed a 100 MW capacity cap on Rate 39 since a large increment of EMS load may require an unusual degree of transmission system reinforcement or upgrades. IPPSA was concerned however, that APL had no empirical data upon which to justify this proposal, and that the main justification for the proposal was APL's apparent "discomfort" with not having such a cap.

In IPPSA's view, including a 100 MW cap in the approved rate was inappropriate and not justified at this time. IPPSA considered that it would be more appropriate to defer considerations about the need for a cap until a point in

#### ALBERTA ENERGY AND UTILITIES BOARD

#### 5. INDIVIDUAL RATES, TOLLS OR CHARGES

# (n) Rate 39 - Export Market Service

time when it appears that there is the potential for a shortage of transmission capacity.

IPPSA submitted that rather than a cap, the Board should consider an economic benefit test of incremental transmission system costs associated with large Rate 39 loads as proposed by Mr. Knecht in his evidence on IPPSA's behalf. Mr. Knecht proposed a study of system-wide incremental costs incurred to meet an incremental Rate 39 demand factoring in any quantifiable project benefits specific to APL's system and in-province customers. The outcome of the test could provide APL with a basis to determine whether it would be appropriate to consider adjustments to the rate existing at that time. When and if the 100 MW capacity is reached by EMS customers, APL can review the rate. IPPSA submitted that there was no need to incorporate the 100 MW cap in Rate 39 at this time. Incorporation in the rate would give rise to difficulties in attempting to remove the cap at a later date.

IPPSA noted that TransAlta's Rate 820, now approved by the Board and used by APL as a model for its Rate 39 proposal, did not incorporate such a cap.

With respect to investment credits, IPPSA noted that APL proposed that Rate 39 customers would receive 30% of the amount of the credit that would be received by a similar Rate 31 customer. IPPSA noted that APL justified the 30% on the basis that Rate 39 revenues are forecast to be 30% of those produced by Rate 31. IPPSA submitted that discounting the amount of benefit which might otherwise flow to a Rate 39 customer was not justified based on

# (n) Rate 39 - Export Market Service

this rationale. IPPSA felt that Rate 39 customers would not and should not impose the same amount of costs on the system as would Rate 31 customers. Furthermore, IPPSA noted that TransAlta's Rate 820 did not envisage the application of a discount to customers eligible for the "unused investment credit benefit." IPPSA submitted that APL's proposal to reduce the investment for Rate 39 customers should not be approved.

IPPSA stated that APL needs to clarify its policies and establish guidelines to enable all parties to understand the circumstances which need to be present in order to be eligible for investment credit. IPPSA's understanding was that the circumstances under which such a credit could be available to IPPs would include the situation where APL could defer its investment in supply facilities by reason of the location of an IPP.

With respect to Imbalance Provisions envisaged under the Rate 39 proposals, IPPSA made the following submissions:

- (a) The proposals are impractical since there is no provision for an imbalance window. IPPSA's opinion was that the rates should include a ±5% balancing allowance, similar to that provided under TransAlta's Rate 820.
- (b) Any over or under deliveries beyond the imbalance margins should be settled by way of charges levied at the system marginal price as proposed in the testimony of Dr. Alan Rosenburg and R.D. Knecht.

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (n) Rate 39 Export Market Service

In his testimony, Dr. Rosenburg, on behalf of IPCAA stated:

"...utilities in different control areas often have 'inadvertent' energy flows from one system to the other because neither system can always exactly match generation and supply within its control area. APL's proposal is that when the exporter delivers more power to APL than is being exported, APL will 'purchase' the excess at 1.5¢/kWh. However, if the exporter 'under-delivers' to APL, APL will charge the exporter anywhere from about 5¢ to 26¢/kWh, treating the under-delivery as a need for 'standby or supplemental power'. The only reason that APL could enforce this type of disparity is that exporters have no alternative. They are not able to sell to and buy from the AIS as Pool members. APL can define whether the service is 'inadvertent' [sic] supply (in which case APL pays a lower rate) or 'standby service' (in which case the exporter pays a high rate for purchasing from APL). (Evidence, p.6-7)

An imbalance like this also makes it uneconomic for self-generating customers to market excess power and thereby prevents low-cost power from reaching the system.

Customers using Rate 39 should have imbalances settled at the AIS Pool price, unless APL can show that the customer is abusing the privilege and is intentionally and/or consistently under-delivering power."

In Reply Argument, IPPSA referred to APL's statement that proposed imbalance provisions are appropriate for the only two realistic export wheeling scenarios, the firm energy contract and the firm power contract. IPPSA submitted that the imbalance provisions under each scenario would result in shortfall charges being out of proportion to over-supply credits.

IPPSA also addressed the proposed short-term export market services Rate 39(b) which is described by APL as "fully interruptible". IPPSA submitted that customers who want interruptible service ought to obtain this at a rate discounted substantially from the firm service rate due to the much lower quality of service provided. IPPSA noted that APL has proposed to set the

# (n) Rate 39 - Export Market Service

rate at 50% of the firm service rate. IPPSA proposed that Rate 39(b) be set at 50% of Rate 39(a).

In addition, a fully interruptible rate should be made available on a non-discriminatory and objective basis, rather than subjecting potential customers to a Class II test to determine eligibility.

IPPSA noted that the EMS rates were designed by APL for potential customers for the purposes of export based upon the embedded costs of transmission and distribution allocated to Rate 31. IPPSA expressed the concern that since Rate 31 was designed for large general service customers who receive service from the system, Rate 39 as designed resulted in an over-allocation of costs and in practical terms is too high to be used. IPPSA submitted that such a rate would result in EMS customers subsidizing domestic ratepayers. In IPPSA's view, the computation of Rate 39 should not include the costs of 144/25 kV substations, which can be viewed as related solely to serving domestic load. Elimination of this component would have the effect of reducing the rate by 27%.

#### ACC

The ACC submitted that transmission access rates should be consistent throughout the Province to provide a level playing field for all participants. Consequently, the level and structure of APL Rate 39 should be similar to that proposed by TransAlta in its Rate 820. The ACC also noted that APL had limited its proposed export market transmission service rate to wholesale

# (n) Rate 39 - Export Market Service

transactions with other utilities and submitted that the proposals should include sales to other IPP's or to retail customers.

The ACC submitted that the rates should be based on cost of service rather than value of service. The ACC was concerned that although APL used cost of service in rate setting for all customer classes, self-generators rates were based on value of service. The ACC submitted that APL had provided no expert studies, precedent, or evidence of general acceptance elsewhere in support of this approach. Also, the use of different principles by APL was discriminatory, since it created two classes of customers. For customers whose rates were based on cost of service, the Board was presented with a cost of service study which can be tested in a hearing. The same would not be true for customers with rates based on value of service. Those customers would pay rates whose fairness was judged by a different and uncertain standard and patently unfair in comparison with the test applied for the other customers.

In support of its position, the ACC referred to the pre-filed evidence and recommendations of Dr. Schmidt on behalf of the ACC.

#### CCA

The CCA opposed IPPSA's suggestion for removal of costs relating to 144/25 kV substations on the basis that IPP's would use the substations in their use of the system for purposes of export.

## (n) Rate 39 - Export Market Service

The CCA supported APL's use of a 100 MW cap to minimize hearing costs and allow APL to assess the effect Rate 39 customers will have on the Alberta Power system. Reference was made to the rebuttal evidence of Mr. Oliver on behalf of the CCA challenging IPPSA's proposal to use an economic test for transmission costs in place of the 100 MW limit otherwise complex and costly customer-specific analyses would be undertaken at the expense of APL's other rate payers. The CCA submitted that the 100 MW cap would ensure that other customers' rates are not unduly impacted by the implementation of export market service rates.

With respect to IPPSA's comments concerning investment credits, the CCA submitted that APL should be required to demonstrate the reasonableness and appropriateness of any credit paid.

The CCA noted that APL indicated that Rate 39 as designed reflected an under-allocation of marketing and customer accounting costs, which were expected to be higher than the costs for regular general service customers. The CCA submitted that higher marketing and customer accounting costs should be reflected in Rate 39, and APL should perhaps be directed to specifically address this issue at its next GRA. The CCA also submitted that the ACC had presented no evidence that the load characteristics and level of service for partial requirements customers are sufficiently predictable to warrant the development and offering of embedded cost rates to these customers.

#### (n) Rate 39 - Export Market Service

The CCA noted, with respect to costs associated with balancing deliveries, that in accordance with the North West Power Pool, transfers to B.C. will be balanced to the scheduled level within every ten minute interval period. However, APL's proposal was that IPPs will be required to balance to the scheduled delivery level within every 15 minute interval (the standard metering level for APL customers). The CCA submitted that this would result in a significant advantage to IPP's compared to the remaining customers who are responsible for a ten minute balancing period for transfers to B.C. Therefore, the costs associated with the ten minute balancing period should be borne by APL's customers using Rate 39.

#### APL

APL indicated that the proposed EMS Rate 39 could be considered a pilot, intended to explore the demand for this type of service and a first step in the development of an appropriate pricing mechanism. APL stated that the rate was based simply on the embedded costs of transmission and distribution allocated to the large general service Rate 31.

APL proposed that the EMS rate be automatically reviewed and reconsidered once a provincial level of 100 MW was reached for several reasons. Firstly, the proposed EMS rates represented an under allocation of costs, as costs such as those for marketing and customer accounting were expected to be higher than for general service customers, due to the complexity of EMS arrangements and individual studies required. Secondly, there is a growing recognition that transmission services involve generation costs in the provision of necessary

# (n) Rate 39 - Export Market Service

support services such as spinning reserve that should be accounted for as a transmission cost. Lastly, a large increase in EMS load might also require an unusual degree of transmission system reinforcement or upgrades.

APL stated that the proposed rate results in bills of a similar level to TransAlta's equivalent Rate 820 recently approved by the Board in Decision E94076. APL considered that a time of use option would introduce an unwarranted level of complexity. Although their rates were structured differently, APL and TransAlta had worked closely to ensure that rate designs were comparable, and would produce bills that were very close for realistic load scenarios (Exhibit 65). APL indicated that its proposed Rate 39 would fairly charge and credit imbalances for the only realistic export wheeling contract scenarios it envisioned, namely the firm energy contract and the firm power contract. Imbalances would be charged reflecting that, unlike gas systems which allow short term storage through linepack, electric systems must maintain frequency, voltage and VAR control in real time (Argument, p.51). APL submitted that the EMS rate level was very similar to the equivalent TransAlta rate, and submitted that the rate should be approved as proposed.

APL submitted that Rate 39B for interruptible service as discounted from firm service should also be approved as proposed in order that APL and EMS customers may gain experience with the rate.

In Reply APL noted that IPPSA and ACC expressed a preference for EMS rates to be cost based. APL submitted that Rate 39 was designed to recover the

# (n) Rate 39 - Export Market Service

embedded transmission costs for the EEMA large industrial rate class and therefore was a cost based rate. APL submitted that, since the EEMA definition of transmission costs includes all substations or transformers which step down voltages to 25 kV from higher voltages, IPPSA's suggestion that the costs of the 144/25 kV substations be excluded in the determination of Rate 39 charges was inconsistent with the EEMA definition and physical operation of the system.

With regard to IPPSA's argument that Rate 39 should be similar, if not identical, to TransAlta's rate for export services, APL submitted that although the structure and components of the two rates appear different, the actual resulting charges would be remarkably similar. APL considered that APL's Rate 39 was simpler to calculate and understand. Also, while TransAlta requires that customers categorize themselves as full or partial requirement customers, APL offers its "menu" of services to all, which allows customers to mix partial requirements and full service rates in a non-discriminatory manner. This was the foundation of APL's approach to industrial rate design and had already been approved by the Board. APL stated that Rate 39 imbalance charges were based on this non-discriminatory principle since the proposed charges for imbalance were consistent with the charges imposed on other customers for similar services. APL submitted that the TransAlta approach, which allows for a 5% grace for standby use, was inconsistent and incompatible with TransAlta's charges for full service customers and necessitated the separation of partial and full requirement services.

# (n) Rate 39 - Export Market Service

APL noted that TransAlta penalizes over delivery by an IPP, since more transmission capacity was used than was contracted for, and provides no compensation for the inadvertent energy which displaces AIS generation requirements. In contrast, APL would credit over delivery at the same level currently used for self-generators (1.5¢/kWh), and simply charge the demand under Rate 39. Also, the selection of a firm energy contract would allow IPP to minimize or avoid imbalance charges by contracting conservatively, and to instead receive an over delivery credit.

APL submitted that for high load factor, firm energy contracts, the imbalance charges would be minimal, and the time of use distinction incorporated in TransAlta's rate would be irrelevant. APL submitted that its proposed rate was comparable to TransAlta's for the type of export contracts APL expects to enter into.

#### Board Findings

The Board considers that since Rate 39 customers would have characteristics similar to large industrial customers, it is appropriate that Rate 39 recover the embedded transmission costs for the EEMA large industrial rate class, including the costs of 144/25 kV substations, since the EEMA definition of transmission costs includes all substations or transformers which step down voltages to 25 kV from higher voltages.

The Board notes that APL and TransAlta have utilized different philosophies in the design of their export service rates. However, the Board considers that

# (n) Rate 39 - Export Market Service

Exhibit 65 indicates that net customer billings would be comparable between the two utilities for similar practical scenarios, notwithstanding the difference in philosophies. Under Rate 39 APL will compensate for the inadvertent energy which displaces AIS generation requirements and APL will credit over delivery at the same levels APL uses for self-generators. The Board is convinced that Rate 39 appropriately reflects APL's rate design philosophy, wherein all customers may subscribe to both partial requirements and full service rates in a non-discriminatory manner.

In light of the foregoing, the Board accepts APL's submission that Rate 39 adds an appropriate export service rate to APL's menu of rates. Therefore, the Board will approve Rate 39 as filed by APL.

The Board also accepts APL's proposal that APL's EMS rate be automatically reviewed and reconsidered once a provincial level of 100 MW is reached. The Board recognizes that a large increase in EMS load might require an unusual degree of transmission system reinforcement or upgrades. Additionally, if the proposed EMS rates represented an under allocation of costs including generation costs for the provision of necessary transmission support services, as APL suspects, then other customers might be subsidizing exporters. Therefore, until APL has further experience with the rate the Board considers that the 100 MW cap is appropriate to protect APL's existing customers.

## (o) Rate 41 - Small Oilfield and Pumping Power

APL indicated that the proposed Rate 41 retained the structure of the existing rate and rolled in an increase equal to the current Rider G of about 4.9%. The trailing step energy rate was increased to 1.5¢/kWh reflecting current estimates of system incremental energy costs. APL also proposed that the billing demand for non-demand metered service be estimated as HP Nameplate multiplied by 0.76 or as kW Nameplate (as explained in BR-APL.4), in order to account for the difference which usually occurs between the sizing of oilfield equipment and the actual connected load. APL indicated that under existing rates billing demand is unfairly based on nameplate connected HP whereas a limited sampling of metered sites by APL indicated that the 0.76 multiplier would be more appropriate.

In an undertaking APL corrected the rate schedule for Rate 41 to account for the change to use of the 0.76 multiplier (Tr. p.316, Ll.5-10) (Exhibit 41). In its revised response to CCA-APL-5 (included in Exhibit 41), APL indicated that Rate 41 was the only rate class with a significant number of non-demand metered accounts that would be affected by the estimated demand calculation. APL indicated that the use of the service factor resulted in the same revenue recovery from Rate 41 since a lower forecast billing demand of 1,215,807 kW led to a higher rate of \$15.30/kW, rather than 1,367,612 kW and \$13.60/kW without the estimated demand calculation.

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (o) Rate 41 Small Oilfield and Pumping Power

#### MI

The MI indicated that, at the Hearing, it was concerned that there would be lost revenue from non-demand metered customers which would be recovered from customers served by rates other than Rate 41. APL's provision of Exhibit 41 convinced the MI that recovery of any revenues lost due to the use of estimated demand would be from Rate 41 customers.

#### Board Findings

The Board notes that about 0.3% of the increase in Rate 41 is caused by the increase in the trailing step energy rate to 1.5¢/kWh. The Board considers that the increase in the trailing step energy rate is an appropriate increase above the average across-the-board increase for Rate 41 customers. Therefore, the Board will reduce the block one energy charge from the \$3.18/kWh APL proposed to \$3.15/kWh to make the increase over existing Rate 41, including all riders, about 0.3%.

# (p) Rates 51, 52 and 56 - REA and Company Farm Service Rates

APL proposed discontinuance of the "time of use" pilot project and Rate 52, since customers indicated that the change in consumption habits was not justified by the savings and had not subscribed to the rate.

For the farm rate classes 51 and 56, APL proposed to increase the energy charge from 5.00¢/kWh to 5.26¢/kWh and the monthly O&M charge from \$11.00/service plus \$1.85/kVA to \$11.61/service plus \$1.98/kVA APL also noted that the rate for the few REAs who had not joined the common pool for O&M was presented in a separate column on the Rate 51 Schedule.

APL noted that many metered farm customers indicated that they considered demand ratchets applied to non-breakered farm services to be unfair. APL indicated that it proposed removal of the demand ratchet for metered non-breakered farm services of 25 kVA or greater to address customer concerns, simplify rate administration and provide a rate structure comparable to that offered by neighbouring utilities. The kVA of capacity would be the greater of 25 kVA or the highest metered kVA demand during the billing period.

In order to allow REA farm customers service under rate schedule 21 and 31 APL proposed Option P - REA Distribution Price Credit. Option P would provide a credit against Rates 21 and 31 to reflect that REA customers should receive a credit for the costs of distribution facilities included in Rates 21 and

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (p) Rates 51, 52 and 56 REA and Company Farm Service Rates

31, since REAs own their distribution facilities. For all REA customers who elect service under Rate Schedule 21 APL proposed that a 14.0% credit adjustment (Option P) be applied to the base rates. For all REA customers who elect service under Rate Schedule 31 APL proposed that a 7.0% credit adjustment (Option P) be applied to the base rates.

#### MI

The MI indicated that it had no objection to the REA/AAMDC's proposal to reduce Rate 51 O&M by 6.7% (Exhibit 56, p.10) if the revenues to make up the \$224,000 shortfall came from an increase to Rate 56, which had a "very low" revenue to cost ratio. The MI noted that in Decision E93035 the Board directed APL to file a Rate 56 which would bring the company farm rate into tolerance and submitted that the revenue to cost ratio of Rate 56 should be increased to 95% (Argument, p.45). The MI noted that APL had not complied with the Board's direction to bring Rate 56 into tolerance and submitted that APL should again be directed to make the necessary adjustments to Rate 56.

#### **IPCAA**

IPCAA submitted that "speculations" as to how APL's study might be adjusted were in no sense established as correct on the evidence. IPCAA noted that acceptance of the adjustment led the REA/AAMDC to calculate an adjusted revenue to cost ratio of 90% for Rate 56 and to recommend a 6.7% reduction (\$224,000) in the pooled farm O&M which would be made up by increasing industrial rate class revenues. IPCAA submitted that the reduction proposal lacked any considered merit, was introduced under cross-examination to avoid

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (p) Rates 51, 52 and 56 REA and Company Farm Service Rates

reasonable or proper testing and would, at any rate, leave Rate 56 with too low a revenue to cost ratio. (Argument, pp.17-18)

#### REA/AAMDC

The REA/AAMDC submitted that, in light of the evidence it supplied that the cost of service study over allocated costs to Rate 56, the Rate 56 revenue to cost ratio was higher than APL indicated and the revenue required to provide the 6.7% reduction in the O&M rate for Rate 51 should come from the recognition of additional power factor penalty revenue.

The REA/AAMDC submitted that a change in APL's proposed rates was required to reflect the REA/AAMDC belief that it was appropriate and fair that the energy rate should continue to recover the full upstream costs out of EEMA (5.69¢/kWh) from farm customers. However, to mitigate the impact on high load factor REAs, the REA/AAMDC recommended that the Board approve an energy charge of 5.45¢/kWh, the monthly O&M charge \$10.33/service plus \$1.77/kVA. The REA/AAMDC noted that the impact on high load factor REAs would be a maximum increase of 2.99% and that there was a "minimal number" of high load factor REAs. The REA/AAMDC submitted that, as they were the representatives of the customers affected by this purely REA issue, that the Board should adopt the alternative rate design they proposed. (Exhibits 26, 66 and 89) (Argument, pp.22-23)

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (p) Rates 51, 52 and 56 REA and Company Farm Service Rates

The REA/AAMDC submitted that their recommended rates should also be reduced to reflect both the 6.7% reduction in the O&M charge and the across-the-board approach they recommended.

#### APL

APL submitted that, while the proposed energy rate did not exactly match the energy cost out of EEMA as had traditionally been the case, the APL's proposed rates would be fair in that they have almost no impact on any farm customer's bill compared to the current bill. Using the energy rate directly out of EEMA would increase the high load factor customers' bills significantly (Undertaking, Tr. p.559, Lines 12-18). APL also submitted that using the higher energy rate arising from the alternate rate designs suggested by the REA/AAMDC would be similarly unacceptable.

#### Board Findings

The Board accepts that Rate 52 should be eliminated since there are no customers willing to take service under the rate and the Board generally considers rate offerings should be as simple as reasonably possible. If farm time of use rates are requested by APL's customers in the future, then new rates can be set at appropriate levels at that time.

The Board also accepts that, since REAs own their distribution facilities, Option P would provide an appropriate credit against Rates 21 and 31 to reflect that REA customers should receive a credit for the costs of distribution facilities included in Rates 21 and 31. Therefore, the Board approves an Option P which

# (p) Rates 51, 52 and 56 - REA and Company Farm Service Rates

allows all REA customers who elect service under Rate Schedule 21 a 14.0% credit adjustment to be applied to the base rates, and which allows all REA customers who elect service under Rate Schedule 31 a 7.0% credit adjustment to be applied to the base rates.

The Board was not convinced by the REA/AAMDC submissions that the Board should increase the rates of the high load factor customers by more than those of the lower load factor customers. The REA/AAMDC noted that the number of high load factor REAs was much smaller than the number of the low load factor REAs and the Board considers that the REA/AAMDC would be representing the interest of the greater number of their REA members in this intra class issue. Therefore, in light of the Board's findings that an across-the-board increase in rates is appropriate in this Decision, the Board will accept APL's proposed rate design, but decrease the monthly O&M charge from \$11.61/service to \$11.05/service. The Board would expect APL to file a Rate 56 which would bring the company farm rate revenue to cost ratio closer to tolerance in its next GRA, if significant rate rebalancing is necessary at that time.

# ALBERTA ENERGY AND UTILITIES BOARD

## 5. INDIVIDUAL RATES, TOLLS OR CHARGES

# (q) Rate 61 - Municipal Street Lighting Service and Rate 63 - Private Lighting Service

APL indicated that it proposed an average increase in each component while retaining the structure of Rates 61 and 63. APL indicated that the total 1993 forecast net contributions were allocated to rate classes based on the 1991 actual contributions by rate class.

#### MI

The MI, noting the actual contributions in 1990 and 1991 (shown in Exhibit 37) and the forecast rate base additions for 1993, submitted that the 1993 contributions forecast was grossly understated and therefore contributed to a drop in the revenue to cost ratio of Rate 61 from 102% in 1992 to 87% in 1993. The MI submitted that use of outdated forecast information led to spurious results and as a result little weight could be placed on the costs allocated to Rate 61.

The MI submitted that the 15.5% increase proposed by the CCA for Rate 61 was not only based on those spurious cost of service results, but also violated the criterion of rate stability. The MI recommended that APL's proposed increase be approved.

#### CCA

The CCA noted that since 1989 Rates 61 and 63 had increased by 22% and 23%, respectively, and currently have revenue to cost ratios of 86% and 89%, while

#### ALBERTA ENERGY AND UTILITIES BOARD

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (q) Rate 61 Municipal Street Lighting Service and Rate 63 Private Lighting Service

Rate 11 had increased by 30% and has a revenue to cost ratio of 99%. The CCA submitted that Rate 61 should be increased to bring its revenue to cost ratio to 100%, with the increased revenue used to reduce Rate 11.

#### Board Findings

The Board notes the submissions of the MI that the methodology used in APL's COSS may have caused the revenue to cost ratios for Rate 61 and Rate 63 to appear lower than appropriate and therefore significant adjustments were not required. However, since the revenue-to-cost ratios are considerably below the 95%-105% range, the Board will accept APL's proposed rate design and allow the rates to increase slightly more than the average increase.

# (r) Rate Riders - General

APL proposed elimination of Option F (idle service) charges for customers served under Rates 11, 18 and 21, since the revenues were small compared to the expense and effort of administering, billing and recovering them. Idle service charges would continue to be applied for customers served under Rates 31, 41, 51, 56 and 61.

The Board notes no parties made submissions with respect to this matter.

#### Board Findings

The Board accepts that Option F should be eliminated for customers served under Rates 11, 18 and 21 for the reasons APL provided.

#### ALBERTA ENERGY AND UTILITIES BOARD

# 5. INDIVIDUAL RATES, TOLLS OR CHARGES

# (s) Option T - Off-Peak Demand Discount

APL indicated that the Option T discount to firm power Rates 21 and 31 was intended to shift load to off-peak hours where possible. Option T provides an incentive to customers to operate with an off-peak demand greater than their on-peak demand by allowing customers to purchase power at 10% of the demand charge for the portion of their off-peak demand that exceeds their on-peak demand.

#### **IPCAA**

IPCAA submitted that some low load factor customers might be prevented from using Option T due to the inclusion of a demand component in the option.

IPCAA submitted that those customers could not as APL suggested access similar service through Rate 33 since it was interruptible.

IPCAA submitted that the rate was "prohibitively expensive for most practical usage" (Argument, p.21) and was more restrictive than a similar Option 16 offered by TransAlta even though off peak supply was common for each utility. IPCAA submitted that it was unfair that TransAlta customers competing to supply incremental production would gain a clear advantage since they would pay no demand charge. IPCAA further submitted that while APL indicated that its pricing was efficient, APL offered no standard by which to objectively measure its efficiency. At any rate, IPCAA submitted that the objective of Option T should not be to create an artificial measure of the value of Rate 33 energy, as APL suggested. (Argument, pp.20-22)

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (s) Opton T Off-Peak Demand Discount

IPCAA recommended that, given the circumstances, APL should be required at a minimum to develop an Option T which would prorate the demand charge based on the number of days usage in a month.

#### APL

APL submitted that Rate 33 provided an effective option for overnight energy on a temporary basis, since, while technically Rate 33 is interruptible, "the probability of that overnight is very low indeed". APL further indicated that, without a demand charge, Option T would provide a price cap on Rate 33 thereby eliminating the opportunity for APL to negotiate value based pricing for short draws on Rate 33. APL submitted that Option T was correctly designed with a demand charge component since it was not intended as a free price hedge for intermittent Rate 33 customers. (Argument, p.64)

## Board Findings

The Board notes that Option T is designed to shift some load to off-peak hours for the benefit of the system and all of its customers. The objective is not to provide a discount which causes all customers - including some low load factor customers as described by IPCAA - to shift their load; rather, it is to provide for the shift of some customers to benefit the system. The Board considers that providing a price cap on Rate 33 would work against the goal of maximizing benefits for customers who do not receive the discounts available to customers who are able to quality for Rate 33. Therefore the Board will approve Option T as proposed by APL.

# (t) Rider I - Peak Shaving Credit

APL proposed to maintain the moratorium on new Option I customers since it considered that no demonstrable benefit would be derived from the addition of further Class III interruptible load to the AIS. APL also proposed two administrative changes to improve the effectiveness of Rider I, including extending the notice of intent to renew from 1 year to 2 years.

#### **IPCAA**

IPCAA submitted that since APL intended to fix the Option I credit on an annual basis, extension of the notice to renew to two years would allow APL to leverage the credits down to an existing Rider I customer while preserving the right to raise the credits the following year to a new customer. IPCAA submitted that APL had not indicated how it would be able to enforce a two year waiting period for new Rider I contracts so that existing Option I customers will not be prejudiced. IPCAA submitted that given the existing moratorium on APL Class III sales, APL's intent to establish a waiting list and adequate system capacity, there was no pressing need to provide greater stability to the capacity planning process. IPCAA submitted that consideration of APL's proposed change to a two year notice period should be deferred until APL's next GRA. (Argument, pp.18-20)

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (t) Rider I Peak Shaving Credit

#### APL

APL indicated that the two year notice period to renew or enter into Option I contracts was appropriate for planning since it would take about two years to install peaking capacity after the need for the capacity is recognized. (Tr. p.521)

## Board Findings

The Board notes that IPCAA's arguments against extension of the notice period are based on its concern that "administrative arrangements not be structured in a way which would permit artificial inducements to changes in credit levels" (Argument, p.20). However, the Board considers that the objective of allowing interruptible contracts was to maximize the net benefits to the system and not to minimize costs to the interruptible customers. If interruptible customers are willing to take a lesser credit, then the system will benefit. Therefore, the Board will approve the changes APL proposed to Rider I, including extension of the notice period.

#### ALBERTA ENERGY AND UTILITIES BOARD

#### 5. INDIVIDUAL RATES, TOLLS OR CHARGES

#### (u) Rider A-1 - Municipal Assessment

#### CCA

The CCA expressed concern that APL had been unwilling to provide them with information regarding the components of Rate Rider A-1 on the basis that this was not a Phase II issue (Tr. p.238). The CCA submitted that the requested information was necessary to allow for review of the rate to determine fairness and reasonableness. The CCA also submitted that this was a Phase II issue as this phase of proceedings is set up under the <u>Public Utilities Board Act</u>, R.S.A. 1980, c. P-37 (PUB Act) to enable the Board to review all rates for fairness and reasonableness.

The information requested by the CCA included details of the property tax assessments and applicable mill rates for each property owned by APL and the fair actual value of machinery, equipment and apparatus used in the exercise of the franchise for the relevant municipalities. It was the CCA's understanding in requesting the information that assessments are performed annually by statutory requirement and delivered to the utility. The CCA submitted that these particular components of Rate Rider A-1 were not brought up at the Phase I proceeding and, therefore, APL is answerable for them during Phase II proceedings as this is when the rates are approved. (Tr. p.242)

The CCA acknowledged that the franchise agreements with the municipalities, which form the basis for the rates, are approved by the Board. However, the

# (u) Rider A-1 - Municipal Assessment

CCA submitted that at the time of approval, the franchise agreements are not subject to the same guidelines which prevail at a Phase II hearing. The utility is therefore answerable at a Phase II hearing for the rates negotiated and approved at a franchise agreement hearing. (Tr. p.238)

In argument, the CCA stated that it was concerned about the significant level of cost increases APL has or has proposed to pass on to customers with respect to franchise agreements entered into with municipalities. Since Rate Rider A-1 is designed to collect a fixed percentage of the gross revenue of the utility within a particular franchise area, this results in an automatic increase when the utility's revenue increases. Due to utility rate increases the dollar amount of funds collected under Rate Rider A-1 has increased significantly in the last few years. The CCA pointed out that automatic increases of this nature appear to contravene s.84(1) of the PUB Act which requires further application to the Board for approval of increases in any rates previously fixed by the Board.

The CCA noted that APL, the MI and the Board all take the position that the amount to be collected under Rate Rider A-1 is set or approved at Phase I. However, although a specific amount is approved at Phase I, the amount collected varies with gross revenue. The CCA pointed out that s.84(1) of the PUB Act prohibits any upward variation from the amount approved. The CCA provided some examples from the Phase II filing and undertakings by APL illustrating this point and supporting the position that APL has not proven that

## (u) Rider A-1 - Municipal Assessment

the rate is fair, just and reasonable. The CCA submitted that the Board was setting rates for the test year 1993 at Phase II, while the forecast amount of revenue to be collected pursuant to Rate Rider A-1 was established in the Phase I process.

The CCA argued that since s.14(8) of the <u>Municipal Taxation Act</u> uses the words "in lieu of," the amounts payable under a franchise agreement in lieu of a tax should bear some relation to the amount which would have been collected under the tax. The CCA submitted that the amounts collected are clearly in excess of the amounts which would be payable under the traditional assessment methodology which is an alternative envisaged by the <u>Municipal Taxation Act</u>. The CCA felt that it was inappropriate for a utility to enter into agreements with municipalities and negotiate amounts which bear no relation to the amounts which would be collected using traditional assessment methodology. For this reason, a utility is duty bound to ensure that the amount payable by consumers is fair, just and reasonable.

In Reply Argument, the CCA expressed concern with the failure of APL to specify the exact amount approved in Phase I of these proceedings. The distinction of limiting Phase II to rate design caused concern because the rates proposed by APL will generate significantly more revenue than that approved by the Board in Phase I. Since the Board has ruled that Rider A-1 is a Phase I issue, APL is limited to collecting the amount set at Phase I.

# (u) Rider A-1 - Municipal Assessment

The CCA submitted that the approval of the franchise tax should be denied for the following reasons:

- (1) Rider A-1 will, if there is an increase in gross revenues, constitute an automatic increase to the consumer in contravention of s.84(1) of the PUB Act.
- (2) The rate approved in Phase I is not followed, adhered to or maintained through Phase II and the actual amounts collected.
- (3) The amounts collected under Rider A-1 are far in excess of the amount which would be collected under the alternate assessment methodology.

  There is, therefore, a marked departure from what was intended under the Municipal Taxation Act by the words "in lieu of."

## MI

The MI agreed with APL that it would be inappropriate to bring forward the issue of approval of Rate Rider A-1 to the Phase II proceedings. The MI stated that each of the rates shown under Rider A-1 arise as a result of a franchise agreement entered into between APL and a municipality, and those agreements have been approved by the Board, during which process the rate was approved.

The MI also submitted that the jurisdiction for the taxing authority comes under the Municipal Taxation Act, which is quite explicit as to the process to be

# (u) Rider A-1 - Municipal Assessment

followed. Also, "taxes other than income" are specifically referred to in Schedule C of 1993 Phase I Decision E93069, which suggests approval by the Board.

The MI pointed out that although the issue was not specifically raised in Phase I, the option to raise the matter was always open to the CCA or any other intervenor. The Board has therefore dealt with the issue and approved an amount which is included in the revenue requirement. (Tr. pp.241-243)

In Reply Argument, the MI referred to the CCA's submission that "the approval of franchise tax should be denied" based on arguments which were essentially the same as those advanced by the CCA in Phase II of Northwestern Utilities Limited's (NUL) 1993/94 GRA. The MI referred to the findings of the Board from that hearing, recorded in Decision E94084 dated December 22, 1994. The findings were that these matters are subject to review in the municipal franchise tax hearing process and the Phase I process, and that each franchise tax charged by NUL has been expressly approved in a Board order.

The MI indicated agreement with these findings and the previous direction of the Board in this proceeding, and submitted that the argument of the CCA has been inappropriately advanced.

- 5. INDIVIDUAL RATES, TOLLS OR CHARGES
- (u) Rider A-1 Municipal Assessment

#### APL

APL submitted that the request by the CCA for information relative to Rate Rider A-1 was directed to the issue of costs. These costs are reviewed during the Phase I process and are not a Phase II matter. The CCA would certainly be entitled to that type of information at some other time. APL further submitted that the franchise agreements referred to in the CCA request for information have been previously reviewed and approved by the Board. (Tr. p.239)

#### Board Findings

The Board notes that individual applications are made to the Board by various municipalities to approve the terms of franchise agreements with APL, including the percentages of gross revenues which are then reflected in Rider A-1. Public notices of franchise applications are published in newspapers in accordance with the Board's instructions, with public hearings conducted when appropriate.

The Board also notes that the forecast amount of revenue to be collected pursuant to Rider A-1 was established in APL's 1993 Phase I process by consensus of the parties, and was approved by the Board under "Taxes Other Than Income" as evidenced in Decision E93069. With regard to what the CCA characterized as "extra revenues" above those approved in APL's Phase I proceeding, the Board notes that in Phase I it approves a forecast of the franchise tax revenues to be collected, which is based primarily on the

#### ALBERTA ENERGY AND UTILITIES BOARD

# 5. INDIVIDUAL RATES, TOLLS OR CHARGES

# (u) Rider A-1 - Municipal Assessment

municipal franchise tax rates approved at the franchise tax hearings. Whether the forecast of franchise revenues based primarily on the approved rates proves correct or incorrect for the test year for which they were forecast or for subsequent years, is simply a consequential aspect of future test year regulation. Therefore, the Board considers that the CCA's argument based on s.84 of the PUB Act is without merit.

The Board does not consider it unjust or unreasonable, at this Phase II hearing, to pass charges on to customers which relate to specific statutory provisions which have been subject to review by the Franchise hearing process and the Phase I hearing process. The Board indicated in a ruling at the Phase II hearing (Tr. pp.338-339) that Phase II was not the appropriate forum to have this issue considered by the Board. The Board considers that, in accordance with the Board's comments at the Hearing, all of the CCA's later submissions relating to franchise tax collections in lieu of property taxes were inappropriate. In addition, the Board notes that this issue, as to whether franchise fees should bear some relationship to amounts which would be otherwise collected under a property tax, has recently been canvassed in detail in proceedings which culminated in Decisions E95048 and E95059. A similar CCA argument was rejected by the Board in those Decisions.

# 5. INDIVIDUAL RATES, TOLLS OR CHARGES

### (v) Rider A-2 - Surcharge

APL indicated that Rider A-2 is intended to discourage wasteful consumption where fuel costs substantially exceed AIS fuel costs. APL proposed an increase of 4.88% in the surcharge for isolated area consumption. The surcharge applies for residential consumption in excess of 600 kWh/mo, and general service and oilfield consumption in excess of 4500 kWh/mo.

### MI

The MI noted that Rider A-2 was described by APL as applying to higher than average energy usage. However, the MI further noted that average general service consumption was 2,700 kWh/mo and average oilfield consumption was 3,900 kWh/mo. Both were lower than the 4,500 kWh/mo level provided for in Rider A-2. Further, APL was unable to quantify the amount of the subsidies without a separate COSS for the isolated systems. The MI had three areas of concern: the propriety of the subsidies to isolated areas, the subsidies' levels and the threshold level for application of the surcharge. The MI submitted that, at its next GRA, APL should deal with each. (Argument, pp.19-21)

### Board Findings

The Board notes that the MI's concerns were not dealt with by APL in reply argument. The Board expects that APL will address the concerns in its next Phase II filing.

### 6. ELECTRIC SERVICE REGULATIONS

### (a) Investment Policy

APL indicated that it had applied the average increase (4.9%) to the investment levels contained in the existing Electric Service Regulations (ESR). Existing industrial investment levels were the present value of the difference between expected revenues and upstream costs over the commercial life of representative services.

APL stated its current policy on early system developments. Where APL has previously identified a system need in an area and provision of the system facilities is advanced to meet the needs of a new incremental customer, that customer will be allocated both the incremental customer and early system costs incurred. However, APL stated that the updating of plans and forecasts complicate application of that policy.

APL also summarized its response to the Board direction that APL should provide guidelines for "early system developments". APL took the position that there was no analytic or deterministic formula available to differentiate between system and customer related facility extensions. APL submitted that such differentiation should be made by applying professional judgement on a case by case basis, considering factors including the number of customers involved, the size and type of load, the size of the investment and load forecasts for the area. (Argument, pp.66-68)

- 6. ELECTRIC SERVICE REGULATIONS
- (a) Investment Policy

### **IPCAA**

IPCAA submitted that APL's indication that it has not yet been able to come up with any useful guidelines for "early system developments," should not mean that the search should be abandoned. IPCAA considered that APL accepted that it wouldn't be unreasonable to lay out potential guidelines for comment. (Argument, p.23)

## Board Findings

The Board recognizes APL's position that there is no analytic or deterministic formula available which may be precisely set out to differentiate between system and customer related facility extensions. In addition, the Board considers that explicit definitions or detailed regulations may not allow for sufficient flexibility in their application if certain circumstances occur which had not been considered in the drafting of those definitions or regulations. Therefore, the Board accepts APL's current early investment policy as appropriate at this time and also accepts that it must be tempered with professional judgement on a case specific basis.

### 6. ELECTRIC SERVICE REGULATIONS

## (b) Other Changes to the Electric Service Regulations (ESR)

APL proposed a number of minor changes to its ESR in the Application (Tab 6A). APL also proposed a number of minor revisions to the wording of its ESR under cover of a letter dated May 26, 1995, which was sent to all registered parties in the Phase II proceedings. No party commented on the revisions proposed in the May 26, 1995 letter.

### CCA

The CCA submitted that, since the ESR is a contract which the customer must subscribe to in APL's service area, the ESR should be drafted with fairness to the customer in mind. The CCA submitted that the "reasonable times" for entry onto a customer's property should be set out in more detail in APL's ESR. Periods of notice should be set out and unconditional access allowed only in emergencies where life or significant property damage is a probability. The CCA submitted that wording similar to Section 27 of the Water, Gas and Electric Companies Act, c.W-4, R.S.A., 1980, would be appropriate.

Using the maximums for each component, the CCA calculated that the maximum residential security deposit and reconnection fee could total \$462.00 and took the position that reconnections were a "more significant cost to the customer than to the utility". (Argument, p.37) The CCA submitted that no more than \$140.00 should be demanded in advance of reconnection including security deposits and that the reconnect fee should be "added to subsequent utility accounts for that customer". (Argument, p.37)

### 6. ELECTRIC SERVICE REGULATIONS

### (b) Other Changes to the Electric Service Regulations (ESR)

The CCA was also concerned that a ratcheted demand or minimum monthly charge would apply for Rates 11 and 18 if reconnection occurred within 12 months of disconnection. In an undertaking APL provided a revised ESR (Section 4.19(d)) page 11 which indicated that the ratcheted demand or minimum monthly charge would not apply for Rates 11, 18 and 21.

### APL

APL indicated that they would only demand the maximum three month residential security deposit if a customer had a history of extremely poor credit. (Tr. p.926)

### Board Findings

The Board considers that the changes to APL's ESR proposed in its filing (Tab 6A) are appropriate and that the revisions of May 26, 1995 improve the understanding or wording of APL's ESR.

The Board notes that it has received no complaints from individuals regarding any APL entry to customers' premises. The Board also notes that the CCA did not bring forward any indication of specific examples in this proceeding wherein APL's rights of entry as set out in the ESR had resulted in any objection by or even any inconvenience to CCA's members. In the absence of any such indication, or any other evidence, the Board considers that it would be inappropriate to change APL's rights of entry.

- 6. ELECTRIC SERVICE REGULATIONS
- (b) Other Changes to the Electric Service Regulations (ESR)

The Board also notes APL's indications that only in the case of extremely poor credit would the maximum security deposit be demanded. The Board considers that it is appropriate to protect customers who pay their bills on time from costs imposed by those who don't. The Board accepts APL's handling of these issues and expects APL to continue to balance flexibility with fairness in the application of its ESR for individual customers, keeping in mind the interests of all of its other customers.

Therefore, the Board will approve the APL's ESR attached as Schedule "B" to this Decision.

### 7. OTHER MATTERS

### (a) EEMA Flow-Through Procedure

### <u>PICA</u>

PICA submitted that any change in APL's costs should be recognized in an EEMA flow-through proceeding at the same time changes in transfer credits are recognized. PICA considered that this would maintain shareholder neutrality to EEMA by allowing rates to change by the net amount of the change in EEMA costs and thereby maintain the match between costs and revenues at approximately the level set by the Board in the most current GRA (Argument, p.26). PICA submitted that without this change, contrary to the intent of EEMA, the cost for electricity seen by an APL customer would be something different than the average cost of generation and transmission for the year.

### APL

APL noted that, since the principles for EEMA flow-through were established by Board approval, in Decision E90082, of TransAlta's September 17, 1990 application to adjust the EEMA transfer payment, both APL and TransAlta have applied for EEMA flow-through riders with the intention to refund or recover only the change in the EEMA transfer and not the total change in the deemed cost. APL submitted that the common principles established in previous flow-through procedures should be retained.

- 7. OTHER MATTERS
- (a) EEMA Flow-Through Procedure

# Board Findings

The Board notes that the principles for EEMA flow-through were established in 1990. The Board agrees with APL that it would be inappropriate to change the common principles established in previous flow-through procedures based only on the reasons provided by PICA.

### 8. FINALIZATION OF INTERIM RATES

Rider G on industrial rates not finalized in Decision E93035 was increased to 20.68% effective July 1, 1993 in APL's 1992 Phase II Decision E93035. In Decision E93068, as amended by Order E93082, the industrial Rider G level was increased to 21.69% effective November 1, 1993 (to allow recovery, in 1993, of APL's 1993 forecast revenue deficiency determined in Decision E93069) and to 20.61% effective January 1, 1994 (15.01% to allow recovery of the industrial rate basket's portion of APL's approved 1992 revenue requirement compounded with 4.88% to allow collection of APL's 1993 annualized revenue requirement on a going forward basis).

In Decision E94034, the Board noted that the issue in regard to finalization of interim rates was the equity of the interim rates for customers billed by the The Board considered that most of those customers industrial rates basket. would have had difficulty dealing with retroactive adjustments dating back to 1991 and 1992, since many customers would have made decisions such as place. on the interim rates in supply choices based purchase and Accordingly, the Board confirmed the interim industrial rates which were in existence to December 31, 1992, as final rates. The Board considered that it would not have been appropriate to decide whether or not the 1993 and 1994 interim industrial rates should have been adjusted until all parties had the opportunity to provide submissions on the matter in the 1993 Phase II proceedings.

### 8. FINALIZATION OF INTERIM RATES

In Decision E94034 the Board finalized the industrial rates to December 31, 1992 and set interim industrial rates, tolls and charges which reflected the rate basket proposed by APL in its 1992 Phase II and which, together with APL's other rates, were forecast to generate total revenues approximately equal to APL's Electric Utility Revenue Requirement approved for the test year 1993 in Decision E93069.

### MI

The MI noted that the rates proposed in this Application provided revenues by rate class close to existing rates and recommended that existing interim rates "be finalized for the periods in which they were in effect". (Argument, p.48)

### Board Findings

The Board has statutory authority to approve rates on an interim basis, and to subsequently adjust or confirm those interim rates in the setting of just and reasonable final rates.

Generally, the Board considers that it is necessary to make a case-by-case judgement as to whether or not interim rates should be adjusted once final rates are approved. In exercising its judgement, the Board may weigh considerations such as impact on each customer class, equity among customer classes, the administrative difficulty of adjusting the rates, and the materiality of the adjustment, among other matters. It must also be recognized that if interim refundable rates based on an approved revenue requirement are

### 8. FINALIZATION OF INTERIM RATES

adjusted, some customers will receive refunds, but other customers will see increased rates.

The Board considers that most customers would have difficulty dealing with retroactive adjustments dating back to 1993, since many customers will have made decisions such as purchase and supply choices based on the interim rates in place. The Board also considers that institutional customers would experience difficulty in dealing with retroactive adjustments given their system of fixed budgeting. In addition, the Board notes that many industrial customers have layered their rates and made decisions on partial requirements rates such as bid, standby and interruptible energy rates based on the relationships existing among the interim rates in place during 1993, 1994 and 1995. Different decisions might well have been made by customers if the rates herein approved had been in place. Furthermore, the Board recognizes that service to some industrial customers may have been commenced or been discontinued over the period in question.

The Board also notes that, on a subclass basis, the demand charges for all blocks and the energy charge in the highest usage block in APL's proposed Rate 31 are significantly different from the interim rate levels. The Board recognizes that the Rate 31 subclasses include a number of institutional customers in addition to industrial customers who made decisions based on the subclass charge levels.

### 8. FINALIZATION OF INTERIM RATES

The Board notes that in Decision E93068, as amended by Order E93082, the interim Rider G level was increased to allow collection of APL's approved 1993 annualized revenue requirement on a going forward basis. In essence the interim Rider G level approved resulted in an across-the-board increase of 4.88%.

Since the Board has determined that only a few rates such as the runout rate and demand charges in Rate 31 should have an increase significantly different than the average increase, the issue of equity in this case is largely related to the equity of the interim rates for customers billed under Rate 31. As previously noted, the customers in industrial rate classes have made their decisions with respect to input costs and other factors, based on the existing interim rates and the inter-relationship in the design and structure of those rates.

The Board notes that extenuating circumstances in this case led to the passage of considerable time while the interim rates were in place. This increases significantly the difficulties in retroactively fixing final rates which would be more equitable than the interim rates which were in place. The Board has concluded that it would be inappropriate to retroactively adjust interim Rate Class 31 or any other rate class under these circumstances and, taking all factors into consideration, concludes that those rates are just and reasonable for the time they were in effect. The Board, therefore, will confirm as final all

# 8. FINALIZATION OF INTERIM RATES

of APL's rates, including Rate 31A, which have been in existence to the date of October 31, 1995.

### 9. ORDER

### IT IS HEREBY ORDERED THAT:

- (1) The rates, tolls and charges, as approved in Decision E94034, are hereby replaced by the rates, tolls and charges contained in Schedule "A" hereto, effective November 1, 1995.
- (2) The rates, tolls and charges, as approved in Decision E94034, are hereby confirmed as final rates up to and including October 31, 1995.
- (3) The Rider M approved in Order E95021, dated March 2, 1995, is hereby replaced by the Rider M included in Schedule "A" hereto.
- (4) The "Electric Service Regulations", as approved in Decision E94034, are hereby replaced by the "Electric Service Regulations" attached as Schedule "B" hereto.

Dated in Edmonton, Alberta this 20th day of October, 1995.

ALBERTA ENERGY AND UTILITIES BOARD

(Signed) B. T. McMANUS, Q.C.

PRESIDING MEMBER

(Signed) A. CALISTA BARFETT

MEMBER

# FOLLOWING ARE

SCHEDULES "A" AND "B"

AND

APPENDIX 1

ATTACHED TO AND FORMING PART OF

ALBERTA ENERGY AND UTILITIES BOARD

DECISION E95102

DATED OCTOBER 20, 1995

ALBERTA ENERGY AND UTILITIES BOARD

(Signed) B. T. McMANUS, Q.C.

PRESIDING MEMBER

(Signed) A. CALISTA BARFETT

MEMBER

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SCHEDULE "A"

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Effective: Supersedes:

### **GENERAL INDEX**

### RESIDENTIAL SERVICE

Rate Schedule 11 Standard Residential Service

Rate Schedule 18 Residential Service

(Lloydminster Franchise Area)

### **SMALL GENERAL SERVICE**

Rate Schedule 21 Standard Small General Service X
Rate Schedule 25 Irrigation Pumping Services
Rate Schedule 26 REA Irrigation Pumping Service

### LARGE GENERAL SERVICE/INDUSTRIAL

Rate Schedule 30 System Support Minimum Charge Rate Schedule 31 Large General Service/Industrial Rate Schedule 31A Energy Rate Options for New Gas Compression Rate Schedule 32 Firm Standby Power Rate Schedule 33A Short Term Reserve Energy Rate Schedule 33B Long Term Reserve Energy Rate Schedule 34 Interruptible Standby Power Rate Schedule 35 WESCUP Wholesale Rate Schedule 36 Rainbow Processing Plant Rate Schedule 38 Temporary Firm Energy **Export Market Services (EMS)** Rate Schedule 39A Rate Schedule 39B Short Term Export Market Services (STEMS)

**OILFIELD** 

Rate Schedule 41 Small Oilfield and Pumping Power

<u>FARM</u>

Rate Schedule 51 REA Farm Service X Rate Schedule 56 Farm Service X

LIGHTING SERVICE

Rate Schedule 61 Municipal Street Lighting Service

Rate Schedule 63 Private Lighting Service

... continued on overleaf

# General Index (continued)

### **RIDERS**

Rider A-1
Rider A-2
Rider E
Special Facilities Charge
Rider M
Temporary EEMA Adjustment Rider
Adjustment for Service Outside the
Boundaries of the Province of Alberta

### **OPTIONS**

Option F Idle Service
Option H Service at Primary or Transmission Voltage
Option I Peak Shaving Credit
Option N Plant Commissioning
Option P REA Distribution Price Credit
Option T Off-Peak Demand
Option U Ratchet Buydown

Effective: Supersedes:

### RATE SCHEDULE 11

# STANDARD RESIDENTIAL SERVICE

**AVAILABLE:** 

To all customers throughout the territory served by the Company except those within the franchise area of the City of Lloydminster.

APPLICABLE:

To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial or industrial use.

RATE:

Charges for service in any one billing month shall be the sum of the following:

(a) <u>Customer Charge</u> \$11.90

(b) Energy Charge

All Energy 7.48¢/kW.h

MINIMUM MONTHLY BILL:

Shall be the Customer Charge.

ELECTRIC SERVICE REGULATIONS:

Effective: Supersedes:

### RATE SCHEDULE 18

# RESIDENTIAL SERVICE (Lloydminster Franchise Area)

(Lioyuminster Franchise Area

**AVAILABLE:** 

To all customers situated within the franchise area of the City of Lloydminster. Customers located outside the franchise area will be served on Rate Schedule 11, even though they may be supplied from Lloydminster's distribution system.

APPLICABLE:

To single-phase electric service at secondary voltage through a single meter, for normal use by a single and separate household. Not applicable to any commercial or industrial use.

RATE:

Charges for service in any one billing month shall be the sum of the following:

(a) <u>Customer Charge</u>

\$10.60

(b) Energy Charge

All Energy

7.48¢/kW.h

MINIMUM MONTHLY BILL:

Shall be the Customer Charge.

ELECTRIC SERVICE REGULATIONS:

Effective: Supersedes:

# RATE SCHEDULE 21

# STANDARD SMALL GENERAL SERVICE

**AVAILABLE:** 

To all customers throughout the territory served by the

Company,

APPLICABLE:

To single or three phase electric service at secondary voltage. Rate 21 A is not applicable for any service in

excess of 50 kW. Rate 21B is not applicable for any

service in excess of 500 kW.

RATE:

The customer may elect either:

OPTION A: ENERGY ONLY

For the first 50 kW.h per kW of billing demand 16.0¢/kW.h

For energy in excess 50 kW.h per kW of

billing demand

8.0¢/kW.h

OPTION B: DEMAND AND ENERGY

Charges for service in any one billing month shall be the sum of the following:

(a) Demand Charge

All kW of billing demand \$4.05 per kW

(b) Energy Charge

For the first 200 kW.h

per kW of billing demand

7.53 ¢/kW.h

For energy in excess of 200 kW.h per kW of

billing demand

3.38¢/kW.h

.. continued on overleaf

### Rate Schedule 21 (continued)

MINIMUM MONTHLY BILL:

Shall be the demand charge, but not less than \$20.25.

### BILLING DEMAND:

The ratchet threshold is 150 kW. The ratchet clause applies only to the portion of the demand in excess of 150 kW and provides for a gradual transition to the fully ratcheted Rate Schedule 31.

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

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

# POWER FACTOR:

Where a customer's power factor is found to be less than 90 percent, the Company may require such customers to install corrective equipment.

# ELECTRIC SERVICE REGULATIONS:

Effective: Supersedes:

### **RATE SCHEDULE 25**

### IRRIGATION PUMPING SERVICES

**AVAILABLE:** 

Throughout the territory served by the Company, between

April 1 and October 31 only.

APPLICABLE:

To seasonal irrigation pumping loads. Rate 25 is not

applicable for any service in excess of 150 kW.

RATE:

Charges for service shall be the sum of the following:

(a) Service Charge

\$27.60 per kW of billing demand

(b) Energy Charge

All energy

3.70¢ per kW.h

MINIMUM CHARGE FOR SEASON:

Shall be the Service Charge but not less than \$138.00.

BILLING DEMAND:

The billing demand will be the greater of the following:

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

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as follows:

kW Billing Demand = kW Nameplate Rating

or

kW Billing Demand = HP Nameplate x 0.746

### Rate Schedule 25 (continued)

IDLE

SERVICES:

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.

BILLING

PERIOD:

One-half of the Season Minimum Charge will be billed before service connection in the Spring but no later than July 1: the balance of the charges will be billed following service disconnection in the fall.

POWER FACTOR:

Where a customer's power factor is found to be less than 90 percent, the Company may require such customers to install corrective equipment.

ELECTRIC SERVICE REGULATIONS:

Effective: Supersedes:

### **RATE SCHEDULE 26**

### REA IRRIGATION PUMPING SERVICE

**AVAILABLE:** 

Throughout the territory served by the Company, between

April 1 and October 31 only.

APPLICABLE:

To the seasonal irrigation pumping energy requirements of REA, individual co-operative and colony farms. Rate 26 is

not applicable for any service in excess of 150 kW.

RATE:

Charges for service for one season shall be the sum of the

following:

	In O & M Pool	Outside of O & M Pool
All Energy	3.7 ¢/kW.h	3.7 ¢/kW.h
Seasonal O & M		
Charges	\$11.20/kW	•

MINIMUM CHARGE

FOR SEASON:

Shall be the Service Charge but not less than \$56.00.

BILLING DEMAND:

The billing demand will be the greater of the following:

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

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as follows:

kW Billing Demand = kW Nameplate Rating

or

kW Billing Demand = HP Nameplate  $\times$  0.746

... continued on overleaf

### Rate Schedule 26 (continued)

### IDLE

SERVICES:

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.

### BILLING PERIOD:

One-half of the Season Minimum Charge will be billed before service connection in the Spring but no later than July 1: the balance of the charges will be billed following service disconnection in the fall.

# POWER FACTOR:

Where a customer's power factor is found to be less than 90 percent, the Company may require such customers to install corrective equipment.

## ELECTRIC SERVICE REGULATIONS:

The Company's Electric Service Regulations approved by the Alberta Public Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company. Copies of the Electric Service Regulations are available for inspection in the offices of Alberta Power Limited during normal working hours.

# ADDITIONAL CHARGES:

Additional charges are made on behalf of the REAs as defined in contracts and are subject to change from time to time. These charges for operation and maintenance as well as the deposit reserve are in addition to the other charge contained in this rate schedule.

Effective: Supersedes:

### RATE SCHEDULE 30

### SYSTEM SUPPORT MINIMUM CHARGE

**AVAILABLE:** 

Throughout the territory served by the Company from the

Alberta Interconnected System.

APPLICABLE:

To all customers interconnected with the Alberta

Interconnected System.

RATE:

A minimum charge for provision of system support shall

apply.

The minimum charge shall be \$3.77/kV.A per month for each kV.A of installed or contracted capacity. Where the customer and Alberta Power agree that the required interconnection capacity is less than the installed capacity, the system support minimum charge will be based on a contractually determined capacity level. Protective devices may be installed to ensure the instantaneous contract capacity level is not exceeded.

For customers requiring a demand metering interval longer than 15 mins, to facilitate the minimization of registered demands, the minimum charge for system support is increased by the following factors:

30 minute demand interval:

125%

60 minute demand interval:

150%

ELECTRIC SERVICE REGULATIONS:

Sheet 1 of 2 Effective: Supersedes:

### **RATE SCHEDULE 31**

### LARGE GENERAL SERVICE/INDUSTRIAL

AVAILABLE:

Throughout the territory served by the Company.

APPLICABLE:

To single or three-phase electric service.

RATE:

Charges for service in any one billing month shall be the sum of the following:

Metered Service:

(a) Demand Charge

For the first 500 kW

of billing demand

\$16.88 per kW

For the next 1,500 kW

of billing demand

\$15.11 per kW

For all over 2,000 kW

of billing demand

\$11.79 per kW.

(b) Energy Charge

For the first 400 kW.h

per kW of billing

demand

1.93¢/per kW.h

For energy in excess of 400 kW.h per kW of

billing demand

1.5¢/per kW.h

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### Rate Schedule 31 (continued)

### (c) Charge for Deficient Power Factor

For customer peak load power factor which is less than 90 percent, an additional charge for deficient power factor equal to a percentage of the trailing step demand charge is applied to the difference between the highest metered kV.A demand and 111 percent of the highest metered demand in the same billing period. The percentage of the trailing step demand charge will be adjusted on January 1 of each year as indicated in the following table:

Year	1995	1996	1997	1998	1999
% of Demand	25 %	40 %	55 %	70 %	85 %

MINIMUM MONTHLY BILL:

Shall be the Demand Charge, but not less than \$844.00.

### **BILLING DEMAND:**

The billing demand will be the greater of the following:

- (a) the highest metered demand during the billing period;
- (b) 85% of the highest metered demand (excluding any demand delivered and billed under Rate Schedule 32, 33, 34 or 38) in the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) contract demand:
- (e) 50 kilowatts.

If energy is taken under Rate 32, 33, 34 or 38 in addition to Rate 31 during the billing period, the billing demand for Rate 31 will be the Rate 31 Base Demand as specified under the corresponding agreement.

Sheet 2 of 2 Effective: Supersedes:

### Rate Schedule 31 (continued)

### BILLING DEMAND:

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as follows:

kW Billing Demand = kW Nameplate Rating

or

kW Billing Demand = HP Nameplate x 0.746

# CONDITIONS OF SERVICE:

Service is available under this rate at only one point of delivery at a voltage level considered standard by the Canadian Standards Association and available from the Company's lines at the service location. Customers requiring service at non-standard voltage levels will be served only at primary or transmission voltages as available, and must provide transformation to desired voltage levels. Customers requiring service at two or more points will be billed as a separate customer at each such point of delivery.

## RATE MODIFICATIONS APPLICABLE:

The rates on this schedule are subject to the addition of the appropriate surcharge for municipal assessment, see Rider A-1. For special facilities charges, see Rider E. For service outside the boundaries of the Province of Alberta, see Rider S.

## ELECTRIC SERVICE REGULATIONS:

Sheet 1 of 2 Effective: Supersedes:

### RATE SCHEDULE 31 A

### ENERGY RATE OPTIONS FOR NEW GAS COMPRESSION

**AVAILABLE:** 

Throughout the territory served by the company, on and after

January 1, 1995.

APPLICABLE:

To single or three phase electric service which is used for gas compression and was connected on or after January 1, 1995. A gas compression load is defined as a single customer site where at least 50% of the electric load is gas compression. This rate schedule will be closed to new loads after January 1, 1997 but will remain in effect up to a maximum of 5 years for loads

connected within this time frame.

RATE:

Charges for service in any one billing month will be based on the customer's choice of one Energy Rate from the following table, and all energy (kW.h) will be charged at that rate. The Minimum Annual Load Factor corresponding to the Energy Rate chosen will be used to determine the minimum annual bill. A new Energy Rate may be chosen once every 12 months.

Minimum Annual Load Factor	Energy Rate		
50%	6.0 ¢/kW.h		
60%	5.3 ¢/kW.h		
70%	4.8 ¢/kW.h		
80%	4.4 ¢/kW.h		
90%	4.1 ¢/kW.h		

... continued on overleaf

### MINIMUM ANNUAL BILL:

The minimum annual bill will be assessed once for every 12 months of service on this rate, and will be calculated as follows:

Minimum = Energy Rate x Minimum Annual Energy Annual Bill

where:

Minimum = 8760 hrs. x Peak x Minimum Annual Annual Energy Demand (kW) Load Factor

If the sum of the 12 monthly energy charges on this rate schedule is less than the minimum annual bill, then the customer will be charged the difference at the end of the 12 month period.

Note: Where rate changes occur within a given 12 month period, the minimum annual bill will be prorated accordingly.

# PEAK DEMAND:

The Peak Demand used to calculate the minimum annual bill will be the greater of the following:

- (a) the highest metered demand in the 12 month period prior to the assessment of the minimum annual bill;
- (b) the estimated demand;
- (c) the contract demand;
- (d) 50 kW.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as follows:

kW Peak Demand = kW Nameplate Rating

or

kW Peak Demand = HP Nameplate x 0.746

Sheet 2 of 2 Effective: Supersedes:

CHARGE FOR DEFICIENT POWER FACTOR:

For customer peak load power factor which is less than 90 percent, an additional charge for deficient power factor equal to a percentage of the trailing step demand charge is applied to the difference between the highest metered kV.A demand and 111 percent of the highest metered demand in the same billing period. The percentage of the trailing step demand charge will be adjusted on January 1 of each year as indicated in the following table:

Year	1995	1996	1997	1998	1999
% of Demand	25 %	40 %	55 %	70 %	85 %

The determination of whether the annual minimum bill shall apply will exclude any payments made for deficient power factor.

# CONDITIONS OF SERVICE:

Service is available under this rate at only one point of delivery at a voltage level considered standard by the Canadian Standards Association and available from the Company's lines at the service location. Customers requiring service at non-standard voltage levels will be served only at primary or transmission voltages as available, and must provide transformation to desired voltage levels. Customers requiring service at two or more points will be billed as a separate customer at each such point of delivery.

# RATE MODIFICATIONS APPLICABLE:

The rates on this schedule are subject to the addition of the appropriate surcharge for municipal assessment, see Rider A-1. For special facilities charges, see Rider E. For service outside the boundaries of the Province of Alberta, see Rider S.

# ELECTRIC SERVICE REGULATIONS:

Effective: Supersedes:

### **RATE SCHEDULE 32**

### FIRM STANDBY POWER

AVAILABLE:

To customers served by the Company from the Alberta Interconnected System.

APPLICABLE:

To provide contracted standby power in the event of a forced outage or derate of customer-owned generating equipment. This rate may also be utilized by full service customers to allow for short term low load factor excursions beyond normal load levels.

RATE:

For the provision of Firm Standby Power, the customer may elect to pay either:

Option A: 26.0¢/kW.h for all standby energy provided,

or

### Option B:

- (i) An annual reservation charge of \$50.40 per kW of contracted Standby Capacity payable in equal monthly amounts of \$4.20 per kW, and
- (ii) 8.85¢/kW.h for all standby energy provided.

# TERMS AND CONDITIONS:

For provision of standby service under this rate schedule, a suitable long term contract is required, specifying:

- (a) The Base Demand, defined as the demand level normally supplied on other rate schedules. The Base Demand may be the highest metered demand (excluding any demand delivered and billed on Rate 33, 34 or 38) in the last 6 months, or it may be negotiated between the customer and the Company.
- (b) The Standby Capacity required. This is the difference between the customer's forecasted maximum demand and the Base Demand.

Option A or B may be nominated once annually, in advance of any standby usage and corresponding billing.

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#### RATE SCHEDULE 32(Continued)

ELECTRIC SERVICE REGULATIONS:

Sheet 1 of 3 Effective: Supersedes:

#### RATE SCHEDULE 33A

#### SHORT TERM RESERVE ENERGY (Up to 10 days)

#### AVAILABLE:

When the company determines that there is sufficient system generation and transmission capacity and energy available for delivery to the customer for periods of up to 10 days.

#### APPLICABLE:

Only to customers who meet all of the following conditions:

- (1) The customer is able to demonstrate to the satisfaction of the company that any energy requirements to be billed on this schedule is incremental load that would not be economically viable on any other applicable rate or combination of rates offered by the Company.
- (2) The incremental demand for Reserve Energy is at least 1 MW.
- (3) The customer can demonstrate that the incremental load requested through the Reserve Energy Rate can be curtailed within 10 minutes.
- (4) No portion of the reserve energy taken is used for Standby purposes. Short term reserve energy contracts may not be initiated during, or taken immediately following consumption billable under Rate Schedule 32 or 34.

#### PROCEDURE:

A customer qualifying for Short Term Reserve Energy must establish with the Company a Rate 31 Base Demand prior to any Short Term Reserve Energy consumption.

For existing customers, the Rate 31 Base Demand will normally be the peak demand used on Rate 31 in the 6 most recent billing periods during which no energy was delivered and billed on Rate 32, 33, 34 or 38.

#### Rate Schedule 33A (Continued)

New customers qualifying for Reserve Energy may select the Rate 31 Base Demand based on forecast loads and economics, provided the Company agrees the applicability conditions are satisfied.

If Short Term Reserve Energy is used simultaneously with Long Term Reserve Energy, the Rate 31 Base Demand is the demand established in the Long Term Reserve Energy contract.

Once established, the Rate 31 Base Demand remains fixed for the purposes of billing all future Short Term Reserve Energy.

A customer requesting Short Term Reserve Energy is required to notify the Company by phone at least 4 hours in advance. Energy in excess of Rate 31 Base Demand, taken with less than four hours notice will be billed under the provisions of Rate 34.

The Company will fax a contract form with the required data to the customer, and the customer will confirm the information with a signature and fax the contract form back to the Company. The fax will specify:

- (1) The start and end dates and times of the Reserve Energy consumption period.
- (2) The Reserve Demand in kW. This is the highest demand the customer forecasts that will be required in excess of Base Demand during the entire Reserve Energy period, and will be specified in kW.

Sheet 2 of 3 Effective: Supersedes:

#### Rate Schedule 33A (continued)

- (3) The Base Demand in kW. The Base Demand enables the Short Term Reserve Energy to be distinguished from load under other rates. By specifying both the Reserve Demand and the Base Demand, the customer can determine the peak demand to be used during the Reserve Energy period. The Base Demand will be the sum of the following:
  - (a) the Rate 31 Base Demand
  - (b) any Reserve Demands from previously negotiated Long Term Reserve contracts still in effect
  - (c) any other Short Term Reserve Demands still in effect.
- (4) The Reserve Energy Price in cents/kW.h as determined by the Company. The price for Short Term Reserve Energy is not negotiable and may vary over time as AIS production and opportunity costs change. The duration of the Reserve Energy consumption period may also affect the price.
- (5) The Minimum Reserve Energy in kW.h. This is 50% of the Reserve Demand times the number of hours in the Short Term Reserve Energy contract period.

INTERRUPTIBILITY OF RESERVE ENERGY:

Energy purchased under the Reserve Energy Rate is interruptible for system security reasons as determined by the Company. Reserve Energy will not be subject to interruption based on economic operating margins. Reserve Energy must be interruptible with 10 minutes notice and for an indefinite period of time. Whenever possible, the Company will give the Reserve Energy customer a longer notification period of potential interruption before issuing a curtailment directive. When a load curtailment directive is given, the customer must operate at or below the Rate 31 Base Demand until the Company gives notification that the interruption period is over, at which time consumption of

#### Rate Schedule 33A (continued)

Reserve Energy may be resumed. If the customer fails to curtail all of the incremental load for the entire interruption period, a penalty surcharge will be assessed for each incidence of non-compliance in the billing period. After three instances of non-compliance in any period of time, the Company may determine that the customer is no longer eligible to use Reserve Energy.

#### METERING OF RESERVE ENERGY:

Purchasing power under the Reserve Energy Rate requires that a customer has revenue approved time of use metering and telemetering installed. The cost of the time of use metering will be the responsibility of the customer.

Telemetering is required for all Reserve Energy Sales with Demands greater than 2,500 kW, and will be the responsibility of the customer.

#### BILLING OF SHORT TERM RESERVE ENERGY:

The charge for Reserve Energy consumed under a Short Term Reserve Energy contract will be the Reserve Energy Price per kW.h as specified by the Company in the Short Term Reserve Energy contract.

The energy to which this price is applied will be the greater of:

- (a) all energy metered during the Short Term Reserve Energy contract period at a demand greater than the Base Demand and less than or equal to the Base Demand plus the Reserve Demand
- (b) the Minimum Reserve Energy as specified in the Short Term Reserve Energy contract.

BILLING FOR
EXCURSIONS
ABOVE THE
CONTRACTED
RESERVE DEMAND:

Energy consumed at a demand greater than the Base Demand plus the Reserve Demand (not covered by another Rate 32, Rate 33, Rate 34 or Rate 38 contract) will be billed at the Interruptible Standby rate of 18.0 cents per kW.h.

Sheet 3 of 3 Effective: Supersedes:

#### Rate Schedule 33A (continued)

BILLING OF RATE 31 WHEN RESERVE ENERGY TAKEN SIMULTANEOUSLY:

During the hours that Reserve Energy is consumed, for the purposes of calculating the Rate 31 bill:

(a) the Rate 31 Base Demand specified under Rate 33 will replace the metered demand

and

the energy metered at a demand equal to or below the Rate 31 Base Demand will be the metered energy.

PENALTY FOR
NON-COMPLIANCE
OF LOAD
CURTAILMENT
DIRECTIVE:

For the first instance of non-compliance the surcharge will equal the Rate 31 trailing step demand charge of \$11.56/kW. For each subsequent instance of non-compliance within 12 months, the surcharge will equal five times the Rate 31 trailing step demand charge.

ELECTRIC SERVICE REGULATIONS:

#### Rate Schedule 33 A (continued)

### **SHORT TERM RESERVE ENERGY CONTRACT - RATE 33(A)**

This form will be completed and signed by Alberta Power after a request for Reserve Energy from a customer by telephone. 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 Alberta Power.

**************************************	CUSTOMER NAME:				7
	Date of Reserve Request: Time of Reserve Request:		Reference No:		
.:33 1)	RESERVE ENERGY CONTRACT	T PERIOD:		<b>804188</b> 000000000000000000000000000000000	eriteria di Ha
	Start Date:	Start Time:			
	End Date:	End Time:			
	Number of Hours in Con	tract Period:		Hours	
	Type: ON-peak	OFF-peak	Blended		
2)	RESERVE DEMAND:		kW		
3)	BASE DEMAND:			Protocococo in un octable da Americina da	
		Rate	31 Base Demand:		kW
	Sum of Reserve Demands on all Lor	ng Term Reserve	Energy Contracts:		kW
	Sum of Reserve Demands on other Short Term Reserve Energy Contracts:				kW
		Tota	Base Demand:		kW
4)	SHORT TERM RESERVE ENER	GY PRICE:		]cents/kW.h	
5)	MINIMUM RESERVE ENERGY				1900 (190) (1900 (190)(1900 (190) (1900 (190) (1900 (1900 (190) (1900 (1900 (1900 (1900 (190) (1900 (1900 (190) (1900 (1900 (190) (1900 (1900 (1900 (1900 (190) (1900 (1900 (190) (1900 (1900 (190) (1900 (1900 (1900 (190) (1900 (1900 (190) (1900 (1900 (190) (1900 (190) (1900 (1900 (190) (1900 (190) (1900 (1900 (190) (1900 (1900 (190) (1900 (190) (1900 (190) (1900 (190) (1900 (190) (1900 (190) (1900 (19
*****	50% x Hours in Contract	Period x Res	erve Demand =		]kW.h
in proper e	Confirmation: 1)			for Alberta Pov	ver Limit
	2)			for	

Sheet 1 of 3 Effective: Supersedes:

#### RATE SCHEDULE 33B

#### LONG TERM RESERVE ENERGY (Longer than 10 Days)

#### **AVAILABLE:**

When the company determines that there is sufficient system generation and transmission capacity and energy available for delivery to the customer for periods of greater than 10 days.

#### APPLICABLE:

Only to customers who meet all of the following conditions:

- (1) The customer is able to clearly demonstrate to the satisfaction of the company that any energy requirements to be billed on this schedule is incremental load that would not be economically viable on any other applicable rate or combination of rates offered by the Company.
- (2) The incremental demand for Reserve Energy is at least 1 MW.
- (3) The customer can demonstrate that the incremental load requested through the Reserve Energy Rate can be curtailed within 10 minutes.

#### RESERVE ENERGY CONTRACT:

A customer qualifying for Reserve Energy requires a contract before commencing Reserve Energy consumption. The contract will result from negotiations between the customer and the Company and will be effective for the period during which the customer consumes Reserve Energy. The contract will specify:

(1) The start and end dates and times of the Reserve Energy consumption period.

#### Rate Schedule 33B (continued)

- (2) The Reserve Demand in kW. This is the highest demand the customer forecasts that will be required in excess of Base Demand during the entire Reserve Energy contract period.
- (3) The Base Demand in kW. The Base Demand enables the Long Term Reserve Energy to be distinguished from load under other rates. The Base Demand will be the sum of the following:
  - the Rate 31 Base Demand. The Rate 31 Base Demand will normally be the peak demand used on Rate 31 in the 6 most recent billing periods during which no energy was delivered and billed on Rate 32, 33, 34 or 38. New customers qualifying for Reserve Energy may select the Rate 31 Base Demand based on forecast loads and economics provided the Company agrees the applicability conditions are satisfied.
  - (b) The sum of the Reserve Demands specified in any other Long Term Reserve Energy contracts effective over the same period.
- (4) The Reserve Energy Load Factor. This will be the customer's forecasted load factor for the incremental load but will not be less than 75%. The Reserve Energy Load Factor applied to the Reserve Demand for the duration of the Reserve Energy contract period will be the Requested Reserve Energy in kW.h.
- (5) The Reserve Energy Price in cents per kW.h of Requested Reserve Energy. This price will be negotiated between the customer and the Company prior to the start date of the Long Term Reserve Energy contract. The price for Long Term Reserve Energy will typically depend on factors such as the length of the contract, the expected amount and load factor of the Reserve Energy, and the market price of customer alternatives.

Sheet 2 of 3 Effective: Supersedes:

#### Rate Schedule 33B (continued)

The Long Term Reserve Energy price will be fixed for the duration of the Reserve Energy contract. The agreed Reserve Energy price may be an escalating structure within the Reserve Energy contract period in which case the contract will specify the periods that each price is in effect.

#### INTERRUPTIBILITY OF RESERVE ENERGY:

Energy purchased under the Reserve Energy Rate is interruptible for system security reasons when necessary as determined by the Company. Reserve Energy will not be subject to interruption based on economic operating margins. Reserve Energy must be interruptible with 10 minutes notice and for an indefinite period of time. Whenever possible, the Company will give the Reserve Energy customer a longer notification period of potential interruption before issuing a curtailment directive. When a load curtailment directive is given, the customer must operate at or below the Rate 31 Base Demand until the Company gives notification that the interruption period is over, at which time consumption of Reserve Energy may be resumed. If the customer fails to curtail all of the incremental load for the entire interruption period, a penalty surcharge will be assessed for each incidence of non-compliance in the billing period. After three instances of non-compliance in any period of time, the Company may determine that the customer is no longer eligible to use Reserve Energy and may terminate the Reserve Energy contract.

#### METERING OF RESERVE ENERGY:

Purchasing power under the Reserve Energy Rate requires that a customer has revenue approved time of use metering installed. The cost of the time of use metering will be the responsibility of the customer.

#### Rate Schedule 33B (continued)

Telemetering is required for all Reserve Energy sales with Demands greater than 2,500 kW and will be the responsibility of the customer.

#### BILLING OF LONG TERM RESERVE ENERGY:

The bill for Long Term Reserve Energy will be the sum of the Reserve Charge and Energy Charge calculated monthly as follows:

#### (1) Reserve Charge = $$7.00 \times RD$

RD is the Reserve Demand in kW as defined in the Reserve Energy Contract

Note: If the Long Term Reserve Energy contract period covers less than an entire billing period, the Reserve Charge shall be prorated to reflect this.

#### (2) Energy Charge = $P \times ARE$

**P** is the negotiated price in cents per kW.h specified in the Reserve Energy contract for the Requested Reserve Energy less the unit Reserve Charge and is calculated as follows:

$$P = NP - (Reserve Charge x 100 / RRE)$$

**NP** is the negotiated price in cents/kW.h as specified in the Long Term Reserve Energy contract

RRE is the Requested Reserve Energy in kW.h for the Billing period and is calculated as follows:

RRE = Reserve Energy Load Factor x
Reserve Demand (kW) x Number of
hours in Reserve Energy contract
period within Billing Period

ARE is the Actual Reserve Energy in kW.h and is all energy metered during the Long Term Reserve Energy contract period in the billing period at a demand greater than the Base Demand and less than or equal to the Base Demand plus the Reserve Demand.

Sheet 3 of 3 Effective: Supersedes:

#### Rate Schedule 33B (continued)

BILLING FOR EXCURSIONS ABOVE THE CONTRACTED RESERVE DEMAND:

Energy consumed at a demand greater than the Base Demand plus the Reserve Demand (not covered by another Rate 32, Rate 33, Rate 34 or Rate 38 contract) will be billed at the Interruptible Standby rate of 18.0 cents per kW.h.

BILLING OF RATE 31 WHEN RESERVE ENERGY TAKEN SIMULTANEOUSLY:

During the hours that Reserve Energy is consumed, for the purposes of calculating the Rate 31 bill:

- (a) the Rate 31 Base Demand specified under Rate 33 will replace the metered demand, and
- (b) the energy metered at a demand equal to or below the Rate 31 Base Demand will be the metered energy.

PENALTY FOR
NON-COMPLIANCE
OF LOAD
CURTAILMENT
DIRECTIVE:

For the first instance of non-compliance the surcharge will equal the Rate 31 trailing step demand charge of \$11.56/kW. For each subsequent instance of non-compliance within 12 months, the surcharge will equal five times the Rate 31 trailing step demand charge.

ELECTRIC SERVICE REGULATIONS:

### Rate Schedule 33 B (continued)

LONG TERM RESERVE ENERGY CONTRACT - RATE 33(B)

To be completed and signed by the customer and Alberta Power Limited BEFORE any Long Term Reserve Energy sales are made.

ranna d		TOMER NAME:[ te of Contract:[		Reference No:		
্র 1)	RESERVE EN	ERGY CONTRA	CT PERIOD:			
	Start Date:		Start Time:		]	
	End Date:		End Time:			
	Number	of Hours in Co	ntract Period:		Hours	
	Type:	ON-peak	OFF-peak	Blended		
2)	RESERVE DE	MAND:	Barriila o curre esternicus.		]kW	TANKEL T
3)	BASE DEMAN	D:	3048m - 2 11 2 m (h 2421 0)	Stalisa (1). La Marabarra de publicada	ed Skart landskit Post i 17 chil	
			Rat	e 31 Base Demand:		kW
	Sum of Reserve Demands on other Long Term Reserve Energy Contracts:					kW
	Total Base Demand:					kW
4)	RESERVE EN	ERGY LOAD FA	CTOR		]%	
5)	LONG TERM	RESERVE ENER	RGY PRICE:		cents/kW.h	.0. 50000000000000000000000000000000000
gragas Turksan				SBCG-Conduct State Structures (1991)		Lucasoracia inte
				for Alberta Powe	er Limited	
				for		

Effective: Supersedes:

#### **RATE SCHEDULE 34**

#### INTERRUPTIBLE STANDBY POWER

AVAILABLE:

To customers served by the Company from the Alberta Interconnected System.

APPLICABLE:

To provide contracted standby power in the event of a forced outage or derate of customer-owned generating equipment. This rate may also be utilized by full service customers to allow for short term low load factor excursions beyond normal load levels.

RATE:

For the provision of Interruptible Standby Power, the customer may elect to pay either:

Option A: 18.0¢/kW.h for all standby energy provided,

or

#### Option B:

- (i) An annual reservation charge of \$36.00 per kW of contracted standby capacity payable in equal monthly amounts of \$3.00 per kW, and
- (ii) 5.0¢/kW.h for all standby energy provided.

#### **INTERRUPTIBILITY:**

Interruptible standby power is interruptible when determined necessary for system security reasons by the company. Under these circumstances the standby customer will be notified that standby power cannot be taken during specified periods, or that standby power currently being taken must be curtailed within 10 minutes. If the standby customer fails to comply with the company request to curtail standby usage, a penalty surcharge will be assessed for each incidence of non-compliance. For the first instance of non compliance the surcharge will equal the Rate 31 trailing step demand charge of \$11.56/kW. For each subsequent instance of non compliance, the surcharge will equal five times the Rate 31 trailing step demand charge.

#### Rate Schedule 34 (continued)

### TERMS AND CONDITIONS:

For provision of standby service under this rate schedule, a suitable long term contract is required, specifying:

- (a) The Base Demand, defined as the demand level normally supplied on other rate schedules. The Base Demand may be the highest metered demand (excluding any demand delivered and billed on Rate 32, 33, or 38) in the last 6 months, or it may be negotiated between the customer and the Company.
- (b) The Standby Capacity required. This is the difference between the customer's forecasted maximum demand and the Base Demand.

Option A or B may be nominated once annually, in advance of any standby usage and corresponding billing.

#### ELECTRIC SERVICE REGULATIONS:

Effective: Supersedes:

#### RATE SCHEDULE 35

#### WESCUP WHOLESALE

AVAILABLE:

To WESCUP for resale to B.C. Hydro to serve Fort Nelson.

RATE:

Charges for service in any one billing month shall be the sum of the following:

(a) Fixed Monthly Charge

\$53,545

(b) Demand Charge

For all kW of billing demand \$3.35/kW

(c) Energy Charge

For all energy

2.03 ¢/kW.h

Energy purchased under the WESCUP Wholesale rate is interruptible. When the company notifies the customer that an Interruptible Load Shed Directive is in effect, the customer's demand must be curtailed within 10 minutes. Failure to curtail load and remain at zero demand for the requested interruption period will result in a penalty surcharge applied to each kW of demand used during the requested interruption period in the billing period. The penalty charge will equal the trailing step Demand Charge of Rate 31. For each subsequent instance of non compliance within a 12 month period, the surcharge will equal five times the trailing step Demand Charge of Rate 31.

MINIMUM MONTHLY BILL:

Shall be the Fixed Monthly Charge plus the Demand Charge applied to the Contract Minimum Demand.

#### Rate Schedule 35 (continued)

BILLING

**DEMAND**:

Shall be the greater of the following:

- (a) the highest metered demand during the billing period
- (b) the Contract Minimum Demand effective during the billing period.

ELECTRIC SERVICE REGULATIONS:

Sheet 1 of 2 Effective: Supersedes:

#### **RATE SCHEDULE 36**

#### RAINBOW PROCESSING PLANT

AVAILABLE:

To the Rainbow Processing Plant located at the Rainbow Lake Oilfield.

MONTHLY LEASE CHARGE:

Charges for lease of generators at Rainbow Lake in any one billing month shall be the sum of the following:

Metered Service:

(a) <u>Demand Charge</u>

For the first 500 kW

of billing demand \$16.88 per kW

For the next 1,500 kW

of billing demand \$15.11 per kW

For all over 2,000 kW

of billing demand \$11.79 per kW.

(b) Energy Charge

For the first 400 kW.h

per kW of billing

demand 1.93¢/per kW.h

For energy in excess of 400 kW.h per kW of

billing demand 1.5¢/per kW.h

#### Rate Schedule 36 (continued)

#### (c) Charge for Deficient Power Factor

For customer peak load power factor which is less than 90 percent, an additional charge for deficient power factor equal to a percentage of the trailing step demand charge is applied to the difference between the highest metered kV.A demand and 111 percent of the highest metered demand in the same billing period. The percentage of the trailing step demand charge will be adjusted on January 1 of each year as indicated in the following table:

Year	1995	1996	1997	1998	1999
% of Demand	25 %	40 %	55 %	70 %	85 %

MINIMUM MONTHLY BILL:

Shall be the Demand Charge, but not less than \$844.00.

#### **BILLING DEMAND:**

The billing demand will be the greater of the following:

- (a) the highest metered demand during the billing period;
- (b) 85% of the highest metered demand (excluding any demand delivered and billed under Rate Schedule 32, 33, 34 or 38) in the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) contract demand;
- (e) 50 kilowatts.

If the demand is based upon the horsepower rating of equipment, the conversion to kW will be made by multiplying the horsepower demand by a factor of 0.746.

Sheet 2 of 2 Effective: Supersedes:

#### Rate Schedule 36 (continued)

## CONDITIONS OF SERVICE:

Service is available under this rate at only one point of delivery at a voltage level considered standard by the Canadian Standards Association and available from the Company's lines at the service location. Customers requiring service at non-standard voltage levels will be served only at primary or transmission voltages as available, and must provide transformation to desired voltage levels. Customers requiring service at two or more points will be billed as a separate customer at each such point of delivery.

#### ELECTRIC SERVICE REGULATIONS:

Sheet 1 of 2 Effective: Supersedes:

#### RATE SCHEDULE 38

#### TEMPORARY FIRM ENERGY (TFE)

#### **AVAILABLE:**

When the Company determines that there is sufficient generation and transmission capacity available. To customers served by the Company from the Alberta Interconnected System, served under a satisfactory long term contract under Rate Schedules 31, 32, 33 or 34.

#### APPLICABLE:

To provide pre-scheduled temporary firm energy to a customer during a planned maintenance outage of the customer's generating equipment or for the testing of motor drives. Temporary firm energy is available only when requested in advance. The notice period must be at least equal to the requested usage period and will in no circumstances be less than twenty-four (24) hours. Temporary Firm Energy may only be scheduled and made available at the Company's discretion.

#### PROCEDURE:

A customer requesting Temporary Firm Energy (TFE) will contact the Company sufficiently in advance of the planned use and determine the availability of TFE.

Following a telephone request, the TFE proforma contract will be completed by the Company, and sent by FAX to the customer. The notice period begins when the Company receives the completed and signed contract by return FAX. The proforma contract will specify:

- (1) The start and end dates and times of the agreed temporary energy draw.
- (2) The TFE demand in kW. This is the highest demand the customer intends to set in excess of the Base Demand during the TFE draw.

#### Rate Schedule 38 (continued)

- (3) The Base Demand in kW. The Base Demand enables TFE to be distinguished from load billed under other rates, and will be the sum of the following:
  - (a) The highest metered Rate 31 demand recorded in the last 6 months.
  - (b) Any reservation capacity associated with Rate 32 or Rate 34 contracts in effect during the billing period.
  - (c) Any Reserve Demands associated with Rate 33 contracts in effect during the billing period.
- (4) The Minimum TFE in kW.h. This is 50% of the maximum temporary demand in kW multiplied by the number of hours in the TFE contract period.

#### BILLING OF TEMPORARY FIRM ENERGY:

The charge for temporary firm energy consumed will be 5.25 ¢/kW.h.

This rate will be applied to the greater of:

- (a) All energy metered during the temporary firm energy contract period at a demand greater than the Base Demand and less than or equal to the Base Demand plus the contract temporary energy demand.
- (b) The Minimum TFE.

# BILLING EXCURSIONS ABOVE THE CONTRACT DEMAND:

Energy consumed at a demand greater than the Base Demand plus the contract temporary demand (not covered by a Rate 32, 33, or 34 contract) will be billed at the firm standby rate of 26.0¢/kW.h.

Sheet 2 of 2 Effective: Supersedes:

#### Rate Schedule 38 (continued)

#### BILLING OF RATE 31 WHEN TFE IS TAKEN SIMULTANEOUSLY:

During the hours that temporary firm energy is consumed, for the purpose of calculating the Rate 31 bill:

(a) The Rate 31 Base Demand will replace the metered demand.

and

(b) The energy metered at a demand equal to or below the Rate 31 Base Demand will be the metered energy.

## METERING REQUIREMENT:

Purchasing power under the TFE Energy Rate requires that a customer has revenue approved time of use metering installed. The cost of the time of use metering will be the responsibility of the customer.

#### ELECTRIC SERVICE REGULATIONS:

#### Rate Schedule 38 (continued)

#### **TEMPORARY FIRM ENERGY (TFE) CONTRACT - RATE 38**

This form will be completed and signed by Alberta Power after a request for Temporary Firm Energy from a customer by telephone. 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 Alberta Power.

1 (1) (1) 1 1	CUSTOMER NAME:				1
	Date of TFE Request:		Reference No:		j
; <b>1</b> )	TFE CONTRACT PERIOD:		seuses eudestusses, et plus innoeme in	id province with the instance of	amura (u. 1991) S
	Start Date:	Start Time:			
	End Date:	End Time:			
	Number of Hours in Co	entract Period:		Hours	
2)	TFE DEMAND:		kW		901 KW U 10 (80 0 18) 4
3)	BASE DEMAND:			14 38666066668861141 1160600	Board in placemen
•		Rate	31 Base Demand:		kW
	Sum of Reservation Demands	associated with any	Standby contracts:		kW
Sum of Reserve Demands on Short and Long Term Reserve Energy C			Energy Contracts:		kw
		Tota	l Base Demand:		kW
4)	MINIMUM TFE				
u Privag	50% x Hours in Co	ontract Period x	TFE Demand =		]kW.h
Cor	nfirmation: 1)			for Alberta Power	Limited
	2)			for	

Effective: Supersedes: Sheet 1 of 2

#### RATE SCHEDULE 39A

#### **EXPORT MARKET SERVICES (EMS)**

AVAILABLE:

Throughout the territory served by the Company.

APPLICABLE:

To owners of generating units sited within the territory served by the Company who have executed contracts with exclusively extra-provincial customers for prescheduled delivery of firm energy or firm power.

RATE:

Billing will be based on demand and energy at the nominated Provincial Boundary and determined by contract or generator output adjusted for losses. Imbalance charges, as described under each contract heading, will be based on demand and energy measurements made at the point of interconnection of the EMS generator with the Alberta Power system. Charges made for each billing month shall be the sum of the following:

(a) Demand Charge

For generator interconnections made at a nominal voltage of 72 kV or above:

\$5.00/kW of billing demand

For generator interconnections made at a nominal voltage below 72 kV:

\$8.61/kW of billing demand

(b) Energy Charge

All energy

0.16¢/kW.h

(c) Imbalance charges or credits as defined in this rate schedule for firm energy or firm power contracts.

#### Rate Schedule - 39A (continued)

## BILLING FOR FIRM ENERGY CONTRACTS:

Under an export contract for firm energy, Alberta Power will arrange the transfer of a prespecified net quantity of energy each month to B. C. Hydro or SaskPower as nominated by the EMS customer. The firm energy contract will not in any way constrain the extra-provincial transfer rate of energy within the month. The billing components will be calculated as follows:

(a) The metered demand will be the demand measured at the point of interconnection of the EMS generator and the Alberta Power system, reduced by the Capacity Loss Factor (CLF) which is deemed to be 0.1 unless determined by specific study i.e.:

Metered demand at nominated provincial boundary = Measured demand at generator (1 - CLF)

The billing demand will be the greater of the following:

- (i) the highest metered demand during the billing period;
- (ii) 85% of the highest metered demand in the 12-month period including and ending with the billing period;
- (iii) the estimated demand;
- (iv) 50 kilowatts.
- (b) The energy will be the transfer amount specified in the EMS contract.

Effective: Supersedes: Sheet 2 of 2

#### Rate Schedule - 39A (continued)

- (c) Imbalance charges or credits will be added, to the extent that the monthly energy production of the EMS generator does not match the prescheduled extra-provincial transfer (E kW.h) made in accordance with the export contract. Imbalance charges or credits will be calculated as follows:
  - (i) Any net energy delivered to Alberta Power during the month in excess of E (1 + ELF) is inadvertent energy delivery and credited at 1.5¢/kW.h.
  - (ii) To the extent that the net energy delivered to Alberta Power during the month is less than E (1 + ELF), the EMS customer is firm energy deficient. Deficient firm energy will be charged on Rate 38 (Temporary Firm Energy).

ELF is the Energy Loss Factor and is deemed to be 0.1 unless determined by specific study.

## BILLING FOR FIRM POWER CONTRACTS:

Under an export contract for firm power, Alberta Power will arrange the transfer of a prespecified quantity of energy each month at a prespecified transfer rate (power level) to B. C. Hydro or SaskPower as nominated by the EMS customer. Under a firm power contract extra-provincial transfers will match the specified firm power level within each 10 minute interval. The billing components will be calculated as follows:

- (a) The metered demand will be the firm extra-provincial transfer power level specified in the EMS contract.
- (b) The energy will be the firm extra-provincial transfer amount specified in the EMS contract.

#### Rate Schedule - 39A (continued)

- (c) Imbalance charges or credits will be added to the extent that the energy delivery rate (power output) of the EMS generator does not match the prescheduled extra-provincial transfer of P kW in a given 15 minute meter interval. Imbalance charges or credits will be calculated as follows:
  - (i) Any energy delivered to Alberta Power in excess of 0.25P (1 + CLF) kW.h in each 15 minute interval is inadvertent energy delivery and credited at 1.5¢/kW.h.
  - (ii) To the extent that energy delivered is less than 0.25P (1 + CLF) kW.h, and power delivered is less than P (1 + CLF) kW in each 15 minute interval, the EMS customer is energy and power deficient. Deficient energy and power will be charged on Rate 32(A) or Rate 32(B) (Standby power) as nominated by the EMS customer, and discounted by 45%.

CLF is the Capacity Loss Factor, and is deemed to be 0.1 unless determined by specific study.

MINIMUM MONTHLY BILL:

Shall be the demand charge but not less than \$430.50.

ELECTRIC SERVICE REGULATIONS:

Effective: Supersedes: Sheet 1 of 2

#### RATE SCHEDULE 39B

#### SHORT TERM EXPORT MARKET SERVICES (STEMS)

#### AVAILABLE:

When the company determines that suitable transmission capacity is available to support a proposed STEMS transaction such that no requirement for system additions or improvements will be created or accelerated due to the STEMS transaction. To satisfy this condition, the STEMS contract must be sufficiently short term and in no circumstances greater than 5 years, or fully interruptible. STEMS are not available where they would displace other export transactions that produce a higher contribution to fixed costs.

#### APPLICABLE:

To owners of generating units sited within the territory served by the Company who have executed short term (less than 5 years) or fully interruptible contracts with exclusively extra-provincial customers for prescheduled delivery of energy or power.

#### RATE:

Billing will be based on demand and energy at the nominated Provincial Boundary and determined by contract or generator output adjusted for losses. Imbalance charges as described under each contract heading will be based on demand and energy measurements made at the point of interconnection of the STEMS generator with the Alberta Power system. Charges made for each billing month shall be the sum of the following:

#### (a) Demand Charge

For generator interconnections made at a nominal voltage of 72 kV or above:

\$2.50/kW of billing demand

For generator interconnections made at a nominal voltage below 72 kV:

\$4.30/kW of billing demand

#### Rate Schedule - 39B (continued)

(b) Energy Charge

All energy

0.08¢/kW.h

(c) Imbalance charges or credits as defined in this rate schedule for firm energy or firm power delivery.

## BILLING FOR FIRM ENERGY CONTRACTS:

Under an export contract for firm energy, Alberta Power will arrange the transfer of a prespecified net quantity of energy each month to B. C. Hydro or SaskPower as nominated by the STEMS customer. The firm energy contract will not in any way constrain the transfer rate of energy within the month. The billing components will be calculated as follows:

(a) The metered demand will be the demand measured at the point of interconnection of the STEMS generator and the Alberta Power system, reduced by the Capacity Loss Factor (CLF) which is deemed to be 0.1 unless determined by specific study i.e.:

Metered demand at nominated provincial boundary = Measured demand at generator (1 - CLF)

The billing demand will be the greater of the following:

- the highest metered demand during the billing period;
- (ii) 85% of the highest metered demand in the 12-month period including and ending with the billing period;
- (iii) the estimated demand;
- (iv) 50 kilowatts.
- (b) The energy will be the transfer amount specified in the STEMS contract.

Effective: Supersedes: Sheet 2 of 2

#### Rate Schedule - 39B (continued)

- (c) Imbalance charges or credits will be added, to the extent that the energy production of the STEMS generator does not match the prescheduled extra-provincial transfer (E kW.h) made in accordance with the export contract. Imbalance charges or credits will be calculated as follows:
  - (i) Any energy delivered to Alberta Power during the month in excess of E (1 + ELF) is inadvertent energy delivery and credited at 1.5¢/kW.h.
  - (ii) To the extent that the energy delivered to Alberta Power during the month is less than E (1 + ELF), the STEMS customer is firm energy deficient. Deficient firm energy will be charged on Rate 38 (Temporary Firm Energy).

ELF is the Energy Loss Factor and is deemed to be 0.1 unless determined by specific study.

## BILLING FOR FIRM POWER CONTRACTS:

Under an export contract for firm power, Alberta Power will arrange the transfer of a prespecified quantity of energy each month at a prespecified transfer rate (power level) to B. C. Hydro or SaskPower as nominated by the STEMS customer. A firm power contract must match the specified firm power level within each 10 minute interval. The billing components will be calculated as follows:

- (a) The metered demand will be the firm power level specified in the STEMS contract.
- (b) The energy will be the transfer amount specified in the STEMS contract.

#### Rate Schedule - 39B (continued)

- (c) Imbalance charges or credits will be added to the extent that the energy delivery rate (power output) of the STEMS generator does not match the prescheduled extra-provincial transfer of P kW in a given 15 minute meter interval. Imbalance charges or credits will be calculated as follows:
  - (i) Any energy delivered to Alberta Power in excess of 0.25P (1 + CLF) kW.h in each 15 minute interval is inadvertent energy delivery and credited at 1.5¢/kW.h.
  - (ii) To the extent that energy delivered is less than 0.25P (1 + CLF) kW.h, and power delivered is less than P (1 + CLF) kW in each 15 minute interval, the STEMS customer is energy and power deficient. Deficient energy and power will be charged on Rate 32(A) or Rate 32(B) (Standby power) as nominated by the STEMS customer, and discounted by 45%.

CLF is the Capacity Loss Factor, and is deemed to be 0.1 unless determined by specific study.

MINIMUM MONTHLY BILL:

Shall be the demand charge but not less than \$430.50.

ELECTRIC SERVICE REGULATIONS:

Effective: Supersedes:

Revised Nov. 29, 1994

#### **RATE SCHEDULE 41**

#### SMALL OILFIELD AND PUMPING POWER

AVAILABLE:

Throughout the territory served by the Company.

APPLICABLE:

To the energy requirement for production in the petroleum and natural gas industries including related operations, such as rectifiers, cathodic protection and radio transmitters.

RATE:

Charges for service in each billing month shall be the sum of the following:

(a) Service Charge

For all kW of billing demand \$15.30 per kW

(b) Energy Charge

For the first 400 kW.h per kW of billing demand 3.15¢ per kW.h

For energy in excess of 400 kW.h per kW of billing demand 1.50¢ per kW.h

Where it is impracticable to meter a customer's service, the Company may bill on the basis of estimated maximum demands. In such case, the monthly bill shall be the demand charge as set forth in (a) above applied to the estimated demand, plus a flat rate of \$12.72 per kW in lieu of the charge for energy.

Where services are demand metered, the meter will be read and reset once a month.

#### Rate Schedule 41 (continued)

MINIMUM MONTHLY BILL:

Shall be the Demand Charge, but not less than \$61.20.

#### **BILLING DEMAND:**

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

- (a) the highest metered demand during the billing period;
- (b) the highest metered demand during the 12 months including and ending with the billing period;
- (c) the contract demand;
- (d) the estimated demand;
- (e) 4 kW

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as follows:

kW Billing Demand = kW Nameplate Rating

or

kW Billing Demand = HP Nameplate x 0.746

### POWER FACTOR:

Where a customer's power factor is found to be less than 90 percent, the Company may require such customers to install corrective equipment.

#### ELECTRIC SERVICE REGULATIONS:

Effective: Supersedes:

#### RATE SCHEDULE 51

#### **REA FARM SERVICE**

AVAILABLE:

Throughout the territory served by the Company.

APPLICABLE:

To bona-fide farming operations which are served by a

Rural Electrification Association.

RATE:

Charges for service in any one billing month shall be the

sum of the energy charge and O & M charges as indicated

in the following table:

·	REA Farm In O&M Pool	REA Farm Outside O&M Pool
All Energy:	5.26¢/kW.h	5.26¢/kW.h
Monthly O&M Charges:	\$11.05/service plus \$1.98/kV.A	-

KV.A OF CAPACITY:

For breakered services of 25 kV.A or less, the kV.A of

capacity for bill purposes will be set by the breaker size as

shown below:

 Breaker Amperes
 25/41
 35/50
 50/75
 75/110
 100/150
 200

 Transformer
 3
 5
 7.5
 10
 15
 25

 Capacity in kV.A
 25
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#### Rate Schedule 51 (continued)

For non-breakered farm services of 25 kV.A or greater, the kV.A of capacity for billing purposes shall be established as the greater of the following:

- (i) the highest metered kV.A demand during the billing period;
- (ii) 25 kilovoltamperes.

### ADDITIONAL CHARGES:

Additional charges are made on behalf of the REAs as defined in contracts and are subject to change from time to time. These charges are for operation and maintenance if the REA is not part of the O & M pooling agreement, as well as the deposit reserve and are in addition to the charges contained in this rate schedule.

MINIMUM MONTHLY BILL:

Shall be the Monthly O & M charges.

QUARTERLY BILLING:

The service charge shall be calculated by multiplying the monthly service charge by a factor of three. The minimum quarterly bill shall be three times the monthly minimum.

ELECTRIC SERVICE REGULATIONS:

Capacity in kV.A

Effective: Supersedes:

## **RATE SCHEDULE 56**

#### FARM SERVICE

**AVAILABLE:** Throughout the territory served by the Company. APPLICABLE: To bona-fide farming operations served directly by the Company. RATE: Charges for service in any one billing month shall be the sum of the energy charge, O & M charges and capital recovery charges as follows: (a) All Energy 5.26¢/kW.h (b) Monthly O&M Charges \$11.05/service plus \$1.98/kV.A Monthly Capital Recovery \$7.57/service (c) plus \$1.87/kV.A KV.A OF CAPACITY: For breakered services of 25 kV.A or less, the kV.A of capacity for bill purposes will be set by the breaker size as shown below: Breaker Amperes 25/41 35/50 50/75 75/110 100/150 200 3 5 Transformer 7.5 10 15 25

... continued on overleaf

## Rate Schedule 56 (continued)

For non-breakered farm services of 25 kV.A or greater, the kV.A of capacity for billing purposes shall be established as the greater of the following:

- (i) the highest metered kV.A demand during the billing period;
- (ii) 25 kilovoltamperes.

MINIMUM MONTHLY BILL:

Shall be the sum of the monthly O & M charges and monthly capital recovery charges.

QUARTERLY BILLING:

The service charge shall be calculated by multiplying the monthly service charge by a factor of three. The minimum quarterly bill shall be three times the monthly minimum.

ELECTRIC SERVICE REGULATIONS:

The Company's Electric Service Regulations approved by the Alberta Public Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company. Copies of the Electric Service Regulations are available for inspection in the offices of Alberta Power Limited during normal working hours.

## **RATE SCHEDULE 61**

## MUNICIPAL STREET LIGHTING SERVICE

AVAILABLE:

Throughout the territory served by the company.

APPLICABLE:

To standard mercury vapor and sodium vapor street lights. Not applicable for private lighting. As of the effective date of this rate schedule, all installations are to be paid for by the Customer.

RATE:

(1) For lamps installed by the Company, charges for service in any one billing month shall be the sum of the following. This portion of the rate is closed.

	Customer <u>Charge</u>	Demand <u>Charge</u>
Low Pressure Sodium Lamps	\$9.68 per Lamp	3.26¢ per watt of billing demand
All Other Lamps	\$6.47 per Lamp	3.26¢ per watt of billing demand

(2) For lamp installations paid by the Customer (see Note 1), charges for service in any one billing month shall be the sum of the following:

	Customer <u>Charge</u>	Demand <u>Charge</u>
Low Pressure Sodium Lamps	\$4.84 per Lamp	3.26¢ per watt of billing demand
Decorative Lamps per Contract	\$3.16 per Lamp	4.21¢ per watt of billing demand
All Other Lamps	\$3.00 per Lamp	3.26¢ per watt of billing demand

... continued on overleaf

#### Rate Schedule 61 (continued)

BILLING DEMAND:

For the purpose of administration, the billing demand shall be deemed to be the manufacturer's lamp wattage.

ELECTRIC SERVICE REGULATIONS:

The Company's Electric Service Regulations approved by the Alberta Public Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company. Copies of the Electric Service Regulations are available for inspection in the offices of Alberta Power Limited during normal working hours.

Note: 1. In order for the "Installations paid by Customer" portion of the rate to apply, the customers must pay the total estimated cost of installation which will be made, owned, maintained by the Company.

Contracts may require customers to purchase and maintain inventory of decorative lamps.

#### **RATE SCHEDULE 63**

## PRIVATE LIGHTING SERVICE

AVAILABLE:

Throughout the territory served by the Company.

APPLICABLE:

To off street private lighting and to Municipal Corporations for lighting at 120/240 volt service in summer villages with minimum six-month billing. As of the effective date of this rate schedule, all installations are to be paid for by the Customer.

RATE:

- (1) For lamps installed by the Company, charges for service in any one billing month shall be the sum of the following. This portion of the rate is closed.
  - (a) Customer Charge \$5.80 per lamp
  - (b) Demand Charge 2.95¢ per watt of billing demand
- (2) For lamps installed by the Company for seasonal use only (six month minimum period), charges for service in any one billing month shall be the sum of the following. This portion of the rate is closed.
  - (a) Customer Charge \$10.23 per lamp
  - (b) Demand Charge 2.95¢ per watt of billing demand
- (3) For energy and maintenance only (customer pays installation).
  - (a) Customer Charge \$3.17 per lamp
  - (b) Demand Charge 1.90¢ per watt of billing demand

... continued on overleaf

#### Rate Schedule 63 (continued)

- (4) For twelve month service through customer's meter. This portion of the rate is closed.
  - (a) Customer Charge \$5.91 per lamp
  - (b) Demand Charge 1.90¢ per watt of billing demand

## BILLING DEMAND:

For the purpose of administration, the billing demand shall be deemed to be the manufacturer's lamp wattage.

## ELECTRIC SERVICE REGULATIONS:

The Company's Electric Service Regulations approved by the Alberta Public Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company. Copies of the Electric Service Regulations are available for inspection in the offices of Alberta Power Limited during normal working hours.

- Note: A. These are sentinel units having 30 inch brackets. They are not regular street lighting units. Lamps are energized by a photo-electric controller and operate approximately 4,000 hours per annum.
  - B. Energy for customer owned lamps will be measured and charged through the customer's meter.

## **DECISION E95102** SCHEDULE "A"

Sheet 1 of 2

Effective:

1995 03 01

Supersedes: 1994 03 01

ELECTRIC SERVICE TARIFF

#### RIDER A-1

#### MUNICIPAL ASSESSMENT

AVAILABLE:

Throughout the territory served by the Company.

APPLICABLE:

To electric service within the municipalities identified in the

list attached to this Rider.

PAYMENT:

2216 2262 2265

The Company snall pay to a municipality each year, in accordance with the franchise agreement between the Company and the municipality, a percent of the gross revenue of the Company derived from the sale of electricity to the consumers in the municipality. The percentage of gross revenue is given in the following categories (and the municipalities to which the categories apply are shown on sheet 2 of this Rider):

#### 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 2.

5% of the gross revenue.

## CATEGORY 2 (B).

6% of gross revenue.

#### CATEGORY 3.

3% of the gross revenue.

#### CATEGORY 4.

8% of the gross revenue.

#### CATEGORY 5.

1% 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;

2.5% of gross revenue in excess of \$500,000.

...continued on overleaf



ALBERTA POWER LIMITED

## Rider A-1 (continued)

#### PAYMENT: (Cont'd.)

## CATEGORY 6.

An amount equal to taxes assessed pursuant to sections 360(1) and 360(2) of the Municipal Government Act Chap. M-26.1.

## SURCHARGE FOR RIDER A-1:

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.

## **EXEMPTIONS:**

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The following are exempt from the surcharge:

- a) Farm customers Rate Schedules 51 and 56
- (b) Irrigation Pumping Rate Schedule 25
- (c) Customers within Indian Reservations
- (d) Rate Schedule 36 Rainbow Processing Plant
- (e) Rider E

...continued on Sheet 2



## DECISION E95102 SCHEDULE "A"

Sheet 2 of 2

Effective: Supersedes: 1995 03 01 1994 03 01

#### ELECTRIC SERVICE TARIFF

#### Rider A-1 (continued)

The percentage revenue (franchise fee and or tax) to be paid by the Company to its franchised municipalities is given by category number on sheet 1 of this Rider. The municipalities, and their category numbers, are as follows:

Alliance 3.6 Andrew 1,6 Beaverlodge 2 Berwyn 1 Big Valley 1 Bonneyville 1,6 Botha 1 Carbon 1,6 Castor 1 Cereal 1 Cold Lake 1 Consort 1,6 Coronation 1 Delburne 1.6 Delia 1 Derwent 3 Dewberry 1 Donalda 3 Donnelly 1 Drumheller 1,6 Eaglesham 1 Elk Point 1 Elnora 6 Empress 1,6 Fairview 2 Falher 1

Forestburg 1 Fort McMurrary 2 Fox Creek 1 Gadsby 1 Galahad 3 Girouxville 2 Glendon 3 Grand Centre 1,6 Grande Cache 1,6 Grande Prairie 2(B),6 Grimshaw 2 Hairy Hill 3 Halkirk 1 Hanna 1,6 Heisler 1 High Level 1,6 High Prairie 1 Hines Creek 1 Hythe 2 Innisfree 1 Jasper Sch.Dist. 5 Jasper Nat'l Park 5 Kinuso 1

Kitscoty 1,6

Lavoy 6 Linden 1 Lloydminster 4,6 Manning 2,6 Mannville 1,6 Marwayne 1,6 McLennan 1 Minburn 3 Morrin 1 Mundare 1 Munson 1.6 Myrnam 1 Nampa 1 Oyen 1 Paradise Valley 1 Reace River 1 Radway 1 Rainbow Lake 1 Rosalind 1 Rycroft 1 Sexsmith 2 Slave Lake 1 Smoky Lake 1,6 Spirit River 2,6

St. Paul 1.6 Stettler 1,6 Swan Hills 2 Three Hills 1,6 Trochu 1 Two Hills 1 Valleyview 1 Vegreville 1 Vermilion 1 Veteran 1,6 Vilna 1 Waskatenau 1 Wanham 1 Wembley 2 Willingdon 1 Youngstown 1

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

Bonnyville Beach Horseshoe Bay Pelican Narrows Rochon Sands Torrington Warsnite Whitesands County No. 01 Grande Pr. County No. 06 Stettler County No. 07 Thornhild County No. 13 Smoky Lake County No. 16 Wheatland County No. 18 Paintearth County No. 19 St. Paul County No. 21 Two Hills County No. 22 Camrose County No. 23 Red Deer County No. 24 Vermilion R.

County No. 27 Minburn County No. 29 Flagstaff County No. 30 Lamont M.D. of Badlands No. 07 M.D. of Greenview No. 16 M.D. of Birch Hills No. 19 M.D. of Saddle Hills No. 20 M.D. of Clear Hills No. 21 M.D. of MacKenzie No. 23 M.D. of Acadia No. 34 M.D. of Starland No. 47 M.D. of Kneehill No. 48 M.D. of Bonnyville No. 87 M.D. of Bonnyville Annexed No. 88 M.D. of Lesser Slave River No. 124 M.D. of Big Lake No. 125 M.D. of Smoky R. No. 130

M.D. of East Peace No. 131

M.D. of Spirit River No. 133
M.D. of Peace No. 135
M. D. of Fairview No. 136
I.D. No. L012
I.D. No. L017
I.D. No. L018
I.D. No. L022
I.D. No. L024
Sturgeon Lake I.R. #154
Peavine N172
Gift Lake N173
East Prairie N174
Elizabeth N187
Fishing Lake N188
Paddle Prairie N221



Special Areas

## DECISION E95102 SCHEDULE "A"

#### SURCHARGES FOR RIDER A-1

Effective: Supercedes: 1995/03/01 1994/03/01

The percentage surcharges listed will be added to all customer's bills according to the taxation in which the customer is located with the exceptions as noted below.

сомм.	TAXATI	ON AUTHORITY	TAX %	сомм	TAXATION AUTHORITY	TAX %	сомм.	TAXATION AUTHORITY	TAX %
403	ALLIAN	CE	3.15	765	GIROUXVILLE	5.34	521	OYEN	3.75
<b>0</b> 01	ANDRE	W	2.91	041	GLENDON	2.55	104	PARADISE VALLEY	1.56
205	BEAVE	RLODGE	4.95	043	GRAND CENTRE	4.70	803	PEACE RIVER	4.86
710	BERWY	'N	2.71	286	GRANDE CACHE	4.66	099	PELICAN NARROWS S.V.	3.87
417	BIG VAL	LLEY	2.39	270	GRANDE PRAIRIE	5.70	101	RADWAY	2.24
017	BONNY	VILLE	4.83	775	GRIMSHAW	4.95	807	RAINBOW LAKE	3.72
018	BONNY	VILLE BEACH S.V.	2.65	045	HAIRY HILL	3.23	528	ROCHON SANDS S.V.	2.98
421	BOTHA		1.95	479	HALKIRK	1.97	529	ROSALIND	2.26
427	CARBO	N	2.66	481	HANNA	4.47	305	RYCROFT	3.05
429	CASTO	R	3.44	483	HEISLER	2.91	310	SEXSMITH	4.87
431	CEREA	L	2.24	781	HIGH LEVEL	5.05	315	SLAVE LAKE	4.65
026	COLD	AKE	4.49	780	HIGH PRAIRIE	4.22	127	SMOKY LAKE	3.83
441	CONSC	ORT	3.38	785	HINES CREEK	2.93	325	SPIRIT RIVER	5.08
439	CORON	NATION	3.90	189	HORSESHOE BAY S.V.	3.18	121	ST. PAUL	4.74
445	DELBU	RNE	2.75	275	HYTHE	4.91	555	STETTLER	4.98
447	DELIA		2.36	055	INNISFREE	2.41	332	SWAN HILLS TOWN	5.14
029	DERWE		3.03	920	JASPER SCH (R004)	4.84	567	THREE HILLS	4.39
031	DEWBE		2.36	280	KINUSO	2.47	569	TORRINGTON	1.79
449	DONAL		3.13	059	KITSCOTY	2.99	571	TROCHU	3.51
745	DONNE		2.57	065	LAVOY	5.02	137	TWO HILLS	4.02
451	DRUMH		4.87	497	LINDEN	2.86	840	VALLEYVIEW	4.07
260	EAGLE		2.37	069	LLOYDMINSTER(AB)	7.55	139	VEGREVILLE	4.69
035	ELK PC		3.79	070	LLOYDMINSTER(SASK)	7.55	141	VERMILIÓN	4.71
457	ELNOR		2.34	792	MANNING	4.99	575	VETERAN	2.46
459	EMPRE		2.42	075	MANNVILLE	3.13	145	VILNA	2.57
760	FAIRVIE		5.01	077	MARWAYNE	2.50	355	WANHAM	2.41
755	FALHER		4.31	795	MCLENNAN	3.50	149	WARSPITE	3.42
471	FORES		3.33	081	MINBURN	3.25	153	WASKATENAU	2.31
<b>6</b> 05		MCMURRAY	5.18	507	MORRIN	2.31	<b>3</b> 65	WEMBLEY	5.10
267	FOX CF		4.11	085	MUNDARE	2.82	580	WHITE SANDS S.V.	4.15
473	GADSB		1.27	509	MUNSON	2.06	157	WILLINGDON	2.60
475	GALAH	AD	2.55	089	MYRNAM	2.55	<b>5</b> 83	YOUNGSTOWN	2.75
				797	NAMPA	2.42			
MOITAXAT	AUTHO	RITY	TAX %	TAXATI	ON AUTHORITY	TAX %	TAXATI	ON AUTHORITY	TAX %
County #	C001	GRANDE PRAIRIE	0.31	Improve	ement District # L012	3.45	M007	M.D. OF BADLANDS	2.47
County #	C006	STETTLER	1.06	improve	ement District # L017	1.03	M016	M.D. OF GREENVIEW	0.35
County #	C007	THORHILD	2.08	Improve	ement District # L018	0.22	M019	M.D. OF BIRCH HILLLS	1.03
County #	C013	SMOKY LAKE	0.61	Improve	ement District # L022	0.22	M020	M.D. OF SADDLE HILLS	0.80
County #	C016	WHEATLAND	0.50	improve	ement District # L024	2.33	M021	M.D. OF CLEAR HILLS	0.63
County #	C018	PAINTEARTH	2.27	A001	SPECIAL AREAS	0.62	M023	M.D. OF MACKENZIE	0.47
County #	C019	ST. PAUL	1.61	<b>B77</b> 0	STURGEON LAKE(IR154)	0.88	M034	M.D. OF ACADIA	1.11
County #	C021	TWO HILLS	2.88	N172	PEAVINE (Metis Sett.)	2,41	MQ47	M.D. OF STARLAND	1.05
County #	C022	CAMROSE	1.72	N173	GIFT LAKE (Metis Sett.)	1.97	M048	M.D. OF KNEEHILL	1.33
County #	C023	RED DEER	1.65	N174	EAST PRAIRIE(Metis Sett.)	2.85	M087	M.D. OF BONNYVILLE	0.67
County #	C024	VERMILION RIVER	1.74	N187	ELIZABETH(Metis Sett.)	1.74	M088	M.D. OF BONNYVILLE ANNEX'D	0.22
County #	C027	MINBURN	0.90	N188	FISHING LAKE(Metis Sett.)	0.72	M125	M.D. OF BIG LAKE	0.34
County #	C029	FLAGSTAFF	0.46	N221	PADDLE PRAIRIE(Metis Sett.)	0.00	M124	M.D. OF LESSER SLAVE RIVER	0.00
County #	C030	LAMONT	2.13				M130	M.D. OF SMOKY RIVER	2.27
							M131	M.D. OF EAST PEACE	0.42
							M133	M.D. OF SPIRIT RIVER	1.10
NOTE: 1		lowing are exempt fro		-			M135	M.D. OF PEACE	1.00
		a) Farm customers Ra					M136	M.D. OF FAIRVIEW	0.44
		) Irrigation Pumping				Rate Schedul	e 36 Rain	bow Processing Plant.	

e) Rider E

c) Customers with Indian Reservations, not listed on this page

#### RIDER A-2

## SURCHARGE FOR SERVICE IN ISOLATED AREAS

**AVAILABLE:** 

In isolated areas excluding Jasper.

APPLICABLE:

To all electric service from local power plants.

RATE:

Service will be rendered at the available residential and general service rates within the interconnected system, with added surcharges to recognize the higher cost of fuel as follows:

(a) Residential Service

> For the first 600 kW.h 0¢/kW.h For all kW.h over 600 kW.h 4.2¢/kW.h

(b) General Service and Oilfield

For the first 4,500 kW.h 0¢/kW.h

For all kW.h over 4,500 kW.h 4.2¢/kW.h

NOTE:

- (1) Special arrangements will be required for supply to loads exceeding 20 kW in these areas.
- (2) Electric service will not be offered for electric heating purposes.

#### RIDER E

## SPECIAL FACILITIES CHARGE

AVAILABLE:

To major new and existing customers as negotiated.

APPLICABLE:

To recover additional costs incurred by the Company in constructing extra facilities to serve the special requirements of major customers.

RATE:

#### (A) Mitsue to Mildred Lake 240 kV Line

Extra Facilities Cost - Additional costs of constructing a 240 kV line instead of a 144 kV line from Mitsue to Mildred Lake.

Sharing - The monthly charge shall be shared as follows:

Suncor Inc. - 33%

Syncrude Canada Limited - 60%

Monthly Charge: \$286,241

The components of this rate related to Return, Income Tax, Depreciation and Operations and Maintenance costs are subject to adjustment at the time of general rate changes.

## (B) Suncor Extension

(i) Extra Facilities Cost - Additional costs of a 72 kV line from the Mildred Lake Substation to the Suncor Plant.

Sharing - The monthly charge shall be paid by Suncor Inc.

Monthly Charge: \$25,072

The components of this rate related to Return, Income Tax, Depreciation and Operations and Maintenance costs are subject to adjustment at the time of general rate changes.

...continued on Overleaf

#### RIDER E (continued)

## (ii) Reroute of Suncor Extension

Monthly Charge: \$3,140 (Remains Fixed) Expiry Date November 2005

#### (C) Suncor Extension

Extra Facilities Cost - Additional costs of a Steepbank River Substation and a 72 kV line to the Suncor Plant.

Sharing - The monthly charge shall be paid by Suncor Inc.

Monthly Charge: \$114,630

The components of this rate related to Return, Income Tax, Depreciation and Operations and Maintenance costs have been levelized and are fixed for the term of the contract.

#### (D) Distribution Facilities

<u>Extra Facilities Cost</u> - Costs associated with leasing 25 kV distribution facilities downstream of the customer's meter.

<u>Sharing</u> - The monthly charge shall be paid by the respective customer to whom the facility applies.

Monthly Charge: The revenue requirement of the leased facilities as specified by the respective customer's contract with the Company.

The revenue requirement will be calculated on a rate base of prior year's book values and will include Return, Income Tax, Depreciation, and Operations and Maintenance costs.

#### OPTION F

#### **IDLE SERVICE**

AVAILABLE:

Throughout the territory served by the Company.

APPLICABLE:

To any customer who wishes to be disconnected and may require service to be restored at a future date. Not available for private lighting.

RATE:

Farm customers served on Rate 51 or 56 will be billed on their regular billing cycle (i.e. either monthly or quarterly) and the idle service charge shall be one-half the total customer and kV.A charges applicable to a 3 kV.A service.

General service, and oilfield customers served on Rate 31 or 41 will be billed monthly, and the idle service charge shall be the greater of the rate minimum, or the contract minimum, where the rate minimum is the greater of:

- (i) the rate minimum of the rate on which the service was billed immediately prior to becoming idle, and
- (ii) the rate under which the service was billed during the majority of its service life.

If the last rate change occurred at least two years previously, the rate minimum is as per the most recent rate.

For streetlight customers, served on Rate Schedule 61, the idle service charge shall be a percentage of the sum of the applicable customer and demand charge for the type and size of lamp rendered idle. For installations paid for by the Company, the percentage is 75%, and for installations paid for by the customers the percentage is 35%.

Charges based on demand ratchets are excluded from the minimum charge unless the service is reconnected within 12 months of disconnection. If a service is reconnected within 12 months of disconnection, the reconnection charge (refer to ESR 4.18) will include an amount to recover the ratcheted demand charges for each month that the service has been idle.

#### OPTION H

#### SERVICE AT PRIMARY OR TRANSMISSION VOLTAGE

AVAILABLE:

Throughout the territory served by the Company.

APPLICABLE:

To service rendered under Rate Schedule 21 or 31, where the customer takes service directly from the Company's transmission lines, transmission substations, or primary distribution lines.

RATE:

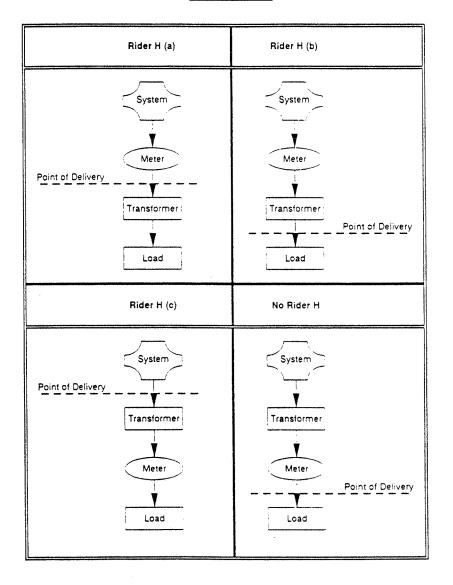
Service will ordinarily be delivered to the customer and metered at utilization voltage. When delivery or metering is necessary at higher voltages for the convenience of either the customer or the Company, the following adjustments will be recognized in rendering the bills for service:

- (a) Service is provided directly from the Company's transmission lines or transmission substations, or one-point service is required by the customer for more than a single utilization voltage or point of use. In these cases, the customer will supply or rent the necessary transformers, and the Company will deliver and meter energy at distribution primary or higher voltages as available and a discount of 50¢ per kW of billing demand will be applied.
- (b) Primary or higher voltage delivery metering is desirable for the convenience of the Company, or to improve accessibility, etc. In this case, demand and energy measurements will be reduced by 1% so as to approximate secondary voltage delivery conditions.
- (c) Primary or higher voltage delivery is made to customer owned substations, but metering is at secondary or utilization voltage for the Company's convenience. In this case, 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.

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#### Rider H (continued)

#### Rider H Definitions



Sheet 1 of 3 Effective: Supersedes:

## OPTION I PEAK SHAVING CREDIT

#### AVAILABLE:

Throughout the territory served by the Company from the Alberta Interconnected System. A temporary moratorium on new Option I sales would apply to all customers who have not given written notice of intent to receive Rider I as of August 1, 1993. The Public Utilities Board has instituted the moratorium on an interim basis pending final review.

#### **APPLICABLE:**

To load supplied to customers on Rate Schedule 31 or Rate Schedule 41, not modified by any other interruptible option, and under a long term contract wherein the Company has the right to require the customer to reduce load within the notice period associated with the credit selected.

To receive credit under Option I, the customer must be in the creditable, interruptible period of a Option I contract. Interruptible service and receipt of Option I credit will commence one year after a standard Option I contract is signed, and continue until the end of the sixth year when the contract is terminated. This will result in a creditable, interruptible service period of five years. Option I credits will be based on the credit level in effect at the time the contract is signed, and fixed for the duration of the contract.

A customer wishing to continue interruptible service under Option I beyond the creditable, interruptible period of 5 years must sign a new contract two years before the termination of the existing contract.

The Option I credit table shall be reviewed and updated annually.

The customer must be able to demonstrate that the Rider I load can be curtailed within the notice period associated with the credit selected.

The customer must have a load reduction capability of at least 1,000 kW and must have revenue approved time-of-use recording metering.

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#### Option I (continued)

#### **APPLICABLE:**

Customers with multiple services may contract to provide this capability in aggregate, provided the costs of any metering and communication equipment necessary to validate compliance is paid for by the customer, and Option I (A) is selected.

#### RATE:

#### Option I (A)

The customer will specify the minimum amount in kW by which the customer will reduce load at each request issued by the Company. Failure to provide the specified load reduction on request will result in a penalty surcharge and will be determined as specified below under General Conditions and Penalties.

A credit will be applied to the customer's bill during each billing period, and will be calculated as follows:

Monthly Credit = SLR x C

where:

SLR is the contractually specified load reduction in kW.

C is the peak shaving credit in \$ per kW per month based on the notice period, maximum interruption duration and cumulative duration per year selected by the customer from the credit table and incorporated into the Rider I contract.

## Option I (B)

The customer will specify only a firm power level. The firm power level may be zero. On request, the customer will reduce load to the specified firm power level. The effective amount of load reduction is not specified and is dependent on the customer's total load at the time of the request. This option is not available when the contracted peak shaving is achieved through aggregation.

Sheet 2 of 3 Effective: Supersedes:

#### Option I (continued)

A credit will be applied to the customer's bill during each billing period, and will be calculated as follows:

Monthly Credit =  $(PMD - FPL) \times LF \times C$ 

where:

PMD is the customer's Peak Metered Demand in kW during the billing period.

FPL is the Firm Power Level in kW specified by the customer.

LF is the customer's on-peak load factor for the entire Rate 31 load, excluding any days during which the customer complied with a load reduction request. For the purposes of this calculation, on-peak is defined as the hours of 7:00 a.m. to 11:00 p.m. weekdays.

The customer may elect to calculate the on-peak load factor based upon the current billing period or to fix the load factor for a 12 month period based upon the previous 12 month period. In the absence of historical data, the load factor for the first 12 month period may be negotiated with the Company.

C is the peak shaving credit in \$ per kW per month based on the notice period, maximum interruption duration, and cumulative duration per year selected by the customer from the credit table.

GENERAL CONDITIONS AND PENALTIES (BOTH OPTIONS A AND B):

Load reduction requests will occur no more than once in a calendar day (i.e. only one instance between 0:00 hrs. and 24:00 hrs. each day). The maximum cumulative load reduction that can be requested in any calendar year is as specified for the credit selected from the credit table.

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#### Option I (continued)

GENERAL CONDITIONS AND PENALTIES (BOTH OPTIONS A AND B):

During the term of a Option I contract, and provided notice of termination has not been given, a customer may elect to change the interruptibility conditions in order to receive a higher credit level as compared on a contemporary schedule. Such changes may be made once per year and only to a higher credit than offered for the customer's current conditions of interruptibility.

Failure to reduce load on request by the specified amount (Option A) or to the Firm Power level (Option B), at the requested time, and for the selected duration will result in a penalty surcharge calculated as follows:

- For the first failure to comply in a 12-month period a surcharge equal to twice the highest monthly credit paid in the last 12 months.
- For each subsequent failure to comply in a 12-month period a surcharge equal to six times the highest monthly credit paid in the last 12 months.

Sheet 3 of 3 Effective: Supersedes:

## Option I (continued)

## Option I Credit Table

Effective for the Creditable Period of Option I Contracts signed after December 31st, 1992

For a max	imum single	event duration	on of 4 hours:
Notice	Cumulative	Duration per	Year* (hours)
(Minutes)	200		800
10	\$2.25	\$2.40	\$2.45
60	\$1.80	\$1.95	\$2.00

For a ma	ximum single	event durati	on of 8 hours:
Notice	Cumulative	Duration per	Year* (hours)
(Minutes)	200	400	800
10	\$2.75	\$3.25	\$3.30
60	\$2.20	\$2.60	\$2.65

For a maximum single event duration of 12 hours:				
Notice	Cumulati	ve Duration per	Year* (hours)	
(Minutes)	200	400	800	
10	· •	\$3.70	\$3.75	
60		\$2.95	\$3.00	

<sup>\*</sup>Note: This is a calendar year.

## DECISION E95102 SCHEDULE "A"

Effective:

1995 03 01 1994 07 01

Supersedes: ELECTRIC SERVICE TARIFF

## RIDER M

## ALBERTA ELECTRIC ENERGY MARKETING AGENCY RIDER

**AVAILABLE:** 

Throughout the territory served by the Company.

APPLICABLE:

To all electric service except as noted below.

RATE:

The applicable rates will be adjusted by the percentages noted

below

NOTE 1:

Rate Schedule	Rider M %
Residential Rate 11	2.14
Residential Rate 18	1.50
REA Farm Service Rate 51	3.19
Farm Service Rate 56	3.19
General Service Rate 21	2.04
Irrigation Rate 25	9.66
Industrial Rate 31	0.24
Industrial Rate 36	(2.16)
Oilfield Rate 41	4.96
Streetlighting Rate 61	0.40
Spacelighting Rate 63	1.04

... continued on overleaf



ALBERTA POWER LIMITED

## Rider M (continued)

#### NOTE 2:

0215 - 2060 - 0295

- (a) Rider M does not apply to Rider E, Rider G or Rider A-1.
- (b) Rider M applies to only energy charges for Rate 51 and Rate 56.
- (c) Rider M does not apply to customers on Rate 33, Rate 35 or Rate 38.
- (d) The following amounts are forecast to be recovered/(refunded) by rate group through Rider M during the period March 1, 1995 to February 28, 1996:

(i)	Rate Schedule	Rider M (\$000)
	Residential Rate 11 Residential Rate 18 REA Farm Service Rate 51 and	1,264 55
	Farm Service Rate 56	727
	General Service Rate 21 Irrigation Rate 25	1,108 10
	Industrial Rate 31	521
	Industrial Rate 36	(173)
	Oilfield Rate 41	1,375
	Streetlighting Rate 61	11
	Spacelighting Rate 63	7

(ii) less the difference between actual and estimated amounts collected or refunded by rate group for the month of February 1995.



#### **OPTION N**

#### PLANT COMMISSIONING

AVAILABLE:

To new or existing customers on Rate Schedule 31 who are building new facilities that will result in additional monthly demands of at least 1,000 kW.

APPLICABLE:

For commissioning a new facility. Option N is available for up to three months of initial service.

RATE:

(1) New Facilities

For a new facility that is not in addition to an existing service, the billing demand for each billing period during the commissioning period shall be:

- (a) 125% of the energy consumed in the billing period divided by the number of hours in the billing period.
- (2) Additions to Existing Facilities

When the new facility being commissioned is an addition to an existing service, the billing demand will be the sum of:

- (a) the Rate 31 Base Demand, defined as the highest billing demand (excluding any demand delivered and billed under Rate 32, 33 or 38) in the last six-month period preceding the current billing month, and
- (b) 125% of the excess energy consumed in the billing period divided by the number of hours in the billing period, where excess energy is defined as all energy associated with metered demands in excess of the Rate 31 Base Demand.

## <u>OPTION P</u>

## REA DISTRIBUTION PRICE CREDIT

AVAILABLE:

Throughout the territory served by the Company

APPLICABLE:

To all REA Farm customers served under General Service Rate Schedule 21, or, Large General Service Rate

Schedule 31.

RATE:

For REA farm customers electing to take service under Small General Service Rate Schedule 21, a credit adjustment of 14.0 % will be applied to the base bill.

For REA farm customers electing to take service under Large General Service Rate Schedule 31, a credit adjustment of 7.0 % will be applied to the base bill.

Effective: 1995 05 01 Supersedes: 1994 05 01

## RIDER S

## ADJUSTMENT FOR SERVICE OUTSIDE THE BOUNDARIES OF THE PROVINCE OF ALBERTA

AVAILABLE:

For service outside the boundaries of the Province of

Alberta.

APPLICABLE:

To all electric service.

RATE:

The available rate for service will be reduced by a percentage adjustment to recognize the use of generation and transmission facilities within the Province of Alberta and the cost adjustment due to the Province of Alberta Income Tax Adjustment.

The following percentages listed will be subtracted from the applicable customers' bills:

(1)	Residential	4.5%
(2)	REA	4.5%
(3)	Company Farm	4.5%
(4)	Other	4.5%

The adjustment does not apply to the applicable Rider A-1.

#### **OPTION T**

#### **OFF-PEAK DEMAND**

AVAILABLE:

To customers served on Rate Schedule 21, or 31 with revenue approved time of use metering.

APPLICABLE:

To customers whose off-peak demand is expected to exceed their on-peak demand.

RATE:

Charges for demand and energy on this rate will be as per Rate Schedule 31 except that the billing demand shall be the greater of the following:

- (a) the highest metered demand during the on-peak hours;
- (b) 85% of the highest metered demand during the on-peak hours (excluding any demand delivered and billed under Rate Schedule 32, 33 or 38) in the 12-month period including and ending with the billing period;
- (c) the estimated demand;
- (d) the contract demand;

#### Plus:

(e) 10% of the amount by which the highest metered demand during the off-peak hours exceeds the greater of the demands calculated from (a) through (d) above.

On-peak is from 7:00 am to 11:00 pm weekdays, and off-peak is 11:00 pm to 7:00 am weekdays, all weekend hours and statutory holidays.

## METERING REQUIREMENT:

Purchasing power under Off-Peak Demand Option T requires that a customer has revenue approved time of use metering installed. The cost of the time of use metering will be the responsibility of the customer.

## OPTION U

#### RATCHET BUYDOWN

**AVAILABLE:** 

Throughout the territory served by the Company to customers served on Rate Schedule 31.

APPLICABLE:

To customers who anticipate significant demand variations from month to month due to the nature of the market for their product. This Option is available for a minimum period of 12 months, and 12 months notice is required to discontinue billing under the provisions of this rider. Furthermore, discontinuation is permitted only upon the anniversary of the Option U contract anniversary date.

Not available for use as supplemental, maintenance, or standby power to customer owned generation facilities.

RATE:

The Demand Charge shall be 120% of the Rate Schedule 31 Demand Charge. The Billing Demand will be the greater of the following:

- (a) the highest metered demand during the billing period;
- (b) the estimated demand;
- (c) the contract demand;
- (d) 50 kilowatts.

SCHEDULE "B"

ALBERTA POWER LIMITED

ELECTRIC SERVICE REGULATIONS

L

Electric Service Regulations Page 1 Effective:

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# ALBERTA POWER LIMITED ELECTRIC SERVICE REGULATIONS

#### 1. INTERPRETATION

## 1.1 Definitions

Unless the context requires otherwise, the following words and phrases, whenever used in these Regulations, the Electric Service Tariff or an application, contract or agreement for service, shall have the meanings set out below.

"billing demand" - the demand upon which billing to a customer is based.

"Board" - the Alberta Energy and Utilities Board (AEUB).

"company" - Alberta Power Limited.

"connected load" - the sum of the capacities or ratings of the electric energy consuming apparatus connected to a supplying system.

"construction contribution" - the difference between the cost of extending the company's facilities to serve a customer and the maximum company investment specified in Schedule B.

"customer" - a person, firm, partnership, corporation, REA, organization or association (including, without limitation, individual members of any unincorporated entity) served by the company, but does not include a public utility, the Alberta Electric Energy Marketing Agency, nor any member of an REA.

"demand" - the maximum rate at which electric energy is delivered by the company (expressed in kilowatts, kilovoltamperes or other suitable unit) at a given instant or averaged over any designated period of time.

"energy" - electric energy (expressed in kilowatt hours).

"extraordinary circumstances" - circumstances not reasonably within the control of the company, including acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, high water, washouts, inclement weather, orders or acts of civil or military authorities, civil disturbances, explosions, breakdown or accident to equipment, and any other cause, whether of the kind herein enumerated or otherwise.

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"facilities" - a physical plant (including, without limitation, generating plants, transmission and distribution lines, transformers, meters, equipment and machinery).

"family dwelling" - a residential dwelling unit which is not a multiple dwelling (see definition of "multiple dwelling").

"in-service date" - the date on which the customer specifies service is to be available or the date the service is actually available, whichever is later.

"interconnected system" - those portions of the company's facilities which are connected with the electrical systems of other electric utilities in the Province of Alberta.

"isolated system" - those portions of the company's facilities which do not form part of the interconnected system.

"load" - the demand and energy delivered to or required at any point of delivery.

"load factor" - the ratio of the average demand (in kilowatts) supplied during a designated period to the peak or maximum load (in kilowatts) occurring in the period. To express load factor as a percentage:

- (a) multiply the energy used in the period by 100;
- (b) multiply the maximum demand by the number of hours in the period; and
- (c) divide (a) by (b).

"multiple dwelling" - a residential building containing more than one residential dwelling unit.

"point of delivery" - the point at which the company's service conductors are connected to the wires or apparatus of a customer.

"power factor" - the ratio of the highest metered kilowatt demand in a billing period to the highest metered kilovoltampere demand in that same billing period.

"REA" - incorporated rural electrification association.

"service" - the delivery of energy by the company at the demand required by a customer at a point of delivery.

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#### 2. INTRODUCTION

#### 2.1 Board Approval

These regulations have been approved by the Board.

The company may amend these regulations by filing a notice of amendment with the Board. Included in the notice to the Board shall be notification of which customer groups are affected by the amendment and an explanation of how affected customers will be notified of the amendments. The amendment will take effect 60 days after such notice is filed unless the Board orders otherwise.

#### 2.2 Electric Service Tariff

These regulations are the Electric Service Regulations referred to in the company's Electric Service Tariff and form part of the Electric Service Tariff.

#### 2.3 Effective Date

These regulations come into force on \_\_\_\_\_\_\_, and replace the company's previous Electric Service Regulations dated July 1, 1993. Whenever the Board approves an amendment to these Regulations, revisions will be issued, with the effective date of the amendments indicated on the top of each affected page.

#### 3. GENERAL PROVISIONS

## 3.1 Regulations Prevail

These regulations apply to the company and to every customer.

No agreement can provide for the waiver or alteration of any part of these regulations unless such agreement is first filed with and approved by the Board.

#### 3.2 Ownership of Facilities

The company remains the owner of all facilities it provides to serve the customer, unless a contract between the company and customer specifically provides otherwise.

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Payment made by customers for costs incurred by the company in installing facilities does not entitle customers to ownership of any such facilities, unless a contract between the company and the customer specifically provides otherwise.

#### 3.3 Use of Energy

Unless otherwise provided in a contract with the company, a customer shall not sell energy provided by the company unless the company has first given written consent.

#### 3.4 Customer Extensions

A customer shall not extend service facilities beyond property owned or occupied by that person.

#### 3.5 Customer Generation

A customer must sign an agreement with the company if he wishes to use service.

- a) in parallel operation with; or
- b) as supplementary, auxiliary or stand-by service to any other source of electric energy.

#### 3.6 Frequency and Voltage Levels

The company will make every reasonable effort to supply energy at 60-Hertz alternating current. The voltage levels and variations will comply with the Canadian Standards Association standards and as specified in Schedule A.

Some voltage levels set out in Schedule A may not be available at all locations served by the company.

#### 4. APPLICATION FOR AND CONDITIONS OF SERVICE

#### 4.1 General Requirements

To enable the company to provide the requested service, applicants for service shall supply information regarding their load and preferred supply conditions.

An applicant may be required to sign an application or a contract for service and may be required to provide credit information or references.

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### 4.2 Conditions of Service

Before connecting any service, the company will inform the customer if there are any special conditions that must be satisfied.

### 4.3 Connection Fee

Whenever a connection is made, the customer will pay a non-refundable connection fee of either:

- (a) \$10 if the connection is made during the company's regular business hours; or
- (b) an amount not to exceed the company's actual costs if the connection is made at any other time,

which will be included in the customer's first billing.

### 4.4 Application of Rate Schedules

The company will endeavor to apply the rate schedule which applies to the service and is most favorable to the customer.

Various riders are also applicable to the service as outlined in the Electric Service Tariff approved from time to time by the Alberta Energy and Utilities Board (AEUB). The System Support Minimum Charge as determined by Rate Schedule 30 will apply to any general service bill.

Where the customer's service requirements change so that some other rate schedule(s) and riders apply to the service, the company will change the customer's billing accordingly.

A customer may elect to have service billed on any other rate schedule applicable to that customer's service requirements. Any change shall not be effective until the next complete billing period. An election under this section may not be made more than once in any 12-month period, unless the customer's service requirements change.

In each circumstance, the company may perform an investment contribution calculation to determine whether any adjustments are required to the customer's contribution amount to recognize the different levels of company investment which apply to each rate schedule.

In addition to payments for electric service, the customer is required to pay the company the amount of any tax or assessment levied by any tax authority on electric service delivered to the customer.

### 4.5 Minimum Monthly Bill

The System Support Minimum Charge as determined under Rate Schedule 30 will apply to any general service bill.

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### 4.6 Multiple Dwellings

Each individual unit within a multiple dwelling will be served as a separate point of delivery, unless the company agrees otherwise.

The company and a customer may agree that one bill will be issued covering all individual units in a multiple dwelling.

Where the company and a customer have agreed that service to a multiple dwelling shall be delivered through a single point of delivery, the applicable general service (non-residential) rate schedule will apply to the service.

Where a customer was, on December 31, 1989, receiving one bill in respect of more than one unit, the customer may continue to be billed on that basis until such time as the customer's load changes or the service conductors and meters serving that customer are relocated.

### 4.7 Totalized Metering

Normally, the company will issue a separate bill for each point of delivery.

When service is provided through multiple points of delivery to a customer's plant site consisting of centralized processing facilities or product transportation facilities located on lands leased or owned by the customer, where such multiple points of delivery are located within a radius of half a mile of each other, the customer and company may agree that the demand and energy at each point of delivery be totalized and only one bill issued for each billing period. Totalized metering is not available for oilfield pumping services.

The customer shall pay the incremental metering cost associated with totalized metering.

### 4.8 Consolidated Billing

The company will issue a separate bill for each point of delivery. However, the customer and company may agree that the company will issue one bill totaling charges for service delivered at more than one point of delivery.

### 4.9 Security Deposit

The company may require any customer to provide a security deposit which shall not exceed the company's estimate of the customer's total bills for any average three-month period.

The company will pay simple interest on the security deposit from the date the deposit is paid, at a rate of interest equal to the rate fixed for the most recent

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issue of Canada Savings Bonds and such interest will be credited to the customer's account on the first billing following December 31 of each year.

The company will refund a security deposit when the customer has established a satisfactory payment history over a 12-month period or when the customer's service is terminated. Any interest owing at the time a security deposit is refunded will be included in the refund or credited to the customer's account.

### 4.10 Use of Security Deposit

If a customer fails to pay any amount billed, the company may apply all or any portion of that customer's security deposit to the unpaid amount.

When the company has to take this step, the customer may be required to pay a security deposit up to the maximum amount allowed in regulation 4.9.

### 4.11 Delay in Taking Service - Subdivision

When a customer requests service to a subdivision, then in addition to any other charges payable by the customer, the customer shall make a payment, not to exceed the maximum company investment specified in Schedule B, for each point of delivery within the subdivision where service will not be taken within 12 months of the in-service date.

When service is taken at a point of delivery within five years of the in-service date, the company will refund the payment applicable to that point of delivery. Otherwise, such payment will be forfeited to the company.

### 4.12 Delay in Taking Service - Other than Subdivision

Except in the case of a customer who requests service to a subdivision under regulation 4.11, if service is not taken within 30 days of the in-service date, the company may begin billing the customer the minimum amount specified in the appropriate rate schedule or as specified in the contract between the company and the customer, whichever is greater.

### 4.13 Extension of Service

If the company's estimated costs of extending facilities at the request of a customer are less than the maximum company investment specified in Schedule B for the type of service provided, the customer will not be required to make any contribution.

In all other cases, an agreement for payment of extension charges must be made between the customer and the company before any work on the extension is commenced.

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The cost of system additions deemed necessary to improve system reliability or to serve a group of customers will not normally be considered a customer cost. If the timing of such additions are advanced to serve an individual customer, then the associated costs of advancement will be considered customer costs.

In lieu of the company investment that normally would apply to an extension of company facilities, a new customer may opt to receive a monthly bill credit with the same present value as the company investment calculated as a perpetuity at current interest rates. Under no circumstances would the normal company investment exceed the actual cost of the extension.

### 4.14 Underground Subdivision Extensions

Underground subdivision extensions shall be undertaken subject to the conditions set out in Schedule "C".

### 4.15 Conversion from Overhead to Underground Service

When a customer requests that existing company facilities be converted from overhead to underground, the customer will be charged for all costs incurred by the company in connection with the conversion, including the following:

- (a) the original capital cost of the existing facilities being removed, less accumulated depreciation, plus
- (b) the estimated cost of removing the existing facilities, less the estimated salvage value, plus
- the estimated cost for the installation of the new underground facilities, less any applicable increase in company investment as specified in Schedule "B".

### 4.16 Temporary Service

Where the company reasonably believes that a requested service will be temporary, it may require the customer requesting the service to pay the company's total estimated cost of installation and removal of the service, plus the cost of unsalvageable material

The company may require that such payment be made before the temporary service is installed.

### 4.17 Mobile Homes

Service shall normally be provided to mobile homes through separate points of delivery, based on the applicable residential rate schedule.

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Service provided to common use areas (e.g. laundry facilities) in a mobile home park shall be separately metered and billed at the applicable general service rate.

In mobile home parks or trailer courts where the company reasonably believes homes are temporary, the company may elect to provide service only through the point of delivery billed to the mobile home park or trailer court.

### 4.18 Relocation of Company Facilities

The company may require a customer to pay all reasonable costs incurred by the company in relocating any company facility at the customer's request.

If requested by the company, the customer shall pay the estimated cost of the relocation in advance.

### 4.19 Reconnection or Restoration of Service

This section applies when the company is asked to reconnect or restore service to a customer whose service was previously restricted by a current-limiting device or discontinued (whether at the request of the customer or not). This section does not apply when a customer's service was disconnected for safety reasons. (See regulation 11.2)

Before reconnecting or restoring service, the customer shall pay:

- (a) any amount owing to the company;
- (b) a reconnection charge of \$45 if the reconnection is made during the company's normal business hours, or, in any other case, an amount not exceeding the company's actual cost of reconnection;
- (c) the security deposit, if any, required under regulation 4.9; and
- (d) the ratcheted demand or minimum monthly charge for each month of disconnection, if service is reconnected within 12 months of disconnection for all rate schedules except 11, 18, and 21.

### 4.20 Construction Contribution Refunds

When a customer provides a construction contribution to obtain service, the company will refund a portion of the service charges if:

- (a) the customer increases the contracted load of the services; or
- (b) another customer shares a part of the service to which the construction contribution relates.

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The refund is payable only if the events in paragraphs (a) and (b) above occur during the initial term of the contract with the customer who originally provided the construction contribution.

### 4.21 Temporary Disconnection and Idle Services

Upon the request of the customer, the company shall disconnect any residential, farm, general service, oilfield or street light service being provided by the company on a temporary basis provided that:

- a) the customer agrees to pay the applicable idle service charge, and
- b) upon the request to restore service the customer will be responsible for and pay any applicable charges outlined in regulation 4.19.

If the customer requests that the service be permanently disconnected, the customer billing for that service will be finalized and at the discretion of the company, the facilities provided by the company will be removed.

If within three (3) years of permanent disconnection the customer requests that the service be restored, the customer must pay all the costs associated with the original disconnection, removal of the facilities and restoration of service.

### 5. RIGHTS OF WAY AND ACCESS TO FACILITIES

### 5.1 Easements

The customer shall grant, or cause to be granted, to the company, without cost to the company, such easements or rights-of-way over, upon or under the property owned or controlled by the customer as the company reasonably requires to provide service to such customer.

### 5.2 Right of Entry

The company's employees or agents shall have the right to enter a customer's property at all reasonable times for the purpose of installing, maintaining, monitoring and removing the company's facilities and for any other purpose incidental to the provision of service.

The customer shall provide the company with reasonable access to company facilities located on the customer's property.

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### 5.3 <u>Vegetation Management</u>

The customer shall permit the company to manage vegetation on the property owned or controlled by the customer to maintain proper clearances and reduce the risk of contact with the company's facilities.

The company shall endeavor to notify a customer before such work is performed.

### 5.4 Interference with Company's Facilities

Customers shall not place any structures that would interfere with the proper and safe operation of the company's facilities or which would adversely affect compliance with any applicable legislation.

### 6. METERS

### 6.1 Installation

The company shall provide, install and seal all meters necessary for measuring the energy supplied to a customer, unless otherwise specifically provided in a contract with the customer.

Each customer shall provide and install a CSA-approved meter receptacle or other CSA-approved facilities suitable for the installation of the company's meter or metering equipment.

### 6.2 Location

Meter locations shall be approved by the company based on type of service and convenience of access to the meter. Where a meter is installed on a customer-owned pole, the pole shall be provided and maintained by the customer as required by the Canadian Electric Code and any other applicable legislation.

### 6.3 Meter Tests and Adjustments

The company may inspect and test a meter at any reasonable time.

At the request of a customer, the company shall arrange for on-site meter verification and if necessary, shall arrange for a meter to be tested by an official designated for that purpose by Consumer and Corporate Affairs Canada or such other federal government agency as may, from tome to time, be designated for the purpose.

If a test determines that the meter is not accurate within the limits set by government standards, the customer's bill will be adjusted accordingly. Where it is impossible to determine when the error commenced, it shall be deemed to have

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commenced three months before the test or on the date of the meter installation, whichever occurred later.

### 6.4 Energy or Demand Diversion

If under any circumstances, a person prevents a meter from accurately recording the total demand or energy supplied, the company may disconnect the service, or take other appropriate actions.

The company may then estimate the demand and amount of energy supplied but not registered at the point of delivery. The customer shall pay the cost of the estimated demand and energy consumption plus all costs related to the investigation and resolution of the diversion.

### 7 METER READING AND BILLING

### 7.1 Reading and Estimates

Customers' bills will be based on meter readings made by the company from time to time or on estimates for those billing periods when the meter is not read.

Whenever a bill is based on an estimate, an adjustment to reflect actual usage will be made after the meter is next read.

For small general service customers whose load requirements are small, consistent, and can be accurately predicted, the billing demand and the kW.h consumption shall be determined from the name-plate rating of the customer's equipment rather than being metered.

### 7.2 Proration of Initial and Final Billings

The amount of any initial and final charges, other than energy, may be prorated, based upon the ratio of the number of days that service was provided to a customer in the billing period to the total number of days in the billing period.

The company may elect not to charge a customer for the billing period if, during that period, demand was five kilowatts or less, service was provided for five days or less and energy consumption was five kilowatt hours or less.

For all new accounts, the company may add the charges for service provided during the initial period to the bill for the following billing period.

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### 7.3 Payment of Accounts

Payment of a bill for service is due and payable on the date indicated on the bill.

Failure to receive a bill does not release a customer from the obligation to pay the amount owing for any service provided by the company.

### 7.4 Late Payment Charge

The company shall add a late payment charge of 1% per month (effectively 12.68 % per annum) on any overdue amount. To avoid a late payment charge, payment of a bill for service must be made by the due date.

### 7.5 Dishonored Cheques

The company may add a service charge of \$20 to a customer's bill in respect of any cheque returned by the customer's bank for any reason.

### 8 SERVICE CHANGES

### 8.1 Notice by Customer

A customer shall give to the company reasonable prior written notice of any change in service requirements, including any change in load to enable the company to determine whether or not it can supply such revised service without changes to its facilities.

### 8.2 Responsibility for Damage

The customer shall be responsible for all damage caused to the company's facilities as the result of the customer changing service requirements without the company's permission.

### 8.3 Changes to Company facilities

If the company must modify its facilities to accommodate a customer load or service change, the customer shall pay for all costs in connection with such modification including the following costs:

- (a) the original capital cost of the existing facilities being removed, less accumulated depreciation, plus
- (b) the estimated cost of removing the existing facilities, less the estimated salvage value, less

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(c) any applicable increased company investment.

### 8.4 Load Management

When a customer satisfies the company that a capital investment has been made with the sole and express purpose of reducing the customer's peak demand for electricity, the customer will be deemed eligible for a ratchet relief. Ratchets from peak demands recorded before the agreed operational date of the demand control measures will be waived.

Demand reductions resulting from a reduction in output or services, or a change of product provided by the customers facilities, or the partial or complete closure of any of the customer facilities do not qualify for ratchet relief.

### 8.5 Forgiveness of New Peak Demands

The company will forgive new peak demands when:

- the new peak demand is the result of a company power outage which consequently required the simultaneous start of the customer's equipment. In this situation, the customer's normal demand will replace the new peak demand for billing purposes; or
- the new peak demand is the result of a fire, explosion or similar disaster at the customer's facility. In this situation, the new peak demand will be used for billing purposes for the billing period during which the new peak demand was established, but it will be waived for ratchet purposes for future bills.

### 9. COMPANY RESPONSIBILITY AND LIABILITY

### 9.1 Continuous Supply

The company shall make all reasonable efforts to maintain a continuous supply of energy to its customers, but the company cannot guarantee an uninterrupted supply of energy.

### 9.2 Planned Outages

The company reserves the right to interrupt, discontinue or reduce the supply of energy to any customer to allow for repairs and improvements to its facilities.

The company shall endeavor to give prior notice to customers who will have service interrupted and will endeavor to ensure that such interruptions are as short and infrequent as circumstances permit.

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### 9.3 Company Liability

The company shall not be liable for any loss, damage, expense, charge, cost or liability of any kind (excepting only direct physical loss, injury or damage to a customer or a customer's property, resulting from the negligent acts or omissions of the company, its employees or agents) arising out of or in any way connected with any failure, defect, fluctuation, reduction or interruption in the provision of service by the company to its customers. For the purpose of the foregoing and without otherwise restricting the generality thereof, "direct physical loss, injury or damage" shall not include loss of profits, loss of earnings, or any other similar damage or loss whatsoever, arising out of or in any way connected with the failure, defect, fluctuation, reduction or interruption in the provision of service to a customer.

### 9.4 Extraordinary Circumstances

Should the company be unable, because of extraordinary circumstances, to provide a continuous supply of energy to a customer, the company's responsibilities, so far as they are affected by the extraordinary circumstances, shall be suspended during the duration of such circumstances. Where practical, the company shall give notice to the affected customers of such extraordinary circumstances.

### 10. CUSTOMER RESPONSIBILITY AND LIABILITY

### 10.1 Provide Permit

The customer shall provide permits, licenses and authorizations prior to commencement of service or any change of service requirements at any point of delivery.

### 10.2 Customer Responsibility

The customer shall be responsible for the installation and condition of all facilities on the customer's side of the point of delivery, except metering or other equipment owned by the company.

The customer shall indemnify and save harmless the company from and against any claim or demand for injury to persons or damage to property arising out of or in any way connected with the use of the service so long as such injury or damage is not caused by the negligent acts or omissions or willful misconduct of the company, its employees and agents.

The customer shall be responsible for any damage to company facilities located on the customer's premises where the damage is caused by the negligent acts or

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omissions or willful misconduct of the customer or anyone permitted by the customer to be on the premises.

### 10.3 Protective Devices

The customer shall be responsible for determining whether he needs any devices to protect his equipment from damage that may result from the provision of service by the company. The customer shall provide and install any such devices.

### 10.4 Service Calls

The company may require a customer to pay the actual costs of a customer-requested service call if the source of the problem is the customer's own facilities.

### 11. TERMINATION OF SERVICE

### 11.1 <u>Customer-requested Termination</u>

Except where otherwise provided in a written agreement between the company and a customer, a customer may, at any time, give the company reasonable notice that he wishes to terminate his service. Upon receipt of such notice, the company shall read the customer's meter within a reasonable time, and, shall use its best efforts to read the customer's meter at the time requested by the customer. A customer shall pay for all service provided to the time of such reading.

A customer is responsible for all service provided until notice of termination is given and the meter is read.

### 11.2 Company Termination for Safety Reasons

The company may, without notice, terminate a customer's service where, in the company's opinion:

- the customer has permitted the wiring of his facilities to become hazardous;
   or
- (b) the wiring of the customer's facilities fails to comply with applicable law; or
- (c) the use of the service may cause damage to the company's facilities or interfere with or disturb service to any other customer.

The company will reconnect the service when the safety problem is resolved and when the customer has provided, or paid the company's costs of providing, such

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devices or equipment as may be necessary to resolve such safety problem and to prevent such damage, interference or disturbance.

### 11.3 Company Termination Other Than For Safety

The company, or anyone acting under its authority, may, upon giving at least 48 hours' notice to the customer, terminate the customer's service or install a current-limiting device to restrict the service to such customer if the customer:

- (a) violates any provision of these regulations or of the company's tariff;
- (b) tampers with any service conductors, meters, seals or any other facilities of the company;
- (c) neglects or refuses to pay the charges for service due to the company within 30 days of the date the bill for such service was rendered;
- (d) violates the provision of any contract or rate schedule applicable to the service;
- (e) changes service requirements without the permission of the company; or
- (f) makes fraudulent use of the service being provided.

### 11.4 Removal of Facilities

Upon termination of service, the company shall be entitled to remove any of its facilities located upon the property of the customer and to enter upon the customer's property for that purpose.

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### SCHEDULE A

### STANDARD SUPPLY SPECIFICATIONS

The Company's standard supply specifications, which are in accordance with Canadian Standards Association standard CAN-C235-83, are as follows:

### (a) Residential:

### 240/120 V - single phase, three wire

- overhead secondary conductors are supplied by the company
- for services less than 100 amps underground conductors are supplied by the company
- for services greater than 100 amps underground conductors are supplied by the customer

### (b) General Service:

### 240/120 V - single phase, three wire

- overhead secondary conductors are supplied by the company
- underground secondary conductors are supplied by the customer

### 208 Y/120 V - three phase, four wire

- overhead secondary conductors are supplied by the company
- underground secondary conductors are supplied by the customer

### 480 Y/277 V - three phase, four wire

- overhead secondary conductors are supplied by the company for loads 15 kV.A to 300 kV.A
- overhead secondary conductors are supplied by the customer for loads 300 kV.A to 1,500 kV.A
- underground secondary conductors are supplied by the customer

### 600 Y/347 V - three phase, four wire

- underground secondary conductors are supplied by the customer for loads 150 kV.A to 2,500 kV.A; and
- underground secondary conductors are supplied by the customer

### 4160 Y/2400 Y - three phase, four wire, 2,000 kV.A to 10,000 kV.A

- overhead secondary conductors are supplied by the customer
- underground secondary conductors are supplied by the customer

### (c) Oilfield:

### 240/120 V - single phase, three wire

- overhead secondary conductors are supplied by the company
- underground secondary conductors are supplied by the customer

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### 208 Y/120 V - three phase, four wire

- overhead secondary conductors are supplied by the company
- underground secondary conductors are supplied by the customer

### 480 Y/277 V - three phase, four wire

- overhead secondary conductors are supplied by the company
- underground secondary conductors are supplied by the customer; and

### 600 Y/347 V - three phase, four wire

- overhead secondary conductors are supplied by the company
- underground secondary conductors are supplied by the customer

### (d) Farm:

### 240/120 V - single phase, three wire

overhead secondary conductors are supplied by the customer; and

### 208 Y/120 V - three phase, four wire

overhead or underground secondary conductors are supplied by the customer.

NOTE: Other voltages may be available under this category.

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### SCHEDULE B

### MAXIMUM COMPANY INVESTMENT

- 1. (a) "capital cost" is defined as the estimated cost of materials, labor, expenses, and any other direct costs incurred by the company in extending service to a point of delivery.
  - (b) "annual costs" are defined as the fixed charges, including return, income tax, and depreciation pertaining to the facilities constructed to serve the customer plus costs of generating and transmitting and distributing electric energy to the customer, operating and maintaining facilities constructed to serve the customer and administrative and general costs incurred by the company in providing service to the customer.
- 2. Subject to the provisions of paragraph 3 and 4 of this Schedule "B", the maximum capital cost which the company will incur to extend service to a point of delivery (herein referred to as the "maximum company investment") shall be determined as follows:
  - (a) Residential Service (Rate Schedules 11 and 18):

\$790 per single family dwelling and \$600 per multiple dwelling based on an estimated service life of 30 years;

(b) <u>Small General Service (Rate Schedules 21)</u>:

\$280 per kilowatt of estimated billing demand, which shall not be less than five kilowatts, provided that if the estimated life is less than 25 years, then the maximum company investment shall be determined in the manner described in paragraph 3;

c) Irrigation Pumping (Rate Schedule 25):

\$65 per kilowatt of estimated billing demand, which shall not be less than five kilowatts, provided that if the estimated service life is less than 30 years, then the maximum company investment shall be determined in the manner described in paragraph 3;

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## (d) Large General Service/Industrial (Rate Schedule 31, with contractual billing demands less than 500 kilowatts):

The maximum company investment level will vary depending on the level of risk in the new extension which is determined by the length of contract the customer is willing to commit to:

Investment	Contractual
<u>Level</u>	<u>Period</u>
\$25/kW	1 year
\$80/kW	2 years
\$140/kW	3 years
\$230/kW	4 years
\$325/kW	5 years

The investment will be based on the contract minimum demand, which shall not be less than 50 kilowatts. If the load characteristics of the new service are expected to vary significantly from the norm, then the maximum company investment will be calculated in accordance with paragraph 3;

## (e) Large General Service/Industrial (Rate Schedule 31, with contractual billing demands greater than 500 kilowatts):

The first 500 kilowatts of contract minimum demand will be calculated as per 2(d) above. For contract periods of five years, the company will invest \$210 per kilowatt of contract demand greater than 500 kilowatts. If the contract period is shorter than five years, the \$210 per kilowatt investment will be prorated as per the table in 2(d) above. If the load characteristics of the new service are expected to vary significantly from the norm, the maximum company investment will be calculated individually for each new extension in accordance with paragraph 3;

### (f) Oilfield and Pumping Power Service (Rate Schedule 41):

The maximum company investment level will vary depending on the level of risk in the new extension which is determined by the length of contract the customer is willing to commit to:

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The investment will be based on the contract minimum demand, which shall not be less than four (4.0) kilowatts. If the load characteristics of the new

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service are expected to vary significantly from the norm, then the maximum company investment will be calculated in accordance with paragraph 3;

(g) Cathodic Protection and Rectifiers (Rate Schedule 41):

\$170 per kilowatt of estimated billing demand, which shall not be less than four (4.0) kilowatts, provided that if the service life is less than 15 years, then the maximum company investment shall be determined in the manner described in paragraph 3;

(h) Farm Service (Rate Schedule 56):

\$315 per kilovoltamperes of estimated billing demand, which shall not be less than three kilovoltamperes, provided, that if the estimated service life is less than 30 years, then the maximum company investment shall be determined in the manner described in paragraph 3; and

(i) Municipal Street Lighting & Private Lighting Service (Rate Schedules 61 & 63):

The company makes no investment.

- 3. In circumstances where the life, revenue or load characteristics of an extension is expected to substantially deviate from the norm, the company will calculate the maximum company investment based on the expected operating characteristics and length of service for the extension of service in question.
- 4. When a service upgrade or extension is required by a customer to allow a conversion to electric power and the cost of the service upgrade or extension is less than the maximum company investment available as determined by paragraphs 2 or 3, then a discretionary expenditure potential exists.

At the company's discretion, a portion of the difference between the cost of the upgrade or extension and the maximum company investment may be credited to the customer subject to all of the following conditions:

- a) the customer signs a new five (5) year electric supply contract at the minimum demand level commensurate with the maximum investment;
- b) the company is satisfied that the fuel conversion would not have been economically viable for the customer with any smaller credit;
- c) the company is satisfied that under prevailing system conditions the additional electric load will result in lower overall unit supply costs for all of the company's customers; and
- d) the fuel conversion is completed on or before December 31st, 1997.

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### SCHEDULE C

### CONDITIONS OF UNDERGROUND SERVICE

The company shall extend service by underground conductor lines upon and subject to the following terms and conditions ("developer" means the person or party who has requested the underground service):

- (a) No service is then available in the area to be served by such extension, and not less than 25 single family dwellings (or such lesser number as may be agreed to by the company) will be connected to such extension (the "underground service area"), each of which is situate upon a parcel of land where other single family dwellings in the underground service area are situate;
- (b) All permanent service in the underground service area shall be provided exclusively through underground conductor lines;
- (c) The developer shall provide, without cost to the company, such rights-of-way, easements, utility corridors and transformer locations as the company may require for the installation, operation and maintenance of such extension, which the developer shall keep free and clear of any buildings, structures, fences, pavement, trees or any other obstructions which may hinder the company in installing, maintaining or removing its facilities;
- (d) The company shall not be obligated to install such extension until it is reasonably satisfied that the extension will not thereafter be damaged or interfered with, and, in any event, any costs incurred by the company in relation to the relocation, reinstallation or as a result of damage to such extension shall be paid by the developer;
- (e) Service, for purposes other than residential use and street lighting, may be provided from such extension only with the consent of the company;
- (f) In relation to the underground service, the developer shall provide a meter socket and service conductor protection from sixty centimeters below grade level to the line side of the meter socket and will ensure that installation of a service having a 100 ampere capacity;
- (g) The developer shall provide to the company a certified copy of the registered plan of subdivision and final construction plans showing the location of sidewalks, curbs and gutters, and underground utilities together with such evidence as the company may reasonably require to the effect that all rules and regulations applicable to the development have been or will be compiled with by the developer.
- (h) Survey stakes indicating grades and property lines shall be installed and maintained by the developer;
- (i) The surface of the ground for a distance of not less than one point five (1.5) meters on each side of the alignments for the underground conductor lines shall be graded by the developer to within eight (8) centimeters of a final grade;

### DECISION E95102 SCHEDULE "B"

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- (j) Unless otherwise agreed to by the company, the developer shall provide a survey for the location of transformers, street light bases and cable routing, as required; and
- (k) Sidewalks, curbs and gutters may be constructed by the developer but not other permanent improvements shall be made until approved by the company.

In addition, the service shall be subject to such other conditions as may be specified by the company from time to time.

### APPENDIX 1

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APPENDIX 1

## ALBERTA POWER LIMITED 1993 GRA

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REVENUE/COST RATIOS AND PERCENTAGE INCREASES

			Per API		****		Per Board	ard		
	Revenues	Net Cost	Proposed	Rev/Cost	% Increase	Net Cost	Revenues	Rev/Cost	Rev/Cost % Increase	
n in Bate Schedule	On Existing Rates (Incl All Riders)	(Prop Rates)	Revenues )	Ratio (c/b)	Over Existing (c/a-1) (	(Appr. Rates)	(Appr. Hates)	Hatio (g/f)	Over Existing (g/a-1)	
	(a)	(q)	(c)	(p)	(e)	€	(B)	( <del>l</del> )	€	
1 Recidential Bate 11	61952	62888	62204	66	0.4%	62833	61951	66	0.0%	
2 Residential Bate 18	3532	4209	3546	84	0.4%	4206	3531	84	0.0%	
3 General Service Rate 21	48940	48084	49259	102	0.7%	48036	48942	102	0.0%	
4 Irrigation Rate 25	117	174	118	68	%6.0	174	118	68	0.8%	
5 Industrial Bate 31		181459	181789	100		181261	182202	101		
6 Date 31 - Clase III Interrintible		27894	33614	121		27894	33974	122		
7 Industrial Rate 31 - Sub Total	216209	209353	215403		-0.4%	209155	216176		0.0%	
8 Bate 33 - Beserve Frierry	8006	6498		137	-1.1%	6498	8909	137	-1.1%	
		2178	2717	125	%0.0	2178	2732	125	%9.0	
10 Bate 36 - Hisky Rainhow Ik		8262		88	-0.4%	8253	7344	83	%9.0	
11 Diffield Bate 41	30566	27414		112	0.6%	27389	30653	112	0.3%	
10 REA Farm Service Rate 51	13462	13485		100	0.5%	13468	13463	100	%0.0	
	21177	25755		83	0.4%	25734	21173	82	%0.0	
	3219	3739		87	0.6%	3737	3237	87	%9.0	
	160	856		89	0.5%	855	764	83	0.5%	
16 Internitible Repetit		9374				9749				
17 Growth in Unbilled Revenue		-3271				-3271				
18 Total	418961	418,998	419,000	100	0.0%	418,996	418,993	100	0.0	

Column Descriptions:
(a) from Tab 2, Schedule 4.3.1
(b) from Tab 7A, Schedule A, pp.7-8, after interruptible benefit sharing: growth in unbilled revenue from Schedule A p.8
(c) from Tab 2, Schedule 4.3.1
(d) after interruptible benefit sharing

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