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HAND DELIVERED

February 18, 2015

Board of Commissioners
of Public Utilities
P.O. Box 21040
120 Torbay Road
St. John's, NL A1A 5B2

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

Re: Newfoundland and Labrador Hydro's 2015 Interim Rates Application

A. Introductory

On January 28th, 2015, Newfoundland and Labrador Hydro ("Hydro") filed an application for interim approval of customer electricity rates to be effective March 1st, 2015 (the "2015 interim rates application"). The 2015 interim rates application is the third application for interim rates since the July 2013 original filing of Hydro's currently outstanding general rate application (the "general rate application").

In principle, Newfoundland Power does not oppose interim rates for Hydro. However, the interim rates proposed in the 2015 interim rates application are not, in Newfoundland Power's view, consistent with the reasonableness requirement of the *Electrical Power Control Act, 1994*.

This letter contains Newfoundland Power's submissions on Hydro's 2015 interim rates application.

B. Overview of the 2015 Interim Rates Application

The 2015 interim rates application seeks to implement the rates proposed in the general rate application, adjusted for a reduced forecast for the price of fuel used by Hydro, revised implementation of Hydro's Industrial Customers rate increase, and modifications to Hydro's rate stabilization plan ("RSP").[1]

[1] See the response to Request for Information TIR-PUB-NLH-001.

The general rate application indicates a revenue deficiency for Hydro in 2015 of $67.8 million.[2] The rates proposed in the 2015 interim rates application would provide full recovery of this revenue deficiency on an annualized basis.

The evidence filed in support of the 2015 interim rates application asserts that "Hydro's forecast income statement under existing rates shows a net loss of $34.6 million for 2015."[3] In addition, Hydro indicates that exclusion of "any" costs, or delays in implementation, will increase future rates to customers.[4] The 2015 interim rates application appears to assume that Hydro's assertion of a forecast loss for 2015 provides, in and of itself, sufficient justification for the Board to approve interim rates for Hydro's customers which are based on untested costs.[5]

Section 3 of the *Electrical Power Control Act, 1994* requires that electricity rates should be reasonable. A key attribute of reasonable rates is that they permit recovery of only those costs reasonably attributed to the provision of service to customers. Section 4 of the *Electrical Power Control Act*, *1994* directs that in setting electricity rates, the Board apply tests that are consistent with generally accepted sound public utility practice.

The Board has historically used tested costs to establish rates, even interim rates.[6] The use of tested costs ensures that the rates are reasonable. The costs which are included in the rates proposed in the general rate application have never been tested. This presents a challenge for the Board in determining reasonable interim rates.

Hydro asserts that a forecast 2015 loss provides sufficient regulatory justification for the Board's approval of the rates requested by Hydro in the 2015 interim rates application. This is not consistent with regulatory practice in this province or Canada generally. In determining the reasonableness of interim rates, Canadian regulators appear to look at factors in addition to any forecast utility revenue deficiency. Further, Hydro's 2015 rate base, costs and return reflected in the general rate application include amounts that are not reasonable for recovery in interim rates at this time.

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[2] In the response to Request for Information TIR-CA-NLH-001, Hydro states that the difference in forecast 2015 net income between proposed rates and existing rates is $67.8 million.

[3] See *2015 Interim Rates Application Evidence*, page 1, lines 8-9.

[4] See the response to Request for Information TIR-CA-NLH-001, page 4, line 1, *et. seq.*

[5] This is also evident in Hydro's responses to information requests. For example, the response to Request for Information TIR-CA-NLH-001 refers to a test used by the Alberta Utilities Commission ("AUC") to evaluate interim rates applications. This response, in evaluating the four factors used by the AUC to assess the quantum and need for a rate increase, appears to rely solely on Hydro's "forecast 2015 net income deficiency" to establish the quantum and need for the rate increase.

[6] See, for example, Order Nos. P.U. 34 (2007), P.U. 37 (2008), P.U. 1 (2009), P.U. 6 (2009), P.U. 25 (2010), P.U. 6 (2012), and P.U. 9 (2013) which approved interim rates for Hydro's island industrial customers for the period January 1, 2008 to August 31, 2013 (based on costs tested in Order No. P.U. 8 (2007)). Similarly, in Order No. P.U. 16 (1998-99), the Board made Newfoundland Power's customer rates interim following testing of the utility's cost of capital. The interim rates approved by the Board were based on a combination of (i) the tested cost of capital and (ii) other costs approved by Order No. P.U. 7 (1996-97).

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A review of (i) the costs Hydro proposes be recovered in interim rates and (ii) regulatory practice in other Canadian provinces should inform the Board in assessing the reasonableness of the rates proposed in the 2015 interim rates application.

C. Hydro's Costs Proposed to be Recovered in Interim Rates

In the 2015 interim rates application, Hydro seeks to have the Board approve rates based on the test-year costs proposed in the general rate application, adjusted for the cost of fuel. The general rate application seeks recovery of costs which have not been tested. Hydro's recovery of some of these costs in interim rates at this time would be contentious. For other costs, such as Hydro's increased return, recovery in interim rates at this time would be premature.

Since January 2014, the Board has been conducting an *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System* (the "supply investigation"). While the supply investigation has not concluded, the Board has indicated that it intends to review the prudency of over $200 million in Hydro expenditures. This review is outstanding. The rates proposed in the general rate application seek to recover both return and amortization in respect of some of those expenditures. Hydro has indicated that excluding the amortization and return on capital projects not approved for inclusion in its rate base and subject to prudency review would reduce the 2015 revenue requirement by $13.1 million.[7]

In the general rate application, Hydro proposes a fuel conversion rate for its Holyrood Thermal Generating Station of 607 kWh/bbl. This is inconsistent with longstanding practice. In Order Nos. P.U. 14 (2004) and P.U. 8 (2007), fuel conversion rates of 630 kWh/bbl were assumed for Hydro's Holyrood operations.[8] There is no clear evidence indicating why the lower fuel conversion rate proposed in the general rate application is reasonable. In fact, the lower fuel conversion rate appears contrary to the evidence.[9] Hydro has indicated that assuming a conversion rate of 630 kWh/bbl for Holyrood operations would reduce the 2015 revenue requirement by $7.2 million.[10]

In the general rate application, Hydro's evidence indicates that the government direction by which it would earn the same return on equity as Newfoundland Power was intended to take effect "…*following* Hydro's next [general rate application]" (emphasis added).[11] Hydro

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7 See the response to Request for Information TIR-NP-NLH-003.

8 The 630 kWh/bbl conversion rate approved in Order No. P.U. 8 (2007) was *agreed* to by Hydro in settlement negotiations.

9 See the response to Request for Information IC-NLH-093, Revision 1, lines 13-15 in the general rate application, where Hydro indicates the conversion rate is largely influenced by the level of loading of the Holyrood units. See Regulated Activities, Schedule V of Hydro's general rate application, where Hydro shows that 2015 forecast Holyrood production is forecast to be higher than 2007 test-year Holyrood production.

10 See the response to Request for Information TIR-NP-NLH-007.

11 See *Newfoundland and Labrador Hydro 2013 General Rate Application (Amended), Evidence, Section 1: Introduction*, page 1.27, lines 17-19.

proposes to earn this return in interim rates. The implementation of OC2009-063 will increase Hydro's return on rate base from that approved by the Board following Hydro's last general rate application. While the entitlement to an improved return on equity has been determined by OC2009-063, the timing of its recovery is clearly linked to the conclusion of the general rate application, not an interim application prior to the general rate application. Use of the improved return in the setting of interim rates prior to conclusion of the general rate application, would therefore be premature. Hydro has indicated that the improved return on equity resulting from the implementation of OC2009-063 in interim rates increases the 2015 revenue requirement by $23.1 million.[12]

All of these cost factors should be considered by the Board in establishing interim rates that are *reasonable* for both Hydro and those it serves.[13]

D. Indications of Canadian Regulatory Practice

Interim rates are used in a number of Canadian regulatory jurisdictions. Typically, regulators consider a variety of factors in evaluating requests for changes in rates on an interim basis.

A good summary of the factors considered by the Alberta Utilities Commission (the "AUC") can be found in the 2008 Alberta Utilities Commission decision in *Re ATCO Electric Ltd.*.[14] The AUC considers factors such as the materiality of any identified revenue deficiency, the possibility of excluding contentious costs from interim rate recovery, the need to preserve the financial integrity and safe operations of the utility, and rate design considerations.[15] Where costs are contentious, the AUC's primary objective is to determine a revenue requirement level,

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12 See the response to Request for Information PUB-NLH-056, Revision 1 in the general rate application. The improved return on Hydro provided by OC2009-063, in effect, reflects a combination of (i) a rate of return on equity equivalent to that granted to Newfoundland Power and (ii) a return on equity on investment in rural assets.

13 As a matter of perspective, there are significant cost reductions to Hydro's current 2015 test-year which will likely be required by the Board for ratemaking purposes but are not mentioned in this submission. For example, lower rate base and cash flow requirements associated with materially lower Holyrood fuel prices are not yet reflected in the 2015 test-year. See the response to Request for Information TIR-NP-NLH-008. Similarly, 2014 forecast capital expenditures totaling $38 million are included in the current 2015 test-year rate base for assets which were not actually in service at year-end 2014. See the response to Request for Information TIR-NP-NLH-011. In Newfoundland Power's view, adjustments of this magnitude are best left for consideration in the general rate application.

14 See *Re ATCO Electric Ltd*., 2008 CarswellAlta 2098.

15 Ibid, and see the response to Request for Information TIR-CA-NLH-001 which outlines the application of this AUC test in *ENMAX Power Corporation; 2015 Interim Distribution and Transmission Tariff Application* (Decision 2014-311). Also see *Re ATCO Gas Ltd*., 2005 CarswellAlta 2281, where the predecessor of the AUC considered that an effective approach which could be used by a utility to determine an appropriate level of interim rates is to look at areas which may be contentious and to exclude all or some portion of those amounts from the amount to be collected through interim rates. In this manner, the potential of over-collection from interim rates would be minimized, which would, in turn, reduce potential fluctuations to customers' rates.

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on an interim basis, that would mitigate against significant revenue over-collection during the expected term of the interim rate.[16]

In their consideration of interim rates, the AUC does not automatically provide a utility with full recovery of a proposed revenue requirement increase. For example, the AUC has granted only a portion of the revenue requirement increase proposed in the principal rate case where such an approach seemed reasonable.[17]

It appears that the Manitoba Public Utilities Commission (the "MPUC") also considers a number of factors in its consideration of interim rate requests. The MPUC also will permit only partial recovery of proposed revenue requirement increases on an interim basis where the circumstances indicate this is reasonable.[18]

The Board has, on a number of occasions, indicated the fundamental principles which guide it in regulatory decision-making, including decision-making relating to the rates charged by Hydro.[19] These principles assist the Board in balancing the interests of both consumers and the utilities that serve them. They also appear to broadly reflect the practice of the AUC and the MPUC in balancing the utility and consumer interests when determining interim rates.

Canadian regulatory practice appears to be consistent with the requirement in section 3 of the *Electrical Power Control Act, 1994* that interim rates must be reasonable from the perspective of both the utility *and* those it serves.

E. Newfoundland Power's Submission

Hydro's last general rate application was filed in 2006. Given the substantial passage of time, it is not surprising that the amended general rate application filed in November 2014 would have substantially different costs. In addition, significant outstanding events, including the Board's prudency review, may affect Hydro's future cost recovery. Finally, the length of time the

16 *AltaLink Management Ltd.*, Re, 2004 CarswellAlta 2064.

17 See *Re ATCO Electric Ltd*., 2008 CarswellAlta 2098, paragraph 24; although in that case ATCO Electric was granted 50% of the proposed increase in the transmission revenue requirement and only 25% of the proposed increase in the distribution revenue requirement on an interim basis (paragraph 25).

18 See *Re Manitoba Hydro*, 2011 CarswellMan 390, where Manitoba Hydro was granted a 2% rate increase on an interim basis after seeking a 2.9% increase.

19 See, for example, Order No. P.U. 7 (2002-2003), page 27 *et. seq.* and Order No. P.U. 14 (2004), page 22, *et. seq.* which considered Hydro's first two general rate applications. The principles identified by the Board included fair return, cost of service, fair cost apportionment, efficiencies, rate stability and predictability and a fair and reasonable end result.

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general rate application has been outstanding is extraordinary.[20] All of these matters complicate the Board's determination of interim rates which satisfy the reasonableness requirement of section 3 of the *Electrical Power Control Act, 1994*.

The 2015 Hydro costs proposed to be recovered by the 2015 interim rates application include a significant amount of costs that are subject to prudency review by the Board or are inconsistent with longstanding practice. In addition, the 2015 interim rates application proposes recovery of higher returns *in advance* of conclusion of the general rate application as opposed to *following* the general rate application as directed by OC2009-063. Exclusion of costs such as these in the establishment of interim rates appears consistent with Canadian regulatory practice.

Canadian regulatory practice indicates partial recovery of a forecast utility revenue deficiency in interim rates may be appropriate in certain circumstances. This helps ensure that costs which are not clearly appropriate for interim rate recovery are not borne prematurely by customers. It also mitigates against revenue over-collection during the time the interim rates are in effect.[21] This type of approach is consistent with the Board's expressed view of reasonableness as a balance of the interests of the utility and those it serves.[22]

In Newfoundland Power's submission, reasonable interim rates for Hydro would not be based upon full recovery of the costs outlined in **C. Hydro's Costs Proposed to be Recovered in Interim Rates** above. Exclusion of all, or part, of such contentious 2015 Hydro costs would ensure greater benefit from the reduced price of fuel would flow to Newfoundland Power's customers. The resulting rate decrease for Newfoundland Power's customers would be materially greater than the 6.3% decrease indicated by Hydro in the 2015 interim rates application.

Based upon the foregoing, the Board should not approve the interim rates proposed by Hydro in the interim rate application because the rates have not been shown by Hydro to be reasonable.

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20 The length of time since the July 2013 filing of the original general rate application has been attributable to a number of procedural considerations and developments. One was the length of time required by Hydro to respond to Requests for Information on the original general rate application. Another was the decision by Hydro a month before commencement of the hearing into the original general rate application to amend and re-file that application some five months later.

21 From 2007 to 2013, large balances accumulated in the RSP under Hydro interim rates. These balances were not distributed in accordance with the approved operation of the RSP which is based upon cost causation. Instead, the provincial government by OC2013-089 (as amended by OC2013-207) directed the credit of $49 million (or 30%) to Hydro's Industrial Customers notwithstanding those customers accounted for less than 10% of system load during the period. This direction effectively reduced the amount of the balance that would have flowed to Newfoundland Power's customers based upon the regulatory principles which underlie the operation of the RSP.

22 It is also consistent with the view expressed by the Newfoundland and Labrador Court of Appeal that the language contained in section 3 of the *Electrical Power Control Act, 1994* emphasizes the need for tempering each of the utility's and its customers' economic interests by consideration of the interests of the other. See the *Stated Case*, June 15, 1998, Docket: 96/141, paragraph 23.

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Instead, the Board should direct Hydro to create interim rates which exclude recovery of specified untested 2015 Hydro costs which the Board determines should not be included in interim rates. In the circumstances, this would satisfy the requirement in section 3 of the *Electrical Power Control Act, 1994* that interim rates must be reasonable from the perspective of both the utility *and* those it serves.

F. Concluding

A copy of this letter, together with copies of the regulatory decisions from other provinces referred to in it, has been forwarded directly to the parties listed below.

If you have any questions regarding the enclosed, please contact the undersigned at your convenience.

Yours very truly,

Gerard M. Hayes
Senior Counsel

Enclosures

c. Geoffrey Young
Newfoundland and Labrador Hydro

Paul Coxworthy
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Yvonne Jones, MP
Labrador

Genevieve M. Dawson
Nunatsiavut Government

2004 CarswellAlta 2064
Alta. E.U.B.

AltaLink Management Ltd., Re

2004 CarswellAlta 2064

AltaLink Management Ltd. and TransAlta Utilities Corporation, 2004-2005 Interim Transmission Tariff

B.T. McManus Member, Gordon J. Miller Member, and R.G. Lock Presiding Member

Judgment: June 2, 2004
Docket: 2004-046

Subject: Public

Related Abridgment Classifications

For all relevant Canadian Abridgment Classifications refer to highest level of case via History.

Headnote

Public law --- Public utilities — Operation of utility — Rates — Approval

Table of Authorities

Cases considered by *B.T. McManus Member, Gordon J. Miller Member, and R.G. Lock Presiding Member*:

AltaLink Management Ltd., Re (2002), 2002 CarswellAlta 1955 (Alta. E.U.B.) — considered

AltaLink Management Ltd., Re (2003), 2003 CarswellAlta 2042 (Alta. E.U.B.) — considered

AltaLink Management Ltd., Re (2004), 2004 CarswellAlta 2031 (Alta. E.U.B.) — considered

AltaLink Management Ltd., Re (2004), 2004 CarswellAlta 2048 (Alta. E.U.B.) — considered

Statutes considered:

Electric Utilities Act, S.A. 2003, c. E-5.1
s. 37(1) — pursuant to

s. 119(1) — pursuant to

Regulations considered:

Electric Utilities Act, S.A. 2003, c. E-5.1
Liability Protection Regulation, Alta. Reg. 66/2004

Generally — referred to

Subject:

***B.T. McManus Member, Gordon J. Miller Member, and R.G. Lock Presiding Member*:**

1 Introduction and Background

1 On March 11, 2004, pursuant to sections 37(1) and 119(1) of the *Electric Utilities Act (EU Act)*, AltaLink Management Ltd. (AltaLink), in its capacity as General Partner of AltaLink, L.P. (ALP), and TransAlta Utilities Corporation (TransAlta)

applied to the Alberta Energy and Utilities Board (EUB or Board) for approval of Transmission Facility Owner (TFO) tariffs, for each of AltaLink and TransAlta, on an interim and refundable basis and for terms and conditions of service (T&C), on an interim basis, both to take effect on May 1, 2004 (Interim Applications).

2 Previously, on February 27, 2004, AltaLink and TransAlta (the Applicants) applied to the EUB for approval of TFO tariffs and terms and conditions of service for May 1, 2004 to December 31, 2007 (2004-2007 GTAs). In a Notice, dated March 22, 2004, the Board established a process and schedule for dealing with the 2004-2007 GTAs, which includes an oral hearing commencing on September 21, 2004. Given the timing of the GTA hearing, the Board's final disposition of the 2004-2007 GTAs will likely not occur until sometime in the first part of 2005.

3 The Applicants' current tariffs, which were finalized and approved in Decision 2004-028, dated March 23, 2004, expire on April 30, 2004. Decision 2004-028 [*AltaLink Management Ltd., Re*, 2004 CarswellAlta 2048 (Alta. E.U.B.)] dealt with AltaLink's Second Refiling, which was required as a consequence of Decision 2003-061 [*AltaLink Management Ltd., Re*, 2003 CarswellAlta 2042 (Alta. E.U.B.)] respecting AltaLink's 2002/03 and 2003/04 GTA and Decision 2004-007 [*AltaLink Management Ltd., Re*, 2004 CarswellAlta 2031 (Alta. E.U.B.)] , respecting AltaLink's First Refiling. The tariff expiration date and the 2004 — 2007 GTA schedule necessitated the filing of the Interim Applications.

4 In recognition of the interim refundable nature of the applied-for TFO tariffs and the requirement for new AltaLink and TransAlta transmission tariffs to take effect from May 1, 2004, the Board established the expedited process and schedule set out below to deal with the Interim Applications.

5 *Table 1. Schedule for AltaLink and TransAlta 2004 Interim Transmission Tariff Applications*

Process Step	***Date***
Information Requests to Applicants	April 8, 2004
Information Responses from Applicants	April 16, 2004
Intervener Submissions	April 23, 2004
Reply Submissions	April 30, 2004

6 The Board considered that this process provided sufficient time for the Board to render a decision on the Interim Applications prior to the Applicants issuing an invoice to the Alberta Electric System Operator (AESO) for transmission services for the month of May 2004.

7 On April 7, 2004, the Board received correspondence from the Industrial Power Consumers Association of Alberta (IPCAA) respecting the Interim Applications. On April 23, 2004, the Board also received submissions from the City of Calgary (Calgary) and the FIRM Group of Customers (FIRM)[1] respecting the Interim Applications.

8 In accordance with the schedule, AltaLink filed its Reply Submission on April 30, 2004. TransAlta did not file a Reply Submission.

9 After review of the filed submissions, the Board determined that it required additional information to assist in its deliberations. The Board sent a supplemental Information Request (IR) to AltaLink on May 13, 2004, and requested AltaLink

to provide a response by May 17, 2004.

10 The Board received AltaLink's response to the supplemental IR on May 17, 2004 and, therefore, considers the record of the Interim Applications to have closed on that date.

2 Details of the Applications

2.1 AltaLink Interim Application

11 AltaLink originally proposed to invoice the AESO the following monthly TFO charges on an interim refundable basis for use of AltaLink's transmission facilities:

- $15,640,000.00 per month for the 8-month period commencing May 1, 2004 and ending December 31, 2004.
- $17,908,139.00 per month for the period commencing January 1, 2005 and continuing thereafter until the Board renders a final decision on AltaLink's 2004-2007 GTA, or upon further order of the Board.

12 AltaLink explained that at the time of the filing of its Interim Application, interim tariffs reflecting dated parameters had been in effect for AltaLink for 15 months and the decision in respect of AltaLink's refiling application was pending. In addition, AltaLink had filed an application for review and variance of Decision 2003-061 (R&V Application) and was uncertain as to the prospect for, or scope of, any review of that decision.

13 With these uncertainties, and the time required from the filing of 2004-2007 GTA to final tariffs, AltaLink determined that it was appropriate to request interim tariffs for the 2005-2007 period that reflected an average of the revenue requirements for each of the years during the period.

14 When AltaLink filed its Information Responses on April 16, 2004, it advised the Board that on March 31, 2004, the *Liability Protection Regulation* (AR 66/2004) came into force and provided TFOs with liability protection from consequential losses. AltaLink indicated that, as a result of the promulgation of AR 66/2004, the $4 million forecast cost of insurance premiums relating to the $1.1 billion layer of third party liability insurance for the 2005, 2006 and 2007 test years was no longer necessary.

15 As noted, subsequent to the filing of AltaLink's Interim Application, the Board rendered Refiling Decision 2004-028 finalizing AltaLink's rates for the 2003/2004 period, subject only to any adjustments that might flow from the Board's ultimate disposition of AltaLink's R&V Application.

16 AltaLink also noted that interveners have raised concerns respecting AltaLink's use of an average of the forecast revenue requirements for the 2005-2007 period as the requested interim rate commencing January 1, 2005.

17 In light of these circumstances, AltaLink amended its Interim Application in its April 16, 2004 IR response letter by requesting that the Board approve monthly interim refundable AESO transmission charges in the amount of:

• $15,640,000.00	May 1, 2004 through December 31, 2004
• $16,208,000.00	January 1, 2005 through December 31, 2005
• $17,650,000.00	January 1, 2006 through December 31, 2006
• $18,867,000.00	January 1, 2007 through December 31, 2007

18 AltaLink proposed that the amended monthly interim AESO charges continue until such time as the Board renders a final decision on the 2004-2007 GTAs, or upon further order of the Board.

19 AltaLink also requested that the Board approve, on an interim basis, the use of AltaLink's currently approved T&C effective May 1, 2004 and continuing in effect until final terms and conditions are approved for AltaLink when the Board renders a final decision on the 2004-2007 GTAs, or upon further order of the Board.

2.2 TransAlta Interim Application

20 With respect to the use of certain assets located on First Nations lands that were not transferred to AltaLink (Withheld Assets), TransAlta proposed to invoice the AESO the following monthly TFO charges on an interim refundable basis:

- $268,875 per month for the 8-month period commencing May 1, 2004 through December 31, 2004.
- $293,390 for the period from January 1, 2005 to December 31, 2007, or until the Board renders a final decision on TAU's 2004-2007 GTA, or upon further order of the Board.

21 TransAlta explained that the revenue requirement was higher relative to the interim ones in place at the time of the filing of its Interim Application because of increasing levels of capital maintenance and higher operating costs in the forecast test period. TransAlta confirmed that its revenue requirement forecast was tied to AltaLink's forecast for increases in operating expenses and capital maintenance and a number of other financial factors.

22 At the time of filing of its Interim Application, TransAlta expected its last approved T&C to be supplanted when it received the Board's final refiling approvals under Decision 2003-061. Accordingly, TransAlta requested that the interim relief provide that (i) TransAlta's existing T&C remain in effect as of May 1, 2004 as interim unless (ii) if prior to May 1, 2004, new T&C for TransAlta are otherwise approved by the Board, then such new T&C become TransAlta's interim T&C effective May 1, 2004.

3 Views of the Interveners

Views of Calgary

23 Calgary submitted that there were numerous areas of contention in AltaLink's 2004-2007 GTA filing and that these areas remain untested. In Calgary's view, amounts pertaining to contentious issues should be excluded in whole or in part. That is the practice that was adopted by other utilities and that is the practice that would be consistent with the Board's

rulings with respect to AltaLink's previous interim application in 2002.

24 With respect to rate of return, Calgary stated that the current risk free rate is lower than when Decision 2003-061 was rendered and suggested that a 9.0% rate would be reasonable. Calgary submitted this, coupled with the current 66:34 debt to equity ratio, would reduce the annual revenue requirement by $12-13 million, using AltaLink's schedules.

25 Calgary noted AltaLink had acknowledged that its cost of debt has been reduced as a result of refinancing its $125 million Real Return Bridge Bond as of December 2003. The financing rate has been reduced from 6.7% to 5.288%. Based on a differential between these two rates of approximately 140 basis points, and a debt amount attributable to the book value of regulated transmission assets in excess of $100 million, Calgary claimed the impact on a reduced revenue requirement would be a minimum of $0.6 million.

26 Calgary noted that the income tax rate for Alberta had been reduced to 11.5%. Using the new rate, Calgary calculated the revenue requirement impact to be approximately $0.5 million, on a 12-month basis.

27 Calgary further noted that AltaLink had requested a $12.1 million, or 35%, increase in operating and maintenance expense (O&M). Calgary suggested a conservative approach would be to consider, at a maximum, 50% or $6.0 million of AltaLink's forecast increase in operating costs, in the context of the Interim Application. Underlying the increase were numerous contentious issues, including, but not limited to, non-arm's length transactions with affiliates, compensation, staff counts and inflation. It would not be prudent to consider any more of the O&M increase than that suggested above, and Calgary maintained it was arguable that even that amount may be overly generous given the circumstances.

28 With respect to capital expenditures, Calgary noted that AltaLink had attempted to make a case for unprecedented additions to rate base. The impact on revenue requirement was approximately $8.0 million in 2004 [annualized], accounting for over 5% of the revenue requirement increase. Calgary submitted there might be some component of the capital projects that will be necessary to preserve the safety and reliability of the system and provide assurance, on an interim basis, of financial integrity for the applicant. In Calgary's view, for the purposes of setting interim rates, one half of the capital expenditures forecast by AltaLink would likely achieve those objectives, reducing the revenue requirement impact by $4.0 million.

29 Calgary also noted that the depreciation update had caused an $8.0 million increase to depreciation expense in the requested revenue requirement, maintaining that none of this was associated with the change in net salvage rates. Calgary claimed the depreciation impact was not an amount related to net income and would not affect the return to its owners. As such it should have little or no bearing on the financial integrity of the Applicant. Therefore, in Calgary's view, exclusion of revenue requirement impact due to depreciation should not be considered a financial hardship.

30 Based on the foregoing analysis and summary of the key contentious issues, Calgary maintained that the difference between the requested increase and the amounts associated with contentious areas was not significant. Calgary submitted the Board should not award AltaLink an interim increase in rates, and that the existing rates should remain in place on an interim refundable basis. Calgary's suggested adjustments are summarized in Table 3.

31 Calgary submitted that no increase should be granted to TransAlta either, as its request was based upon a pro-rata share of AltaLink's costs.

Views of FIRM

32 FIRM noted that in determining the level of the 2003 Interim Transmission Tariffs, the Board considered it appropriate and prudent to examine the areas which would be vigorously contested to determine whether reductions to the applied for revenue requirement were warranted. FIRM submitted that the circumstances of the Interim Applications are substantially comparable and that a similar approach to determining interim rates should be adopted by the Board, maintaining that the Board should examine the areas that would be vigorously contested to determine whether reductions to the applied for revenue requirement were warranted in an attempt to get the interim rates as close as possible to the final rates.

33 FIRM acknowledged that the Board had recently agreed to hear the R&V with respect to a number of matters arising from Decision 2003-061, but argued a Board Order was still in effect and that these matters should therefore not be allowed in interim TFO rates. FIRM therefore submitted that the 25% of the income tax component and Large Corporations Tax related to Ontario Teacher Pension Plan Board (OTPPB or Teachers) be excluded. FIRM estimated the impact of this adjustment to be $4.7 million.

34 FIRM noted that AltaLink had asked for a 10.5 % return on equity and a 37.5% equity ratio, in contrast to the 9.4% return on equity and 34% equity ratio allowed in Decision 2003-061. FIRM suggested that the lower amounts were adequate placeholders for interim rate purposes and estimated the impact of reducing the rate of return, including tax effects, to be $4.5 million. The impact of reducing the equity ratio was estimated to be $4.2 million, including tax effects.

35 FIRM also noted that AltaLink had a depreciation update completed as part of its discontinuation of the constant dollar net salvage (CDNS) methodology for the salvage component of depreciation. AltaLink claimed that this study indicated the composite depreciation rate should increase from 3.01% to 3.63%. FIRM submitted the reasons for these changes must be reviewed in the Phase I portion of the 2004-2007 GTA proceeding and should not be included on an interim basis without further testing. FIRM maintained that the previously approved composite depreciation rate should be used as a placeholder for interim rate purposes and that this non-cash item should not impact AltaLink's financial integrity. The estimated impact of maintaining the current composite depreciation rate, including the income tax and rate base effects, was approximately $13.3 million on an annualized basis.

36 With respect to O&M Expenses, FIRM noted that in refiling Decision 2004-007, the Board approved operating expenses of $35.5 million for the 2003/2004 test year while AltaLink has forecast $30.9 million for 8 months in 2004 (which equated to $46.4 million on an annualized basis). This represented a 31% increase over the 2003/2004 approved operating expense. FIRM submitted this situation was not unlike the previous interim application when AltaLink forecast a 33% increase in operating expenses. FIRM stated that until this significant operating expense increase could be fully tested it would be appropriate to reduce the increase in operating expenses by at least 50% or $7.6 million based on the same rationale relied upon in interim Decision 2002-110 [*AltaLink Management Ltd., Re*, 2002 CarswellAlta 1955 (Alta. E.U.B.)].

37 FIRM also proposed certain other adjustments. FIRM noted the opening balance of property, plant and equipment for the 8 month period May to December 2004 appeared to be overstated by about $8 million. Return, taxes and depreciation on this amount would overstate the 2004 annualized revenue requirement by $1.0 million. FIRM also noted AltaLink had

over-estimated total capital projects excluding direct assigns by 6.5% in 2002/2003. Absent further evidence with respect to 2003/2004, FIRM submitted it would not be unreasonable to reduce forecast additions for 2004 annualized by a similar amount for interim purposes. FIRM submitted return, taxes and depreciation on this amount or approximately $0.5 million should be deducted from the applied for interim rates. Finally, FIRM noted the Alberta corporate tax rate had been reduced to 11.5%. As AltaLink had not used this rate, revenue requirement was overstated by a further $0.4 million.

38 FIRM's proposed adjustments are summarized in Table 3. FIRM noted that with its proposed adjustments the revised monthly tariff for the period May-December 2004 corresponded almost exactly to the existing monthly tariffs approved in refiling Decision 2004-028. FIRM submitted that based on the foregoing, the Board should set the interim tariff commencing May 1, 2004 at the existing approved monthly tariff of $12.5 million per month.

39 FIRM further submitted that no increase should be granted to TransAlta, as TransAlta's request was largely based upon a percentage of AltaLink's.

Views of IPCAA

40 IPCAA did not propose specific reductions to AltaLink's requested interim rates, stating that AltaLink had failed to discharge the onus on it to show its applied for costs are reasonable, and/or that it will suffer financial hardship if not granted interim rates above current levels. IPCCA submitted the proposed O&M increases were not supportable and were excessive, expressing similar concerns with respect to the significant increases in capital costs and maintenance. Additionally, the "placeholders" used for rate of return and the equity levels were not supportable given the current financial conditions, interest rates, and the low risk levels of TFOs.

41 IPCCA maintained financial hardship had not been shown and the Board should award interim rates at current levels.

4 Altalink Reply Submission

42 AltaLink stated that in its 2004-2007 GTA, Interim Application, and Information Responses, it had provided detailed reasons, explanations of cost drivers and supporting facts for the revenue requirement increase requested in its Interim Application. AltaLink maintained that adequate amounts of sustaining and replacement capital were critical to ensure the operational integrity of AltaLink's aging transmission system.

43 AltaLink noted that factors well known to the Board and beyond AltaLink's control were contributing significantly to the increase in forecast revenue requirement. AltaLink noted it was already incurring or committing to incur costs without being compensated for such costs through the current tariff and claimed this was a demonstration of financial hardship.

44 AltaLink disputed Calgary's claims regarding the $125 million debt issue, noting that if one referred to Schedule 8.2 of refiling Decision 2004-007 Refiling, the embedded cost rate for the $125 million debt had an opening balance of 4.99% and a closing balance of 6.68%. Under the mid-year methodology, the effective cost rate is the average of the opening and the closing cost rates and the opening balance was not restated to be the same as the closing balance.

45 In response to Calgary's comments that AltaLink did not address the proposed reduction in the Alberta income tax rate proposed in the latest Alberta Government Budget, AltaLink cited its response to CAL.AML-005 a-b, which indicated that the proposed 2004 Budget is the subject of Bill 27 which received first Reading in the Alberta legislature on March 31, 2004, prior to the legislature's spring break. As Bill 27 had not yet been passed by the Alberta legislature and proclaimed in force at the time of filing, the corporate income tax rate in Alberta remained at 12.5%

46 AltaLink considered FIRM's suggestion to reduce gross labour by 50% until operating expenses can be fully tested to be unfounded and unreasonable. AltaLink submitted that an arbitrary 50% reduction in gross labour would directly impact both capital and operating work planned by an equivalent amount. AltaLink stated it would have to defer planned operating maintenance work, such as brushing, substation and line inspection, routine breaker and transformer maintenance and associated planned capital projects, including line and substation relay replacements.

47 AltaLink replied to Calgary's suggestion that 50% be cut from the capital forecast, by noting that Calgary was not prepared to identify which of the capital maintenance projects Calgary considered to be unnecessary to maintain the safety and reliability of the transmission system or which of the direct assigned projects Calgary considered unnecessary for AltaLink to undertake. AltaLink again stated that the forecast capital maintenance was required to maintain the safety and reliability of the system.

48 AltaLink noted that FIRM had questioned the employee incentive plan because it was partially linked to capital additions. AltaLink wanted the Board to clearly understand that capital projects were undertaken as a result of direct assignments from the AESO or to ensure the prudent, safe and reliable operation of the transmission system, stating it was important to customers that employees be motivated to complete projects within budget and on time.

49 AltaLink also noted that Calgary had recommended that the increase in depreciation expense be disallowed; claiming that the depreciation impact was not an amount related to net income and would not affect the return to its owners. AltaLink stated that Calgary's assertion was wrong, pointing out that depreciation was not neutral from the perspective of cash flow to the utility. AltaLink explained depreciation is capital that is recovered and is used to finance new capital additions required by the utility. The less depreciation recovered, the more that has to be borrowed.

50 Finally, AltaLink responded to FIRM's concern over the balance in the property, plant and equipment account. FIRM had noted the actual closing balance for 2002/2003 property, plant and equipment was $1,493.0 million as compared to the forecast of $1500.9 million in the GTA. AltaLink explained that FIRM had made an incorrect comparison. The $1500.9 million (line 19, column (e) of Schedule 7.9 included $10.4 million of computer software whereas the $1493.0 million did not include the computer software. Computer software was included in rate base through necessary working capital and appeared on Schedule 7.9 for the purposes of capital continuity only. AltaLink claimed the correct comparison was from line 15 of Schedule 7.9, column (e) that shows $1490.5 million, which can be compared to $1493.0 million shown in the Report on Operations.

5 Views of the Board

51 The Applicants' applied-for 2004, 2005, 2006 and 2007 interim rates are based on their 2004-2007 GTAs and are substantially higher than their revenue requirements and rates approved in Decision 2004-028.[2]

52 AltaLink expects its revenue requirement over the May 1, 2004 to April 30, 2005 (Next Year) to be 26.5 % more than the currently approved annual revenue requirement of $150.1 million. The increase is attributable to five major areas in the percentages shown in Table 2.

53 *Table 2. AltaLink's Comparison of its Forecast Revenue Requirement for May 1, 2004 through April 30, 2005 with its 2003/04 Approved Revenue Requirement*

Forecast increase attributable to:	*Amount of Increase ($ Million)*	*% Increase*
Growth in Rate Base	8.0	5.3
Return and Taxes	9.5	6.3
Depreciation Technical Update	8.0	5.4
Operating Expenses	12.1	8.1
Insurance & Other	2.2	1.5
Total	39.8	26.5

54 Each of Calgary, FIRM and IPCAA submitted that the Board should approve the continuation of the tariff approved in Decision 2004-028 on an interim refundable basis. They contend that AltaLink's requested rates are unreasonable, given the amount of untested areas of the 2004-2007 revenue requirement on which the applied for interim rates are based. In coming to their conclusions that the currently approved rates should continue on an interim refundable basis, each of Calgary and FIRM reviewed various elements of AltaLink's applied for annual revenue requirements and substituted values that they considered to be more reasonable. In the end result, Calgary and FIRM's estimates of the monthly forecast revenue requirement were not significantly different than the currently approved monthly AESO charges. Table 3 summarizes the various reductions proposed by Calgary and FIRM.

55 *Table 3. Summary of Adjustments Proposed by Firm and Calgary ($ Millions)*

Description of Adjustment	*Calgary*	*FIRM*
Reduction in allowed rate of return	12.0	4.5
Reduction in allowed equity ratio		4.2
Elimination of income tax allowance for Teachers		4.7
Reduction to depreciation expense	8.0	13.3[3]
Reduction in O&M expense	6.0	7.6
Reduction in Alberta tax rate	0.5	0.4
Capital expenditures	4.0	0.5
May 2004 opening balance to PP&E		1.0
Insurance	2.0	
Debt interest adjustment	1.0	

56 To support their argument for a continuation of the currently approved rates on an interim refundable basis, each of Calgary, FIRM and IPCAA submitted that AltaLink has not shown that it would suffer financial hardship if the applied for higher interim rates were not approved.

57 In the Board's view, Decision E92036 and Decision 2002-110 established a reasonable and similar framework for setting an appropriate interim rate that would be in effect until a final decision on the Applicants' 2004-2007 GTA could be rendered.

58 In Decision E92036, the Board acknowledged that one approach would be to review those particularly contentious

areas with a view to reducing the applied for amounts with the objective of mitigating what would otherwise be an over collection of revenues during the period in which interim rates would be in effect.

59 In Decision 2002-110, which dealt with the Applicants' interim tariffs for 2003, the Board examined a number of areas in which the Applicants and interveners held widely differing views on the level of forecast revenue requirement. The Board then determined whether reductions to the applied for revenue requirement were warranted. The primary objective was to determine a revenue requirement level, on an interim basis, that would mitigate against significant revenue over collection during the expected term of the interim rates.

60 Given the nature of the interveners' submissions in this proceeding and the significant increases in revenue requirement requested by the Applicants, the Board considers that it would be prudent in this instance to use an approach similar to that adopted in Decision 2002-110 to determine an appropriate interim tariff. Accordingly, the Board will examine the Interim Applications in the areas that are likely to attract much attention and debate in the 2004-2007 GTA review and hearing (Contentious Areas). For the most part, these areas represent the components of the revenue requirement where material cost increases are forecast to occur.

61 When determining whether changes to the applied for amounts in the Contentious Areas should be made for the purposes of the interim calculation, the Board will assess the likelihood and the magnitude of the applied for material cost increases that AltaLink has forecast to occur while the interim tariff is expected to be in effect. The Board considers that where material cost increases in the Contentious Areas appear probable, it is desirable to include those costs in AltaLink's transmission rates sooner rather than later to ensure that the customers who receive the service are the ones that actually pay for it. Including material and probable cost increases in interim rates also serve to provide proper price signals to the customers receiving the service. Furthermore, it enables better management of costs and revenues over the interim period, thereby reducing the possibility of financial hardship and excessive cost of interim borrowings to AltaLink.

62 The Board will also assess whether any reductions to the applied for amounts are likely to result in financial hardship to the Applicants or impact their ability to provide safe and reliable transmission services to the AESO for the benefit of all Albertans when making its determinations. However, in the event that AltaLink, as the operator, believes that certain expenditures are mandatory to maintain service reliability, even in the face of interim rates that the Board has determined appropriate, then AltaLink, as the operator, must decide how best to proceed and then rely on the subsequent processes to justify its actions.

63 The Board will now examine each of the major areas where costs are forecast to increase significantly and will determine how much of the forecast revenue requirement increase AltaLink should be allowed to recover on an interim refundable basis, pending a final decision on the 2004-2007 GTAs. However, the Board will first address the period of time during which the interim rate and T&C are expected to be in effect.

5.1 Expected Duration of Interim Rate and T&C

64 The Applicants have requested interim tariffs for the May 1, 2004 to December 31, 2007 period, or until such time as a final decision on their 2004-2007 GTAs is rendered, or upon further order of the Board.

65 In the Board's view, the current schedule for the 2004-2007 GTAs should result in the completion of the evidentiary part of the proceedings by the end of 2004. On this basis, the Board expects that a final decision on the 2004-2007 GTAs would be rendered by June 30, 2005 at the latest. Therefore, the interim tariffs that result from this Decision will likely only be necessary for about 12 to 14 months.

66 Therefore, the Board considers that the term of the interim tariffs should be no longer than May 1, 2004 to June 30, 2005 period (Interim Term). Should more time be needed to render a final decision on the 2004-2007 GTAs, the Board believes that a short extension to the Interim Term could be easily accommodated.

67 For ease of comparison with the last approved May 1, 2003 to April 30, 2004 fiscal year, the Board will focus on the forecast revenue requirement for the Next Year, but will set interim tariffs for the Interim Term. In the Board's view, setting tariffs for the Interim Term would reduce, and possibly eliminate, the need to set new interim rates in 2005.

5.2 Growth in AltaLink Rate Base

68 AltaLink has forecast its rate base to increase by $235.5 million from May 1, 2004 to December 31, 2007.

69 Projects directly assigned from the AESO to serve projected load and generation growth contribute to approximately 61% of the applied for increase to rate base; replacement of aging assets through capital replacement projects accounts for 13% and the remaining 26% is attributable to sustaining projects, new technology projects, and IT projects. AltaLink has stated that the forecast growth is occurring already and is significant when measured against the past number of years.

70 Higher rate base is reflected in the revenue requirement forecast through increased returns, depreciation and income taxes. AltaLink has forecast increases in these revenue requirement components over the Next Year to be $3.7 million for increased return, $3.9 million for depreciation, and $0.3 million of income tax expense respectively for a total of $8.0 million.

71 For the 14-month Interim Term, AltaLink estimated that the revenue requirement would increase by $35.2 million.

72 It should be noted that the Interim Term consists of 14 months as compared to the 12 months contained in the Next Year period. Because of the two additional months in the Interim Term, comparisons of forecast revenue requirement increases over the Next Year and the Interim Term to the last approved 2003-2004 fiscal year can be misleading. Forecast revenue requirement over the 14-month Interim Term when compared to the last approved 12-month 2003-2004 fiscal year must include amounts for all revenue requirement components for the additional two months. In contrast, for the Next Year comparison, because the two periods are the same, only incremental forecast revenue requirement related to increased returns, depreciation and income taxes are included. This explains why the Interim Term increases are significantly higher than the Next Year increases.

73 While recognizing that some components of the capital projects are necessary for safety and reliability purposes, Calgary has suggested that only half may fall into this category and recommended a $4 million annual reduction to

AltaLink's requested revenue requirement. Calgary has also questioned the accuracy of AltaLink's forecast and noted that AltaLink has at its disposal a deferral account mechanism for projects that it is required to build.

74 AltaLink has defended its forecast, observing that its previous forecasted increase in net plant was $41.5 million for the period in question[4] compared to the actual increase for that same period of $42.1 million.[5] AltaLink stated that it executed its capital projects not knowing what the Board would ultimately approve and came within 1.5% of forecast.

75 For purposes of this interim decision, the Board accepts AltaLink's statement that significant growth in rate base is already occurring and assumes that the aforementioned rate base cost drivers and their proportionate share of contribution to the increased revenue requirement over the May 1, 2004 to December 31, 2007 period will also be applicable in the Next Year. The Board is of the view that the lack of recent major additions to the bulk transmission system and the new Transmission Development Policy being developed by Alberta Energy will both contribute to the demand for new transmission facilities.

76 Calgary's suggestion that allowed capital expenditures be reduced by 50% is arbitrary and may cause AltaLink operational difficulties in determining capital expenditure priorities. The bulk of AltaLink's capital forecast is the result of direct assignments from the AESO. In the Board's view, these projects have a high probability of proceeding since they are underpinned by EUB applications in which the AESO would have justified the need for the projects. Therefore, for interim rate making purposes, the Board will consider that, at a minimum, this portion of the forecast rate base increase will occur and is needed for the reliable operation of the provincial transmission network. The Board recognizes that, while it may be desirable to do, it is not absolutely critical or urgent to ensure that the associated revenue requirement increases be precisely recovered through interim rates over the Next Year because the direct assigned capital projects are subject to a deferral account mechanism.

77 The Board's preliminary review of AltaLink's capital maintenance/upgrade forecast and AltaLink's recent forecasting accuracy persuade the Board that the majority of the expenditures in this area will be needed for system safety and reliability and are likely to be executed over the Next Year.

78 The Board considers that specific rate base increases due to IT projects, new technology, and sustaining projects for the Next Year are best determined by the full review of the 2004-2007 GTA process. However, in recognition that some of these projects could impact AltaLink's operations during the Next Year, it would be reasonable to include a portion of this rate base increase for interim rate making purposes in order to provide AltaLink with some measure of operational flexibility.

79 AltaLink's revenue requirement includes an income tax rate of 12.5% for Alberta. At the close of the Spring 2004 session of the Alberta Legislature, Bill 27 was passed and came into force on May 11, 2004. Given this, the Board considers that the 11.5% rate should be reflected in the determination of AltaLink's monthly rate for the Interim Term.

80 In light of the foregoing, the Board has determined that on a balance of probabilities, it would be reasonable to allow approximately 85% of AltaLink's forecast capital expenditures for purposes of calculating interim rates. This would result in an increased revenue requirement of some $30 million, or a reduction of some $5 million from the applied for increase in revenue requirement during the Interim Term.

5.3 AltaLink's Assumptions on Equity Return, Capital structure and Income Tax Allowance

81 The equity return and equity ratio in AltaLink's Interim Application reflects AltaLink's position in the recently completed Generic Cost of Capital (GCC) proceeding that the appropriate equity rate of return for AltaLink is in the range of 10.50% to 10.75% on a common equity of 37.5%.[6]

82 In contrast, in Decisions 2003-061 and 2004-028, the Board approved an equity rate of return of 9.4% and a debt to equity ratio of 66% to 34%.

83 Noting that the risk free rate used for establishing AltaLink's equity return in Decisions 2003-061 and 2004-028 has changed since the Board's determination was made, Calgary recommended the use of a 9.0% equity rate of return for setting AltaLink's interim rates. While there may have been a change in the risk free rate, the Board is of the view that until a decision is rendered in respect of the GCC process, AltaLink's currently approved equity return and capital structure are the appropriate "placeholders" to be used for interim ratemaking purposes. Therefore, when determining rates for the Interim Term, the Board will use an equity return of 9.4% and a capital structure consisting of 34% equity.

84 AltaLink's applied for interim rates also include an allowance for deemed income tax and large corporations tax related to the OTPPB's investment in ALP (OTPPB Income Tax Expense). In Decisions 2003-061 and 2004-028, the Board denied such an allowance in the revenue requirement approved for the May 1, 2002 to April 30, 2004 period.

85 The OTPPB Income Tax Expense matter will be addressed in the AltaLink's R&V Application process that is currently before the Board. Therefore, consistent with its views on AltaLink's equity return and capital structure, the Board considers that, until the OTPPB Income Tax Expense matter is resolved through the R&V process, AltaLink should not be allowed to collect through its interim rates any deemed income tax expenses related to the OTPPB's investment in ALP.

86 Accordingly, in its determination of AltaLink's interim monthly AESO charges for the Interim Term, the Board will exclude any OTPPB Income Tax Expense included in AltaLink's applied for revenue requirement.

87 Based on its projected rate base additions over the Next Year, AltaLink estimated using the GCC applied for equity return and capital structure instead of the currently approved values, and assuming a full income tax allowance, would result in a $9.5 million increase in revenue requirement over the Next Year. The corresponding increase in revenue requirement during the Interim Term is estimated to be $11.1 million. For the reasons stated above, the Board will not allow AltaLink to recover this amount through its interim tariff and will reflect this finding in its determination of the amount of revenue requirement that should be used to determine the interim tariff.

88 Accordingly, for all of the above reasons, the Board will reduce AltaLink's applied for revenue requirement during the Interim Term by $ 11.1 million to reflect its decision respecting return, capital structure, and the income tax treatment of OTPPB.

5.4 AltaLink Depreciation Technical Update

89 In Decision 2003-061, the Board directed AltaLink to return to the traditional method for determining net salvage rates. AltaLink stated that in order to carry out that directive, a technical update was required. AltaLink has estimated that the technical update, combined with the increase in depreciation expense associated with the significant growth in rate base, will lead to a revenue requirement increase of $8.0 million. This increase accounts for 5.4% of the 26.5 % revenue requirement increase over the Next Year. During the Interim Term the increase in revenue requirement is estimated to be $9.3 million. The increased revenue requirement results from a change in the composite depreciation rate from 3.01% to 3.63%.

90 Calgary has submitted that the depreciation impact is not an amount related to net income and will not affect the return to AltaLink's owners. FIRM's view is that the reasons for the changes in the composite rate must be reviewed in the 2004-2007 GTA proceeding and should not be included on an interim basis without further testing. FIRM proposed that the previously approved composite depreciation rate should be used as a placeholder for interim rate purposes and that this non-cash item should not impact AltaLink's financial integrity. AltaLink points out that depreciation affects its cash flow and the amount that it has to borrow to finance new capital additions.

91 The Board agrees that, absent an demonstration of financial harm, the appropriate approach to dealing with the revenue requirement resulting from the depreciation update is to use the approved composite depreciation as a placeholder for interim rate purposes, as suggested by FIRM. The Board acknowledges that depreciation expenses affect cash flow and can be used to fund capital projects. However, AltaLink has not demonstrated to the Board's satisfaction how exclusion of the technical depreciation increase from the revenue requirement for the Interim Term would cause it financial hardship.

92 Accordingly, the Board will not include the $9.3 million applied for increase in revenue requirement due to the technical update of depreciation costs when determining AltaLink's interim rates.

5.5 AltaLink Operating Expenses

93 AltaLink's operating expenses generally relate to net salary and wages, contract manpower and general operating expense. For the Next Year, AltaLink has forecast a $12.1 million increase in operating expenses from the $34.6 million that was approved for the 2003/04 test year. This represents an increase of approximately 35% from the previous fiscal year and accounts for 8.1% of the 26.5 % revenue requirement increase over the Next Year. For the Interim Term, the forecast increase in revenue requirement is $14.2 million.

94 Increases not accounted for by inflation, are primarily related to the following:

- Costs disallowed in the last GTA that are required to be expended to prudently, safely and reliably operate and maintain the transmission system;
- The need to prudently increase expenditures for operating and maintaining the expanding transmission system; and
- External factors beyond AltaLink's control that are driving cost increases for AltaLink.

95 Calgary has suggested that 50% of the overall operating expense increase from the last fiscal year, or $6.0 million, be used for determining AltaLink's interim rates. While FIRM had a different amount of reduction, it too recommended that only 50% of its estimated increase be allowed in the revenue requirement to be used to calculate interim rates.

96 AltaLink has on staff 25 full time equivalents (FTE) in excess of the 220 FTEs that were approved by the Board in the last GTA. AltaLink also proposes to undertake activities that it claims had to be deferred because not all of its requested cost increases were approved in its last GTA. The Board is of the view that until the costs that were disallowed in AltaLink's last GTA can be fully reviewed and assessed, AltaLink should not be allowed to recover any significant amounts of these disallowed costs.

97 In a previous section of this Decision, the Board concluded that 85% of the forecast rate base addition should be used for interim rate making purposes. Consistent with this determination, it follows that a commensurate FTE increase related to operating and maintaining the expanding transmission system should also be recovered during the Interim Term.

98 In addition to the 25 FTE in excess of its complement approved in the last GTA, AltaLink proposes to add a significant amount of FTEs over the Next Year (13 for the 8 months in 2004 and some portion of the 44 FTE addition for 2005). These proposed FTE additions relate to the operations, regulatory and corporate services functional areas.

99 The Board is generally of the view that until the need for all of the applied for FTE increases in each of AltaLink's functional areas can be reviewed and established through the 2004 — 2007 GTA process, it would not be appropriate to allow AltaLink to start recovering through interim rates the full amount of expenses related to AltaLink's significantly increased applied for FTE complement level. However, the Board recognizes that not having sufficient people to operate and maintain the system could potentially expose the system to some risk of failure. The Board will bear this in mind when determining the amount of increased operating expenses that should be recovered through interim rates during the Next Year.

100 The Board recognizes that other factors driving the cost increases such as increased vegetation management may indeed be required over the next few years. While it may be appropriate to allow some of these expenditures to be recovered through the interim rates, the Board is not persuaded that there is an immediate urgency for all of these expenditures to be recovered over the Next Year before they are fully tested.

101 Similarly, the Board considers that it would be appropriate for AltaLink to recover through interim rates, only a minimal amount of expenses related to contract manpower and services, and other general operating expenses such as IT related ones.

102 In summary, the Board is of the view that until AltaLink has the opportunity to justify its operating expense increases in its upcoming 2004 — 2007 GTA proceeding, it would be reasonable to allow only a portion of the applied for increases to be recovered through interim rates during the Interim Term. For all of the reasons discussed above, and particularly the FTE increase related to the expanding transmission system, the Board considers Calgary and FIRM's recommendations to be conservative and believes that, on balance, a more reasonable percentage increase would be in the 70% to 80% range. Therefore, for purposes of establishing interim rates for the Interim Term, the Board will use an overall operating expense increase of $10.5 million and will adjust the applied-for revenue requirements accordingly.

5.6 AltaLink Insurance & Other

103 AltaLink has forecast a $2.7 million increase in self-insurance reserve and insurance premium fundings, hearing cost funding, and property taxes over the Next Year. The corresponding amount over the Interim Term is $2.8 million.

104 The increase with respect to property taxes is related to the forecast growth in AltaLink's property tax base and gradual increases in mill rates.

105 The increase in the forecast cost of insurance, which account for the majority of the increase revenue requirement in this category, relates to increased coverage and increased premiums. AltaLink has indicated that an increase of $2.5 million per year or $0.2 million per month is necessary in its interim tariff due to increases in insurance expenses. AltaLink has also provided a list of and a discussion of each of the commercial insurance coverage it proposes to have in place.

106 Increased funding of reserve accounts are also proposed. AltaLink has provided details with respect to the functioning of the self-insurance reserve (SIR).

107 For purposes of setting interim rates, the Board considers AltaLink's explanations respecting the increased insurance expense to be reasonable and will therefore allow the requested increase. While the Board is approving this increase in expense on an interim basis it considers AltaLink's proposal to flow actual insurance premiums through the SIR to be an issue that should be debated during the hearing.

108 No increase is expected in property taxes for the 8-month test period in 2004 and AltaLink has forecast no increase in hearing cost expenses for the Interim Term. Therefore the Board considers no increase for these items is necessary for purposes of setting interim rates.

5.7 TransAlta Forecast Revenue Requirement

109 TransAlta forecast increase in revenue requirement over the Next Year is attributable to the areas in the percentages shown in the Table 4 below.

110 *Table 4. TransAlta's Forecast Increases to its Monthly Revenue Requirement for May 1, 2004 to December 31, 2004 and for 2005*

	2004		***2005***	
Factors Contributing to TransAlta's Increased Monthly Revenue Requirement	***$ Increase ($ 000)***	***Increase as a % of Current Rate***	***$ Increase ($ 000)***	***Increase as a % of Current Rate***
Revised Debt/equity Ratios and Equity Return	7.2	11.9	9.6	12.8
Increased Rate Base	3.9	6.5	10.0	13.3
Revised Depreciation Rates	8.1	13.5	10.8	14.5
Increased Operations and Maintenance Fee to AltaLink	14.7	24.5	19.0	25.5
Additions to Hearing Cost Reserve Funding	12.5	20.8	8.3	11.2
Other Operating Expense Increases	6.3	10.4	7.1	9.5

Increased Income Tax due to above changes	7.5	12.4	9.8	13.2
Total	60.2	100.0	74.6	100.0

111 TransAlta explained that the increase in costs was related to:

1. A significant outstanding hearing cost amount (currently in the order of $280,000) from the 2002/2004 proceeding waiting Board approval and additional hearing costs from this proceeding.

2. Significant additions to rate base related mainly to capital maintenance throughout the forecast period that increases the requirement for return, income tax and depreciation.

3. Significant increases in the cost of contracted manpower between 2003/2004 and the balance of 2004 and 2005.

4. An increase in the return on equity and the amount of equity making up rate base to a level TransAlta believes to be prudent.

112 In keeping with their recommendation that AltaLink not be given an interim rate increase, the interveners submitted that no increase should be granted to TransAlta either, as TransAlta's request was based upon a pro-rata share of AltaLink's costs.

113 In recognition of the linkages between the two applications, the Board considers that it would be reasonable to grant TransAlta a similar percentage of its applied for monthly increase. The Board has approved $1.3 million of AltaLink's applied for $3.4 million monthly rate increase, or approximately 40% of the increase requested by AltaLink. Accordingly, the Board will use 40% of TransAlta's requested monthly rate increase to determine TransAlta's interim monthly AESO Charges.

5.8 Board Conclusions on Interim Applications

AltaLink

114 Based on the reasoning in the preceding sections, the Board concludes that it would be appropriate to include $42.8 million of AltaLink's $72.1 million increase in revenue requirement for the Interim Term to determine interim refundable monthly AESO charges.

115 The Board allowed revenue requirement and resulting interim monthly rates for AltaLink for the May 1, 2004 to June 30, 2005 period are summarized in the Table 5 below.

116 *Table 5. Board Approved Revenue Requirement and Interim Monthly Rates for AltaLink for May 1, 2004 to April 30, 2005*

AltaLink Annual Revenue Requirement	***2003/04 Approved ($ Million)***	***Applied For May 1, 2004 to June 30, 2005 ($ Million)***		***Board Approved May 1, 2004 to June 30, 2005 ($ Million)***	
		Increase	***Total***	***Increase***	***Total***

Total Return	47.5	17.0	64.5	10.8	58.2
Operating Expense	34.6	20.0	54.6	15.4	50.0
Self Insurance Reserve and Insurance Premium Funding	0.5	2.6	3.1	2.5	3.1
Hearing Cost Funding	1.5	0.3	1.8	0.3	1.8
Taxes Other Than Income Tax	12.6	2.4	15.1	2.1	14.7
Miscellaneous Revenue	(5.9)	(1.5)	(7.5)	(1.4)	(7.3)
Depreciation & Amortization	47.8	21.0	68.7	11.0	58.7
Income Taxes	11.5	10.4	22.0	2.1	13.6
Total	*150.1*	72.1	*222.3*	42.8	*192.9*
Monthly Rate	*12.5*	5.2	*15.9*	3.1	*13.8*

117 Note: Totals may not add due to rounding.

118 The monthly rate in Table 5 represents a composite of the rate that would apply from May 1, 2004 to December 31, 2004 and the rate that would apply from January 1, 2005 to June 30, 2005. As such, relative to the allowed Interim Term revenue requirement, the composite monthly rate would over collect revenues in the 2004 period and under collect in the 2005 period. Notwithstanding this, the Board considers that because the rate would be interim and refundable, it would be appropriate to establish a single rate for the Interim Term.

119 Accordingly, the Board approves on an interim refundable basis a monthly rate of $13.8 million for AltaLink, which shall remain in effect from May 1, 2004 to June 30, 2005, or until a final decision of the Board is rendered on the Applicants' 2004-2007 GTAs, or upon further order of the Board.

TransAlta

120 For the reasons above, the Board will determine a single interim rate for TransAlta for the May 1, 2004 to June 30, 2005 period instead of two different rates for the May 1, 2004 to December 31, 2004 and the January 1, 2005 to June 30, 2005 periods. The computation of TransAlta's blended rate for May 1, 2004 to June 30, 2005 is shown in Table 6 below.

121 *Table 6. Board Approved Revenue Requirement and Interim Monthly Rates for TransAlta for May 1, 2004 to June 30, 2005*

		2004 (May 1 to Dec 31)	**2005 (Jan 1 to Jun 30)**	**May 1, 2004 — June 30, 2005**	
				Total	***Rate***
TransAlta Interim Application					
	Currently Approved Monthly Rate	208,667	208,667		
	Requested Monthly Rate Increase	60,208	74,583		
	Total Requested Monthly Increase	*268,875*	*283,250*		
	Requested Revenue Requirement Increase			3,850,500	
	Requested Blended Monthly Rate				*275,036*
Board Approved					
	Currently Approved Monthly Rate	208,667	208,667		

Approved Monthly Rate Increase (40%)	24,083	29,833		
Total Approved Monthly Increase	*232,750*	*238,500*		
Approved Revenue Requirement			3,293,003	
Approved Blended Monthly Rate				*235,214*

122 Accordingly, the Board approves on an interim refundable basis a monthly rate of $235,214 for TransAlta, which shall remain in effect from May 1, 2004 to June 30, 2005, or until a final decision of the Board is rendered on the Applicants' 2004-2007 GTAs, or upon further order of the Board.

123 The Board's review and exclusion of costs associated with certain contentious areas of the Applicants' untested 2004-2007 GTAs for the purpose of establishing interim refundable rates for the May 1, 2004 to June 30, 2005 period, does not in any way prejudge the final determination of these matters that the Board will make when deciding the Applicants' 2004-2007 GTAs.

6 Order

124 For and subject to the reasons set out in this Decision, IT IS HEREBY ORDERED THAT:

(1) The Interim Transmission Tariffs for AltaLink, in its capacity as General Partner of AltaLink. L.P., and TransAlta shall be as set out in the attached Schedule A and Schedule B and applies on an interim and refundable basis effective May 1, 2004.

(2) The currently approved AltaLink and TransAlta TFO Terms and Conditions, which were finalized in Decision 2004-028, apply on an interim basis effective May 1, 2004.

(3) The Interim Transmission Tariffs and the AltaLink and TransAlta TFO Terms and Conditions of service in (1) and (2) above shall remain in effect for the lesser of the term specified in Schedules A and B, or until a final decision of the Board is rendered on AltaLink and TransAlta's 2004 - 2007 General Tariff Applications, or upon further order of the Board.

APPENDIX A — Altalink Management Ltd., 2004/05 Interim Rate Schedule, Transmission Tariff (Effective May 1, 2004)

Available:	To the Transmission Administrator.
Applicable:	To the Transmission Administrator for the use of AltaLink's transmission facilities commencing May 1, 2004 and ending on June 30, 2005.
Rate:	The Transmission Rate charged to the Transmission Administrator for the use of AltaLink's transmission facilities commencing May 1, 2004 shall be: Monthly Charges: $ 13.8 million

APPENDIX B — Transalta Utilities Corporation, 2004/05 Interim Rate Schedule, Transmission Tariff (Effective May 1, 2004)

Available:	To the Transmission Administrator.
Applicable:	To the Transmission Administrator for the use of TransAlta's transmission facilities commencing

	May 1, 2004 and ending June 30, 2005.
Rate:	The Transmission Rate charged to the Transmission Administrator for the use of TransAlta's transmission facilities commencing May 1, 2004 shall be:
	Monthly Charges: $235,214

Footnotes

1 The FIRM Group of Customers is comprised of the Alberta Association of Municipal Districts & Counties, the Alberta Federation of REA's Ltd., Alberta Irrigation Projects Association, Alberta Urban Municipalities Association, the Consumers Coalition of Alberta, Public Institutional Consumers of Alberta (PICA) and the Utilities Consumer Advocate.

2 Decision 2004-028 was issued on March 23, 2004 and finalized AltaLink and TransAlta's rates for May 1, 2002 to April 30, 2004.

3 Includes tax and rate base effects, FIRM argument P. 5

4 Decision 2004-007, Schedule 7.

5 AltaLink, L.P. Report of Finances and Operations May 1,2002 to April 20, 2003, dated March 26, 2004.

6 Joint Argument of AltaLink, Aquila Networks Canada (Alberta) Ltd., EPCOR Distribution Inc. and EPCOR Transmission Inc. dated February 23, 2004, starting at lines 8 page 12 to line 24, page 13.

End of Document

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2005 CarswellAlta 2281
Alta. E.U.B.

ATCO Gas, Re

2005 CarswellAlta 2281, [2007] A.W.L.D. 2816

ATCO Gas, 2005-2007 General Rate Application Interim Rate Application

B.T. McManus Presiding Member, Gordon J. Miller Member, and Laurie J. Bayda Acting Member

Judgment: August 29, 2005
Docket: 2005-099

Subject: Public

Related Abridgment Classifications

For all relevant Canadian Abridgment Classifications refer to highest level of case via History.

Headnote

Public law --- Public utilities — Operation of utility — Rates — Approval

Table of Authorities

Cases considered by *B.T. McManus Presiding Member, Gordon J. Miller Member, and Laurie J. Bayda Acting Member*:

ATCO Electric Ltd., Re (2002), 2002 CarswellAlta 1961 (Alta. E.U.B.) — considered

ATCO Gas, Re (2002), 2002 CarswellAlta 2053 (Alta. E.U.B.) — considered

ATCO Gas, Re (2003), 2003 CarswellAlta 2127 (Alta. E.U.B.) — considered

ATCO Gas, Re (2004), 2004 CarswellAlta 2054 (Alta. E.U.B.) — referred to

ATCO Gas, Re (2005), 2005 CarswellAlta 2258 (Alta. E.U.B.) — referred to

ATCO Group, Re (2002), 2002 CarswellAlta 1953 (Alta. E.U.B.) — referred to

Subject:

***B.T. McManus Presiding Member, Gordon J. Miller Member, and Laurie J. Bayda Acting Member*:**

1 Introduction

1 ATCO Gas (AG) filed a General Rate Application (GRA) for the 2005-2007 test period on May 13, 2005. On June 8, 2005, AG filed an application (the Application) with the Board requesting approval for proposed rates on an interim basis. AG proposed that the interim rates would be effective September 1, 2005, and would reflect an increase in revenue from existing 2004 rates in the amount of $9.3 million for ATCO Gas North (AGN). No interim rate increase was requested for ATCO Gas South (AGS).

2 Particulars of the Application

2 AG provided the following information in support of the Application:

• In the Overview of the GRA, AG indicated that the 2005 revenue shortfall for AGN was $18.5 million. ATCO submitted that this was a substantial shortfall and that the forecast shortfalls for 2006 and 2007 were substantially higher at $26.6 million and $34.5 million respectively. The requested interim increase of $9.3 million represented approximately 50% of the forecast 2005 shortfall and was proposed to be collected between September 1, 2005 — December 31, 2005.

3 AG also proposed that the interim increase should be applied to all customer rates on an across-the-board basis, and provided detailed calculations of the billing determinants and proposed rates for each rate class for AGN customers.

4 AG indicated that, to minimize rate shock and maintain intergenerational equity, it would be in the best interests of customers to implement an interim increase in rates for AGN. AG also indicated that an interim increase in the level proposed would be consistent with the last approved increase for AGN and was in the range of historic approvals for Northwestern Utilities (NUL) and Canadian Western Natural Gas Ltd (CWNG). Since past rate applications involved contentious changes to capital structure and return on common equity that would not be an issue in this proceeding, AG asserted that the request for 50% of the estimated shortfall was reasonable. AG provided excerpts from previous Board Decisions in support of its requested increase and its request that the interim increase be applied across-the-board.

5 By letter dated July 15, 2005, the Board requested that interested parties provide submissions with respect to the Application by July 22, 2005, and that AG provide a response to those submissions by July 29, 2005. However, a submission was received on July 8, 2005 from the Consumer Group (CG) to which AG replied on July 13, 2005. CG filed a response to AG's reply in a letter dated July 15, 2005.

3 Positions of AG and the Interveners

6 The CG disagreed with AG that implementation of the applied for interim rate would minimize rate shock. In their July 15 response letter to AG, CG contended that the difference between $9.3 million and $18.5 million only constituted a 1% difference to customer end bills. As such, CG concluded that rate shock and intergenerational equity should not be considered issues in this instance.

7 CG argued that AGN should not receive an interim rate adjustment. CG claimed that there were significant amounts that AGN included in its Application that had been reduced or denied by the Board in previous proceedings. Additionally, CG stated that there were other amounts that represented unusually large increases over 2004 amounts. In total CG suggested that $19.3 million in reductions should be applied to AGN's forecasted shortfall. Since this amount exceeded AGN's total revenue deficiency, CG asserted that no interim rate adjustment ought to be approved. CG's support for the $19.3 million in reductions is described below.

8 CG noted that in its application AG forecasted a one-time Federal deferred income tax refund for the North. This amount is required to be refunded to customers in accordance with direction set out in Decision 2003-072 [2003 CarswellAlta

2127 (Alta. E.U.B.)] .[1] CG argued that as no interest was being paid on this amount, it should be used to offset the 2005 forecasted revenue shortfall rather than applied to offset projected expenditures in 2006 as proposed by AG.

9 CG also noted the Board's direction in Decision 2003-072 which directed AG:

> ... to re-evaluate the MRRP [Meter Relocation and Replacement Project] and incorporate in its Refiling, a revised proposal for replacement of meters with underground entries over a 10-year timeframe, and replacement/relocation of meters with aboveground entries on a schedule coincident with the recall program.[2]

10 CG noted that the AG GRA application forecast that the MRRP will cost $30 million per year; an amount greater than the cost of $28 million forecast in the last rate application. For this reason, CG requested that for interim purposes, the MRRP should be limited to $25 million per year. This was the amount approved by the Board for MRRP expenditures for 2004 in Decision 2004-036 [2004 CarswellAlta 2054 (Alta. E.U.B.)][3]

11 CG also argued that AG's forecast expenditures on urban mains replacements was too high at $19.1 million for 2005. CG considered that the Board directed AG in Decision 2003-072:

> ... to reduce the 2004 test year forecast for Urban Mains Replacements to $7.092 million.[4]

12 In its previous forecast, AG budgeted $15.1 million for urban mains replacements in 2004. Therefore, CG submitted that AG's forecast amount for urban mains replacements in 2005 should be reduced to $7 million per year.

13 For the 2005 test year, AG forecast a $5 million increase in movable equipment as compared to 2003 and 2004 actual expenditures. As was noted by CG, the 2005 moveable equipment expenditure forecast was significantly greater than 2006 and 2007 forecast amounts. CG submitted that, for interim purposes, AG's 2005 moveable equipment forecast be reduced by $5 million.

14 In total, CG submitted that the net impact on AG's capital expenditure forecasts pertaining to the above noted items is a reduction of $22 million. The net effect on the revenue requirement of these reductions would be $2.1 million, of which CG argued that $1.1 million should be attributed to AGN.

15 In Decision 2003-072, the Board determined that AG had not established that monthly meter reading was necessary. Therefore, the Board directed AG to revise its forecast to reflect the costs of reading meters on a bi-monthly basis. However, CG noted that AG has continued to provide monthly meter reading and has included forecast monthly meter reading costs in its 2005-2007 GRA. CG stated that in Decision 2003-072, ATCO Gas estimated monthly meter reading expenses at $5.5 million plus capital costs of $577,000. CG argued that none of the costs of monthly meter reading should be included in the interim rates and argued that AGN's interim request should be reduced by $3 million.

16 Also noted by the CG, AG forecasted the addition of 84 full-time employees (FTEs) in 2005. Including labour and benefits expenses, CG noted that the average estimated cost per new FTE was $62,300 per year. Without further testing, CG contended that this amount was front loaded and only the costs of 42 FTEs should be considered for the purpose of interim rates. CG remarked that this would reduce AG's forecast 2005 expenses by $2.5 million, of which CG argued $1.3 million

ought to be attributed to AGN.

17 CG noted that Account 701 advertising expense was forecast to be $6.0 million in 2005; an increase over the $3.0 million allowed by the Board in Decision 2003-072 for the 2003-2004 test years. CG observed that in its 2003-2004 GRA, AG applied for a similar increase. CG submitted that for interim purposes the Account 701 advertising costs should be limited to $3 million for AG. CG argued that $1.5 million of this amount should be attributed to AGN.

18 In addition, CG remarked that in Decision 2005-039 [2005 CarswellAlta 2258 (Alta. E.U.B.)][5] the Board reduced Customer Communication Costs by $250,000 reflecting the costs associated with the GCRR for which AG was no longer responsible. CG asserted that this amount should also be excluded from interim rates.

19 Furthermore, CG noted that the Board reduced AG's administration costs to reflect the transfer of the retail function to Direct Energy Regulated Services (DERS). CG indicated that AG stated in its latest compliance filing that it had reduced administrative expenses by $1.029 million in the north and by $1.068 million in the south. These amounts reflected savings in administrative costs in the last 7 months of 2004. CG contended that since AG argued that there should not be any reductions in administrative costs as a result of the transfer, it was unlikely that AG would have removed any of these costs from its 2005-2007 GRA. Therefore, CG asserted that for interim purposes, AGN's administrative costs should be reduced by $1.675 million for 2005.

20 CG stated that AG included in its forecast expenses an amount of $500,000 for external legal fees in excess of the Board Scale for 2005, half of which would be attributable to AGN. Since hearing costs in excess of the Board Scale are not allowed for any participants (either companies or interveners), CG argued for a $0.3 million reduction to expenses for AGN interim rates.

21 Similarly, CG submitted that $339,000 for donations included for 2005 should be excluded from both the GRA and the interim rate application. CG argued that historically the Board ruled that donations were not a cost to be borne by customers. As such, CG contended AGN's forecasted expenses be reduced by $0.3 million.

22 CG noted that AG proposed changes to its depreciation study that would result in a net depreciation expense increase of $1.683 million for the 2005 test year. CG asserted that there was no urgent or compelling reason for AG to recover increased depreciation expense caused by changes to service life and net salvage assumptions. CG contended that for interim purposes AGN depreciation expense should be reduced by $0.9 million.

23 CG and the Utilities Consumer Advocate (UCA) noted that AG has forecast an increase of $3 million in ATCO I-Tek charges from 2004 to 2005. The unit prices were based on an MSA that was renewed early in 2005 and included a 3.8% inflation increase for labour. CG and the UCA indicated that the areas relating to Distributed Hardware and Application Service Provider (ASP) applications were forecasted to have the largest increases. Since the Board previously directed ATCO Gas to reduce ATCO I-Tek charges by 7.5% in Decision 2002-069 [2002 CarswellAlta 1953 (Alta. E.U.B.)] ,[6] CG and the UCA contended that ATCO I-Tek charges should be reduced by 10% for interim purposes. The result would be a $0.7 million reduction for AGN in 2005.

24 CG also submitted that I-Tek Business Services (ITBS) charges ought to be reduced by 11.1%. CG noted that these charges were reduced by the Board in Decision 2002-069 by this amount. The $22.5 million that AG forecast in spending on ITBS was based on a new Master Service Agreement (MSA). CG contended that it was unlikely that the 11.1% reduction ordered by the Board was incorporated in this Application. Therefore, for the purposes of interim rates, CG argued that ITBS charges to ATCO Gas should be reduced by $2.5 million with $1.3 million of that amount being attributable to AGN.

25 CG noted that Industrial Gas Consumers Association of Alberta (IGCAA) submitted evidence in an ATCO Pipelines Application No. 1393613[7] suggesting that costs allocated to unregulated portions of the network, (the Muskeg River Pipeline) have been understated by approximately $1.6 million at the expense of ATCO Pipelines other customers. CG argued that if this evidence was found to be compelling in the ATCO Pipelines proceeding, that it could have a significant impact for AG. CG estimated that charges to AGN could be reduced by as much as $0.6 million for 2005.

26 In addition, ATCO Pipelines was expected to receive $4 million worth of TBO (Transportation By Others) revenues from NOVA Gas Transmission Limited (NGTL). Of this amount, CG contended that $0.4 million would accrue to AGN.

27 Finally, if NGTL's proposed rate design was accepted by the Board, CG claimed that ATCO Pipelines would save 13% over current rates. CG argued that this amount would translate to savings for AGN of $0.15 million.

28 CG maintained that the outcome of the ATCO Pipelines and NGTL proceedings could have a significant impact on the AGN's costs. For this reason, CG submitted that AGN's interim revenue should be reduced by $1.15 million.

29 AG reviewed CG's submission and replied that the focus of an interim rate application should not be to pre-judge contentious issues, but rather to avoid rate shock and provide intergenerational equity. AG stated that an intervener's suggestion of an issue being contentious should not automatically make it so. AG argued that it was for this reason that it only requested 50% of the forecast revenue shortfall as opposed to the full amount. AG noted that it would be unlikely that it would be able to implement adjusted rates based on the outcome of the GRA Decision before March 2003. ATCO Gas asserted that if the full amounts of the shortfall for 2005 and 2006 were approved by the Board, customers would face a significant increase in rates at that time. AG concluded that in order to mitigate any possible rate shock, the Application should be approved as filed.

30 In response to CG's assertion that the forecast federal deferred income tax refund should be repaid in 2005, AG responded that the $6 million refund would almost fully offset $6.9 million of one-time charges for AGN customers that would occur in 2006. AG argued that moving the repayment to 2005 would cause a significant increase in rates for 2006 which may contribute to rate shock.

31 With respect to the proposed changes in depreciation analysis, ATCO Gas noted that CG did not find the amount to be contentious. Rather, AG argued that CG disputed the timing of those amounts. AG submitted that CG was again ignoring the impact of rate on customers and that its request for a $0.9 million reduction was unjustified.

32 AG submitted that it considered it inappropriate for CG to speculate on the outcome of other proceedings that may impact ATCO Pipelines. AG argued that for this reason the $1.1 million reduction sought by CG was unwarranted.

33 AG submitted that removing the above noted items from CG's analysis decreased CG's proposed reduction from $19.3 to $11.3 million. Therefore, AG noted that, following the reasoning of CG, an interim rate increase of at least $7.2 million should be allowed. An award of such an amount, however, would have to be premised on the assumption that the Board would completely agree with the interveners regarding the contentious issues which AG considered unlikely. AG therefore argued that the Application should be approved as filed.

4 Views of the board

34 AG argued that to mitigate potential rate shock, promote rate stability and maintain intergenerational equity; an interim rate adjustment would be in the best interests of customers. CG identified a number of contentious issues to be debated during the hearing. The Board recognizes that there are significant differences between AG and the interveners regarding the appropriate forecast revenue requirement.

35 With respect to the criteria that the Board should utilize when evaluating the need for an interim rate increase, the Board has considered the arguments of the parties and prior interim rate decisions. In Decision E92036[8] the Public Utilities Board (PUB) indicated at pages 10 and 11:

> The Board considers that an effective approach which could be used by a utility to determine an appropriate level of interim rates is to look at areas which may be contentious and to exclude all or some portion of those amounts from the amount to be collected through interim rates. In this manner the potential of over-collection from interim rates would be minimized which in turn reduces potential fluctuations to customers' rates.

36 In Order E93028[9] the PUB stated at page 14:

> The Board considers that interim rate increases are generally warranted where the forecast revenue deficiency identified for a given period is probable and material. The Board considers it generally appropriate that customers' rates for a period reflect the costs associated with that period in order to maintain intergenerational equity. Furthermore, approving interim rates in a timely manner avoids rate spikes that may otherwise result if recovery of the revenue deficiency is delayed.

37 Further, at page 18 the PUB denied NUL's request to implement an interim rate increase in respect of certain classes only, stating:

> The Board is not persuaded at this time that a need exists to change its long maintained position that interim rates should be based on an existing rate structure and costing methodology....The Board considers that this method least influences the existing Board approved rate structure.

38 In Decision 2002-115 [2002 CarswellAlta 2053 (Alta. E.U.B.)][10] the Board stated at page 10:

In the present circumstances, the Board considers that interim rate increases are generally warranted given that the forecast 2003 revenue deficiency is material. An interim rate increase aimed at recovering a portion of any shortfall that is ultimately demonstrated and approved provides for a leveling out of the impact of any final rate increase, thereby promoting rate stability and easing any rate shock to customers at a later date. The Board also considers it appropriate that customers' rates for a given period reflect the costs associated with that period in order to maintain intergenerational equity. While acknowledging the submission of the CG that ATCO has not claimed financial harm or an inability to continue safe utility operations without an interim rate increase, the Board considers it appropriate, given the magnitude of the forecast 2003 revenue deficiencies for AGS and AGN, that some degree of interim rate increase is warranted.

39 Further at page 11 of Decision 2002-115, the Board considered the award granted in the context of previous awards and found the percentage increase granted to be "in line with those awarded by the Board in previous interim rate Decisions."

40 The Board also notes the discussion in Decision 2002-108 [2002 CarswellAlta 1961 (Alta. E.U.B.)][11] of the use of carrying costs as a means of keeping parties whole and thereby potentially avoiding interim rate changes. The Board also discussed the need to consider large forecasted impacts to rates when evaluating a requested interim rate increase that appears at page 12:

However, if large rate adjustments are forecast, the Board might decide that the need of appropriate price signals to customers is more significant than the need to minimize the number of changes in rates.

41 The foregoing excerpts reference a number of factors that the Board has employed in evaluating an application for an interim rate increase. These factors can be grouped into two categories, those that relate to the quantum of, and need for, the rate increase and those that related to more general public interest considerations.

42 Quantum and need factors are those which relate to the specifics of the requested rate increase and include:

- The identified revenue deficiency should be probable and material
- All or some portion of any contentious items may be excluded from the amount collected
- Is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?
- Can the applicant continue safe utility operations without the interim adjustment?

43 If all or a portion of the suggested rate increase appears appropriate after a consideration of the quantum and need factors, the Board must assess certain general public interest factors to see if a rate increase is justified, these include:

- Interim rates should promote rate stability and ease rate shock
- Interim adjustments should help to maintain intergenerational equity
- Can interim rate increases be avoided through the use of carrying costs

- Interim rate increases may be required to provide appropriate price signals to customers

- It may be appropriate to apply the interim rider on an across-the-board basis

44 The Board recognizes that the above listed considerations may be given different weighting depending on the specific circumstances surrounding each application. The Board has considered the above factors in its deliberations.

45 The Board notes AG's comment regarding the impact of revenue shortfalls on AG's financial results for 2005[12] as stated in AG's discussion with the Board and parties in the June 14, 2005 Information Workshop. In this Application, the Board considers that the forecast shortfall of $18.5 million could be considered a material amount if the entire amount had to collected from customers.

46 AG suggested that $9.3 million or approximately 50% of the forecast 2005 revenue shortfall would be a reasonable interim rate adjustment. In determining the reasonableness of the requested amount, the Board notes the number of contentious issues and the amounts of revenue increases related to those issues. The Board has balanced the quantum of contentious revenue related issues with the quantum of the forecast shortfalls and the impact to rates that would be associated with a range of shortfall collection scenarios. While the amount of the requested rate increase would only constitute 2% of current customer bills, the Board considers that by the time the GRA decision is rendered and amended rates have been implemented, AG may have to collect all of the 2005 and some portion of 2006 shortfalls. Given the potential magnitude of these shortfalls, the Board considers it appropriate to award some degree of interim rate adjustment to avoid future rate shock. The Board also considers that applying the interim increase on an equal percentage basis to the energy, fixed and demand charges for all rate classes[13] is a reasonable method of applying the interim increase that is simple and cost effective to apply.

47 The Board considers that an increase in rates, on an interim basis, to generate an amount of $7.0 million in additional revenue in 2005 compared with current rates, will mitigate the risk of future rate shock caused by additional rate increases during 2006, maintain intergenerational equity, ensure rate stability and provide a reasonable level of revenue to the Applicant. The Board considers that this level of increase is sufficient to recognize the possibility of some increase being awarded with respect to rates in 2005 and therefore alleviating the impact of collecting shortfalls during 2006.

48 The Board has prepared Appendix 1 showing the Interim Rates to be applicable to billings on and after September 1, 2005 until replaced by subsequent decisions or orders of the Board.

49 In determining the level of interim rates for AGN, the Board is not making any finding or determination with respect to any of the matters to be considered in the upcoming GRA. The Board recognizes that the evidence before it is untested and that a number of areas of concern identified by the interveners could result in an adjustment to forecasted shortfalls.

5 Order

50 IT IS HEREBY ORDERED THAT:

(1) Appendix 1, Rider G of this Decision is hereby approved as an additional rider to the current rate schedules, on an interim basis for ATCO Gas North service zone, applicable to billings on and after September 1, 2005 until replaced by subsequent orders of the Board.

Appendix 1

Effective by Decision 2005-099

On consumption September 1, 2005

ATCO GAS NORTH RATE RIDER "G" TO DELIVERY SERVICE RATES

Applicable to the fixed and variable charges in ATCO Gas North DSP Delivery Service Rates 1, 11, 3, 13 and 13b. Effective on all consumption commencing September 1, 2005.

Surcharge to Fixed Charge, Variable Charge and Demand Charge	9.96	'

Footnotes

1 Decision 2003-072 — ATCO Gas 2003/2004 General Rate Application, Phase I, dated October 1, 2003

2 Decision 2003-072, p. 81

3 Decision 2004-036 — ATCO Gas 2003/2004 General Rate Application — Compliance Filing, dated April 28, 2004

4 Decision 2003-072, p. 47

5 Decision 2005-039 — ATCO Gas 2003/2004 GRA Impact of the Retail Transfer and ITBS Volume Forecast, dated May 3, 2005

6 Decision 2002-069 — Affiliate Transactions and Code of Conduct Proceeding, Part A: Asset Transfer, Outsourcing Arrangements, and GRA Issues, dated July 26, 2002

7 Muskeg River Pipeline Module

8 Interim Decision E92036, Canadian Western Natural Gas Company Limited, Re: Interim Rates effective April 1, 1992, dated April 2, 1992

9 Order E93028, Northwest Utilities Limited, Re: Interim Rates for 1993, dated March 31, 1993

10 Decision 2002-115, ATCO Gas 2003/2004 General Rate Application Interim Rate Application, dated December 24, 2002

11 Decision 2002-108, ATCO Electric Ltd. 2003 Distribution Tariff and Transmission Facility Owner's Tariff Part A: 2003 Interim DT and TFO Tariff, dated December 11, 2002

12 AG Application letter June 8, 2005 P1

13 Equivalent to the "Across-the-board" basis per AG submission

End of Document

2008 CarswellAlta 2098
Alberta Utilities Commission

ATCO Electric Ltd., Re

2008 CarswellAlta 2098, [2009] A.W.L.D. 902

ATCO Electric Ltd.; 2009 Interim Distribution Tariff and Transmission Facility Owner's Tariff

A. Michaud Acting Commr., B. Lyttle Commr., C.D. Rees V-Chair

Judgment: December 19, 2008
Docket: 2008-134

Counsel: None given

Subject: Public

Related Abridgment Classifications

For all relevant Canadian Abridgment Classifications refer to highest level of case via History.

Headnote

Public law --- Public utilities — Operation of utility — Rates — Approval

Table of Authorities

Cases considered:

ATCO Electric Ltd., Re (2005), 2005 CarswellAlta 2284 (Alta. E.U.B.) — considered

ATCO Gas, Re (2005), 2005 CarswellAlta 2281 (Alta. E.U.B.) — referred to

Per Curiam:

1 Introduction

1 On October 31, 2008 ATCO Electric Ltd. (AE) filed an application (the Interim Application) with the Alberta Utilities Commission (AUC or Commission), for approval on an interim refundable basis of the 2009 Interim Distribution Tariff, the 2009 Interim Transmission Facility Owner's Tariff, and amendment to the 2009 Rider B — Balancing Pool Adjustment Rider, effective January 1, 2009.

2 The Notice of Application, issued on November 12, 2008, established the following schedule for the written process which was followed to deal with the Application:

Process Step	*Deadline Date & Time*
Participation Closing Date and Submission of Statements of Intent to Participate	4:00 pm, November 19, 2008
Information Requests to Applicant	4:00 pm, November 20, 2008
Information Responses from Applicant	4:00 pm, November 27, 2008
Argument	4:00 pm, December 2, 2008
Reply Argument	4:00 pm, December 5, 2008

3 The deadlines for Argument and Reply Argument were subsequently extended to December 4, 2008 and December 9, 2008 respectively, due to a temporary filing system disruption.

4 The AUC received a Statement of Intention to Participate (SIP) from the Utilities Consumer Advocate (UCA). The Commission was the only party to submit Information Requests.

5 To assist with Commission analysis AE was requested to file supplemental rate impact schedules on December 15, 2008 which were based on the UCA's proposal, which is summarized in Section 3 of this Decision.

6 The close of record for this proceeding was December 15, 2008.

2 Background

7 AE's proposed 2009 Interim Tariffs would recover approximately 77% (or $45.7 million) of the Distribution revenue requirement increase and 86% (or $26.2 million) of the Transmission revenue requirement increase requested in the 2009 - 2010 General Tariff Application[1] (GTA).

8 For purposes of the Interim Application AE excluded two items it considered to be potentially contentious. These amounts, which were part of the proposed GTA revenue requirement, related to a management fee and an increase in equity thickness. AE indicated that any difference between the forecast revenues collected from the approved interim and the approved GTA final rates for 2009 would be dispensed through a future Rider G application.

9 To establish distribution rates for the Interim Application, AE proposed to apply the same methodology and application of scaling factors as was filed with the Commission in its 2009 - 2010 GTA. AE indicated that a complete explanation of the cost drivers that supported the proposed revenue requirement increases was available in its 2009-2010 GTA. AE stated that it would be filing a detailed 2010 Phase II Application shortly to address all Phase II related matters.

10 AE also proposed to amend its Rider B — Balancing Pool Adjustment to increase the refund to customers from $5.00/MW.h to $6.50/MWh, effective January 1, 2009, to align with the AESO's proposed Rider F increase.

3 Discussion of Issues

11 The UCA submitted that AE's proposed interim increases based on its requested revenue requirement were excessive and that UCA evidence related to the GTA recommended reductions in a number of areas for consideration by the Commission. These areas included the management fee, inflation, opening rate base balances, rate base additions, numerous O&M areas, corporate aircraft, income tax and the Vancouver Olympics. The UCA suggested that there were more contentious areas than the two identified in AE's Interim Application.

12 The UCA argued that AE's justification[2] in explaining how it met the AUC's two part test, which is summarized in Section 4 of this decision, did not demonstrate any form of financial hardship that it would encounter if the interim application was not approved. Given that a decision on AE's GTA is not anticipated until sometime in the second quarter or early in the third quarter of 2009, the UCA acknowledged that some form of interim increase was justified.

13 The UCA recommended that no more than 25% of the proposed GTA revenue requirement shortfall should be included in customer rates for the Distribution interim rates, and no more than 50% for the Transmission interim rates. The UCA did not oppose AE's proposed use of a scaling methodology to determine the interim rates. Additionally, the UCA did not oppose AE's proposed future Rider G application treatment for the $22.3 million refund[3] due to AE customers related to the Benchmarking and ATCO I-Tek IT True Up proceeding, provided the appropriate interest was credited to AE customers as part of the carrying charge calculations.

14 AE argued that the UCA proposal for reductions to the interim revenue requirement increases did not provide any explanation of how the proposed reductions provided a stable transition to 2010 distribution rates. AE indicated that it faced significant cost pressures regarding the services it provided and that it required the opportunity to collect the revenue required for providing these services. AE stated that further target revenue requirement reductions would negatively impact its financial position.

4 Commission Findings

15 In Decision 2005-102 [2005 CarswellAlta 2284 (Alta. E.U.B.)],[4] the Alberta Energy and Utilities Board (Board) applied a two-part test to determine the interim TFO tariff requested by AE for 2005. In doing so, the Board specifically considered the principles outlined in Decision 2005-099 [*ATCO Gas, Re*, 2005 CarswellAlta 2281 (Alta. E.U.B.)].[5] The Commission has considered the principles outlined in Decision 2005-099 in arriving at its decision for this proceeding.

16 The factors used in evaluating interim rate increases can be grouped into two categories, namely:

1. Those that relate to the quantum of, and need for, the rate increase

    • Is the identified revenue deficiency probable and material?

    • Can all or some portion of any contentious items be excluded from the amount collected?

    • Is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?

    • Can the applicant continue safe utility operations without the interim adjustment?

2. Those that relate to more general public interest considerations

    • Do the interim rates promote rate stability and ease rate shock?

    • Do the interim adjustments help maintain intergenerational equity?

    • Can interim rate increases be avoided through the use of carrying costs?

    • Are the interim rate increases required to provide appropriate price signals to customers?

    • Is it appropriate to apply the interim rider on an across-the-board basis?

17 The considerations forming each of the two categories above may be given different weighting depending on the specific circumstances surrounding each application.

18 The Commission agrees with the comments made by the UCA that AE has provided limited information with respect to the two part test to support its interim tariff request. In particular, the Commission considers that AE has not provided specific evidence to allow examination of the manner in which the principles of financial integrity, financial hardship or continuation of safe utility operations may be affected.

19 Further, the Commission considers that through the use of carrying costs, utilities can be kept whole during the transition from one revenue requirement to another.

20 The Commission notes that the UCA supported some form of interim increase.

21 Notwithstanding the above noted limitations in the evidence submitted by AE to support its request under the two-part test, the Commission acknowledges that a decision on AE's GTA may not be rendered until the second quarter or early in the third quarter of 2009. The Commission is persuaded that some interim rate increase is appropriate to minimize the shortfall for that portion of 2009, and to reduce rate shock and intergenerational inequity.

22 In arriving at its decision respecting what level of interim rate increase would be appropriate, the Commission reviewed both AE's and the UCA's proposals before it.

23 In determining the interim increase amounts the Commission is not making any findings or determinations with respect to any matters to be considered in the current GTA. The Commission notes, however, AE's position regarding the requested 2009 interim rates, that "the transition to final 2010 rates should be as smooth as possible." The Commission considers that increasing rates by the levels proposed by AE does not reflect the principle of gradualism in determining appropriate rates given that it is a reasonable assumption that the final approved rates could be based on an amount that is less than the interim increase proposed by AE, as was suggested by the UCA. In addition, the Commission considers that the level of the interim revenue requirement proposed by AE is a significantly higher dollar amount than in previous interim applications and it therefore warrants examination through the existing GTA process for such factors as changes in economic outlooks before these increases are incorporated as part of rates, including interim rates.

24 The Commission considers that to better provide both gradualism and a transitional rate level, it would be preferable to have an interim increase that reflects an intermediate position between the current rates and the proposed final rates. Based on past practice for interim rate orders in similar circumstances, the Commission has generally maintained current rates or granted 50% of the revenue requirement increase.

25 Given the above considerations, the Commission is persuaded by the UCA's argument. Accordingly the Commission approves 50% of the proposed GTA revenue requirement increase for AE's transmission tariff for 2009, and 25% of the proposed GTA revenue requirement increase for AE's distribution tariff for 2009, effective January 1, 2009, as shown in the table below:

Table 1. Commission Approved Revenue Requirement (RR) Increases for DT and TFO Tariffs

	AE 2009 GTA Proposed Total RR ($ million)	AE 2009 GTA Proposed RR Increase $ million	AE 2009 Interim Proposed RR Increase ($ million) (% Recovery)[6]	UCA 2009 Proposed Interim RR Increase ($ million) (% Recovery)[7]	Commission Approved RR Increase ($ million) (% Recovery)
DT Tariff	$421.6	$59.5	$45.7 (77%)	$14.9 (25%)	**$14.9 (25%)**
TFO Tariff	$209.2	$30.4	$26.2 (86%)	$15.2 (50%)	**$15.2 (50%)**

Table 2. Percentage Impact of Commission Approved Interim Rates vs. Current Rates for Average Use Customers (based on DT Base Rates and Rider B Components)

Rate Class	August — December 2008 DT Base Rates	Rider B	Total DT Base Rates & Rider B	January 2009 DT Base Rates	Rider B	Total DT Base Rates & Rider B	Impact
		$/month			$/month		
D-11 Residential	52.85	(3.17)	49.68	53.61	(4.12)	49.49	**0%**
D-21 Commercial	262.87	(38.69)	224.18	267.95	(50.22)	217.73	**-3%**
D-25 Irrigation	1,359.69	(63.07)	1,296.62	1,512.69	(82.58)	1,430.11	**10%**
D-26 REA Irrigation	994.85	(63.07)	931.78	1,150.60	(82.58)	1,068.02	**15%**
D-31 Industrial	524.33	(87.25)	437.08	548.86	(113.39)	435.47	**0%**
D-41 Oilfield	343.43	(47.22)	296.21	349.53	(61.41)	288.12	**-3%**
D-51 REA Farm	45.53	(6.68)	38.85	47.29	(8.68)	38.61	**-1%**
D-56 Farm	66.06	(6.68)	59.38	67.54	(8.68)	58.86	**-1%**
D-61 Street Lighting	9.15	(.46)	8.69	9.18	(.60)	8.58	**-1%**
D-63 Private Lighting	12.89	(.46)	12.43	12.95	(.60)	12.35	**-1%**
T-31 Industrial	21,296.55	(5,110.00)	16,186.55	21,670.62	(6,643.00)	15,027.62	**-7%**

26 The above table includes the tariff components which are affected by Commission findings in this Decision. Appendix 2 to this Decision (Rate Impact Schedules) provides a comparison of impacts based on the total tariff, which includes the energy component and Rider G which was only effective from August 1, 2008 to December 31, 2008.

27 With respect to the 2009 interim Distribution Tariff, the Commission notes that the UCA was not opposed to the scaling factor approach to achieve interim distribution rates. The Commission considers that AE's proposed scaling approach is a reasonable way to allocate the interim rate increase. Therefore the Commission approves the scaling factor approach to increase distribution rates by $14.9 million, as contained in Appendix 4 to this Decision (Determination of Adjustment Factors).

28 The Commission also notes AE's proposal to increase the refund associated with Rider B — Balancing Pool Adjustment from $5.00/MWh to $6.50/MWh to align with the AESO's proposed Rider F increase. The Commission approves this request so that AE may flow through the appropriate refund rider to customers. Appendix 3 of this Decision contains the Rider B Balancing Pool Rider Determination.

29 Regarding AE's proposed treatment[8] of the Benchmarking of ATCO IT and CC&B services true-up, the Commission notes the UCA did not oppose AE's Rider G approach, provided that the appropriate amount of interest was credited to AE customers as part of the carrying charge calculations. The Commission finds AE's recommendation to be reasonable. The

Commission directs AE to true-up the amount related to the Benchmarking of ATCO IT and CC&B services, currently estimated to be $22.3 million that is due to customers, as part of the next Rider G application. Additionally, the Commission directs AE to include the application of interest based on AUC Rule 23: *Rules Respecting Payment of Interest* to be credited to AE customers as part of the carrying charge calculations.

5 Order

30 IT IS HEREBY ORDERED THAT:

(1) ATCO Electric Ltd.'s 2009 Interim Distribution Tariff of $362.1 million shall be increased by $14.9 million to $377.0 million on an interim basis effective January 1, 2009, with use of the scaling factors as applied for by AE to achieve this increase.

(2) ATCO Electric Ltd.'s 2009 Transmission Facility Owner tariff of $178.8 million shall be increased by $15.2 million to $194.0 million on an interim basis effective January 1, 2009. Appendix 5 to this Decision provides the Interim 2009 Transmission Tariff.

(3) ATCO Electric Ltd.'s existing Rider B — Balancing Pool Adjustment Rider shall be increased to a refund of $6.50/MWh to coincide with the AESO Rider F increase, effective January 1, 2009.

APPENDIX 1 — 2009 Interim Distribution Tariff

ATCO ELECTRIC LTD.
2009 INTERIM DISTRIBUTION TARIFF
EFFECTIVE JANUARY 1, 2009

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PRICING ADJUSTMENTS (RIDERS)	
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Balancing Pool Adjustment	Rider B
Special Facilities Charge	Rider E
Temporary Adjustment	Rider G
Interim Adjustment	Rider J
Interim RRT Adjustment	Rider Q

Price Schedule D11 Standard Residential Service

Availability

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

Price

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

	Customer Charge	***Energy Charge***
Transmission	-	1.59 ¢ / kW.h
Distribution	41.82 ¢ / day	3.93 ¢ / kW.h
Service	26.49 ¢ / day	-
TOTAL PRICE	*68.31 ¢ / day*	*5.52 ¢ / kW.h*

Application

1. *Price Option* - the following price option may apply:

   Idle Service (Option F)

2. *Price Adjustments* - the following price adjustments (riders) may apply:

   Municipal Assessment (Rider A-1)

   Balancing Pool Adjustment (Rider B)

   Temporary Adjustment (Rider G)

   Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D21 Standard Small General Service

Availability

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

Price

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

	Customer Charge	***Demand Charge***		***Energy Charge***
			For the first 200 kW.h per kW of billing demand	**For energy in excess of 200 kW.h per kW of billing demand**
Transmission	-	7.38 ¢/kW/day	0.47 ¢ / kW.h	0.47 ¢ / kW.h
Distribution	-	14.42 ¢/kW/day	2.34 ¢ / kW.h	-
Service	30.79 ¢ / day	-	-	-
TOTAL PRICE	*30.79 ¢ / day*	*321.80 ¢/kW/day*	*32.81 ¢ / kW.h*	*30.47 ¢ / kW.h*

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

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

(b) 85% of the difference between the highest metered demand in the twelve month period including and ending with the billing period and 150 kW, if this is greater than zero;

(c) the estimated demand;

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

(e) 5 kilowatts.

Application

1. *Power Factor Correction* - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.

2. *Price Options* - the following price options may apply:

Idle Service (Option F)

Service for Non-Standard Transformation and Metering Configurations (Option H)

REA Distribution Price Credit (Option P)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Municipal Assessment (Rider A-1)

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D22 Standard Small General Service - Energy Only

Availability

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

Price

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

	Energy Charge	
	For the first 50 kW.h per kW of billing demand	**For energy in excess of 50 kW.h per kW of billing demand**
Transmission	0.56 ¢ / kW.h	0.56 ¢ / kW.h
Distribution	16.25 ¢ / kW.h	5.31 ¢ / kW.h
Service	-	-
TOTAL PRICE	*16.81 ¢ / kW.h*	*5.88 ¢ / kW.h*

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

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

(b) the estimated demand;

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

(d) 5 kilowatts.

The minimum annual charge is 12 times the sum of:

(a) the Service Charge from Price Schedule D21; and

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

Application

1. *Power Factor Correction* - where the power factor at a Point of Service is found to be less than 90%, the Company may require the installation of corrective equipment.

2. *Price Options* - the following price option may apply:

Idle Service (Option F)

Service for Non-Standard Transformation and Metering Configurations (Option H)

3. *Price Adjustments* - the following additional charges (riders) may apply:

Municipal Assessment (Rider A-1)

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D24 Standard Small General Service Isolated Industrial Areas

Availability

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

Price

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

	Customer Charge	***Demand Charge***		***Energy Charge***
			For the first 200 kW.h per kW of billing demand	**For energy in excess of 200 kW.h per kW of billing demand**
Distribution	-	14.42 ¢/kW/day	2.34 ¢ / kW.h	-
Service	30.79 ¢ / day	-	-	-
TOTAL PRICE	*30.79 ¢ / day*	*14.42 ¢/kW/day*	*2.34 ¢ / kW.h*	-

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

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

(b) 85% of the difference between the highest metered demand in the twelve month period including and ending with the billing period and 150 kW, if this is greater than zero;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD);

(e) 5 kilowatts.

Application

1. *Power Factor Correction* - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.

2. *Price Options* - the following price options may apply:

Idle Service (Option F)

Service for Non-Standard Transformation and Metering Configurations (Option H)

REA Distribution Price Credit (Option P)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Municipal Assessment (Rider A-1)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Price Schedule D25 Irrigation Pumping Service

Availability

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

Price

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

	Customer Charge	*Demand Charge*	*Energy Charge*
Transmission	-	10.49 ¢/kW/day	0.47 ¢ / kW.h
Distribution	-	6.18 ¢/kW/day	-
Service	14.41 ¢ / day	-	-
TOTAL PRICE	*14.41 ¢ / day*	*16.67 ¢/kW/day*	*0.47 ¢ / kW.h*

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

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

(b) the estimated demand;

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

(d) 5 kilowatts.

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

Application

1. *Idle Service* - in the event the service remains idle for two consecutive seasons, the Company may remove its facilities, unless the Customer pays the minimum charge for the upcoming season prior to December 31, of the preceding year.

2. *Power Factor Correction* - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D26 REA Irrigation Pumping Service

Availability

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

Price

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

Customers in the REA O & M Pool

	Customer Charge	***Demand Charge***	***Energy Charge***
Transmission	-	10.49 ¢/kW/day	0.47 ¢ / kW.h
Distribution	-	1.95 ¢/kW/day	-
Service	14.41 ¢ / day	-	-
TOTAL PRICE	*14.41 ¢ / day*	*12.43 ¢/kW/day*	*0.47 ¢ / kW.h*

Customers outside of the REA O & M Pool

	Customer Charge	***Demand Charge***	***Energy Charge***
Transmission	-	10.49 ¢/kW/day	0.47 ¢ / kW.h
Distribution	-	-	-
Service	14.41 ¢ / day	-	-
TOTAL PRICE	*14.41 ¢ / day*	*10.49 ¢/kW/day*	*0.47 ¢ / kW.h*

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

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

(b) the estimated demand;

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

(d) 5 kilowatts.

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

REA Specific Charges:

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

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

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

Application

1. *Idle Service* - in the event the service remains idle for two consecutive seasons, the Company may remove its facilities, unless the Customer pays the minimum charge for the upcoming season prior to December 31, of the preceding year.

2. *Power Factor Correction* - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D31 Large General Service / Industrial Distribution Connected

Availability

• For System Access Service and Distribution Access Service, single or three-phase distribution connected, for all Points of Service throughout the territory served by the Company. This rate is not applicable for any Small Oilfield and Pumping Power service with yearly average operating demands of less than or equal to 50 kW.

• For distribution connected loads greater than 500 kW, the Point of Service must be equipped with interval data metering.

Price

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

	Customer Charge	***Demand Charge***		***Energy Charge***
		For the first 500 kW of billing demand	**For all billing demand over 500 kW**	
Transmission	-	11.42 ¢/kW/day	4.02 ¢/kW/day	0.46 ¢ / kW.h
Distribution	12.62 ¢/day	16.56 ¢/kW/day	11.56 ¢/kW/day	-
Service	$1.6261 /day	-	0.26 ¢/kW/day	-
TOTAL PRICE	*$1.7523 /day*	*27.98 ¢/kW/day*	*25.84 ¢/kW/day*	*0.46 ¢ / kW.h*

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

(a) The highest metered demand during the billing period (including any demand delivered and billed under Price Schedules D32 and D33);

(b) 85% of the highest metered demand (including any demand delivered and billed under Price Schedules D32 and D33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD);

(e) 50 kilowatts.

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

(a) The highest metered demand during the billing period (excluding any demand delivered and billed under Price Schedules D32 and D33);

(b) 85% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D32 and D33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Transmission Contract Demand (TCD);

(e) if any of the above are equal to or greater than 1000 kW, 80% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D32 and D33) in the 24-month period.

(f) 50 kilowatts.

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

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

Charge for Deficient Power Factor - For customer power factor which is less than 90%, an additional charge for deficient power factor of 15.23¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. *Price Options* - the following price options may apply:

Idle Service (Option F)

Service for Non-Standard Transformation and Metering Configurations (Option H)

REA Distribution Price Credit (Option P)

2. *Price Adjustments* - the following price adjustments (riders) may apply:

Municipal Assessment (Rider A-1)

Balancing Pool Adjustment (Rider B)

Special Facilities Charge (Rider E)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule T31 Large General Service / Industrial Transmission Connected

Availability

- For System Access Service, for all Points of Service throughout the territory served by the Company that are directly connected to a transmission substation, and do not make any use of distribution facilities owned by ATCO Electric.

- The Point of Service must be equipped with interval data metering.

Price

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

	Demand Charge		***Energy Charge***
	For the first 500 kW of billing demand	**For all billing demand over 500 kW**	
Transmission	Current AESO DTS Rate Schedule less under frequency load shedding credit	Current AESO DTS Rate Schedule less under frequency load shedding credit	Charges per current AESO DTS Rate Schedule
Distribution	8.20 ¢/kW/day	-	-
Service	1.73 ¢/kW/day	-	-
TOTAL PRICE	*9.92 ¢/kW/day + Current AESO DTS Rate Schedule less under frequency load shedding credit*	*Current AESO DTS Rate Schedule less under frequency load shedding credit*	

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

(a) The highest metered demand during the billing period (including any contract opportunity demand delivered and billed under Price Schedule T33);

(b) 85% of the highest metered demand (including any contract opportunity demand delivered and billed under Price Schedule T33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) 50 kilowatts.

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

(a) The billing demand charged to ATCO Electric by AESO at a Point of Delivery, that is attributable to the customer at that Point of Delivery;

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

(c) the ratchet level as set out by the AESO at a Point of Delivery, *where (a) through (c) exclude any contracted Opportunity Demand delivered and billed under Price Schedule T33;*

(d) the estimated demand;

(e) the Transmission Contract Demand (TCD) for Customers served from diversified PODs, or 90% of the TCD for Customers served from dedicated PODs;

(f) 50 kilowatts

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

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

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

Application

1. *Price Options* - the following price option may apply:

Service for Non-Standard Transformation and Metering Configurations (Option H)

2. *Price Adjustments* - the following price adjustments (riders) may apply:

Municipal Assessment (Rider A-1)

Balancing Pool Adjustment (Rider B)

Special Facilities Charge (Rider E)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Price Schedule D32 Generator Interconnection and Standby Power

Availability

• For Points of Service served by the Company with on-site generating equipment connected to the distribution system, which may be used to supply load at the same site.

• To provide standby power to the on-site load in the event of a forced outage or derate of on-site generating equipment, to provide power for generator startup, and to provide supplemental power if the on-site demand requirements exceed the generator capacity.

• To provide credits to Generators for reduced DTS charges from AESO.

• To charge Generators if the Point of Delivery attracts STS charges from AESO.

• For interconnection of the generator to the distribution system.

• The Point of Service must be equipped with 4-quadrant interval data metering, for both supply and demand, the cost of which will be in addition to the charges under this rate.

Price

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

	Customer Charge		***Demand Charge***	***Energy Charge***
		For the first 500 kW of billing demand	**For all billing demand over 500 kW**	
Transmission	-	11.42 ¢/kW/day	14.02 ¢/kW/day	0.46 ¢ / kW.h
Distribution	12.62 ¢/day	16.56 ¢/kW/day	11.56 ¢/kW/day	-
Service	$1.6261 /day	-	0.26 ¢/kW/day	-
TOTAL PRICE	*$1.7523 /day*	*27.98 ¢/kW/day*	*25.84 ¢/kW/day*	*0.46 ¢ / kW.h*

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

(a) The highest metered demand during the billing period (including any demand delivered and billed under Price Schedule D33);

(b) 85% of the highest metered demand (including any demand delivered and billed under Price Schedule D33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD).

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

(a) The highest metered demand during the billing period (excluding any demand delivered and billed under Price Schedule D33);

(b) 85% of the highest metered demand (excluding any demand delivered and billed under Price Schedule D33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Transmission Contract Demand (TCD);

(e) if any of the above are equal to or greater than 1000 kW, 80% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D33) in the 24-month period including and ending with the current billing period;

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

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as *kW Billing Demand* =

kW Nameplate Rating, or *kW Billing Demand = HP Nameplate × 0.746.*

Charge for Deficient Power Factor - For customer power factor which is less than 90%, an additional charge for deficient power factor of 15.23¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest billing kW demand in the same billing period, where billing demand is as defined in this price schedule.

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

Capital Recovery Charges:

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

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

Incremental Operations and Maintenance Charges:

The minimum monthly incremental Operations and Maintenance charge will be:

(0.01315% × Incremental Interconnection Cost) per day

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

Incremental Administration and General Charges:

The minimum monthly incremental Administration and General charge will be:

(0.00432% × Incremental Interconnection Cost) per day

Generator Credits for reduction in Billing Determinants at the Point of Delivery:
*Credit = DTS * (A - B)* *Where:*

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

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

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

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

Generator Charges for a Point of Delivery:
*Charge = STS * A* *Where:*

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

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

Application

1. *Price Options* - the following price options may apply:

   Idle Service (Option F)

   Service for Non-Standard Transformation and Metering Configurations (Option H)

2. *Price Adjustments* - the following price adjustments (riders) may apply:

   Municipal Assessment (Rider A-1)

   Balancing Pool Adjustment (Rider B)

   Temporary Adjustment (Rider G)

   Interim Adjustment (Rider J)

   Interim RRT Adjustment (Rider Q)

Price Schedule D33 Transmission Opportunity Rate Distribution Connected

Availability

• Available only to Points of Service which are eligible as determined by AESO for Demand Opportunity Service, throughout the territory served by the Company for loads greater than 1,000 kW.

• Available only when AESO determines that there is sufficient transmission capacity. Service on this rate is interruptible for transmission system security reasons at AESO's request.

• The Point of Service must be equipped with revenue approved time of use metering. The cost of the time of use metering is in addition to the charges in this rate.

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

Price

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

	Customer Charges	*Demand Charges*	*Demand Charges*	*Energy Charges*	*Energy Charges*
		For all kW of Opportunity Contract Demand	**For the peak kW above the Opportunity Contract Demand**	**For all kW.h metered above the Base Demand, not exceeding the Opportunity Contract Demand**	**For all kW.h metered above the Opportunity Contract Demand**
Transmission	Transaction Charge per AESO DOS Rate Schedule	-	Per Price Schedule D32	Per AESO DOS Rate Schedule	Per Price Schedule D32
Distribution	12.62 ¢/day	16.56 ¢/kW/day	11.56 ¢/kW/day	-	-
Service	$1.6261 / day	-	0.26 ¢/kW/day	-	-
TOTAL PRICE	*$1.7523 / day + AESO DOS Rate*	*16.56 ¢/kW/day*	*11.82 ¢/kW/day + D32*	*Per AESO DOS Rate Schedule*	*Per Price Schedule D32*

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

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

Application

1. *Base Demand* - A Customer qualifying for this rate must establish a Base Demand with the Company on Price Schedule D31 prior to receiving service under this rate (which will be submitted as part of the attached form).

(a) For existing Customers, the Price Schedule D31 Base Demand will normally be the maximum billing demand in the 12 most recent billing periods.

(b) New Customers qualifying for this rate may select the Large General Service/Industrial D31 Base Demand based on forecast loads and economics, provided the Company agrees that the conditions of applicability are satisfied.

(c) Once established, the Price Schedule D31 Base Demand remains fixed for the purposes of billing all future service on this rate.

2. *Applicable Charges* - This rate schedule applies in conjunction with rate D31, in that the first block demand charges apply only to the first 500 kW of the combined demand (i.e. D31 and D33, and D32 should there be an excursion above contracted opportunity demand), and the remainder of the combined demand is subject to the second and third block

demand charges. The Service Customer Charge does not apply again as it has already been applied to the base load on Price Schedule D31.

3. *Options* - A Customer requesting service under this rate must select the provisions of one of AESO's DOS Rate Schedules. The Customer is subject to AESO's minimum Opportunity Service charges, attributable to that customer.

4. *Notice Period* - A Customer requesting service under this rate is required to provide notification as prescribed in the AESO tariff in relation to DOS service.

5. *Load Curtailment* - When a load curtailment directive is given, the load at the point of service must not exceed the Price Schedule D31 Base Demand until the Company gives notification that the interruption period is over, at which time consumption of energy may be resumed.

6. *Non-Compliance Charges* - In the event of a load curtailment directive, if the load served under this rate is not curtailed for the entire interruption period, any charges incurred by the Company will be charged to the Point of Service on this rate.

7. *Price Options* - the following price options may apply:

Service for Non-Standard Transformation and Metering Configurations (Option H)

8. *Price Adjustments* - the following price adjustments may apply:

Municipal Assessment (Rider A-1)

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

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

Customer Name:

Date of Request:
Time of Request:

1. OPPORTUNITY CONTRACT PERIOD:

Start Date: | Start Time:
End Date: | End Time:
Number of Hours in Contract Period: Hours

2. TRANSMISSION OPPORTUNITY SERVICE OPTION:

AESO "DEMAND OPPORTUNITY SERVICE": DOS 7 Minutes:
DOS 1 Hour:
DOS Term:

3. OPPORTUNITY CONTRACT DEMAND: kW

4. BASE DEMAND:

Large General Service/Industrial Price Schedule D31 Base Demand:		kW
Sum of Demands on all Opportunity Service Contracts:		kW
Total Base Demand:		kW

Confirmation: 1) ______________________ for ATCO Electric
2) ______________________ for ______________

Graphic 1

Price Schedule T33 Transmission Opportunity Rate Transmission Connected

Availability

• For System Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company that are directly connected to a transmission substation, and do not make any use of distribution facilities owned by ATCO Electric.

• Available only to Points of Service which are eligible as determined by AESO for Demand Opportunity Service, throughout the territory served by the Company from the Alberta Interconnected System for loads greater than 1,000 kW.

• Available only when AESO determines that there is sufficient transmission capacity. Service on this rate is interruptible for transmission system security reasons at AESO's request.

• The point of service must be equipped with revenue approved time of use metering. The cost of the time of use metering is in addition to the charges in this rate.

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

Price

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

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

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

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

Application

1. *Base Demand* - A Customer qualifying for this rate must establish a Base Demand with the Company on Price Schedule T31 prior to receiving service under this rate.

(a) For existing Customers, the Price Schedule T31 Base Demand will normally be the maximum billing demand in the 12 most recent billing periods.

(b) New Customers qualifying for this rate may select the Large General Service/Industrial T31 Base Demand based on forecast loads and economics, provided the Company agrees that the conditions of applicability are satisfied.

(c) Once established, the Price Schedule T31 Base Demand remains fixed for the purposes of billing all future service on this rate.

2. *Applicable Charges* - This rate schedule applies in conjunction with rate T31, in that the first block demand charges apply only to the first 500 kW of the combined demand (i.e. T31 and T33, and T31 again should there be an excursion above contracted opportunity demand), and the remainder of the combined demand is subject to the second block demand charges.

3. *Options* - A Customer requesting service under this rate must select the provisions of one of AESO's DOS Rate Schedules. The Customer is subject to AESO's minimum Opportunity Service charges, attributable to that customer.

4. *Notice Period* - A Customer requesting service under this rate is required to provide notification as prescribed in the AESO tariff in relation to DOS service.

5. *Load Curtailment* - When a load curtailment directive is given, the load at the point of service must not exceed the Price Schedule T31 Base Demand until the Company gives notification that the interruption period is over, at which time consumption of energy may be resumed.

6. *Non-Compliance Charges* - In the event of a load curtailment directive, if the load served under this rate is not curtailed for the entire interruption period, any charges incurred by the Company will be charged to the Point of Service on this rate.

7. *Price Options* - the following price option may apply:

Service for Non-Standard Transformation and Metering Configurations Option H(d).

8. *Price Adjustments* - the following price adjustments may apply:

Municipal Assessment (Rider A-1)

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

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

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

Confirmation: 1) ______________________ for ATCO Electric
2) ______________________ for ______________

Graphic 2

Price Schedule D34 Large General Service/Industrial Isolated Industrial Areas

Availability

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

Price

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

	Customer Charge	*Demand Charge*		*Energy Charge*
		For the first 500 kW of billing demand	**For all billing demand over 500 kW**	
Distribution	12.62 ¢/day	16.56 ¢/kW/day	11.56 ¢/kW/day	-
Service	$1.6261 /day	-	0.26 ¢/kW/day	-
TOTAL PRICE	*$1.7523 /day*	*16.56 ¢/kW/day*	*11.82 ¢/kW/day*	-

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

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

(b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD);

(e) 50 kilowatts.

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

Charge for Deficient Power Factor - For customer power factor which is less than 90%, an additional charge for deficient power factor of 15.23¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. *Price Options* - the following price options may apply:

   Idle Service (Option F)

   Service for Non-Standard Transformation and Metering Configurations (Option H)

   REA Distribution Price Credit (Option P)

2. *Price Adjustments* - the following price adjustments (riders) may apply:

   Municipal Assessment (Rider A-1)

   Special Facilities Charge (Rider E)

   Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Price Schedule D41 Small Oilfield and Pumping Power

Availability

For System Access Service and Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company. This rate is available only to Points of Service for production energy requirements in the petroleum and natural gas industries including related operations, such as rectifiers, cathodic protection and radio transmitters with yearly average operating demand less than or equal to 50 kilowatts.

Price

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

	Customer Charge	***Demand Charge***	***Energy Charge***
Transmission	-	9.69 ¢/kW/day	0.47 ¢ / kW.h
Distribution	40.93 ¢ / day	37.13 ¢/kW/day	-
Service	50.54 ¢ / day	-	-
TOTAL PRICE	*$0.9147 / day*	*46.82 ¢/kW/day*	*0.47 ¢ / kW.h*

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

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

(b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;

(c) the estimated demand;

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

(e) 4 kilowatts.

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

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

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

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

Charge for Deficient Power Factor - where a Customer's power factor is found to be less than 90%, the Company may require such Customers to install corrective equipment. For Customer power factor which is less than 90%, an additional charge for deficient power factor of 35.36¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. *Demand Metered* - where services are demand metered, the meter will normally be read and reset at least once every two months.

2. *Price Options* - the following price option may apply:

Idle Service (Option F)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Municipal Assessment (Rider A-1)

Balancing Pool Adjustment (Rider B)

Special Facilities Charge (Rider E)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D44 Small Oilfield and Pumping Power Isolated Industrial Areas

Availability

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

Price

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

	Customer Charge	***Demand Charge***
Distribution	40.93 ¢ / day	37.13 ¢/kW/day
Service	50.54 ¢ / day	-
TOTAL PRICE	*$0.9147 / day*	*37.13 ¢/kW/day*

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

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

(b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD);

(e) 4 kilowatts.

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

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

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

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

Charge for Deficient Power Factor - where a Customer's power factor is found to be less than 90%, the Company may require such Customers to install corrective equipment. For Customer power factor which is less than 90%, an additional charge for deficient power factor of 35.36¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. *Demand Metered* - where services are demand metered, the meter will normally be read and reset at least once every two months.

2. *Price Options* - the following price options may apply:

Idle Service (Option F)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Municipal Assessment (Rider A-1)

Special Facilities Charge (Rider E)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Price Schedule D51 REA Farm Service

Availability

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

Price

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

- Please refer to individual REA Tariffs to determine applicable REA charges.

REA Farms in O & M Pool

	Customer Charge	*Demand Charge*	*Energy Charge*
Transmission	-	5.38 ¢/kV.A/day	0.47 ¢ / kW.h
Distribution	-	8.57 ¢/kV.A/day	-
Service	33.11 ¢ / service / day	-	-
REA Specific Charges	See REA Tariff	-	-
Total Price	*C{ 1} ¢ / service/ day*	*13.95 ¢/kV.A/day*	*0.47 ¢ / kW.h*

REA Farms Outside of O & M Pool

	Customer Charge	*Demand Charge*	*Energy Charge*
Transmission	-	5.38 ¢/kV.A/day	0.47 ¢ / kW.h
Distribution	See REA Tariff	See REA Tariff	-
Service	See REA Tariff	-	-
REA Specific Charges	See REA Tariff	-	-
Total Price	*C{ 1} ¢ / service /day*	*D{ 1} ¢/kV.A/day*	*0.47 ¢ / kW.h*

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

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

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

(b) For non-breakered REA farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:

i. the highest metered kV.A demand during the billing period;

ii. the estimated demand;

iii. 25 kV.A.

REA Specific Charges

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

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

Application

1. *Demand Metering* - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions.

2. *Price Option* - the following price option may apply:

Idle Service (Option F)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Price Schedule D52 REA Farm Service Excluding Wire Services Provider Functions

Availability

• Applicable to any Rural Electrification Association, for whom the Company is not acting as the Wire Services Provider, as defined in the EUA.

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

Price

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

	Customer Charge	*Demand Charge*	*Energy Charge*
Transmission	-	5.38 ¢/kV.A/day	0.47 ¢ / kW.h
Distribution	-	-	-
Service	24.78 ¢/service/day	-	-
TOTAL PRICE	*24.78 ¢/service/day*	*5.38 ¢/kV.A/day*	*0.47 ¢ / kW.h*

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

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

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

(b) For non-breakered REA farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:

i. the highest metered kV.A demand during the billing period;

ii. the estimated demand;

iii. 25 kV.A.

Application

1. *Demand Metering* - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions.

2. *Price Option* - the following price option may apply:

Idle Service (Option F)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D56 Farm Service

Availability

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

Price

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

	Customer Charge	***Demand Charge***	***Energy Charge***
Transmission	-	5.38 ¢/kV.A/day	0.47 ¢ / kW.h
Distribution	19.84 ¢/service/day	12.39 ¢/kV.A/day	0.47 ¢ / kW.h
Service	33.11 ¢/service/day	-	-
TOTAL PRICE	*52.95 ¢/service/day*	*17.77 ¢/kV.A/day*	*0.94 ¢ / kW.h*

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

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

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

(b) For non-breakered farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:

i. the highest metered kV.A demand during the billing period;

ii. the estimated demand;

iii. the contract demand;

iv. 25 kV.A.

Application

1. *Demand Metering* - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions for Distribution Service Connections.

2. *Price Options* - the following price option may apply:

Idle Service (Option F)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D61 Street Lighting Service

Availability

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

• Not available for private lighting.

Price

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

Decorative Lighting (61 A)

• For decorative lighting fixtures installed, owned and maintained by the Company.

• The customer is responsible for the full cost of installation.

• Includes maintenance only.

• Specific contracts may require customers to purchase and maintain inventory of decorative lamps if the customer's lighting fixtures are not the same as the standard used by the company.

	Decorative Lamps	
	Customer Charge	**Demand Charge**
Transmission	-	0.016 ¢ /watt/day
Distribution	16.74 ¢/fixture/day	0.017 ¢ /watt/day
Service	5.61 ¢/fixture/day	-
TOTAL PRICE	*22.35 ¢/fixture/day*	*0.033¢ /watt/day*

Investment Option (61 B)

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

	All Lamps	
	Customer Charge	**Demand Charge**
Transmission	-	0.016 ¢ /watt/day
Distribution	45.95 ¢/fixture/day	0.017 ¢ /watt/day
Service	5.61 ¢/fixture/day	-
TOTAL PRICE 51.56	*¢/fixture/day*	*0.033 ¢ /watt/day*

Distribution Investment Option (61 C)

• For customer owned and installed lighting.

• For installation and maintenance of distribution facilities up to, but not including the customer owned conductor serving the light fixtures.

• The Company may require that the Point of Service be metered and served on Price Schedule D21, if the load requirements change over time, or if loads that are not lighting loads are served from the same Point of Service.

	All Lamps	
	Customer Charge	**Demand Charge**
Transmission	-	0.016 ¢ /watt/day
Distribution	22.09 ¢/fixture/day	0.017 ¢ /watt/day
Service	5.61 ¢/fixture/day	-
TOTAL PRICE	*27.70 ¢/fixture/day*	*0.033 ¢ /watt/day*

No Investment Option (61 E)

• Available for new installations only.

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

• The customer is responsible for the full cost of installation.

- The customer is responsible for the full cost of replacement.

- Includes maintenance only.

	All Lamps	
	Customer Charge	**Demand Charge**
Transmission	-	0.016 ¢ /watt/day
Distribution	16.74 ¢/fixture/day	0.017 ¢ /watt/day
Service	5.61 ¢/fixture/day	-
TOTAL PRICE	*22.35 ¢/fixture/day*	*0.033 ¢ /watt/day*

Application

1. *Price Option* - the following price option may apply:

    Idle Service (Option F)

2. *Price Adjustments* — the following price adjustments (riders) may apply:

    Municipal Assessment (Rider A-1)

    Balancing Pool Adjustment (Rider B)

    Temporary Adjustment (Rider G)

    Interim Adjustment (Rider J)

    Interim RRT Adjustment (Rider Q)

Price Schedule D63

Availability

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

Price

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

Investment Option (63 A)

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

	Customer Charge	**Demand Charge**
Transmission	-	0.016 ¢ /watt/day
Distribution	22.56 ¢/fixture/day	0.014 ¢ /watt/day

Service	13.09 ¢/fixture/day	-
TOTAL PRICE	*35.65 ¢/ fixture/day*	*0.030 ¢ / watt/day*

Summer Village Option (63 B)

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

	Customer Charge	***Demand Charge***
Transmission	-	0.016 ¢ /watt/day
Distribution	36.37 ¢/fixture/day	0.014 ¢ /watt/day
Service	13.09 ¢/fixture/day	-
TOTAL PRICE	*49.46 ¢/fixture/day*	*0.030 ¢ / watt/day*

No Investment Option (63 C)

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

	Customer Charge	***Demand Charge***
Transmission	-	0.016 ¢ /watt/day
Distribution	11.97 ¢/fixture/day	0.004 ¢ /watt/day
Service	13.09 ¢/fixture/day	-
TOTAL PRICE	*25.06 ¢/fixture/day*	*0.020 ¢ / watt/day*

Metering Option (63 D)

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

	Customer Charge	***Demand Charge***
Transmission	-	0.016 ¢ /watt/day
Distribution	23.94 ¢/fixture/day	0.014 ¢ /watt/day
Service	13.09 ¢/fixture/day	-
TOTAL PRICE	*47.03 ¢/fixture/day*	*0.030 ¢ / watt/day*

Distribution Investment Option (63 E)

- For customer owned and installed lighting.

• For installation and maintenance of distribution facilities up to, but not including the customer owned conductor serving the light fixtures.

• The Company may require that the Point of Service be metered and served on Price Schedule D21, if the load requirements change over time, or if loads that are not lighting loads are served from the same Point of Service.

	Customer Charge	*Demand Charge*
Transmission	-	0.016 ¢ /watt/day
Distribution	15.66 ¢/fixture/day	0.014 ¢ /watt/day
Service	13.09 ¢/fixture/day	-
TOTAL PRICE	*28.75 ¢/fixture/day*	*0.030 ¢ / watt/day*

Application

1. *Price Adjustments* - the following price adjustments (riders) may apply:

Municipal Assessment (Rider A-1)

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Option F Idle Service

Availability

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

Price Adjustment

The Idle Service charges shall be:

Price Schedule	***Applicability***	***Idle Service Charge***
D11	Service outside cities, towns, villages, hamlets, Indian reserves and Metis settlements	The price schedule monthly Distribution Customer Charge plus the Transmission Customer Charge.
D21—D22	Service outside cities, towns, villages, hamlets, Indian reserves and Metis settlements	The sum of the Distribution Demand Charge plus the Transmission Demand Charge where:—(a) Distribution Demand Charge is the greater of the contract demand or rate minimum, and—(b) Transmission Demand Charge is the price schedule rate minimum
D24—D34—D44	All Points of Service	The sum of the Distribution Demand Charge where the Distribution Demand Charge is the greater of the contract demand or rate minimum.

D25—D26	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).
D31—D32—D41	All Points of Service	The sum of the Distribution Demand Charge plus the Transmission Demand Charge where:—(a) Distribution Demand Charge is the greater of the contract demand or rate minimum, and—(b) Transmission Demand Charge is the greater of the contract demand or rate minimum
D33	All Points of Service	Charges based on base demand level established under Price Schedule D31.
T31	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).
T33	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).
D51—D52—D56	All Points of Service	The sum of the Distribution Customer charge and the Distribution and Transmission Demand Charges applicable to a 3 kV.A service.
D61	All Points of Service	The sum of the Distribution Demand Charge plus the Transmission Demand Charge
D63	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).

Application

1. If the Customer's Point of Service is reconnected within 12 months of disconnection, the minimum monthly charge for each month of disconnection will be applied to the Point of Service.

2. For further information on idle services, refer to Terms and Conditions 14.1 — Disconnection and Idle Service.

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

Option H Service for Non-Standard Transformation and Metering configurations

Availability

• For Points of Service throughout the territory served by the Company under Price Schedule D21, D22, D31, T31, D32 where metering and / or delivery voltage are non-standard.

• Standard service for distribution connected customers is delivered and metered at the utilization voltage. When delivery or metering is necessary at other voltages, for the convenience of either the customer or the Company, bills for service will be adjusted as outlined below in (a) to (c).

• Standard service for transmission connected customers is delivered to the customer and metered at the substation voltage. When delivery is required at lower voltages, bills for service will be adjusted as outlined below in (d). Section (b) may also apply to transmission connected customers.

Price Adjustment

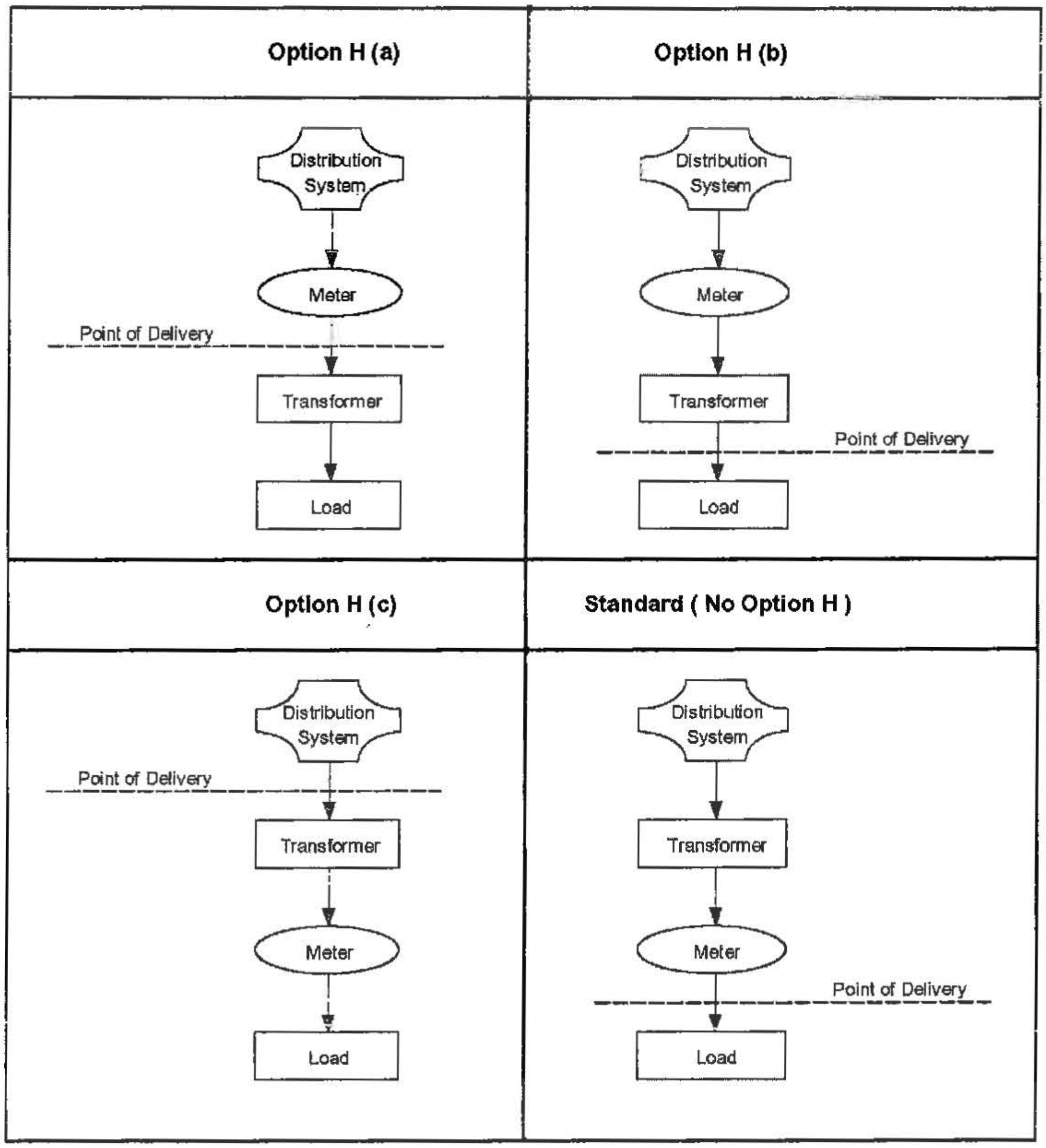
(a) If the point of delivery and metering is on the primary side (25 kV) of a transformer (including cases where one-point service is required by the customer for more than a single utilization voltage or point of use), and the customer owns or rents the necessary transformer(s), a *discount of 2.88 ¢/kW/day* of billing demand will be applied. This adjustment does not apply o customers connected directly to the transmission system who are exempt from the Distribution Charge on the applicable rate.

(b) If primary or higher voltage delivery metering is desirable for the convenience of the Company, or to improve accessibility, etc., *demand and energy measurements will be reduced by 1%* so as to approximate secondary voltage delivery conditions.

(c) If primary or higher voltage delivery is made to customer owned transformers, but metering is at secondary or utilization voltage for the Company's convenience, *demand and energy measurements will be increased by 1%* so as to approximate primary or transmission voltage delivery conditions and *a discount, as specified in (a)* shall apply.

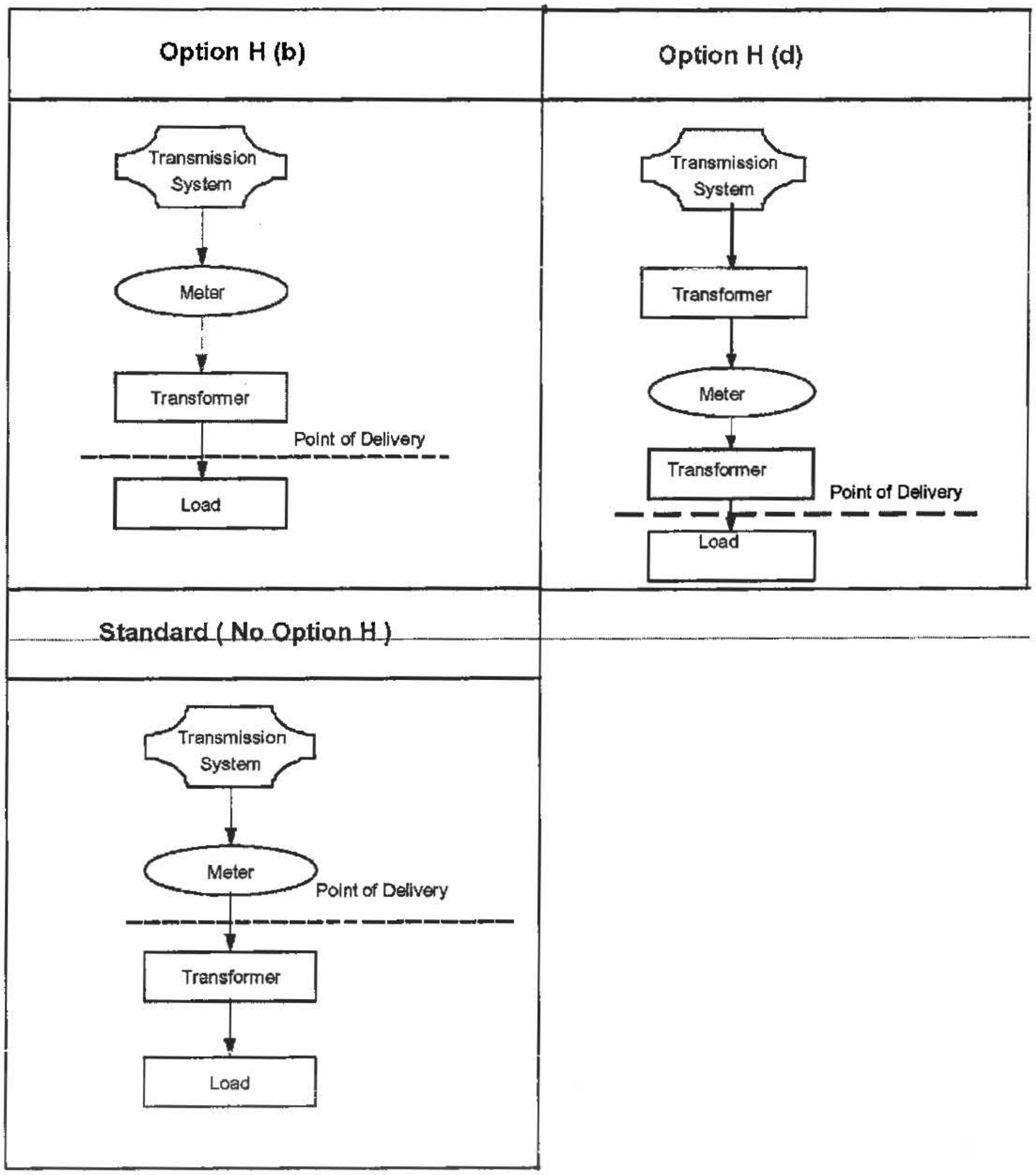
(d) Customers who are connected directly to the transmission system, but take service from the low side of a transformer (with primary side 25kV), and do not own or rent any necessary transformer(s), and are exempt from the Distribution Charge on the applicable rate, a *surcharge of 2.88 ¢/kW/day* of billing demand will apply.

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



Graphic 3

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



Graphic 4

Option P REA Distribution Price Credit

Availability

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

Price Adjustment

Standard Small General Service Price Schedule D21

For REA farm Points of Service electing to take service under Small General Service Price Schedule D21, a credit adjustment of 42% will be applied to the base bill.

Large General Service / Industrial Price Schedule D31

For REA farm Points of Service electing to take service under Large General Service / Industrial Price Schedule D31, a credit adjustment of 28% will be applied to the base bill.

Rider A-1 Municipal Assessment

Availability

• Applicable throughout the territory served by the Company to electric service within the municipalities identified in Table 2.

• The following are exempt from the surcharge:

(a) Farm customers (Price Schedules D51, D52 and D56)

(b) Irrigation Pumping customers (Price Schedule D25 and D26)

(c) Customers within Indian Reservations not listed in Table 2

(d) Special Facilities Charge (Rider E) customers

Price Adjustment

• The Company pays to a municipality each year or month, in accordance with the franchise agreement between the Company and the municipality, a percent of the gross revenue, or wires revenue, of the Company derived from the sale or delivery of electricity to the consumers in the municipality.

• The percentage of gross revenue (franchise fee and/or tax), or wires revenue, to be paid by the Company to its franchised municipalities is given by category number in Table 1. The municipalities, and their category numbers, are listed in Table 2. For Category 7 the municipalities and percentages of yearly wires revenue are listed in Table 3. For Category 8 the municipalities and percentages of monthly wires revenue are listed in Table 4.

• For all categories except Category 8, an estimated surcharge will be added to each customer's bill within a municipality in order to recover the above payments. Adjustments will be made once each year for any difference between the estimated surcharge collected and the actual surcharge required.

• For Category 8, the percentages listed in Table 4 will be applied to the monthly billing. The amount billed will be paid to the municipality in accordance with the franchise agreement between the Company and the municipality.

Table 1 — Percent of Gross Revenue by Category

CATEGORY 1	2% of the first $100,000 of gross revenue;—3% of the next $200,000 of gross revenue;—4% of

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

Table 2 — Category Numbers of Municipalities

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

Table 2 — Category Numbers of Municipalities

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

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

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

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

Beaverlodge	7.20%	High Prairie	7.80%	Oyen	7.75
Botha	4.50%	Hines Creek	6.50%	Radway (County 7)	3.00%
Carbon	3.50%	Hythe	7.25%	Rycroft	4.30%
Cereal	5.00%	Jasper (ID)	7.50%	Sexsmith	8.20%
Donnelly	5.00%	Kitscoty	5.00%	Stettler	7.50%
Fort McMurray	7.60%	Manning	7.50%	Wembley	6.70%
Fox Creek	6.30%	McLennan	8.25%	Youngstown	4.00%
Galahad	6.75%	Morrin	6.00%		
Girouxville	7.00%	Munson	3.00%		
Grimshaw	7.50%	Nampa	5.00%		

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

Alliance	6.00%	Forestburg	1.00%	Peace River	5.00%
Andrew	2.00%	Fox Creek	4.50%	Rainbow Lake	7.75%
Berwyn	1.75%	Gadsby	5.00%	Rosalind	0.50%
Big Valley	1.00%	Glendon	1.50%	Slave Lake	7.10%
Bonnyville	6.80%	Grande Cache	4.60%	Smoky Lake	3.25%
Castor	5.00%	Grande Prairie	7.75%	Spirit River	4.50%
Cold Lake	4.25%	Halkirk	1.00%	St Paul	7.00%
Consort	3.50%	Hanna	3.50%	Swan Hills	4.00%
Coronation	3.75%	High Level	6.50%	Three Hills	5.00%
Delia	0.50%	High Prairie	6.25%	Trochu	3.50%
Delburne	1.50%	Innisfree	1.50%	Two Hills	2.75%
Derwent	6.00%	Kinuso	3.50%	Valleyview	5.25%
Donalda	1.50%	Linden	4.00%	Vegreville	5.00%
Drumheller	9.00%	Lloydminster	10.50%	Vermilion	3.50%
Elk Point	3.60%	Mannville	2.50%	Veteran	3.00%
Elnora	1.00%	Marwayne	2.30%	Vilna	4.00%
Empress	2.00%	Minburn	1.00%	Willingdon	2.00%
Fairview	6.00%	Myrnam	2.00%		
Falher	6.25%	Paradise Valley	2.00%		

Rider E Special Facilities Charge

Availability

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

Price

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

Application

• Facility charges will normally be billed monthly. Monthly charges are subject to change as new facilities are added or currently installed facilities are retired.

• For facilities shared among more than one customer, a separate contract will be established for each customer making use of the facilities.

• Facilities constructed under Rider E are owned and maintained by the Company.

Rider B Balancing Pool Adjustment

Availability

• This Rider B is designed to flow through a Balancing Pool Refund from the Alberta Electric System Operator (AESO).

• Applicable to all customers with the exception of customers served on Price Schedule D24, Price Schedule D34, and Price Schedule D44, at points of service, throughout the territory served by the Company for energy consumption effective January 1, 2009.

• The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Applicable Distribution Tariff Price Schedule	***Charge (¢/kW.h) "+" = Charge "-" = Refund***
D11 Residential	-0.687
D21 Small General Service	-0.688
D22 Small General Service — Energy Only	-0.688
D25 Irrigation Pumping Service	-0.707
D26 REA Irrigation Pumping Service	-0.707
D31 Large General Service/Industrial — Distribution Connected	-0.681
T31 Large General Service/Industrial — Transmission Connected	Flow through
D32 Generator Interconnection and Standby Power	-0.681
D33 Transmission Opportunity Rate — Distribution Connected	-0.681
T33 Transmission Opportunity Rate — Transmission Connected	Flow through
D41 Small Oilfield and Pumping Power	-0.701
D51 REA Farm Service	-0.692
D52 REA Farm Service — Excluding Wires Service Provider	-0.692
D56 Farm Service	-0.692
D61 Street Lighting Service	-0.687
D63 Private Lighting Service	-0.686

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

Rider G Temporary Adjustment

Availability

- This Rider G is designed to true-up 2005 Rider G and dispense of new deferral balances.

- Applicable to all customers, at points of service, throughout the territory served by the Company for energy consumption effective January 1, 2009.

- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Applicable Distribution Tariff Price Schedule	*Charge (¢/kW.h) "+" = Charge "-" = Refund*
D11 Residential	0.000
D21 Small General Service	0.000
D22 Small General Service — Energy Only	0.000
D25 Irrigation Pumping Service	0.000
D26 REA Irrigation Pumping Service	0.000
D31 Large General Service/Industrial — Distribution Connected < 2MW	0.000
D31 Large General Service/Industrial — Distribution Connected > 2MW	0.000
T31 Large General Service/Industrial — Transmission Connected < 2MW	0.000
T31 Large General Service/Industrial — Transmission Connected > 2MW	0.000
D32 Generator Interconnection and Standby Power < 2 MW	0.000
D32 Generator Interconnection and Standby Power > 2 MW	0.000
D33 Transmission Opportunity Rate — Distribution Connected	0.000
T33 Transmission Opportunity Rate — Transmission Connected	0.000
D41 Small Oilfield and Pumping Power	0.000
D51 REA Farm Service	0.000
D52 REA Farm Service — Excluding Wires Service Provider	0.000
D56 Farm Service	0.000
D61 Street Lighting Service	0.000
D63 Private Lighting Service	0.000

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

Rider J Interim Adjustment

Availability

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

Rider Q RRT Adjustment

Availability

- Rider Q is designed to true-up outstanding 2003 and 2004 Non-Energy Regulated Rate Tariff (RRT) matters.

• The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Price

This Rider will apply on energy consumption effective January 1, 2009.

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

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

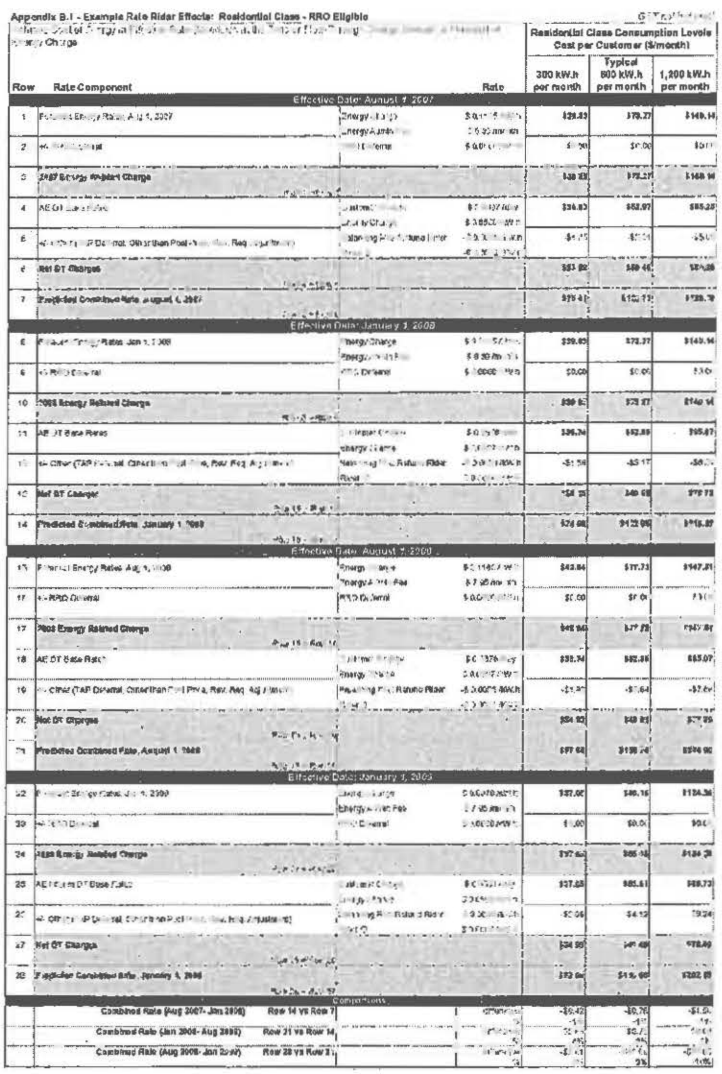
APPENDIX 2 — Rate Impact Schedules

ATCO Electric 2009 Interim Tariff Application

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

	January 1, 2008					***August 1, 2008***					***January 1, 2009***				
Rate Class	***DT Base Rates***	***Rider G***	***Rider Q***	***Rider B***	***Net***	***DT Base Rates***	***Rider G***	***Rider Q***	***Rider B***	***Net***	***DT Base Rates***	***Rider G***	***Rider Q***	***Rider B***	***Net***
D11 Residential—600 kWh	$52.85	$0.00	$0.00	-$3.17	$49.68	$52.85	-$0.67	$0.00	-$3.17	$49.01	$53.61	$0.00	$0.00	-$4.12	$49.49
D21 Commercial—20 kW; 7300 kWh	$262.87	$0.00	$0.00	-$38.69	$224.18	$262.87	-$27.81	$0.00	-$38.69	$196.37	$267.95	$0.00	$0.00	-$50.22	$217.72
D31 Industrial—50 kW; 16,650 kWh	$524.33	$0.00	$0.00	-$87.25	$437.08	$524.33	-$63.44	$0.00	-$87.25	$373.64	$548.86	$0.00	$0.00	-$113.39	$435.47
D41 Oilfield—20 kW; 8,760 kWh	$343.43	$0.00	$0.00	-$47.22	$296.21	$343.43	-$45.55	$0.00	-$47.22	$250.66	$349.53	$0.00	$0.00	-$61.41	$288.13
D51 REA Pooled—7	$45.53	$0.00	$0.00	-$6.68	$38.85	$45.53	$1.18	$0.00	-$6.68	$40.03	$47.29	$0.00	$0.00	-$8.68	$38.60

.5 kVA; 1,255 kWh															
D56 Farm—7.5 kVA; 1,255 kWh	$66.06	$0.00	$0.00	-$6.68	$59.38	$66.06	-$5.50	$0.00	-$6.68	$53.88	$67.54	$0.00	$0.00	-$8.68	$58.85
D61 Street Lights—250 Watts	$9.15	$0.00	$0.00	-$0.46	$8.68	$9.15	-$2.93	$0.00	-$0.46	$5.76	$9.18	$0.00	$0.00	-$0.60	$8.58
D63 Private Lights—250 Watts	$12.89	$0.00	$0.00	-$0.46	$12.43	$12.89	-$3.23	$0.00	-$0.46	$9.20	$12.95	$0.00	$0.00	-$0.60	$12.34
T31 Industrial—2 MW 1,022 MWh	$19,041.87	$0.00	$0.00	-$5,110.00	$13,931.87	$21,296.55	-$5,110.00	$0.00	-$5,110.00	$11,076.55	$21,670.62	$0.00	$0.00	-$6,643.00	$15,027.62


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

Row	Rate Component	Rate	300 kW.h per month	Typical 600 kW.h per month	1,200 kW.h per month

Residential Class Consumption Levels Cost per Customer ($/month)

Graphic 5

Appendix B 2 - Example Rate Rider Effects: Small General Service Class - RRO Eligible

Row	Rate Component		Rate	Small General Service Class Consumption Levels Cost per Customer ($/month) 5,475 kW.h per month Demand 15 kW	Typical 7,300 kW.h per month Demand 20 kW	9,125 kW.h per month Demand 25 kW
	Effective Date: August 1, 2007					
1	[illegible]	Energy Charge Energy Admin Fee	[illegible]	[illegible]	$819.79	$1,023.1[illegible]
2	[illegible]	[illegible]	[illegible]	[illegible]	$0.00	[illegible]
3	2007 Energy Related Charge			[illegible]	[illegible]	[illegible]
4	[illegible] DT Base Rates	[illegible]	[illegible]	$190.8[illegible]	$201.8[illegible]	[illegible]
5	[illegible]	[illegible] Pool Refund Rider	[illegible]	[illegible]	[illegible]	[illegible]
6	Net DT Charges			[illegible]	[illegible]	[illegible]
7	Predicted Combined Rate, August 1, 2007			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2008					
8	[illegible]	Energy Charge Energy Admin Fee	[illegible]	$615.44	[illegible]	$1,023.1[illegible]
9	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
10	2008 Energy Related Charge			[illegible]	[illegible]	[illegible]
11	[illegible] Base Rates	[illegible]	[illegible]	$190.4[illegible]	$262.87	$326.27
12	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
13	Net DT Charges			[illegible]	[illegible]	[illegible]
14	Predicted Combined Rate, January 1, 2008			[illegible]	[illegible]	[illegible]
	Effective Date: August 1, 2008					
15	[illegible] Energy Rates, Aug 1, 2008	Energy Charge Energy Admin Fee	[illegible]	[illegible]	[illegible]	[illegible]
16	+/- RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
17	2008 Energy Related Charge			[illegible]	[illegible]	[illegible]
18	[illegible] DT Base Rates	[illegible] Energy Charge Blk 2 Demand Charge	[illegible]	$190.4[illegible]	$262.87	$326.27
19	[illegible]	[illegible] Pool Refund Rider	[illegible]	[illegible]	[illegible]	[illegible]
20	Net DT Charges			[illegible]	[illegible]	[illegible]
21	Predicted Combined Rate, August 1, 2008			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2009					
22	[illegible] Energy Rates, Jan 1, 2009	Energy Charge Energy Admin Fee	[illegible]	[illegible]	$714.5[illegible]	[illegible]
23	+/- RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
24	2009 Energy Related Charge			[illegible]	[illegible]	[illegible]
25	[illegible] Rates	[illegible] Energy Charge Blk 1 Energy Charge Blk 2 Demand Charge	[illegible]	[illegible]	[illegible]	[illegible]
26	[illegible] Deferral, [illegible]	[illegible] Refund Rider [illegible]	[illegible]	[illegible]	[illegible]	[illegible]
27	Net DT Charges			[illegible]	[illegible]	[illegible]
28	Predicted Combined Rate, January 1, 2009			[illegible]	[illegible]	[illegible]
	Comparisons					
	Combined Rate (Aug 2007 - Jan 2008)	Row 14 vs Row 7	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008 - Aug 2008)	Row 21 vs Row 14	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008 - Jan 2009)	Row 28 vs Row 21	[illegible]	[illegible]	[illegible]	[illegible]

Graphic 6

Appendix B 3 - Example Rate Rider Effects: Small General Service Class - Not RRO Eligible

Row	Rate Component		Rate	Small General Service Class Consumption Levels Cost per Customer ($/month) 5,475 kW.h per month Demand 15 kW	Typical 7,300 kW.h per month Demand 20 kW	9,125 kW.h per month Demand 25 kW
	Effective Date: August 1, 2007					
1	Forecast Energy Rates, Aug 1, 2007	Energy Charge [illegible]	[illegible]	$616.44	$819.28	$1,023.12
2	[illegible] RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	2007 Energy Related Charge			[illegible]	[illegible]	$1,023.[illegible]
4	AE DT [illegible]	[illegible]	[illegible]	$100.66	$281.[illegible]	$323.45
5	[illegible] TAP Deferral [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	Net DT Charges			[illegible]	[illegible]	[illegible]
7	Predicted Combined Rate, August 1, 2007			[illegible]	[illegible]	$1,[illegible]
	Effective Date: January 1, 2008					
[illegible]	Forecast Energy Rates, Jan 1, 2008	Energy Charge [illegible] Fee	[illegible] $0.42 [illegible]	$518.44	$819.79	$1,023.11
9	[illegible] Deferral	[illegible] Deferral	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	2008 Energy Related Charge			[illegible]	[illegible]	[illegible]
11	[illegible]	Customer Charge [illegible]	[illegible]	$180.48	$263.87	$339.27
12	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	Net DT Charges			[illegible]	[illegible]	$277.[illegible]
[illegible]	Predicted Combined Rate, January 1, 2008			[illegible]	[illegible]	[illegible]
	Effective Date: August 1, 2008					
[illegible]	Forecast Energy Rates, Aug 1, 2008	Energy Charge [illegible] Fee	[illegible]	$642.54	$881.00	$1,075.24
16	[illegible]	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
17	2008 Energy Related Charge			[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	$100.48	$262.87	$329.37
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
20	Net DT Charges			[illegible]	[illegible]	[illegible]
21	Predicted Combined Rate, August 1, 2008			[illegible]	[illegible]	$1,[illegible]
	Effective Date: January 1, 2009					
22	Forecast Energy Rates, Jan 1, 2009	Energy Charge Energy Access Fee	[illegible]	$538.[illegible]	$714.52	$891.[illegible]
23	[illegible] RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	2009 Energy Related Charge			[illegible]	$714.[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	$380.37	$267.[illegible]	$333.[illegible]
[illegible]	[illegible] TAP Deferral [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
27	Net DT Charges			[illegible]	[illegible]	[illegible]
[illegible]	Predicted Combined Rate, January 1, 2009			[illegible]	[illegible]	$1,[illegible]
	Comparisons					
	Combined Rate (Aug 2007 - Jan 2008)	Row 14 vs Row 7	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008 - Aug 2008)	Row 21 vs Row 14	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008 - Jan 2009)	Row 28 vs Row 21	[illegible]	[illegible]	[illegible]	[illegible]

Graphic 7

Appendix B 4 - Example Rate Rider Effects: Large General Service Distribution - RRO Eligible

Row	Rate Component		Rate	12,200 kW.h per month Demand 50 kW	Typical 16,850 kW.h per month Demand 50 kW	20,800 kW.h per month Demand 50 kW
	Effective Date: August 1, 2007					
1	[illegible] Energy [illegible], 2007	Energy Charge [illegible]	[illegible]	$1,310.36	$1,764.82	$2,227.36
2	[illegible]	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
3	2007 Energy Related Charge			[illegible]	[illegible]	[illegible]
4	AE DT Base Rates	[illegible] Energy Charge, Demand Charge [illegible]	[illegible]	$475.94	$407.55	$565.25
5	[illegible] Other (TAP Deferral, [illegible])	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6	Net DT Charges			[illegible]	[illegible]	[illegible]
7	Predicted Combined Rate August 1, 2007			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2008					
8	[illegible]	Energy Charge [illegible]	[illegible]	$1,310.36	$1,764.82	$2,227.36
9	[illegible] RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	$0.0[illegible]
10	2008 Energy Related Charge			[illegible]	$1,764.82	[illegible]
11	AE DT Base Rates	[illegible] Energy Charge, Demand Charge [illegible]	[illegible]	$592.74	$524.33	$514.77
12	[illegible] Other (TAP Deferral, [illegible])	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
13	Net DT Charges			[illegible]	[illegible]	[illegible]
14	Predicted Combined Rate January 1, 2008			[illegible]	[illegible]	[illegible]
	Effective Date: August 1, 2008					
15	[illegible] Energy [illegible], Aug 1, 2008	Energy Charge, Energy Admin Fee	[illegible]	$1,381.33	$1,854.78	$2,314.87
16	[illegible] RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	$0.00
17	2008 Energy Related Charge			[illegible]	[illegible]	[illegible]
18	AE DT Base Rates	[illegible] Energy Charge, Demand Charge [illegible]	[illegible]	$592.74	$524.33	$514.77
19	[illegible] Other (TAP Deferral, [illegible])	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
20	Net DT Charges			[illegible]	[illegible]	[illegible]
21	Predicted Combined Rate August 1, 2008			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2009					
22	[illegible]	Energy Charge, Energy Admin Fee	[illegible]	$1,181.84	[illegible]	$1,957.54
23	[illegible]	[illegible] Deferral	[illegible]	[illegible]	[illegible]	[illegible]
24	2009 Energy Related Charge			[illegible]	[illegible]	[illegible]
25	[illegible] DT [illegible]	[illegible] Energy Charge, Demand Charge [illegible]	[illegible]	[illegible]	[illegible]	[illegible]
26	[illegible] Other (TAP Deferral, [illegible] Adjustment)	[illegible]	[illegible]	[illegible]	-$113	[illegible]
27	Net DT Charges			[illegible]	[illegible]	[illegible]
28	Predicted Combined Rate January 1, 2009			[illegible]	[illegible]	[illegible]
	Comparisons					
	Combined Rate (Aug 2007- Jan 2008)	Row 14 vs Row 7	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008- Aug 2008)	Row 21 vs Row 14	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008- Jan 2009)	Row 28 vs Row 21	[illegible]	[illegible]	[illegible]	[illegible]

Graphic 8

Appendix B-5 - Example Rate Rider Effects: Large General Service Distribution - Not RRO Eligible

[illegible]

Row	Rate Component	Rate		Large General Service Class Consumption Levels Cost per Customer ($/month): 657,000 kW.h per month Demand 1,500 kW	Typical 876,000 kW.h per month Demand 2,000 kW	1,095,000 kW.h per month Demand 2,500 kW
	Effective Date: August 1, 2007					
1	[illegible] Energy Rate, Aug 1, [illegible]	Energy Charge Energy Admin Fee	$0.[illegible]/kWh $[illegible]	$70,053.84	$93,405.12	$116,756.80
2	[illegible]	RRO Deferral	$[illegible]	$[illegible]	$[illegible]	$[illegible]
3	**2007 Energy Related Charge**			$70,053.84	$93,405.12	$116,756.80
4	AE DT Base Rates	Customer Charge Energy Charge Demand Charge Blk 1 Demand Charge Blk 2 Balancing Pool Refund Rider [illegible]	[illegible]	$13,943.45	$18,013.95	$21,027.20
5	+/- Other (TAP Deferral, Other than [illegible], Rev. Req. Adj. [illegible])			-$3[illegible]	-$[illegible]	-$[illegible]
6	**Net DT Charges**			$12,794.[illegible]	$[illegible]	$20,444.00
7	**Predicted Combined Rate, August 1, 2007**			$[illegible]	$[illegible]	$137,[illegible]
	Effective Date: January 1, 2008					
8	[illegible] Energy Rate, Jan 1, 2008	Energy Charge Energy Admin Fee	$0.1[illegible] $0.[illegible]	$70,053.04	$93,405.72	$116,756.80
9	+/- RRO Deferral	RRO Deferral	$0.[illegible]	$[illegible]	$0.00	$0.00
10	**2008 Energy Related Charge**			$70,0[illegible]	$9[illegible]	$11[illegible]
11	AE DT Base Rates	Customer Charge Energy Charge Demand Charge Blk 1 Demand Charge Blk 2 Balancing Pool Refund Rider [illegible]	[illegible]	$14,137.01	$18,000.71	$23,262.41
12	+/- Other (TAP Deferral, Other than [illegible], Rev. Req. Adj. [illegible])			-$3,142.[illegible]	-$4,5[illegible]	-$[illegible]
13	**Net DT Charges**			$10,994.[illegible]	$[illegible]	$17,[illegible]
14	**Predicted Combined Rate, January 1, 2008**			$[illegible]	$[illegible]	$[illegible]
	Effective Date: August 1, 2008					
15	[illegible] Energy Rate, Aug 1, 2008	Energy Charge Energy Admin Fee	$0.11[illegible]/kWh $[illegible]	$72,873.76	$97,167.67	$121,463.86
16	+/- RRO Deferral	RRO Deferral	$0.[illegible]	$[illegible]	$0.[illegible]	$0.[illegible]
17	**2008 Energy Related Charge**			$[illegible]	$97,437.67	$1[illegible]
18	+E DT Base Rates	Customer Charge Energy Charge Demand Charge Blk 1 Demand Charge Blk 2 Balancing Pool Refund Rider [illegible]	[illegible]	$14,137.61	$18,000.71	$23,265.41
19	+/- Other (TAP Deferral, Other than [illegible], Rev. Req. Adj. [illegible])			-$1,[illegible]	-$[illegible]	-$[illegible]
20	**Net DT Charges**			$12,[illegible]	$16,897.[illegible]	$20,510.[illegible]
21	**Predicted Combined Rate, August 1, 2008**			$[illegible]	$113,[illegible]	$141,[illegible]
	Effective Date: January 1, 2009					
22	[illegible] Energy Rate, Jan 1, 2009	Energy Charge Energy Admin Fee	$[illegible]/kWh $[illegible]	$81,538.06	$83,178.97	$102,718.69
23	+/- RRO Deferral	RRO Deferral	$0.00[illegible]/kWh	$[illegible]	$0.[illegible]	$[illegible]
24	**2009 Energy Related Charge**			$[illegible]	$[illegible]	$[illegible]
25	+E DT Base Rates	Customer Charge Energy Charge Demand Charge Blk 1 Demand Charge Blk 2 Balancing Pool Refund Rider [illegible]	[illegible]	$15,023.77	$19,007.1[illegible]	$24,794.67
26	+/- Other (TAP Deferral, Other than [illegible], Rev. Req. Adj. [illegible])			-$4,474.17	-$[illegible]	-$[illegible]
27	**Net DT Charges**			$10,[illegible]	$[illegible]	$1[illegible]
28	**Predicted Combined Rate, January 1, 2009**			$[illegible]	$[illegible]	$1[illegible]
	Comparisons					
	Combined Rate (Aug 2007- Jan 2008)	Row 14 vs Row 7	[illegible]	-$1,[illegible]	-$[illegible]	-$[illegible]
	Combined Rate (Jan 2008- Aug 2008)	Row 21 vs Row 14	[illegible]	$[illegible]	$[illegible]	$[illegible]
	Combined Rate (Aug 2008- Jan 2009)	Row 28 vs Row 21	[illegible]	$[illegible] -15%	-$[illegible]	$[illegible] -15%

Graphic 9

Appendix 5.5 - Example Rate Rider Effects: Small Oilfield Class - RRO Eligible

Row	Rate Component		Rate	8,570 kW.h per month Demand 15 kW	Typical 9,780 kW.h per month Demand 20 kW	10,958 kW.h per month Demand 25 kW
	[illegible]			Small Oilfield Class Consumption Levels Cost per Customer ($/month)		
	Effective Date: August 1, 2007					
1	[illegible] Energy Rate, Aug 1, 2007	Energy Charge; Energy Admin Fee	[illegible]; $0.15/month	$790.3[illegible]	$943.5[illegible]	$1,177.01
2	+/- RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
3	**2007 Energy Related Charge**			[illegible]	[illegible]	[illegible]
4	[illegible] DT [illegible]	[illegible]	[illegible]	$233.[illegible]	$330.34	$407.36
5	+/- Other (TAP Deferral, [illegible])	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6	**Net DT Charges**			[illegible]	[illegible]	[illegible]
7	**Predicted Combined Rate, August 1, 2007**			[illegible]	$1,241.[illegible]	[illegible]
	Effective Date: January 1, 2008					
8	[illegible] Energy Rate, Jan 1, 2008	Energy Charge; Energy Admin Fee	[illegible]	$790.2[illegible]	$943.5[illegible]	$1,177.01
9	+/- RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
10	**2008 Energy Related Charge**			$790.71	[illegible]	[illegible]
11	AE DT Base Rate	Customer Charge; Energy Charge; Demand Charge	[illegible]	$284.48	$342.43	$422.39
12	+/- Other (TAP Deferral, [illegible])	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
13	**Net DT Charges**			[illegible]	[illegible]	[illegible]
14	**Predicted Combined Rate, January 1, 2008**			[illegible]	[illegible]	[illegible]
	Effective Date: August 1, 2008					
15	[illegible] Energy Rate, Aug 1, 2008	Energy Charge; Energy Admin Fee	[illegible]	$720.94	$979.23	$1,221.01
16	+/- RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
17	**2008 Energy Related Charge**			[illegible]	[illegible]	$1,271.81
18	AE DT Base Rate	Customer Charge; Energy Charge; Demand Charge	[illegible]	$284.48	$343.45	$433.38
19	+/- Other (TAP Deferral, [illegible] Rev. Req. Adjustment)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
20	**Net DT Charges**			[illegible]	[illegible]	[illegible]
21	**Predicted Combined Rate, August 1, 2008**			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2009					
22	[illegible] Energy Rate, Jan 1, 2009	Energy Charge; Energy Admin Fee	[illegible]	[illegible]	[illegible]	[illegible]
23	+/- RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
24	**2009 Energy Related Charge**			[illegible]	[illegible]	[illegible]
25	AE [illegible] DT Base Rate	Customer Charge; Energy Charge; Demand Charge	[illegible]	$300.81	$340.[illegible]	[illegible]
26	+/- Other (TAP Deferral, Other than [illegible] Rev. Req. Adjustment)	[illegible]	[illegible]	[illegible]	-$61.4[illegible]	[illegible]
27	**Net DT Charges**			[illegible]	[illegible]	[illegible]
28	**Predicted Combined Rate, January 1, 2009**			[illegible]	$1,[illegible]	[illegible]
	Comparisons					
	Combined Rate (Aug 2007- Jan 2008)	Row 14 vs Row 7	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008- Aug 2008)	Row 21 vs Row 14	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008- Jan 2009)	Row 28 vs Row 21	[illegible]	[illegible]	[illegible]	[illegible]

Graphic 10

Appendix B 7 - Example Rate Rider Effects: Small Oilfield Class - Net RPO Eligible

Row	Rate Component		Rate	Small Oilfield Class Consumption Levels Cost per Customer ($/month): 6,570 kW.h per month Demand 15 kW	Typical 8,760 kW.h per month Demand 20 kW	10,950 kW.h per month Demand 25 kW
	Effective Date: August 1, 2007					
1	Forecast Energy Rates, Aug 1, 2007	Energy Charge Energy Admin Fee	[illegible]	[illegible]	[illegible]	$1,177.01
2	+/- RPO Deferral	RPO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
3	RPO Energy Related Charge			[illegible]	[illegible]	[illegible]
4	DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	[illegible]	$336.34	[illegible]
5	+/- Other (TAP Deferral, Other than Fuel Price, Reg. Adjustment)	Balancing Pool Refund Rider, Rider G	[illegible]	[illegible]	[illegible]	[illegible]
6	Net DT Charges			[illegible]	[illegible]	[illegible]
7	Predicted Combined Rate August 1, 2007			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2008					
8	Forecast Energy Rates, Jan 1, 2008	Energy Charge Energy Admin Fee	[illegible]	[illegible]	[illegible]	[illegible]
9	+/- RPO Deferral	RPO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
10	RPO Energy Related Charge			[illegible]	[illegible]	[illegible]
11	DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	[illegible]	[illegible]	[illegible]
12	+/- Other (TAP Deferral, Other than Fuel Price, Reg. Adjustment)	Balancing Pool Refund Rider, Rider G	[illegible]	[illegible]	[illegible]	[illegible]
13	Net DT Charges			[illegible]	[illegible]	[illegible]
14	Predicted Combined Rate, January 1, 2008			[illegible]	[illegible]	[illegible]
	Effective Date: August 1, 2008					
15	Forecast Energy Rates, Aug 1, 2008	Energy Charge Energy Admin Fee	[illegible]	[illegible]	$970.23	$1,221.01
16	+/- RPO Deferral	RPO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
17	RPO Energy Related Charge			[illegible]	[illegible]	[illegible]
18	DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	[illegible]	$343.43	[illegible]
19	+/- Other (TAP Deferral, Other than Fuel Price, Reg. Adjustment)	Balancing Pool Refund Rider, Rider G	[illegible]	[illegible]	[illegible]	[illegible]
20	Net DT Charges			[illegible]	[illegible]	[illegible]
21	Predicted Combined Rate August 1, 2008			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2009					
22	Forecast Energy Rates, Jan 1, 2009	Energy Charge Energy Admin Fee	[illegible]	[illegible]	[illegible]	[illegible]
23	+/- RPO Deferral	RPO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
24	RPO Energy Related Charge			[illegible]	[illegible]	[illegible]
25	[illegible] DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	[illegible]	[illegible]	[illegible]
26	+/- Other (TAP Deferral, Other than Fuel Price, Reg. Adjustment)	Balancing Pool Refund Rider, Rider G	[illegible]	[illegible]	[illegible]	[illegible]
27	Net DT Charges			[illegible]	[illegible]	[illegible]
28	Predicted Combined Rate January 1, 2009			[illegible]	[illegible]	[illegible]
	Comparisons					
	Combined Rate (Aug 2007- Jan 2008) Row 14 vs Row 7		difference	[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008- Aug 2008) Row 21 vs Row 14		difference	[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008- Jan 2009) Row 28 vs Row 21		difference	[illegible]	[illegible]	[illegible]

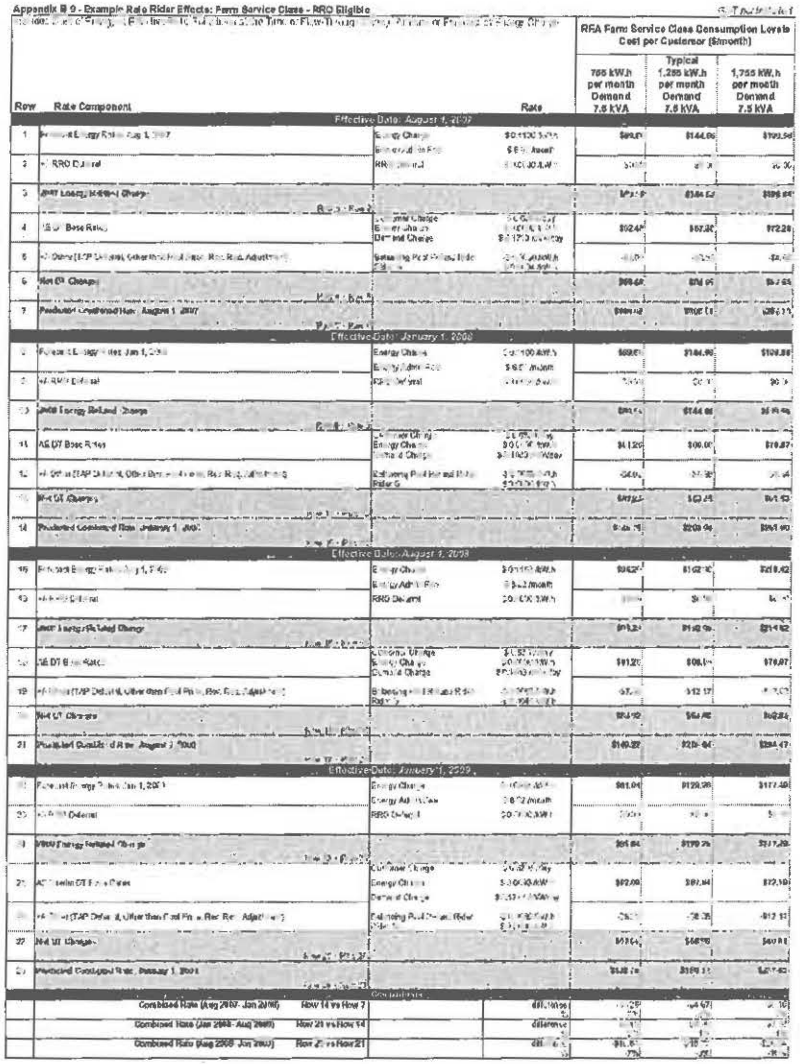
Graphic 11

Appendix B.8 - Example Rate Rider Effects: REA Farm Service Class (Pooled) - RRO Eligible

[illegible]

Row	Rate Component		Rate	REA Farm Service Class Consumption Levels Cost per Customer ($/month)		
				756 kW.h per month Demand 7.5 KVA	Typical 1,256 kW.h per month Demand 7.5 KVA	1,755 kW.h per month Demand 7.5 KVA
	Effective Date: August 1, 2007					
1	Forecast Energy Rates, Aug 1, 2007	Energy Charge Energy Admin Fee	[illegible] $2.01 [illegible]	$90.66	$144.90	$199.90
2	RRO Deferral	RRO Deferral	$0.000 [illegible]	$0.00	$0.00	$0.00
3	2007 Energy Related Charge			$90.[illegible]	[illegible]	[illegible]
4	DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible] $0.[illegible]/kW.h [illegible]	$45.00	$47.48	$49.76
5	Other (Deferral, [illegible], Rec. [illegible] Adjustment)	Balancing Pool Refund Rider	[illegible]	-$1.0[illegible]	-$1.07	-$2.[illegible]
6	Net DT Charges			$4[illegible]	$46.[illegible]	$47.[illegible]
7	Predicted Combined Rate August 1, 2007			$13[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2008					
8	Forecast Energy Rates, Jan 1, 2008	Energy Charge Energy Admin Fee	$0.11[illegible] [illegible]	$90.66	$144.60	$199.60
9	RRO Deferral	RRO Deferral	$0.00[illegible]	$0.[illegible]	$0.00	[illegible]
10	2008 Energy Related Charge			[illegible]	$144.[illegible]	[illegible]
11	DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	$43.07	$48.56	$47.20
12	Other (DAP Deferral, [illegible] Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	$0.00[illegible]	[illegible]	[illegible]	$0.04
13	Net DT Charges			[illegible]	[illegible]	[illegible]
14	Predicted Combined Rate January 1, 2008			[illegible]	[illegible]	[illegible]
	Effective Date: August 1, 2008					
15	Forecast Energy Rates, Aug 1, 2008	Energy Charge Energy Admin Fee	$0.1[illegible] $2.2[illegible]	$95.28	$152.98	$210.82
16	RRO Deferral	RRO Deferral	[illegible]	$0.00	$0.00	[illegible]
17	2008 Energy Related Charge			[illegible]	[illegible]	[illegible]
18	DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	$43.07	$48.56	$47.20
19	Other (DAP Deferral, [illegible] Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	[illegible]	-$7.31	-$6.[illegible]	-$7.[illegible]
20	Net DT Charges			$30.7[illegible]	$40.[illegible]	[illegible]
21	Predicted Combined Rate August 1, 2008			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2009					
22	Forecast Energy Rate Jan 1, 2009	Energy Charge Energy Admin Fee	[illegible] $3.20 [illegible]	$91.04	$120.28	$177.40
23	RRO Deferral	RRO Deferral	$0.00[illegible]	[illegible]	[illegible]	[illegible]
24	2009 Energy Related Charge			[illegible]	[illegible]	$177.40
25	DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	$44.94	$47.20	$49.64
26	Other (DAP Deferral, [illegible] Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider	[illegible]	-$6.[illegible]	-$9.60	-$12.14
27	Net DT Charges			[illegible]	[illegible]	[illegible]
28	Predicted Combined Rate January 1, 2009			$130.78	[illegible]	$214.[illegible]
	Comparisons					
	Combined Rate (Aug 2007 - Jan 2008)	Row 14 vs Row 7	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008 - Aug 2008)	Row 21 vs Row 14	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008 - Jan 2009)	Row 28 vs Row 21	[illegible]	[illegible]	-$25.[illegible]	-$35.36 -14%

Graphic 12



Appendix B 9 - Example Rate Rider Effects: Farm Service Class - RRO Eligible

Row	Rate Component		Rate	RFA Farm Service Class Consumption Levels Cost per Customer ($/month): 765 kW.h per month Demand 7.5 kVA	Typical 1,265 kW.h per month Demand 7.5 kVA	1,755 kW.h per month Demand 7.5 kVA
	Effective Date: August 1, 2007					
1	[illegible]	Energy Charge	[illegible]	[illegible]	$144.06	[illegible]
2	+/- RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3	[illegible]			[illegible]	[illegible]	[illegible]
4	[illegible] Base Rates	Customer Charge; Energy Charge; Demand Charge	[illegible]	[illegible]	[illegible]	$72.28
5	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6	Net [illegible] Charges			[illegible]	[illegible]	[illegible]
7	[illegible] August 1, 2007			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2008					
8	[illegible]	Energy Charge	[illegible]	[illegible]	[illegible]	[illegible]
9	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
10	[illegible]			[illegible]	[illegible]	[illegible]
11	[illegible] Base Rates	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
12	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
13	Net [illegible] Charges			[illegible]	[illegible]	[illegible]
14	[illegible]			[illegible]	[illegible]	[illegible]
	Effective Date: August 1, 2008					
15	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
16	[illegible]	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
17	[illegible]			[illegible]	[illegible]	[illegible]
18	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	$76.97
19	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
20	Net [illegible] Charges			[illegible]	[illegible]	[illegible]
21	[illegible]			$140.27	[illegible]	[illegible]
	Effective Date: January 1, 2009					
22	[illegible]	Energy Charge	[illegible]	$81.04	[illegible]	[illegible]
23	[illegible]	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
24	[illegible]			[illegible]	[illegible]	[illegible]
25	[illegible]	Customer Charge; Energy Charge; Demand Charge	[illegible]	$92.09	[illegible]	[illegible]
26	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
27	Net [illegible] Charges			[illegible]	[illegible]	[illegible]
28	[illegible]			[illegible]	[illegible]	[illegible]
	Comparison					
	Combined Rate (Aug 2007- Jan 2008)	Row 14 vs Row 7	difference	[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008- Aug 2008)	Row 21 vs Row 14	difference	[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008- Jan 2009)	Row 28 vs Row 21	[illegible]	[illegible]	[illegible]	[illegible]

Graphic 13

Appendix B.10 - Example Rate Rider Effects: Street Light Service Class D61 Option A

Row	Rate Component		Rate	36 kW.h 1 Fixture Demand 100 Watt	Typical 88 kW.h 1 Fixture Demand 250 Watt	140 kW.h 1 Fixture Demand 400 Watt
	[illegible]			Street Light Service Class Consumption Levels Cost per Customer ($/month)		
	Effective Date: August 1, 2007					
1	[illegible] Energy Rate, Aug 1, [illegible]	Energy Charge Energy Admin Fee	[illegible] [illegible]	$6.74	$10.57	$14.31
2	+ RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
3	2007 Energy Related Charge			$6.74	[illegible]	[illegible]
4	AE DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	$7.47	$8.91	$10.36
5	+ Other (TAP Deferral, Other than [illegible] Rider Adjustment)	[illegible] Rider	[illegible]	[illegible]	[illegible]	-$3.09
6	Net DT Charges			[illegible]	[illegible]	[illegible]
7	Projected Combined Rate, August 1, 2007			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2008					
8	Forecast Energy Rate Jan 1, 2008	Energy Charge Energy Admin Fee	[illegible] [illegible]	$6.74	$10.67	$14.91
9	+ RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
10	2008 Energy Related Charge			$6.76	[illegible]	[illegible]
11	AE DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	$7.71	$9.16	$10.60
12	+ Other (TAP Deferral, Other than Pool Price, Rider Adjustment)	[illegible] Rider	[illegible]	[illegible]	[illegible]	[illegible]
13	Net DT Charges			$7.42	[illegible]	[illegible]
14	Projected Combined Rate January 1, 2008			[illegible]	[illegible]	[illegible]
	Effective Date: August 1, 2008					
15	Forecast Energy Rate, Aug 1, 2008	Energy Charge Energy Admin Fee	[illegible] [illegible]	[illegible]	[illegible]	$12.42
16	+ RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
17	2008 Energy Related Charge			[illegible]	[illegible]	$12.42
18	AE DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	$7.71	$9.15	$10.60
19	+ Other (TAP Deferral, Other than Pool Price, Rider Adjustment)	[illegible] Rider G	[illegible]	[illegible]	[illegible]	[illegible]
20	Net DT Charges			[illegible]	$8.76	[illegible]
21	Projected Combined Rate, August 1, 2008			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2009					
22	Forecast Energy Rates, Jan 1, 2009	Energy Charge Energy Admin Fee	[illegible] [illegible]	[illegible]	[illegible]	$12.98
23	+ RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
24	2009 Energy Related Charge			[illegible]	[illegible]	[illegible]
25	AE Interim DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	$7.70	$9.14	$10.87
26	+ Other (TAP Deferral, Other than Pool Price, Rider Adjustment)	Balancing Pool Refund Rider	[illegible]	[illegible]	[illegible]	[illegible]
27	Net DT Charges			[illegible]	[illegible]	[illegible]
28	Projected Combined Rate January 1, 2009			[illegible]	[illegible]	[illegible]
	Comparisons					
	Combined Rate (Aug 2007- Jan 2008)	Row 14 vs Row 7	difference %	[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008- Aug 2008)	Row 21 vs Row 14	difference %	[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008- Jan 2009)	Row 28 vs Row 21	difference %	[illegible]	[illegible]	[illegible]

Graphic 14

Appendix B.11 - Example Rate Rider Effects: Irrigation Pumping Service GST [illegible] Included

Includes Cost of Energy in [illegible] Rate [illegible] Flow-Through Charge [illegible] Forecast of Energy Charge

Row	Rate Component		Rate	9,760 kW.h per month Demand 30 kW	Typical 11,680 kW.h per month Demand 40 kW	14,600 kW.h per month Demand 60 kW
				Irrigation Pumping Service Class Consumption Levels Cost per Customer ($/season)		
	Effective Date: August 1, 2007					
1	Forecast Energy Rates, Aug 1, 2007	Energy Charge Energy Admin Fee	$0.11[illegible] /kW.h $[illegible]	$1,018.03	$1,334.28	$1,665.43
2	+ RRO Deferral	[illegible] Deferral	$0.[illegible] /kW.h	$[illegible]	$[illegible]	$[illegible]
3	2007 Energy Related Charge	Row 1 + Row 2		$1,0[illegible]	$1,344.[illegible]	$1,[illegible]
4	+ DT Base Rates	[illegible] Charge Energy Charge Demand Charge	$[illegible] /day $[illegible] /kW.h $0.1[illegible]	$843.96	$1,119.64	$1,380.61
5	+ Other (2007 Deferral, [illegible], Rev. Req. Adjustment)	Balancing Pool Refund Rider [illegible]	-$0.00[illegible] /kW.h $[illegible] /kW.h	$45.04	$[illegible]	$79.07
6	Net DT Charge	Row 4 + Row 5		$[illegible]	$1,172.[illegible]	$1,[illegible]
7	Predicted Combined Rate, August 1, 2007	Row 3 + Row 6		$1,[illegible]	$2,[illegible]	$3,[illegible]
	Effective Date: January 1, 2008					
8	Forecast Energy Rates, Jan 1, 2008	Energy Charge Energy Admin Fee	$0.11[illegible] /kW.h $[illegible]	$1,018.03	$1,334.28	$1,666.43
9	+ RRO Deferral	[illegible] Deferral	$[illegible] /kW.h	$[illegible]	$0.00	$0.0[illegible]
10	2008 Energy Related Charge	Row 8 + Row 9		$1,0[illegible]	$1,[illegible]	$1,[illegible]
11	+ DT Base Rates	[illegible] Charge Energy Charge Demand Charge	$[illegible] /day $[illegible] /kW.h $0.1[illegible] /kW/day	$1,027.63	$1,280.60	$1,601.80
12	+ Other (TAP Deferral, [illegible], Rev. Req. Adjustment)	Balancing Pool Refund Rider [illegible]	-$0.00[illegible] /kW.h $0.[illegible]	-$[illegible]	-$[illegible]	-$79.[illegible]
13	Net DT Charge	Row 11 + Row 12		$[illegible]	$1,[illegible]	$1,[illegible]
14	Predicted Combined Rate, January 1, 2008	Row 10 + Row 13		$1,[illegible]	$2,[illegible]	$3,[illegible]
	Effective Date: August 1, 2008					
15	Forecast Energy Rates, Aug 1, 2008	Energy Charge Energy Admin Fee	$0.1[illegible] /kW.h $[illegible]	$1,0[illegible]	$1,[illegible]	$1,712.[illegible]
16	+ RRO Deferral	RRO Deferral	$[illegible] /kW.h	$[illegible]	$[illegible]	$0.[illegible]
17	2008 Energy Related Charge	Row 15 + Row 16		$1,[illegible]	$1,[illegible]	$1,712.[illegible]
18	AE DT Base Rates	[illegible] Charge Energy Charge Demand Charge	$[illegible] /day $[illegible] /kW.h $[illegible] /kW/day	$1,0[illegible]	$1,263.[illegible]	$1,[illegible]
19	+ Other ([illegible] Deferral, [illegible], Rev. Req. Adjustment)	Balancing Pool Refund Rider [illegible]	-$0.00[illegible] /kW.h -$0.00[illegible] /kW.h	-$[illegible]	-$140.0[illegible]	-$175.[illegible]
20	Net DT Charge	Row 18 + Row 19		$[illegible]	$1,[illegible]	$1,[illegible]
21	Predicted Combined Rate, August 1, 2008	Row 17 + Row 20		$1,[illegible]	$[illegible]	$[illegible]
	Effective Date: January 1, 2009					
22	Forecast Energy Rates, Jan 1, 2009	Energy Charge Energy Admin Fee	$[illegible] /kW.h $[illegible]	$[illegible]	$1,1[illegible]	$1,[illegible]
23	+ RRO Deferral	RRO Deferral	$[illegible] /kW.h	$0.00	$0.[illegible]	$0.[illegible]
24	2009 Energy Related Charge	Row 22 + Row 23		$[illegible]	$1,[illegible]	$1,[illegible]
25	AE Interim 2009 Base Rates	[illegible] Charge Energy Charge Demand Charge	$[illegible] /day $[illegible] /kW.h $0.1[illegible] /kW/day	$1,142.22	$1,512.[illegible]	$1,[illegible]
26	+ Other (TAP Deferral, [illegible], Rev. Req. Adjustment)	Balancing Pool Refund Rider [illegible]	-$0.00[illegible] /kW.h $[illegible]	-$[illegible]	-$[illegible]	-$[illegible]
27	Net DT Charge	Row 25 + Row 26		$1,[illegible]	$1,[illegible]	$1,[illegible]
28	Predicted Combined Rate, January 1, 2009	Row 24 + Row 27		$1,[illegible]	$[illegible]	$[illegible]
	Comparisons					
	Combined Rate (Aug 2007- Jan 2008)	Row 14 vs Row 7	$ Term [illegible] %	$[illegible] [illegible]	$[illegible] [illegible]	$[illegible] [illegible]
	Combined Rate (Jan 2008- Aug 2008)	Row 21 vs Row 14	$ [illegible] %	$[illegible] [illegible]	$27.[illegible] [illegible]	$[illegible] [illegible]
	Combined Rate (Aug 2008- Jan 2009)	Row 28 vs Row 21	$ [illegible] %	$[illegible] 0%	$[illegible] [illegible]	$4.[illegible] [illegible]

Graphic 15

Appendix B.12 - Example Rate Rider Effects: REA Irrigation Pumping Service

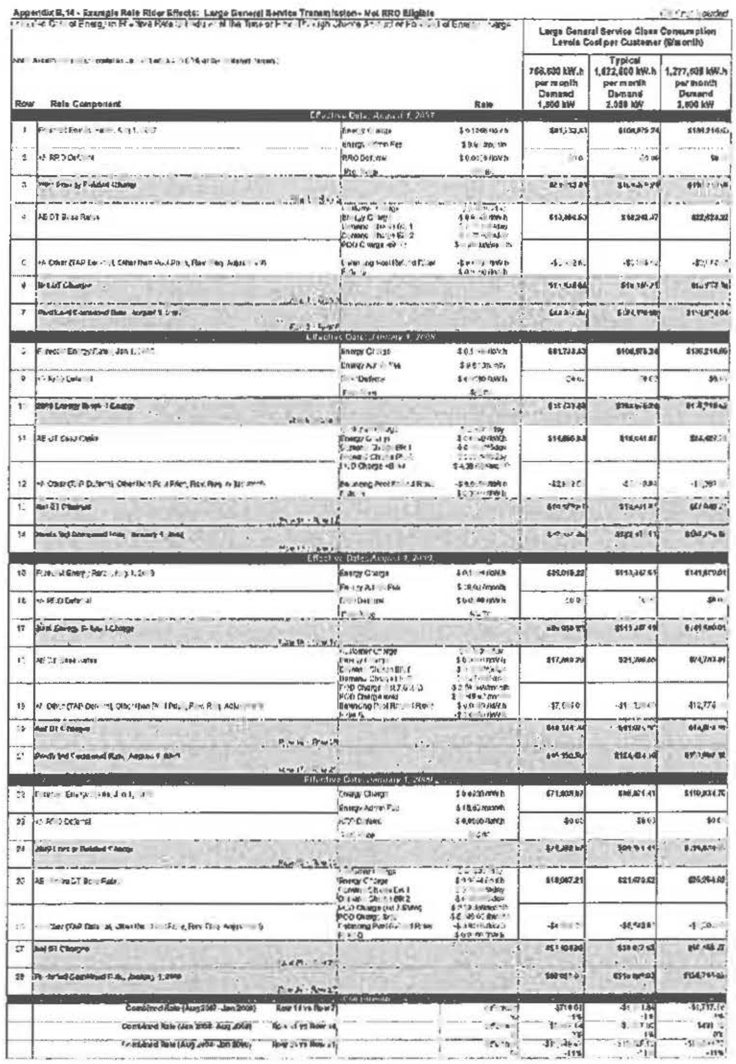
Row	Rate Component		Rate	REA Irrigation Pumping Service Class Consumption Levels Cost per Customer ($/season) 8,760 kW.h per month Demand 30 kW	Typical 11,680 kW.h per month Demand 40 kW	14,600 kW.h per month Demand 50 kW
	Effective Date: August 1, 2007					
1	Forecast Energy Rates, Aug 1, 2007	Energy Charge Energy Admin Fee	[illegible]	[illegible]	[illegible]	[illegible]
2	+/- [illegible] Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
3	2007 Energy-Related Charge			[illegible]	[illegible]	[illegible]
4	[illegible]	Customer Charge Energy Charge Demand Charge	[illegible]	$407.[illegible]	$616.[illegible]	$769.[illegible]
5	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider [illegible]	[illegible]	$40.64	[illegible]	[illegible]
6	Net DT Charges			[illegible]	[illegible]	[illegible]
7	Predicted Combined Rate, August 1, 2007			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2008					
8	Forecast Energy Rates, Jan 1, 2008	Energy Charge Energy Admin Fee	[illegible] $6.93 /month	$1,013.[illegible]	$1,3[illegible]	$1,[illegible]
9	+/- [illegible] Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
10	2008 Energy-Related Charge			$1,0[illegible]	[illegible]	[illegible]
11	AE DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	[illegible]	[illegible]	$1,2[illegible]
12	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider [illegible]	[illegible]	$47.[illegible]	[illegible]	[illegible]
13	Net DT Charges			[illegible]	[illegible]	[illegible]
14	Predicted Combined Rate, January 1, 2008			[illegible]	[illegible]	[illegible]
	Effective Date: August 1, 2008					
15	Forecast Energy Rates, Aug 1, 2008	Energy Charge Energy Admin Fee	[illegible] $9.90 /month	$1,0[illegible]	$1,3[illegible]	$1,712.0[illegible]
16	+/- [illegible] Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
17	2008 Energy-Related Charge			[illegible]	[illegible]	[illegible]
18	AE DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	[illegible]	[illegible]	$1,[illegible]
19	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider [illegible]	[illegible]	[illegible]	$14[illegible]	[illegible]
20	Net DT Charges			[illegible]	[illegible]	[illegible]
21	Predicted Combined Rate, August 1, 2008			$1,762.[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2009					
22	Forecast Energy Rates, Jan 1, 2009	Energy Charge Energy Admin Fee	[illegible]	[illegible]	$1,1[illegible]	[illegible]
23	+/- RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]	[illegible]
24	2009 Energy-Related Charge			[illegible]	[illegible]	[illegible]
25	[illegible] DT Base Rates	Customer Charge Energy Charge Demand Charge	[illegible]	[illegible]	[illegible]	[illegible]
26	+/- Other (TAP Deferral, Other than Pool Price, Rev. Req. Adjustment)	Balancing Pool Refund Rider Rider [illegible]	[illegible]	[illegible]	[illegible]	[illegible]
27	Net DT Charges			[illegible]	[illegible]	[illegible]
28	Predicted Combined Rate, January 1, 2009			[illegible]	[illegible]	[illegible]
	Comparisons					
	Combined Rate (Aug 2007-Jan 2008)	Row 14 vs Row 7	difference %	[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008-Aug 2008)	Row 21 vs Row 14	difference %	[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008-Jan 2009)	Row 28 vs Row 21	difference %	[illegible]	[illegible]	[illegible] 0%

Graphic 16

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

Row	Rate Component		Rate	Private Street Light Service Class Consumption Levels Cost per Customer ($/month): 35 kW.h 1 Fixture Demand 100 Watt	Typical 88 kW.h 1 Fixture Demand 250 Watt	140 kW.h 1 Fixture Demand 400 Watt
	Effective Date: August 1, 2007					
1	Forecast Energy Rates, Aug 1, 2007	Energy Charge; Energy Admin Fee	[illegible]; $2.00 [illegible]	$6.74	$10.67	$14.31
2	[illegible] RRO Deferral	RRO Deferral	[illegible]	$0.[illegible]	$0.[illegible]	[illegible]
3	2007 Energy Related Charge			$7.24	$10.67	$17.41
4	[illegible] Base Rates	Customer Charge; Energy Charge; Demand Charge	[illegible]	$10.73	$12.80	$14.00
5	[illegible] Other (TAF Deferral, Other than Pool Price, Rev. Req. Adjustment)	[illegible] Refund Rider [illegible]	[illegible]	[illegible]	[illegible]	$4.14
6	Net DT Charges			[illegible]	$9.79	[illegible]
7	Predicted Combined Rate, August 1, 2007			$19.47	$20.29	$24.94
	Effective Date: January 1, 2008					
8	Forecast Energy Rates, Jan 1, 2008	Energy Charge; Energy Admin Fee	[illegible]; $2.25 [illegible]	$5.74	$14.67	$16.61
9	[illegible] RRO Deferral	RRO Deferral	[illegible]	$0.0[illegible]	$0.[illegible]	[illegible]
10	2008 Energy Related Charge			$9.74	$14.67	$18.61
11	[illegible] Base Rates	Customer Charge; Energy Charge; Demand Charge	[illegible]	$11.62	$12.89	$14.17
12	[illegible] Other (TAF Deferral, Other than Pool Price, Rev. Req. Adjustment)	[illegible] Refund Rider [illegible]	[illegible]	-$0.30	-$0.40	[illegible]
13	Net DT Charges			[illegible]	$11.40	[illegible]
14	Predicted Combined Rate, January 1, 2008			$12.17	[illegible]	$25.24
	Effective Date: August 1, 2008					
15	Forecast Energy Rates, Aug 1, 2008	Energy Charge; Energy Admin Fee	[illegible]; $2.61 [illegible]	$8.11	$8.00	$12.02
16	[illegible] RRO Deferral	RRO Deferral	[illegible]	$0.00	$0.[illegible]	[illegible]
17	2008 Energy Related Charge			$3.11	$8.99	$12.44
18	[illegible] Base Rates	Customer Charge; Energy Charge; Demand Charge	[illegible]	$11.82	$12.80	$14.17
19	[illegible] Other (TAF Deferral, Other than Pool Price, Rev. Req. Adjustment)	[illegible] Refund Rider [illegible]	[illegible]	$1.47	[illegible]	[illegible]
20	Net DT Charges			[illegible]	[illegible]	[illegible]
21	Predicted Combined Rate, August 1, 2008			[illegible]	$18.11	[illegible]
	Effective Date: January 1, 2009					
22	Forecast Energy Rates, Jan 1, 2009	Energy Charge; Energy Admin Fee	[illegible]; $2.61 [illegible]	$6.28	$9.12	$12.98
23	[illegible] RRO Deferral	RRO Deferral	[illegible]	$0.0[illegible]	$0.0[illegible]	$0.0[illegible]
24	2009 Energy Related Charge			[illegible]	$9.12	[illegible]
25	[illegible] DT Base Rates	Customer Charge; Energy Charge; Demand Charge	[illegible]	$11.90	$12.85	$14.39
26	[illegible] Other (TAF Deferral, Other than Pool Price, Rev. Req. Adjustment)	[illegible] Refund Rider [illegible]	[illegible]	-$0.24	[illegible]	[illegible]
27	Net DT Charges			[illegible]	[illegible]	[illegible]
28	Predicted Combined Rate, January 1, 2009			[illegible]	$21.[illegible]	$26.61
	Comparisons					
	Combined Rate (Aug 2007 - Jan 2008)	Row 14 vs Row 7	difference; %	[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008 - Aug 2008)	Row 21 vs Row 14	difference; %	[illegible]; 11%	[illegible]	[illegible]; 27%
	Combined Rate (Aug 2008 - Jan 2009)	Row 28 vs Row 21	difference; %	[illegible]	[illegible]	$6.4[illegible]; 20%

Graphic 17



Graphic 18

ATCO ELECTRIC

ATCO ELECTRIC 2009 DISTRIBUTION INTERIM TARIFF APPLICATION

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

	Admin. Charges Fixed ($ / Day)	Cost of Energy October 2008 ($ / kWh)
D11	0.265	0.09701
D21	0.282	0.09672
D31	0.601	0.09379
T31	0.601	0.09379
D41	0.296	0.09358
D51	0.274	0.09645
D56	0.274	0.09645
D25	0.312	0.09497
D61	0.087	0.07405
D63	0.087	0.07405
D26	0.312	0.09497

Rates used are the RRO Rates as posted on Direct Energy Regulated Services website Oct 6/2008) These rates are used for the January 1, 2009 scenarios (less Rider).

APPENDIX 3 — Rider B — Balancing Pool Rider Determination

Rider B - 2009 Balancing Pool Rider Determination

Rate Class	*A* *Proposed 2009 AESO Rider F (¢/kW.h)*	*B* *Distribution Losses Note 1 (%)*	*C=A*(1+B)* *Proposed 2009 ATCO Electric Rider B (¢/kW.h)*
D11	0.650	5.66%	0.687
D21/D22	0.650	5.90%	0.688
D25/D26	0.650	8.77%	0.707
D31/D32/D33	0.650	4.79%	0.681
T31/T33	0.650		flow through
D41	0.650	7.86%	0.701
D51/D52	0.650	6.49%	0.692
D56	0.650	6.49%	0.692
D61	0.650	5.69%	0.687
D63	0.650	5.53%	0.686

Note 1: Distribution losses obtained from ATCO Electric's approved 2008 DTA (Section 10 Load Research EDLA Model).

APPENDIX 4 — Determination of Adjustment Factors

Table 1 Scaling Factor Determination All Revenue in $'000's

Year	*Column No.*	*Scenario*	*(A) Trans Demand Revenue*	*(B) Trans Energy Revenue*	*(C) T31 Trans Demand Revenue*	*(D) T31 Trans Energy Revenue*	*(E) Dist Revenue*	*Power Factor*	*Total*
Before Scaling									
		12 mo. 2008 final rates	57,459	52,946	14,619	7,352	214,585	4,286	351,247
		Adj for D11	9,435	(9,435)					
2009		Adj for D61	(101)	101					
		Adj for D63	(16)	16					
	(1)	Total	66,777	43,627	14,619	7,352	214,585	4,286	351,247
	(2)	Target	81,323	41,440	14,619	7,352	213,180	4,286	362,200
	(3)	Scaling Factor	*1.217830*	*0.949866*	*1.000*	*1.000*	*0.993451*	*1.000*	*1.031*
After Scaling									
2009		12 mo. 2008 final rates after scaling	69,943	52,820	14,619	7,352	213,180	4,286	362,200
		Adj for D11	11,491	(11,491)					
		Adj for	(96)	96					

	D61 Adj for D63	(15)	15					
(4)	Total	81,323	41,440	14,619	7,352	213,180	4,286	362,200

Table 2 Breakdown of Transmission Rate All Revenue in $'000's
Based on 2008 Refiling Application

	Demand Related Portion	*Energy Related Portion*	*Total Trans Revenue*
D11	9,435	5,023	14,458
D61	155	101	256
D63	26	16	42

Factored Future Costs for 2009				*(F)* *Scaling Factor*
D11	11,491	4,771	16,262	*1.125*
D61	189	96	284	*1.112*
D63	31	15	47	*1.114*

Table Summary

Table 1, Row 1 sets out the forecast revenue for 2009 based on ATCO Electric's final approved 2008 DT. The revenues are split out by the transmission component in Column (A) and Column (B), which relates to recovery of costs under the distribution rates associated with transmission access - by demand and energy. An adjustment to revenues (between Demand and Energy components) for D11, D61, and D63 was made to align it with the allocation of costs based on ATCO Electric's Phase II transmission cost of service study. Column (C) and (D) relate to demand and energy revenue associated with direct connect transmission customers, and Column (E) relates to the revenue required to collect costs specifically associated with the distribution and service functions by all classes. Rider A1 has been excluded from this calculation. Row (2) sets out the revenue requirement for 2009, or the "target" revenue in which the rates are designed to achieve. In order to get the forecast revenue equal to the forecast revenue requirement, the distribution and transmission components of the distribution rates will be adjusted by the scaling factor in Row (3). This applies to all rate classes.

However, for rates D11, D61, and D63 — since these rates recover total transmission revenue under only one component (demand or energy) while the costs are incurred under both demand and energy, the scaling factor is iterated against the weighted average of the demand and energy related costs until the revenue equals the costs recovered under the rate. Revenue adjustments are made for these components in Table 1 to ensure that revenue is reflected in the manner in which they are recovered. For example, D11 collects $14.5M in transmission revenue of which, $9.4M is associated with demand related costs.

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

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

APPENDIX 5 — 2009 Interim Transmission Tariff

EFFECTIVE: 2009-01-01
SUPERSEDES: 2008-01-01

ATCO ELECTRIC LTD.

2009 RATE SCHEDULE
INTERIM TRANSMISSION TARIFF

AVAILABLE:	To the Transmission Administrator
APPLICABLE:	To the Transmission Administrator for use of the Company's transmission facility for the 2009 calendar year.
RATE:	Interim Charges to the Transmission Administrator for the 2009 calendar year shall be:
Annual Tariff:	$194,000,000
Monthly Charges:	$16,166,667

Footnotes

1 ATCO Electric Ltd. 2009-2010 General Tariff Application (Application No. 1578371, Proceeding ID. 86)

2 Application, Section 2.1 — AE's Proposed Target Revenue Requirement: Two-Part Test

3 Information Response to AUC-AE-1

4 Decision 2005-102 — ATCO Electric Ltd. 2005 Interim Transmission Facility Owner Tariff (Application 1407551) (Released: September 7, 2005)

5 Decision 2005-099 — ATCO Gas 2005-2007 General Rate Application Interim Rate Application (Application 1404168) (Released: August 29, 2005)

6 Application, Table 3 — Proposed Increases to 2009 Revenue Requirements for 2009 Interim Rates, Page 6

7 UCA Argument, December 2, 2008

8 Information Response to AUC-AE-1

Decision **2014-311**

Alberta Utilities Commission

ENMAX Power Corporation

2015 Interim Distribution and Transmission Tariff Application

November 12, 2014

The Alberta Utilities Commission
Decision 2014-311: ENMAX Power Corporation
2015 Interim Distribution and Transmission Tariff Application
Application No. 1610874
Proceeding No. 3433

November 12, 2014

Published by
The Alberta Utilities Commission
Fifth Avenue Place, Fourth Floor, 425 First Street S.W.
Calgary, Alberta
T2P 3L8

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The Alberta Utilities Commission
Calgary, Alberta

ENMAX Power Corporation
2015 Interim Distribution and Transmission Tariff Application

Decision 2014-311
Application No. 1610874
Proceeding No. 3433

1 Introduction

1. On September 25, 2014, ENMAX Power Corporation (EPC) submitted an application (application) to the Alberta Utilities Commission (AUC or Commission), pursuant to sections 37, 102, 119 and 124(2) of the *Electric Utilities Act*, SA 2003, c. E-5.1, applying for the following:

(i) Approval to implement 2015 distribution access service (distribution) rates on an interim basis, as described in Section 3 of the application,[1] calculated in Appendix 1[2] and set out in the rate schedules provided in Appendix 2,[3] effective January 1, 2015.

(ii) Approval to implement 2015 transmission rates on an interim basis, as described in Section 4 of the application, calculated in Appendix 3[4] and set out in the rate schedules provided in Appendix 4,[5] effective January 1, 2015.

2. On September 29, 2014, the Commission issued a notice of application advising interested parties to file a statement of intent to participate (SIP) to the Commission no later than October 9, 2014. In the SIPs, parties were asked to indicate whether they supported or objected to the application, provide reasons for their positions and comment on the need for further process and the supporting rationale.

3. The following parties registered in the proceeding by the specified deadline:

- FortisAlberta Inc.
- ATCO Electric Ltd.
- Alberta Electric System Operator (AESO)
- EPCOR Distribution & Transmission Inc.

4. None of the above-listed parties objected to the application or requested further process.

5. On October 21, 2014, the Commission issued a process letter classifying the proceeding as a *notice-only process* proceeding and advising that the Commission had two questions for EPC. On October 22, 2014, EPC filed its responses to the Commission's questions.[6]

---

1 Exhibit No. 3, application.
2 Exhibit No. 5, application, Appendix 1.
3 Exhibit No. 6, application, Appendix 2.
4 Exhibit No. 7, application, Appendix 3.
5 Exhibit No. 8, application, Appendix 4.
6 Exhibit No. 14.01, Commission process letter; Exhibit No. 15.01, Commission information request; Exhibit No. 16.01, EPC responses to information request.

6. The Commission considers that the record for this proceeding closed on October 22, 2014.

7. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

2 Details of the application

8. On July 24, 2013, EPC filed an application with the AUC requesting approval of EPC's 2014 Phase I Distribution Tariff Application (DTA) and 2014-2015 Transmission General Tariff Application (GTA) (collectively Proceeding No. 2739).[7] According to EPC, even if a decision for Proceeding No. 2739 is issued in December 2014, given the likely timing of a compliance filing, it is unlikely that final 2014 rates will be approved before the end of 2014, and therefore final 2014 rates will not be available to be used as the basis of interim 2015 rates by January 1, 2015.[8]

9. EPC's current distribution and transmission tariffs were approved on an interim basis in Decision 2013-436[9] and have been in place on an interim basis since January 1, 2014. If existing 2014 interim rates continue for 2015, EPC forecasted a total revenue shortfall of $10.229 million for distribution and $14.260 million for transmission.[10]

10. EPC stated that the shortfall amount is significant. To reduce the impact of the rate increase that will be required when the final 2015 distribution and transmission rates are implemented, EPC requested approval of interim distribution and transmission rates to be effective January 1, 2015 and continuing until such time as the AUC approves revised interim or final 2015 distribution and transmission rates. EPC advised that, once matters in Proceeding No. 2739 have been decided by the Commission, EPC will make the required adjustments or applications to set final 2015 distribution and transmission rates.[11]

2.1 Distribution

11. EPC submitted that its forecast distribution revenue for 2015, included in Appendix 1 to the application, is $192.571 million based on current interim distribution rates. EPC's forecast distribution revenue requirement is $202.800 million, as determined by escalating the 2014 DTA revenue requirement by the placeholder performance-based regulation (PBR) formula described in Section 3 of the application. Consequently, if the 2014 DTA is approved as applied for, and no

7 Application for Approval of 2014 Phase I Distribution Tariff Application and 2014-2015 Transmission General Tariff Application, Exhibit No. 3, Application 1609784, Proceeding No. 2739.

8 Exhibit No. 3, application, paragraph 2.

9 Decision 2013-436: ENMAX Power Corporation, 2014 Interim Distribution and Transmission Tariff Application, Application No. 1610012, Proceeding ID No. 2886, December 11, 2013.

10 Exhibit No. 3, application, paragraph 4.

11 Exhibit No. 3, application, paragraphs 3 and 20.

interim rate adjustment is made effective January 1, 2015, there will be a distribution revenue shortfall of $10.229 million from January 1, 2015 to December 31, 2015.[12]

12. In order to calculate its distribution revenue shortfall calculations, EPC adopted the PBR formula established in Decision 2012-237 (first generation PBR) for other utilities to adjust their distribution base rates on an annual basis:[13]

$$R_t = \underbrace{BR_{t-1} * (1+ (I-X))}_{\text{Base rates } (BR_t)}$$

Where:

R_t = Upcoming year's rates for each class

BR_{t-1} = Current year's base rates for each class

I = Inflation Factor ("I factor")

X = Productivity Factor ("X factor")

13. For its 2015 interim rate calculations, EPC adopted the first generation PBR formula using EPC's proposed 2014 DTA revenue requirement as BR_{t-1}.[14]

14. EPC requested the following first generation PBR placeholders for interim distribution rate setting purposes only:

(i) I factor placeholder of 2.93%, where the I factor placeholder is calculated the same as the first generation PBR I factor approved in Decision 2012-237, using the Alberta Average Weekly Earnings ("AWE") from July 2012 to June 2014 with a weighting of 55%, and the Alberta Consumer Price Index ("CPI") from July 2012 to June 2014 with a weighting of 45%. The Statistics Canada data for each index showing the placeholder I factor calculation is provided in Appendix 1, Schedule 1.2; and

(ii) X factor placeholder of 1.16%, where the X factor placeholder is the same as the first generation PBR X factor of 1.16% approved in Decision 2012-237.[15]

15. In response to a Commission information request, EPC revised the data used in calculating the I factor and calculated a new 2015 I factor of 2.65 per cent. EPC also provided revised 2015 interim distribution rate calculations and tariffs.[16]

12 Exhibit No. 3, application, paragraph 12; Appendix 1, schedules 1.1 and 1.5; 2014 Phase I DTA and 2014-2015 Transmission GTA; Exhibit No. 106.6, Schedule 12-1, Retail Sales of $310.888 (Line 21) less the cost of Sales of $111.615 million (Line 9), Application No. 1609784, Proceeding ID No. 2719.

13 Exhibit No. 3, application, paragraph 6; Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Application No. 1606029, Proceeding ID No. 566, September 12, 2012, at paragraph 963.

14 Exhibit No. 3, application, paragraph 7.

15 Exhibit No. 3, application, paragraph 8.

16. EPC noted that its proposal to use first generation PBR placeholders is for convenience, and does not necessarily mean that it will propose these factors in its forthcoming second generation PBR application, or that it accepts these factors would be reasonable for the same. EPC submitted that the use of first generation PBR placeholders is reasonable and conservative for the purposes of determining 2015 interim distribution rates.[17]

17. EPC's distribution rates would require an increase of 5.31 per cent to collect the forecast 2015 distribution revenue requirement of $202.800 million. However, EPC's proposed interim rate adjustment will result in an increase to distribution rates of 3.19 per cent, which will enable EPC to recover 60 per cent of its revenue shortfall and collect $198.710 million in 2015 distribution revenue. This will reduce the forecast 2015 distribution revenue shortfall from $10.229 million to $4.090 million.[18]

18. EPC also proposed that the requested interim distribution base rate increase of 3.19 per cent be applied to all rate classes on an across-the-board basis, therefore maintaining the currently approved rate structure based on EPC's last approved Phase II cost of service study.[19]

19. Subsequent to receiving a decision in Proceeding No. 2739, EPC plans to file for approval of a capital tracker, or K factor, in 2015 as part of the second generation PBR application or as a separate filing. While EPC did not propose a K factor placeholder in the application, EPC indicated that it will request approval to adjust the 2015 interim distribution base rates subsequent to the filing of its capital tracker application.[20]

20. In the application, EPC referred to its 2015 billing determinant forecast:

> EPC's forecast 2015 Distribution revenue is $192.571 million if the existing 2014 interim Distribution rates are continued in 2015 without an adjustment, based on the 2015 billing determinant forecast.[21]

21. In response to a Commission information request on the 2015 billing determinant forecast, EPC:

- confirmed that the forecast is a new forecast that has not been previously approved by the Commission
- explained that the forecast is based on the same methodology used in EPC's 2014 DTA but with updated historical data and key economic indicators
- submitted that it considers the forecast to be interim and will be including the forecast for full testing in its forthcoming PBR application[22]

16 Exhibit No. 16.01, AUC-EPC-1; Exhibit No. 16.02, Appendix 1, revised 2015 interim distribution rate calculations; Exhibit No. 16.03, Appendix 2, revised 2015 interim distribution tariffs.
17 Exhibit No. 3, application, paragraphs 9 and 10.
18 Exhibit No. 3, application, paragraphs 13 to 15.
19 Exhibit No. 3, application, paragraph 16.
20 Exhibit No. 3, application, paragraph 17.
21 Exhibit No. 3, application, paragraph 12.
22 Exhibit No. 16.01, AUC-EPC-2.

2.2 Transmission

22. EPC submitted that its forecast transmission revenue for 2015, included in Appendix 3 to the application, is $61.708 million based on current interim transmission rates. EPC's forecast transmission revenue requirement for 2015 is $75.968 million, as applied for in its 2014-2015 transmission GTA. Consequently, if the 2014-2015 GTA is approved as applied for and no interim rate adjustment is made effective January 1, 2015, there will be a transmission revenue shortfall for 2015 of $14.260 million from January 1, 2015 to December 31, 2015.[23]

23. EPC's transmission revenue requirement would require an increase of 23.11 per cent to collect the forecast 2015 transmission revenue requirement of $75.968 million, as applied for in its 2014-2015 GTA. However, EPC requested approval of an interim increase to its existing transmission revenue requirement of 13.87 per cent, which will allow EPC to recover 60 per cent of its revenue shortfall. The proposed adjustment would result in 2015 transmission revenue of $70.264 million, reducing the forecast 2015 transmission revenue shortfall from $14.260 million to $5.704 million.[24]

2.3 Test to support interim tariff applications

24. In the application, as justification for its interim rates, EPC relied on the two-part test that was originally used by the Commission's predecessor, the Alberta Energy and Utilities Board, in evaluating interim rate applications, and has since been used by the Commission. The two-part test is as follows:

> The first part of the test relates to quantum and need, and includes the following considerations:
>
> i. Is the identified revenue deficiency probable and material?
> ii. Can all or some portion of any contentious items be excluded from the amount collected?
> iii. Is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?
> iv. Can the applicant continue safe utility operations without the interim adjustment?
>
> The second part of the test relates to the public interest and includes the following considerations:
>
> i. Will the interim rates promote rate stability and ease rate shock?
> ii. Will the interim adjustments help to maintain intergenerational equity?
> iii. Can the interim rate increases be avoided through the use of carrying costs?
> iv. Are the interim rate increases required to provide appropriate price signals to customers?
> v. Is it appropriate to apply the interim rider on an across-the-board basis?[25]

3 Issues and Commission findings

25. When evaluating the merits of an interim rate application, the Commission applies the above-stated test. It weighs the potential benefits of rate stability and minimization of rate shock and intergenerational inequity that might result on approval of final rates against the costs that

---

23 Exhibit No. 3, application, paragraph 19; 2014 Phase I DTA and 2014-2015 Transmission GTA, Exhibit No. 124, Application No 1609784, Proceeding ID No. 2719; Appendix 3, Schedule 3.1.

24 Exhibit No. 3, application, paragraphs 21 to 23.

25 Exhibit No. 3, application, paragraphs 24-25.

underpin the interim rate increase, whether they be contentious or non-contentious items, the impact the revenue deficiency has on the financial welfare of the utility, and the potential impact on safe utility operations.

26. The above-listed considerations in the two-part test may be given different weighting depending on the specific circumstances of each application. The Commission has evaluated the application with these considerations in mind.

27. The Commission has reviewed the transmission and distribution revenue shortfall calculations included in appendices 1 and 3 of the application, including the revised I factor calculations, and is satisfied that they are accurate.

28. In respect of the 2015 billing determinant forecast, the Commission accepts EPC's explanation and is satisfied that the forecast, using previously approved methodologies and updated historical data and key economic indicators, is sufficient for the purposes of 2015 interim distribution rates based on 60 per cent of EPC's applied-for 2014 DTA. The 2015 billing determinant forecast will be tested in EPC's upcoming PBR proceeding. The Commission will make a determination at that time on the reasonableness of the forecast.

29. The Commission considers that the forecast distribution revenue shortfall of $10.229 million and transmission revenue shortfall of $14.260 million, amounting to a total revenue deficiency of $24.289 million, is a material amount if the entire amount had to be collected from customers.

30. The Commission is also cognizant of the financial hardship that such a material deficiency could have on EPC, as it stated in its application, "[t]hese deficiencies will reduce cash flow, which will in turn require increased short-term borrowing. Long-term borrowing may also be impacted, if the existing rates will be in place for the majority of 2015."[26]

31. The Commission also notes EPC's arguments that it has experienced load growth and system infrastructure expansion over the formula-based ratemaking (FBR) term of 2007 to 2013, while revenues were decoupled from costs. Consequently, EPC submitted that its distribution rate base grew significantly, and the cost of providing service has increased beyond the difference between the approved FBR inflation and productivity factors.[27]

32. To understand the impact of EPC's proposed interim rate increases on typical customer bills, the Commission has reviewed the bill comparison submitted by EPC.[28] The Commission has used the bill comparison information to prepare Table 1 below which illustrates that the interim rate increase will promote rate stability for customers.

26 Exhibit No. 3, application, paragraph 31.
27 Exhibit No. 3, application, paragraph 27.
28 Exhibit No. 5, application, Appendix 1, Schedule 1.8.

Table 1. Bill impacts

	Total charges		
Rate Class	Without interim rates	With interim rates	
	2015 PBR base rates January 1, 2015 (per cent)	2015 interim rates January 1, 2015 (per cent)	2015 PBR base rates January 1, 2015 (per cent)
Residential rate D100	4.0	0.6	1.6
Small commercial rate D200	2.9	0.4	1.2
Medium commercial rate D300	3.7	0.6	1.5
Large commercial - secondary rate D310	2.3	0.4	0.9
Large commercial - primary rate D410	1.0	0.2	0.4

33. Given the magnitude of the potential revenue shortfall and resultant financial impact to EPC and rate shock to customers' bills as demonstrated in Table 1 above, the Commission considers that some degree of interim rate adjustment should be made. The Commission is aware that the financial hardship to EPC could be mitigated by the award of carrying costs; however, it will not mitigate the risk of potential rate shock to customers. The Commission finds that approval of an interim increase to EPC's distribution rates will provide a gradual and stable transition to EPC's final 2015 distribution rates.

34. The Commission recognizes that while EPC's transmission tariff initially only applies to a single customer, the AESO, the increases to EPC's transmission tariff will flow-through to EPC's customers by way of EPC's system access service (SAS) rates and transmission access charge (TAC) deferral account riders. Consequently, the Commission accepts EPC's submission that "the proposed interim Transmission rates will help levelize the transmission Tariff throughout 2015, reducing the magnitude of the increase once final 2015 Transmission rates are approved"[29] and finds that, given the magnitude of the potential shortfall, an interim increase to its transmission rates will enable a more gradual transition to final 2015 transmission rates.

35. To better provide for both a gradual increase and a transitional rate level, the Commission considers that it is preferable to have an interim increase that reflects an intermediate position between the current rates and the proposed final rates. The Commission notes that for the period from January 1, 2014 to August 1, 2014, EPC estimated a distribution revenue shortfall of $20.175 million and a transmission revenue shortfall of $11.748 million.[30] The Commission approved EPC's request to collect 60 per cent of EPC's shortfall, reducing the forecasted shortfall to $8.069 million of revenue for distribution and $4.699 million of revenue for transmission.

36. In determining the reasonableness of the requested amount, the Commission notes that it received no objection from interveners on this application and accepts EPC's submission that a collection of 60 per cent of both its forecast distribution and transmission revenue deficiencies is

[29] Exhibit No. 3, application, paragraph 40.
[30] Decision 2013-436, paragraphs 7 and 11.

sufficient to account for any potentially contentious elements of EPC's 2014 DTA and 2014-2015 GTA. The Commission recognizes that the combined shortfall of $24.489 million is approximately $7.5 million lower than the combined shortfall than requested in EPC's 2014 Interim Distribution and Transmission Tariff Application. The Commission finds that as the proposed rate increases are requested on an interim basis, rates will be trued up once the final 2015 rates for distribution and transmission are approved.

37. The Commission also considers that applying the interim distribution rate increase to all rate classes on an across-the-board basis continues to be a reasonable method that is simple and cost effective to apply, and preserves the currently approved rate structure based on EPC's last approved Phase II cost of service study.

38. Accordingly, the Commission finds that the collection of 60 per cent achieves a reasonable balance in recognition of rate stability and minimization of rate shock that might result on approval of final rates against the costs that underpin the interim rate increase, contentious or non-contentious items, the impact the revenue deficiency has on the financial welfare of the utility, and the potential impact on safe utility operations. Consequently, the Commission approves the interim distribution and transmission rates as filed in this application effective January 1, 2015. The Commission approves:

- A 3.19 per cent interim increase to the distribution revenue requirement which represents 60 per cent of the 5.31 per cent applied for shortfall in the interim distribution revenue requirement. This interim increase is designed to decrease the forecast 2015 revenue shortfall from $10.229 million to $4.090 million; and

- An interim increase to the interim transmission revenue requirement of 13.87 per cent which represents 60 per cent of the 23.11 per cent applied for shortfall in the interim transmission revenue requirement. This interim increase is designed to decrease the forecast 2015 revenue shortfall from $14.260 million to $5.704 million.

39. In determining the level of interim rates for EPC, the Commission is not making any finding or determination with respect to any of the matters in EPC's 2014 DTA and 2014-2015 GTA, which is currently pending before the Commission.

40. The Commission has attached appendices 2 and 3 to this decision showing the interim distribution and transmission rates to be applicable on and after January 1, 2015, until replaced by subsequent decisions or orders of the Commission.

4 Order

41. It is hereby ordered that:

(1) The interim distribution tariff rates schedules attached as Appendix 2 to this decision are approved on an interim basis effective January 1, 2015.

(2) The interim transmission tariff attached as Appendix 3 to this decision is approved on an interim basis effective January 1, 2015.

Dated on November 12, 2014.

The Alberta Utilities Commission

(original signed by)

Bill Lyttle
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
ENMAX Power Corporation (EPC) T. Carle R. Lottermoser
ATCO Electric Ltd. (AE) B. Yee L. Kerckhof
Alberta Electric System Operator (AESO) J. Martin R. Sharma
EPCOR Distribution & Transmission Inc. (EPCOR) J. Baraniecki G. Zurek N. Lamers
FortisAlberta Inc. (Fortis) T. Dalgleish J. Croteau M. Stroh J. Walsh

The Alberta Utilities Commission Commission Panel B. Lyttle, Commission Member Commission Staff G. Bentivegna (Commission counsel) P. Howard C. Runge J. Graham

Appendix 2 – Interim distribution tariff

(return to text)

Appendix 2 - Interim distribution tariff

(consists of 18 pages)

Appendix 3 – Interim transmission tariff

(return to text)

Appendix 3 - Interim transmission tariff

(consists of 1 page)

ENMAX POWER CORPORATION ("EPC")

DISTRIBUTION TARIFF

RATE SCHEDULE

RATES IN EFFECT AS OF JANUARY 1, 2015

EPC DISTRIBUTION TARIFF RATE SCHEDULE

DISTRIBUTION TARIFF

RESIDENTIAL

RATE CODE D100

Rate Schedule for the provision of Electricity Services to residential Customers of a Retailer.

ELIGIBILITY

1. Sites which use Electricity Services for domestic purposes in separate and permanently metered single family dwelling units with each unit either metered separately or incorporated into a common building with other units.

2. As a single phase or three phase wire service supplied at a standard voltage normally available.

3. Sites eligible under 1 and 2 that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service and Facilities Charge	per day	$0.427587
System Usage Charge	per kWh	$0.008896
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Variable Charge	per kWh	$0.019463

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. No more than one additional unit of living quarters within a single family dwelling, such as a basement suite equipped with cooking facilities, may be provided Electricity Services through one Meter under Rate Code D100. If the dwelling contains more than one additional self-contained unit of living quarters, a Commercial Rate will apply unless a separate Meter is installed for each unit.

   All new construction in R2 or higher density areas shall have a separate Meter for each suite, or alternatively the Electricity Services may be invoiced at the appropriate commercial rate.

2. If a Residential Site has a garage with a separate meter, the garage will be assigned a commercial rate.

3. If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

SMALL COMMERCIAL

RATE CODE D200

Rate Schedule for the provision of Electricity Services to small commercial Customers of a Retailer.

ELIGIBILITY

1. Commercial Sites where the Energy consumption is less than 5,000 kWh per month (includes all unmetered services that are not Rate Code D500).
2. Sites eligible under 1 that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service and Facilities Charge	per day	$0.979551
System Usage Charge	per kWh	$0.007632
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Variable Charge	per kWh	$0.015905

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. Temporary Construction/Service

   Construction and rental costs for necessary transformers and equipment required for any temporary Electricity Services (whether single or three phase, or whether served from an overhead or underground source), shall be payable by the Customer to EPC in advance and based on an EPC estimate. Construction costs include costs associated with:

(a) up and down labour;

(b) unsalvageable material;

(c) vehicles; and

(d) equipment.

2. Temporary Connection Service

   Where applied-for Connection Services are to be used for temporary purposes only, the Customer will pay EPC, in advance of the installation:

   (a) EPC's total cost of installation and removal of the Facilities required for the temporary service; and

   (b) the cost of unsalvageable material.

3. Unmetered Services

   For unmetered services where individual energy consumption is small and easily predicted, estimated consumption will be based on equipment nameplate rating and operational patterns.

4. If a Site that qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

MEDIUM COMMERCIAL

RATE CODE D300

Rate Schedule for the provision of Electricity Services to medium commercial Customers of a Retailer.

ELIGIBILITY

1. For Sites whose Energy consumption is equal to or greater than 5,000 kWh per month for at least six of the last 12 invoice periods, provided a peak demand greater than 150 kVA was not registered twice in the previous 365 days.

2. Sites eligible under 1 above that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$5.539776
Facilities Charge	per day per kVA of Billing Demand	$0.037608
System Usage Charge	per kWh	$0.004081
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Demand Charge	per day per kVA of Billing Demand	$0.118081
Variable Charge	per kWh	$0.004047

Where

kVA of “Billing Demand” is defined as the greater of “Metered”, “Ratchet” or “Contract” Demand:

(a) “Metered Demand” is the actual metered demand in the Tariff bill period;

(b) "Ratchet Demand" is 90% of the highest kVA demand in the last 365 days ending with the last day of the Tariff bill period; and

(c) "Contract Demand" is the kVA contracted for by the Customer.

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. Non-Standard Residential "Bulk-Metering".

2. Bulk Metering is the metering of multiple-unit residential occupancies under one corporate identity, (e.g., town housing, apartments, mobile home parks). Where bulk-metering exists, the Customer shall not re-sell electricity, but may include electricity as part of the rental charge and not separate therefrom.

3. Includes Medium Commercial Sites served at primary voltage that existed prior to November 2004 rate class changes.

4. If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

5. D300 Primary Voltage Service Customers
    a. For locations or buildings that receive primary voltage service, there will be a transformation credit of $1.335496 per day applied to the Service Charge, and a transformation credit of $0.009234 per day per kVA of Billing Demand applied to the Facilities Charge.
    b. The transformation credit is applicable only to D300 sites receiving primary voltage service prior to January 1, 2009.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

LARGE COMMERCIAL - SECONDARY

RATE CODE D310

Rate Schedule for the provision of Electricity Services to large commercial (secondary) Customers of a Retailer.

ELIGIBILITY

1. For Electricity Services that registered a monthly peak demand greater than 150 kVA twice in the previous 365 days and served at secondary voltage.

2. Sites eligible under 1 that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$16.089680
Facilities Charge	per day per kVA of Billing Demand	$0.098202
System Usage Charge On Peak	per kWh	$0.006604
System Usage Charge Off Peak	per kWh	$0.000000
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Demand Charge	per day per kVA of Billing Demand	$0.138805
Variable Charge On Peak	per kWh	$0.004574
Variable Charge Off Peak	per kWh	$0.003573

Where

kVA of "Billing Demand" is defined as the greater of "Metered", "Ratchet" or "Contract" Demand:

(a) "Metered Demand" is the actual metered demand in the Tariff bill period,

(b) "Ratchet Demand" is 90% of the highest kVA demand in the last 365 days ending with the last day of the Tariff bill period,

(c) "Contract Demand" is the kVA contracted for by the Customer.

"On Peak" is all Energy consumption from 8 a.m. to 9 p.m. Monday to Friday inclusive, excluding statutory holidays (as according to the ISO Rules definition),

"Off Peak" is all Energy consumption not consumed in On Peak hours.

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all service supplied under this Tariff.

OTHER

If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

LARGE COMMERCIAL - PRIMARY

RATE CODE D410

Rate Schedule for the provision of Electricity Services to large commercial (primary) Customers of a Retailer.

ELIGIBILITY

1. For Electricity Services that are served at primary voltage.
2. Sites eligible under 1 above that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$19.830314
Facilities Charge	per day per kVA of Billing Demand	$0.013834
System Usage Charge On Peak	per kWh	$0.008095
System Usage Charge Off Peak	per kWh	$0.000000
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Demand Charge	per day per kVA of Billing Demand	$0.138700
Variable Charge On Peak	per kWh	$0.004512
Variable Charge Off Peak	per kWh	$0.003525

Where

kVA of "Billing Demand" is defined as the greater of "Metered", "Ratchet" or "Contract" Demand:

(a) "Metered Demand" is the actual metered demand in the Tariff bill period,

(b) "Ratchet Demand" is 90% of the highest kVA demand in the last 365 days ending with the last day of the Tariff bill period,

(c) "Contract Demand" is the kVA contracted for by the Customer,

"On Peak" is all Energy consumption from 8 a.m. to 9 p.m. Monday to Friday inclusive, excluding statutory holidays (as according to the ISO Rules definition),

"Off Peak" is all Energy consumption not consumed in On Peak hours.

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. The Customer is responsible for supplying all transformers whether owned by Customer or rented.
2. "Primary Metering" shall be metering at EPC's primary distribution voltage with any subsequent transformation being the sole responsibility of the Customer.
3. Multi-Sites
   a) For Customers that have a normally used service connection (preferred service) and a second service connection used strictly as a backup service (alternate service), the demands of the two service connections will be totaled on an interval basis and charged based on Rate Code D410.
   b) For Customers that use more than one service connection on a regular basis, demands of all the service connections will be totaled on an interval basis and charged based on Rate Code D410 provided the service connections are:
      i) positioned on adjacent and contiguous locations;
      ii) not separated by private or public property or right-of-way; and
      iii) operated as one single unit.
4. If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

STREETLIGHTS

RATE CODE D500

Rate Schedule for the provision of Electricity Services to Customers of a Retailer.

ELIGIBILITY

For all photo cell controlled lighting services including all streetlights, traffic sign lighting, roadway lighting and lane rental lighting. Services with photo cell controlled lighting will not be eligible for a Meter.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
System Usage Charge	per kWh	$0.017490
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Variable Charge	per kWh	$0.016804

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

LARGE DISTRIBUTED GENERATION

RATE CODE D600

Rate Schedule for the provision of Electricity Services to Sites with on-site generation with a minimum export capacity of 1,000 kVA.

ELIGIBILITY

1. For services with on-site generation connected in parallel with the EPC Electric Distribution System with a minimum export capacity of 1,000 kVA.
2. For Electricity Services that are served at primary voltage.
3. For sites equipped with bi-directional interval recording metering.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$19.830314
Dedicated Facilities Charge	per day	customer specific
System Usage Charge On Peak	per kWh	$0.008095
System Usage Charge Off Peak	per kWh	$0.000000
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
ISO Costs/Credits	$	Flow through

1. The customer specific Dedicated Facilities Charge daily amount will be determined as follows:

   Dedicated Facilities Charge = ((DFA + GA) x (CRF + OMA))/365 days.

Where:

a) DFA = current cost of dedicated feeder assets

b) GA = general assets associated with DFA and equal to 10.8% of DFA

c) CRF = Capital Recovery Percentage Factor based on EPC's weighted cost of capital and approved depreciation rate.

d) OMA = Operation, maintenance and administration factor equal to 3.1% of DFA.

The customer specific Dedicated Facilities Charge daily amount will be outlined in the Interconnection Agreement which will also include the term of the Agreement and an annual inflation adjustment.

2. The System Usage Charge will be determined using the net of the energy inflow and energy outflow at the Meter(s). System Usage Charge will be waived for sites that only have dedicated facilities and do not use the EPC primary feeder system.

3. "On Peak" is all Energy consumption from 8 a.m. to 9 p.m. Monday to Friday inclusive, excluding statutory holidays (as according to the ISO Rules definition), "Off Peak" is all Energy consumption not consumed in On Peak hours.

4. Flow-Through of ISO Costs/Credits will be determined by applying the ISO DTS rate (and any applicable riders) to the difference between the POD billing determinants with and without the site(s) billing determinants.

5. An initial fee will be charged for the incremental cost of bi-directional meter(s).

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of EPC form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

5. The Customer is responsible for supplying all transformers whether owned by customer or rented.

6. "Primary Metering" shall be metering at EPC's primary distribution voltage with any subsequent transformation being the sole responsibility of the Customer.

7. Multi-Site Locations

   c) For locations or buildings that have a normally used service connection (preferred service) and a second service connection used strictly as a backup service (alternate service), the demands of the two service connections will be totaled on an interval basis and charged on Rate Code D600.

   d) For locations that use more than one service connection on a regular basis, demands of all the service connections will be totaled on an interval basis and charged on Rate Code D600.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

TRANSMISSION CONNECTED

RATE CODE D700

Rate Schedule for the provision of Distribution Access Service to Customers of a Retailer that are connected directly to EPC Facilities at a transmission voltage.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$19.830314
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
ISO Costs	$	Flow through

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

TRANSMISSION RATE SCHEDULE

EFFECTIVE JANUARY 1, 2015

ENMAX POWER CORPORATION
RATE SCHEDULE
INTERIM 2015 TRANSMISSION TARIFF

ELIGIBILITY

To the Alberta Electric System Operator for use of ENMAX Power Corporation's Transmission facilities for the period

RATE

The Transmission tariff charged to the Alberta Electric System Operator is:

Monthly Charge: $5,855,318.18

TERMS AND CONDITIONS

The terms and conditions of ENMAX Power Corporation form part of this rate schedule and apply to service supplied under this tariff.

2011 CarswellMan 390
Manitoba Public Utilities Commission

Manitoba Hydro, Re

2011 CarswellMan 390

The Public Utilities Act, Re

Interim Rates for Manitoba Hydro Effective April 1, 2011

Graham Lane Chair, Robert Mayer V-Chair

Judgment: March 30, 2011
Docket: 40/11

Counsel: None given

Subject: Public

Related Abridgment Classifications
For all relevant Canadian Abridgment Classifications refer to highest level of case via History.

Headnote

Public law --- Public utilities — Operation of utility — Rates — Fairness and impartiality

Public law --- Public utilities — Operation of utility — Rates — Miscellaneous

Table of Authorities

Cases considered by *Graham Lane Chair*:

Bell Canada v. Canadian Radio-Television & Telecommunications Commission (1989), 38 Admin. L.R. 1, [1989] 1 S.C.R. 1722, 60 D.L.R. (4th) 682, 97 N.R. 15, 1989 CarswellNat 586, 1989 CarswellNat 697 (S.C.C.) — considered

Statutes considered:

Public Utilities Board Act, R.S.M. 1987, c. P280
s. 27 — referred to

s. 44 — referred to

s. 48 — referred to

s. 58 — referred to

***Graham Lane Chair*:**

1.0 Executive Summary

1 By this Order, the Public Utilities Board (Board), which heard submissions on March 9, 2011 from Manitoba Hydro (MH or Hydro) and Interveners as to whether the Board should approve a further interim electricity rate increase, approves an average 2.0 % interim rate increase, to be effective April 1, 2011.

2 The increase is to be applied to the energy rate across all customer classes with the exception of Area and Roadway Lighting which will not receive any interim rate increase at this time. As well, in applying this interim rate increase to the Residential Class, MH is to apply the Residential rate increase to eliminate the inversion and then keep the two energy block rates equal.

3 The Board is satisfied that a further interim rate adjustment is required ahead of an expected fall conclusion of MH's General Rate Application (GRA). This latest interim rate increase is expected to increase MH's annual revenue by approximately $22 million, while the interim increase implemented April 1, 2010 is estimated to have increased MH's annual revenue by approximately $33 million. Combined, the two interim rate increases should increase MH's annual revenue for the Utility's 2011/12 fiscal year by approximately $55 million.

4 The evidence before the Board, as of March 9, 2011, provides *prima facie* support for the granting of an interim rate increase as of April 1, 2011, although the increase approved herein is of 2.0%, that less than the 2.9% sought by MH.

5 From the evidence adduced to date, there is a reasonable basis for being concerned that MH's projected string of 3.5% annual rate increases (from 2012 through, to and including, 2021), and the interim increases granted in this General Rate Application (which collectively accumulate to an approximate 45% rate increase for consumers between 2011 and 2021) may, when finalized, be insufficient in light of MH's major capital development plans (which includes the construction of Wuskwatim, Keeyask and Conawapa Generating Stations and Bipole III transmission line). However, the GRA hearing is far from over, with much more evidence and testimony to be heard and considered.

6 The Board concludes, also on an interim basis, that MH's current ratepayers should share in the risks surrounding MH's

major development plans with future generations of ratepayers, with the sharing of the risks to take place through higher rates to the current generation of ratepayers.

7 The Board's major concerns revolve around the Utility's Preferred Development Plan for MH's self described "decade of investment". The Plan, which includes the completion of Wuskwatim and the construction of Bipole III, Keeyask Generating Station and Conawapa Generating Station, was conceived some time ago.

8 However, since MH formulated its Preferred Development Plan, MH's future domestic load forecasts have been significantly reduced (pushing back the date new generation is required to meet domestic demand); the term sheets entered into by MH and its American counterparties have yet to be converted into firm contracts; short-term and spot export sales prices have fallen dramatically (to 2.3 cents per kilowatt on average for the past two years); and, there is a risk that if the present development plan is implemented sharper rate increases may be required of the Utility's Manitoba consumers than MH currently projects.

9 Following the conclusion of the GRA hearing, the Board intends to finalize all of its interim rate decisions related to MH; parties are aware that rates set on an interim basis may be confirmed or varied.

2.0 Background

10 On December 1, 2009 MH filed a GRA seeking 'across-the-board' 2.9% rate increases to be effective both on April 1, 2010 and April 1, 2011. On December 10 and 22, 2009 and March 12, 2010, the Board held Pre-hearing Conferences (PHC) to identify Interveners for participation in the GRA public process; whether and how to incorporate a review of MH's risks and risk management into the GRA process; and, to establish a timetable for the orderly exchange of evidence (to lead up to public hearings that, eventually, began in January 2011).

11 The Board granted Intervener status to Consumers' Association of Canada (Manitoba) Inc. and Manitoba Society of Seniors (CAC/MSOS); Manitoba Industrial Power Users Group (MIPUG); Manitoba Keewatinowi Okimakanak, Inc. (MKO); Resource Conservation Manitoba and Time to Respect Earth's Ecosystems (RCM/TREE); City of Winnipeg (City); and, Southern Chiefs Organization (SCO), collectively referred to as the "Interveners".

12 While the Board rejected an Application for intervener status from a former consultant to MH (the 'New York Consultant'/'NYC'), who made serious allegations of mismanagement and risk involving the Utility, the Board provided a role for the NYC. NYC's public document (setting out the NYC's allegations) was distributed to Interveners, placed on the public record and responded to by KPMG in a review engaged by MH.

13 At the PHCs in December 2009, when various timetables were discussed, it became clear that there was no agreement on the timetable that would facilitate the potential for final April 1, 2010 rate adjustments, should any be ordered by the Board.

14 Subsequently, the Board accepted a recommendation by RCM/TREE, supported by MH, that MH's rate increase

request for April 1, 2010 be considered on an interim basis, pending finalization subsequent to the completion of the GRA process.

15 Accordingly, the Board held an Interim Rate Consideration Hearing on January 19, 2010, where the Board heard submissions from MH and Interveners as to whether interim rate adjustments should be made effective April 1, 2010, pending completion of the GRA hearing process. The Board subsequently granted interim rate increases effective April 1, 2010.

16 The Board also determined in 2010 that the oral evidentiary public hearing (a major component of the GRA proceeding) would consider, among other issues, MH's risks and risk management; revenue requirement; the cost of service study (a comparison of assigned revenues and costs employed in the consideration of whether rates are fair and reasonable); and, MH's general rate design.

17 The initial plan was for the hearing to begin in the summer of 2010, with a conclusion expected for the fall of that year. However, as a result of a number of events and factors, the major factor being the extensive range and complex nature of the issues to be considered, the oral hearing did not begin until early January 2011, and is now not anticipated to conclude (with a final GRA order) until the fall of this year, 2011.

18 With the revised expectation that the GRA would not conclude until long after April 1, 2011, and noting that MH has projected a rate increase which the Utility has factored into its long-term plans, the Board sought submissions from Interveners and MH with respect to possibly approving a further interim rate adjustment, that to take effect April 1, 2011. Submissions were received from MH and Interveners on March 9, 2011.

3.0 Intervener Positions

19 CAC/MSOS opposed interim rate increases effective April 1, 2011.

20 This Intervener submitted that in considering the setting an interim rate, the Board should consider regulatory precedent for the fixing of "just and reasonable" rates, citing *Bell Canada v. Canadian Radio-Television & Telecommunications Commission*, [1989] 1 S.C.R. 1722 (S.C.C.) paragraph 57, which states:

> ....The very purpose of interim rates is to allay the prospect of financial instability which can be caused by the duration of proceedings before a regulatory tribunal. In fact in this case the respondent asked for and was granted interim rate increases on the basis of serious apprehended financial difficulties. The added flexibility provided by the power to make interim orders is meant to foster financial stability throughout the regulatory proceeding. The power to revisit the period during which interim rates were in force is a necessary corollary of this power without which interim orders made in emergency situations may cause irreparable harm and subvert the fundamental purpose of ensuring that rates are just and reasonable.

21 CAC/MSOS noted that the underlying purpose of interim rates, always in the context of just and reasonable rates, is to foster financial stability for a utility throughout a regulatory process, so as to protect the utility against serious apprehended

financial difficulties that could flow from an extended duration of a regulatory process.

22 Holding that there was no serious apprehended financial difficulty in the case of MH, CAC/MSOS opposed an April 1, 2011 interim rate increase while acknowledging that the Board has the regulatory discretion to grant an interim rate increase.

23 CAC/MSOS held that such discretion should only be exercised in circumstances where current rates are not just and reasonable, and recommended that in deliberating on whether to set interim rates the Board consider criteria based both upon case law and the Board's decision in Order 18/10:

• First, has the Board concluded that a lengthy delay in the regulatory proceeding is likely to take place?

• Secondly, has the tribunal reached the conclusion that there is an unusual financial need such that either a rate increase is necessary to allay the prospect of financial instability or address serious apprehended financial difficulties, which can be caused by the duration of the proceeding?; and

• Third, has the Corporation established a prima facie basis that the proposed interim rate is just and reasonable?

24 CAC/MSOS opined that MH's current financial condition is much improved from the Utility's prior forecasts, noting that MH's GRA is based on the financial forecasts of IFF-09-1, which indicated that MH would need an additional $33 million of revenue from domestic customers in 2010/11 and a cumulative additional $69 million for 2011/12. CAC/MSOS observed that MH's actual net income for 2009/10 was $39 million higher than MH's projection in its IFF-09 forecast.

25 In addition, CAC/MSOS noted that MH's updated forecasts for 2010/11 and 2011/12 (represented in the projections of IFF10) reflect an anticipated material improvement in MH's expectations for both net income and retained earnings for the two years (with retained earnings now projected to be $93 million higher than that forecast in IFF 09).

26 CAC/MSOS suggested that even if the 2.9% increase for April 1, 2011 sought by MH was not implemented, MH would still be materially better off (as measured by the level of projected retained earnings) as at March 31, 2012 than the Utility had originally forecast. Accordingly, CAC/MSOS submitted that MH's materially improved financial results neither support a conclusion of a state of financial instability nor that of a serious apprehended financial difficulty (to arise from a delay of the Board approving another rate increase for the Utility following the close of evidence).

27 CAC/MSOS further noted that MH's OM&A expenditures have risen materially over the years, and suggested that there was insufficient evidence to suggest effective cost management by the Utility. For CAC/MSOS, Hydro's improved financial position arises from rate increases and subpar forecasting.

28 CAC/MSOS also submitted that it would be premature for the Board, by approving an interim rate increase as of April 1, 2011, to partially pre-fund the Utility's Preferred Development Plan (particularly until there is greater certainty that the Utility's plan will unfold as planned). For CAC/MSOS, based on the record of the proceeding to-date, it is still unclear whether the export sales term sheets will become firm contracts, and even whether the construction of Keeyask Generating Station will prove to be an appropriate action and proceed.

29 CAC/MSOS underlined its view of uncertainty associated with MH's Preferred Development Plan, listing three concerns drawn from the evidence of Mr. Rose of ICF (a witness engaged by the Utility), those being (a) natural gas prices and forecast prices are significantly (38-49%) lower than was the case in 2009 when the IFF-O9 was developed; (b) forecasts of the value of carbon emission allowances (expected by MH to assist the pricing of its exports) have been significantly downgraded — both in terms of the time frame within the value would be established and as to the likely magnitude of the assumed positive effect for Hydro's export pricing (the forecast carbon value now 40% to 60% lower than previously forecast); and, (c) the number of anticipated coal plant retirements in the MISO area — MH's export market, are now expected to be fewer than before.

30 CAC/MSOS observed that there is a significant amount of evidence yet to be provided in the hearing, including from the Independent Experts engaged by the Board and from Intervener witnesses.

31 CAC/MSOS, having fundamental issues with MH's GRA and holding that their issues have yet been fully tested, opined that it would be imprudent for the Board to make a directional judgment at this time, ahead of evidence yet to come. CAC/MSOS also contended that MH had failed to comply with Directive 4 of Board Order 32/09, which directed that an overall analysis of the risks faced by MH be carried out. CAC/MSOS noted that KPMG's study did not provide the comprehensive risk analysis requested by the Board.

32 CAC/MSOS further held that there would be a material risk that MH would draw the wrong inference from another interim rate approval, and that the granting of a 2.9% interim rate increase could be interpreted by the Utility as the Board approving its scenarios (as set out in IFF09 and IFF10), which incorporate its Preferred Development Plan, even though MH failed to comply with Directive 4 of Order 32/09.

33 CAC/MSOS also submitted that the sought interim rate increase should not be granted because Manitoba consumers are vulnerable, facing economic and employment uncertainty, citing that electricity and other cost increases are increasing pressure on household budgets, while wage settlements have not kept pace with inflation. CAC/MSOS further observed that MH's rate increases over the last seven years have exceeded the general rate of inflation, and suggested that the flow of rate increases should be "slowed".

34 CAC/MSOS concluded that the Board rejecting or moderating MH's proposed 2.9% interim rate increase would provide welcome relief to vulnerable consumers, and provide an opportunity for a more "sober" consideration of the issues, while sending a "message" to MH that it is not enough to rely on subpar forecasts and domestic rate increases to meet the Utility's projected future financial obligations.

4.0 MIPUG

35 MIPUG joined CAC/MSOS in opposing the granting of interim rate increases as of April 1, 2011.

36 MIPUG noted that while, in support of its interim rate request, MH had cited BC Hydro's high rate increases proposals, MH had not "featured" Hydro-Quebec's action of requesting a zero percent increase at this time.

37 MIPUG stated that the Board has, to-date, only heard "one side of the story" and opined that a balanced view of the Utility's circumstances have yet to be presented, with, to this point in the proceeding, only Hydro's view and Hydro's evidence tested, and that only somewhat tested as cross-examination of Hydro's panel by Interveners has yet to occur. MIPUG also noted that none of the Interveners have had the opportunity of having their witnesses testify.

38 With respect to KPMG's risk review (KPMG's panel of witnesses was cross-examined by both the Board and Interveners), MIPUG noted that the review failed to quantify MH's risks (as sought by the Board in Order 32/09) and submitted that further rate increases should be halted until such time that there is sufficient evidence on the quantum and probability of MH's risks.

39 Also, MIPUG noted that the Board may be missing critical information that may reside in alternative IFF scenarios not provided by MH, and that identification and examination of alternative scenarios are required before a further interim rate increase is approved.

40 Noting the Board's reluctance for retroactive rate changes, MIPUG also submitted that the establishing of an across the board interim rate increase could create continued inequity for some classes - especially those with Revenue to Cost Ratios outside the Zone of Reasonableness.

41 MIPUG also submitted that a "special test" has to be met in considering whether to establish interim rates, and referenced *The Public Utilities Board Act*, particularly Sections 44, 27 and 48, the latter which states:

> The Board shall not make an order involving any outlay, loss, or deprivation to any owner of a public utility, or to any person without due notice and full opportunity to all parties concerned to produce evidence, and be heard at a public hearing of the Board, except in the case of urgency...

42 MIPUG also cited court cases that it submitted supported is position that an interim rate increase should not be granted. In particular, MIPUG relied on a *Bell Canada* case (also cited by CAC/MSOS), and set out the criteria used by the CRTC in considering interim rate adjustments, that being:

> The Commission considers that, as a rule, general rate increases should only be granted following the full public process contemplated by Part III of its Telecommunications Rules of Procedure. In the absence of such a process, general rate increases should not in the Commission's view be granted, even on an interim basis, except where special circumstances can be demonstrated. Such circumstances would include lengthy delays in dealing with an application that could result in a serious deterioration in the financial condition of an applicant absent a general interim increase.

43 MIPUG also referred to an Alberta Utilities Commission (AUC) decision dealing with interim rates. MIPUG reported that in AUC Order 2002-115, the Commission set out the factors to be considered in evaluating the merits of a proposed interim rate increase:

> These factors can be grouped into two categories, those that relate to the quantum of, and need for, the rate increase and those that relate to more general public interest considerations.

44 The quantum and need factors cited by AUC, as reported by MIPUG, included: (a) that the identified revenue deficiency should be probable and material; (b) a response to the question of whether the interim increase was required to either preserve the financial integrity of the applicant or to avoid financial hardship for the applicant; (c) a response to the question whether the applicant could continue safe utility operations without the interim adjustment; and, (d) recognition that contentious costs could be excluded from the revenue requirement to be met.

45 MIPUG suggested that if all or a portion of the suggested rate increase appears appropriate after consideration of the above listed factors, the Board must then assess certain general public interest factors to see if a rate increase is justified, including the following: (a) whether Interim rates would promote rate stability and ease rate shock; (b) whether interim rate adjustments would help maintain intergenerational equity; (c) whether an interim rate increase was required to provide appropriate price signals to consumers; (d) whether deferring costs from being taken into account in determining revenue requirements should be considered to avoid interim rate increases; and, (e) whether, if an interim rate increase is to be approved, it is appropriate to do so on an across-the-board basis.

46 MIPUG suggested that the above considerations could be given different weighting depending on the specific circumstances, and held that in applying the above factors by MIPUG, MH does not meet the requirements for an interim rate increase.

47 MIPUG noted the following factors as not supporting MH having an urgent need for an interim rate increase: (a) MH's forecast electricity operations net income for 2010/11 and 2011/12 have increased from the $78 million and $87 million set out in IFF-09 to $149 million and $125 million in IFF-10; (b) MH's forecast electricity operations retained earnings for 2010/11 and 2001/12 has increased from the $2.261 billion and $2.331 billion forecast in IFF-09 to $2.354 billion and $2,279 billion in IFF-10; (c) MH's quarterly report for the three months ending December 31, 2010 indicates that export revenues for the first nine months of 2010 /11 were higher in both absolute dollar terms and average revenue per unit sold compared to the first nine months of 2009/10; (d) MH's IFF-10 forecast has short-term and long-term debt rates lower than that forecast in IFF-09; and, (e) MH's indicates water levels and water storage through December 2010 is both higher than was the case 2009, and well above average.

48 With respect to "Public Interest" factors, MIPUG noted that domestic consumers have been subject to a series of rate increases exceeding inflation over the past several years and, for MIPUG, current economic conditions considered from a public interest perspective suggest that ratepayers should not be burdened with an additional interim rate increase.

5.0 RCM/TREE

49 In addition to its oral submission of March 9, 2011, RCM/TREE provided a written submission supporting MH's request for an interim rate increase. This Intervener maintained that the Board has the legal jurisdiction and wide discretion, derived from statute, to make interim rate adjustments based on the facts before it.

50 RCM/TREE urged that a long-term view on rates be adopted, and advocated steady annual rate increases be implemented. The Intervener noted that MH's annual export revenues and net income levels are volatile because of water flows and varying export prices, and, by taking a long-term view, rate increases would not be a "start/stop" process based on the "fortunes" of the previous year.

51 RCM/TREE envisions regular incremental increases, this to smooth the impact of meeting the higher capital costs of such new generation that is required for Manitoba growth. RCM/TREE submits that "skipping" an annual rate increase would not only deprive MH of needed additional income (during the Utility's "decade of investment"), but result in negative revenue impacts into the future by setting a lower baseline for future rate increases.

52 RCM/TREE also perceives MH's risks as asymmetrical, with the downside of revenue expectations during adverse conditions being more severe than variations to the positive side during favourable conditions, and recommended that rates be sufficient to allow for MH to create and maintain sufficient retained earnings to withstand future negative events.

53 RCM/TREE noted that its witnesses have yet to testify, and anticipated that one of its witnesses would make recommendations related to rate design. RCM/TREE suggested that the Board approve an interim increase now and adjust rate design and address cost allocation issues with the final Order. For RCM/TREE, if an interim rate increase were granted but the final Order failed to address cost of service and rate design issues, the result would perpetuate what the Intervener holds to be a suboptimal rate design.

54 With respect to any future Energy Intensive Industry Rate proposal (on two occasions, MH has submitted an application only to later withdraw it), RCM/TREE requested that it be included in the consultation process.

6.0 SCO

55 SCO submitted a written brief that requested that in any revision of rates, the quantum of the increase be set aside and earmarked for all Manitoba First Nations. The purpose of such segregation and designation of funds would be, in SCO's view, to offset any compensation required to be paid to First Nations as a result of the "negligent operations" of MH's projects and facilities. Any rate increase should, in SCO's view, be set-aside until an environmental assessment on MH's projects takes place and is concluded.

7.0 MH's Submissions

56 MH requested the Board approve an 'across all rate classes' interim rate increase of 2.9%, with the exception of the Area and Roadway Lighting class, effective April 1, 2011. For MH, the implications of a later implementation date would be that MH would either forego needed revenue or that a higher future rate increase will be required. For the Utility, any delay in the implementation of the sought-after rate increase will result in more pressure driving up the magnitude of a future rate increase.

57 MH noted that its proposal was modest compared to a recent application made by BC Hydro, which applied for a rate increase of 9.73% for each of the next three years (a cumulative increase of over 32% for fiscal years 2012 to 2014). MH stated that its long-term rate strategy involves regular and modest incremental rate increases; with the Utility holding that a 2.9% rate increase as of April 1, 2011 would be consistent with that goal. MH advised that it is mindful of the interest of its ratepayers and promotes gradualism in its rate applications.

58 MH submits that Intervener suggestions that MH must first demonstrate urgency or a serious apprehension of financial

difficulties as a prerequisite for an interim rate increase are erroneous. MH maintained that there is nothing in legislation requiring a state of urgency or requiring MH to be in financial difficulty for the Board to approve an interim rate increase, noting that the Board has never accepted such a premise.

Term Sheets

59 With respect to the Utility's term sheets [with Minnesota Power (MP) and Wisconsin Public Service, (WPS)]; MH stated negotiations are continuing with significant progress taking place. MH held that both American customers remain strongly committed to proceeding with the proposed transactions and that a major factor delaying completion of the negotiations is defining required American transmission facilities, their associated costs, and the allocation of such costs.

60 MH indicated that transmission discussions have been undertaken with the CapX Group (Minnesota transmission-owning utilities), and, at the request of CapX, the new Manitoba-US major interconnection was identified in the fall of 2010 for inclusion in MISO's transmission expansion plan as a major regional transmission project (with the goal of it becoming an approved project in the 2012 MISO transmission expansion plan — if approved the cost of the transmission is to be "socialized", i.e. shared by all utilities within the MISO region).

61 MH reported that MISO filed (having received approval from FERC in December 2010) a modification of the MISO Transmission Tariff to include multi-valued projects (MVPs) that allow for cost regionalization of major regional transmission projects. If the MH transmission interconnection is approved as a MVP in the 2012 MISO transmission expansion plan, MH reported that would allow MP and WPS to conclude contract negotiations with MH such as to meet the revised and now current in-service dates for new MH generation.

Risk

62 In response to Interveners' claims that MH did not comply with risk related directives of Board Order 32/09, and with respect to assertions of Interveners that the KPMG report did not address Order 32/09, MH noted that there were very unique circumstances surrounding the commissioning of the KPMG report, and, that to suggest that the Board has not been provided with the "full picture" of the risks faced by the Corporation is, from MH's perspective, inaccurate.

63 MH reported that it has filed its full corporate risk management report, which identifies all of the major risks faced by the Corporation, and the ICF report. MH further cited the fact that the Board commissioned Independent Experts to produce a risk related report, with a wide scope. MH also noted that in addition, extensive interrogatories (IRs) have been filed and responded to, related to risk.

Load Forecast

64 MH observed (citing the economic downturn) that there have been significant reductions in its forecasts of the future load of industrial customers, claiming that the forecast reductions in industrial load will be significantly offset by expected increases in the remaining domestic load, in particular with respect to residential loads.

65 MH also stated that the forecast industrial load growth reductions, indicated to be in the order of a fifteen year delay in reaching previously forecast future loads, would have little impact on forecast future domestic revenues because of the differences in unit prices within the different customer rate classes (the average industrial rate is about 3.7¢/kW.h, the residential rate is close to 7¢/kW.h).

Energy Intensive Rate Application

66 MH stated that the economic downturn also drove it's decision to defer filing a new application for an Energy Intensive Industrial Rate (EIIR) — the concept of EIIR is that large additional loads from industrial customers, billed now at an average rate of below 4 cents a kW.h, could result in "lost" incremental revenues as that same power could be sold on export to American counterparties at higher prices. (With the average export price now below 4 cents and with short-term or spot export sales as low as 1 cent, the premise behind the EIIR was challenged.)

67 MH reported having met with MIPUG and individual large customers on topics related to new industrial rates for new or additional loads. MH stated that numerous meetings were held throughout the spring, summer, and fall of 2010, culminating in a November 2, 2010 workshop presentation to which all MIPUG members were invited.

68 MH reported that a further workshop is planned for March 16, 2011, and this meeting would broaden consultation to include remaining customers served at voltages between 30 kV and 100 kV. MH further advised that its future consultations would include RCM/TREE, CAC/MSOS and the government.

69 Upon completion of stakeholder consultation, MH indicated it plans to file a new EIIR Application with Board.

OM&A

70 MH stated that there are various "uncontrollable" business cost drivers that have contributed to the Utility's OM&A expense increases that, the Corporation acknowledges, have exceeded the rate of inflation.

71 These "higher than inflation" expenses include increased maintenance costs due to aging infrastructure, higher environmental and regulatory requirements, costs related to customer additions and new facilities, higher pension costs (the result of investment fund performance and low interest rates), higher material and commodity prices, and higher employee costs (due to additional resource requirements and competitive wage pressures).

72 MH indicated it had taken steps to constrain the rate of increase in OM&A costs, including a hiring freeze (excepting for trainees and specific key personnel hires), limiting out-of-province travel and other measures. MH advised that the measures taken had been effective in reducing the year-over-year change in OM&A expenses in 2010/11, when compared to 2009/10. For the ten-month period ended December 31, 2010, MH reported that its restraint measures had avoided $16 million in costs.

International Financial Reporting Standards (IFRS)

73 MH stated that the forecasts of IFF-10 reflect the most likely impacts of the expected and required conversion to IFRS accounting standards. The likely required changes include a reduction to capitalizing overheads (with a corresponding increase to operating costs) and an expected "write-off" to retained earnings of amounts previously capitalized or deferred (the latter including Demand Side Management ('DSM'), energy efficiency expenditures) but no longer allowed such treatment.

74 The adoption of IFRS will, according to MH, result in changes to the timing of the recognition of certain costs in MH's current operating accounts, and MH indicated that some mechanism may be required to defer recognition of these costs for rate setting purposes. In this regard, MH indicated that it would provide the PUB with alternatives to consider.

Debt to Equity Ratio

75 MH believes that its debt to equity ratio and the 25% equity ratio target continue to be important financial metrics to be considered in rate setting, particularly given planned future capital expenditures.

76 MH responded to questions raised by the Board as to whether Accumulated Other Comprehensive Income (AOCI) and Contributions In Aid of Construction (CIAC) should continue to be included in the determination of equity for use in calculating the debt to equity ratio.

77 MH stated that in as much as AOCI is a component of equity, in accordance with Generally Accepted Accounting Principles (GAAP), it is appropriate to include the balance as part of equity and as a component in the debt-equity calculation, noting that AOCI primarily reflects unrealized gains or losses associated with the translation of MH's U.S. dollar (United States currency, USD) debt. MH asserted that the translation of the USD denominated debt into Canadian dollar equivalents at each balance sheet date is important, and the result is the best indication of what that debt represents in Canadian currency at that point in time. (MH's exports sales to American counterparties are priced in USD, and if and as the Canadian dollar appreciates relative to the American dollar, the value of the exports in Canadian dollars decreases, offsetting over time currency gains that have and or may arise with respect to USD debt.)

78 MH further noted that rating agencies Standard & Poors and Moody's both accept AOCI as a component of equity for use in debt to equity calculations, and that, as well, both BC Hydro and Hydro Quebec include AOCI in their debt to equity determinations.

79 MH asserted that Contributions in Aid of Construction (CIAC) should continue to be included as an element of equity, to be taken into account in the determination of the debt to equity ratio, as it represents non-refundable contributions provided by customers towards service extension costs (CIAC amounts are non-refundable, are amortized into income at the same rate as the corresponding assets are depreciated, and do not represent liabilities of the Corporation.).

80 For MH, since the equity ratio measures the portion of the Corporation's assets that are not funded by debt, the inclusion of CIAC in equity conforms with the purpose of the equity ratio calculation.

81 Nonetheless, MH advised that the debt to equity ratio at January 31, 2011 was 74/26, and that if AOCI were excluded from that calculation the ratio would change to 76/24, and, if CIAC was also excluded, the ratio would change to 78/22.

Pensions

82 With respect to the pension deficit (pension obligations less pension assets), MH stated that its pension fund investments have recovered since the economic and market downturn of 2008/09, and that the impact of the negative returns on pension investments in that fiscal year have been partially offset by positive returns since. As of March 31, 2010, MH reported an overall deficit obligation deficit of $89 million, and that it expected the deficit to decrease further by March 31, 2011.

83 MH further stated that the Civil Service Superannuation Board has considered seeking increases to both employer and employee pension contributions, but that no changes have yet been made by government.

84 MH further indicated that the International Accounting Standards Board (IASB) has issued an exposure draft, which, if approved, will require all pension gains or losses to be recorded directly into AOCI. As a result of the current level of deferred actuarial losses on the pension plan, the application of these accounting changes will have, according to MH, a relatively small negative impact on the Utility's debt to equity ratio in the short-term, with the effects expected to be fully offset in future periods due to either improved asset values, higher interest rates and/or future amortization of losses.

Upside vs. Downside Risk

85 With respect to the Board's questions as to: (a) whether there is appropriate sharing of risks between this generation and future generations of electricity ratepayers?; (b) is MH speculating (the word was not employed in a negative sense) on behalf of current ratepayers with the outcomes to be realized by future generations of ratepayers?; (c) as to how symmetrical the Utility's downside risk is in comparison to its upside risk?; and, (d) is it possible that higher rate increases may be required than forecasted in the future?

86 MH stated that answers to these questions are complex, and that the future is far from certain. That said, for the Utility to do nothing is not an option. For Hydro, the nature of its business demands that decisions be made far in advance of new supply requirements coming on-stream, this in order to provide for the continuance of the supply of energy needed to meet the requirements of the Province.

87 MH advised that it has been informed by the Minister Responsible for MH that it is the Government's intention to assign responsibility to an independent body to carry out a Needs and Justification assessment of MH's proposed major new generation projects, which, presumably, would include a review of alternate development approaches. MH indicated that it is confident that this upcoming review process will address any and all questions related to the "upside and downside" risks of development.

Forecasting

88 With respect to concerns raised by CAC/MSOS related to MH's forecasts, MH acknowledged they are just that — forecasts, and that forecasts represent a view of the future based on "known" information. MH advised it cannot control conditions that will actually occur and which will cause variations to forecasts.

89 For MH, the one thing known with certainty is that actual results will be different from forecast.

MH's Conclusion

90 MH concluded its submission by repeating its request for an interim rate increase of 2.9% across all customer classes with the exception of Area and Roadway Lighting, to take effect April 1, 2011,

8.0 Board Findings

91 The Board acknowledges that the GRA hearing is far from over and that important new evidence and witness testimony is yet to come. As well, the Board further acknowledges that Interveners have yet to have the opportunity to cross-examine the MH panel or the witnesses that they, and the Board, have engaged. Finally, the Board acknowledges that its preference is to have concluded a GRA proceeding before approving rate changes.

92 This hearing is unique in the Board's regulatory history, and not only with respect to interim grid rate Orders awaiting finalization, along with an interim diesel rate decision, but also with respect to the complexities of the issues; the importance of the potential outcomes for ratepayers, the Utility and the Province; and, as well, this proceeding's length, scope, cost and public profile.

93 MH filed its GRA December 1, 2009, and in the normal course of events the hearing would have taken place and been concluded with a final rate order issued well before the summer of 2010.

94 Circumstances resulted in a lengthy delay in the commencement of the oral hearing, and while the importance of the matters before the Board have also contributed to the lengthy process, the facts are that MH has indicated plans to spend in the range of $20 billion in a "decade of investment", a plan that requires a need for massive new borrowings and, as it would appear, a decade of higher than inflation rate increases. MH projects that during the decade of investment it will seek annual rate increases of 3.5% each year, accumulating in the range of 45% in the 'decade of investment'.

95 CAC/MSOS is correct in noting that from 2004 on, MH's rates have increased by considerably more than the rate of inflation. However, it is also useful to take into account that before 2004, MH rates, other than industrial rates which actually fell, remained frozen for approximately a decade. It is also useful to note that since 2004, the Utility has had to confront a drought, which led to a loss in one fiscal year in excess of $400 million, a credit crisis and major global recession (which contributed to a reduction in demand and a fall in export prices), and with what some observers have portrayed as a "game

changer"- new production techniques that have led to major new reserves of natural gas and plunging and now low natural gas prices (which has also contributed to lower export prices).

96 It has not been an uneventful decade for MH, and it would seem the next decade will be as equally challenging. MH plans a "decade of investment" and, ahead of new Manitoba domestic demand, the construction of major new generation and transmission assets to support the entering into major new export sales contracts with American counterparties, contracts yet to be finalized and which will involve both commitments and risks.

97 In the end, the results of MH's actions are of considerable significance to not only Manitoba and the Utility's customers, but to the overall Manitoba economy. If the new investments planned by MH do not generate the export revenues MH's expects, or if the costs of its planned investments exceed their current forecasts and are not able to be fully recovered by the now forecast domestic rates and export sales revenue then domestic rates will have to rise higher, and perhaps faster, than the levels now predicted by MH.

98 Contract and construction risks are not the only risks faced by MH. Already long identified by the Board and the Utility are risks including equipment failure, drought, currency fluctuations, interest and finance cost increases, market disruptions, load forecast variances, etc. etc.

99 For MH to be able to borrow at reasonable financial terms, the billions of dollars required to complete MH's plans for its decade of investment (billions of dollars to be guaranteed by the Province — MH borrowings may, if as projected, represent 50% or more of the Province's overall debt), lenders have to be confident with the Utility's plans and have assurances with respect to the future balances to arise out of Utility revenues and expenditures. So, the state of the capital structure of the Utility, now and into the future, is a very important matter.

100 While the GRA hearing is not over, with much evidence, testimony, cross-examination and final argument yet to come, the Board is cognizant of aspects of the Utility's financial circumstances and indications as to the revenue requirements for the future.

101 The Board has had regulatory responsibilities related to MH for many years, and is familiar with its practices, plans, forecasts and, to a significant yet limited degree, risks. In response to Interveners' views as to the ability of the Board to approve an interim rate increase and that approving an across-the-board interim increase could disadvantage certain classes, the Board finds:

a) that it has the necessary jurisdiction — urgency is not a required condition; and

b) the Board's comments in previous rate orders, which have advised that cost attribution is but one factor in the Board's determination of just and reasonable rates, stand.

102 Unlike the circumstances of the April 1, 2010 interim rate increase, the GRA is now well underway and while considerable evidence remains to be provided and tested, sufficient evidence is already on the record to justify the Board's consideration of granting another interim rate increase. MH has filed an extensive GRA (including its latest published annual report and financial forecasts), and thousands of interrogatories have been posed and responded to (involving MH, the Board,

Interveners and expert witnesses).

103 As well, MH's witnesses from two consultancies engaged by MH (ICF and KPMG), have submitted briefs, testified and been cross-examined, and while Board Counsel had yet to complete the cross-examination of MH's panel of internal witnesses as at the date submissions were received on the question of an interim rate increase (and ahead of Interveners cross-examining the MH witness panel), a panel that includes MH's Senior Vice President and Chief Financial Officer, a considerable portion of the Board's cross-examination had been undertaken by March 9, 2011.

104 As to the evidence of witnesses engaged by Interveners and the Independent Experts engaged by the Board, reports have been filed, although the witnesses have yet to testify and be cross-examined.

105 Accordingly, having considered filings and submissions to and including March 9, 2011, the Board finds that the evidence received and considered to-date, supplemented by the submissions of the parties provided on March 9, 2011, provide *prima facie* justification for an interim 2.0% average rate increase, effective April 1, 2011.

106 The increase is to be applied to the energy portion across all rate classes, exempting the Area and Roadway Lighting class. MH is to apply the Residential rate increase to the first energy block rate, to eliminate the inversion and then keep the two energy block rates equal, effective April 1, 2011.

107 With respect to Area and Roadway Lighting (ARL), while the Board will again exempt the class from an interim rate increase to be applied to other classes of customers, it puts the ARL class on notice that further exemptions are far from assured. The Board will careful assess the revenue to cost ratio and other factors that apply to rate setting in determining the relative positioning of the ARL class' rates.

108 With respect to Residential rates, when the inverted rate was established, circumstances were different than what they are now. Natural gas prices were very high, so high that there was a risk that property owners would consider switching their heating source from natural gas to electricity and MH has yet to reflect consideration of home heating loads in its rate design.

109 There are rate design issues still to be considered with possible revision in the Board's final GRA Order.

110 In the remainder of the GRA Hearing and in its deliberations following closing argument, the Board will reassess its view on inverted rates for residential properties, particularly for those where gas heat is not an option.

111 With respect to rate differentiation between classes and overall rate design matters, MH's plans for massive capital spending and the Utility's projections of a series of annual rate increases of 3.5% extending over a decade, allows the Board ample opportunity to adjust the rates of individual customer classes if it deems such adjustments are necessary.

112 A major component of this GRA is the identification and review of risks faced by MH, and how such risks should be reflected in consumer rates, and in what quantum and time. MH has testified that while current circumstances and results are important, the Utility's long-term prospects, with its planned new generating stations expected to have service lives of up to one hundred years, need to be taken into account.

113 MH's major capital expenditure development plans include the completion of Wuskwatim Generating Station (which, although originally forecast to cost $900 million, is now expected to cost $1.6 billion), the construction of Bipole III (MH indicates the proposed new transmission line and converter stations are required for reliability purposes — though also required if major new generating stations are built), and the construction of Keeyask Generating Station and then Conawapa Generating Station. MH's current long-term financial projections involve the expenditure in excess of $17 billion, to be funded by debt and projected accumulated net income.

114 If MH's major capital plan is implemented, the Utility's assets and loans will more than double over the period of approximately ten years. The major new assets to be constructed, three generating stations (the first, Wuskwatim, to be in service by the end of fiscal 2011/12) and Bipole III, will come at costs very much higher than the cost of generation stations and transmission facilities built in decades past.

115 With the construction of these assets, the cost per kWh of overall sold electricity will rise significantly, with the marginal cost being a multiple of the historical and present average cost.

116 MH's comparatively low rates for Manitoba consumers (the comparison being other Canadian and American electric utilities) are founded in large part on the relatively low undepreciated capital costs of the Utility's pre-2010 generation and transmission assets, for which annual amortization costs are very low and the original loans have either been fully paid off or considerably paid down, resulting in relatively low finance expenses. The last major generation station to come into service was Limestone, basically twenty years ago.

117 Another factor providing for low rates is MH's ongoing deferral and capitalization of expenditures incurred related to its construction development plans. Every year, approximately 1/3rd of MH's OM&A expenditures are capitalized or deferred, meaning these expenditures are neither considered current period costs nor taken into account in rate setting.

118 To avoid future deficits, the evidence suggests that if the Utility's present capital expenditure development plan is implemented, both domestic rates and export sales prices will have to rise significantly. As developments are completed and new assets put into service, expenditures previously capitalized or deferred, including those carried within Construction Work in Progress on the Utility's Balance Sheet, begin being recorded in the annual income statements as 'costs'. These costs include amortization of "capital" costs as well as the financial costs (interest and the Province's guarantee fee) and any operating costs associated with operating the then in-service asset.

119 A component of MH's currently projected future rate increases relate to the expectation of ongoing general economic price inflation, the other major component being the inclusion in annual "booked" costs, the costs noted above (again: amortization, financial and operating associated with new generation and transmission assets after they come into service).

120 Another issue that plays, or may play, a significant role in the forecast of future rate increases is the Utility's debt to equity ratio, a financial test considered to be important by lenders, the Utility, the Board and Interveners. For a considerable period of time, the accepted target for the ratio is 75% debt to 25% equity. As developments proceed and expenditures are incurred, whether expensed in the period or deferred or capitalized, debt generally increases, placing downward pressure on the equity ratio. While it has been generally accepted that the target ratio is unlikely to be maintained through a development phase, when major expenditures are being incurred but the asset or assets being constructed are not yet in service and are, for the time period of development, non-performing assets, the target and the Utility's present actual ratio is still considered important and plays a role in rate setting.

121 The Board notes that circumstances have changed significantly, not only since the Utility's capital expenditure plans were formed as represented in IFF-09 and prior IFFs, but since MH filed its GRA and since the April 1, 2010 interim rate increase was implemented.

122 The changed circumstances include:

a) An increased awareness of the causes of and implications of "much" lower than expected natural gas prices (the implementation of new production methods has allowed for the economic extraction of natural gas from shale deposits, and the gas in the deposits discovered to-date has dramatically increased North American reserves — with this new supply source, the market price of natural gas has disconnected from its historical relationship to the price of oil and fallen to levels not seen for a decade or more);

b) Much reduced prices and bountiful supplies of natural gas has reduced the marginal cost of production of electricity from natural gas. With MH's major American export customers employing gas generation to meet peak demand, and, more recently, also base demand, the low natural gas prices are also driving down the prices MH has been receiving from its American export counterparties for non-firm short-term and spot export sales;

c) As indicated, MH's short-term and spot sales prices of electricity to American counterparties have fallen sharply, bringing the average price received for exported electricity to below 4 cents per kWh (short-term and spot sales have come at a price as low as 1 cent per kWh. and MH is unable to provide assurances that prices will "recover" in the near future);

d) With firm (contracted) export sales, at average prices less than 6 cents per kWh, remaining at volumes well within the capacity of MH's current hydro-electric generation, MH has confirmed that Wuskwatim's initial generation, which will come at an "all-in" price of 10 cents per kWh is unlikely to recover, at least initially, more than 3 cents per kWh. In short, Wuskwatim's initial generation is expected to produce losses rather than to contribute to net income;

e) As suggested from the Wuskwatim experience, the estimated construction costs for MH's planned major new assets (Bipole III's cost estimates are the subject of discussion, if not controversy, while the forecasts for the construction costs of Keeyask and Conawapa have increased substantially), affecting the price required by MH to make profitable export sales from or through the use of these new generating and transmission assets;

f) It would appear that the cost of Bipole III, mandated by the government to be constructed on the west side of the Province, has risen considerably from the initial estimate of $2.2 Billion — the Board understands that a large component of the anticipated increase in cost has to do with the required converter stations);

g) The Canadian dollar has strengthened against the American dollar, while this development reduced the cost of historical debt financed in U.S. dollars, and resulted in major "unrealized gains" on foreign exchange for MH with respect to U.S. denominated debt outstanding, it also has negative implications for the Canadian dollar value of exports to the United States, as those exports are priced in American dollars;

h) Political developments in the United States, and the decision of the Canadian government to follow "carbon" developments in America, has reduced the probability and/or quantum of a "carbon premium' being placed on MH's exports of "clean" hydro-electric electricity to the United States (again, if a carbon premium does come about, it is likely to come at a lower value and later date for that premium, than previously anticipated);

i) The risk of inflation is increasing, globally, including in Canada, and with inflation one would expect, eventually, higher interest rates;

j) Delays in the conversion of MH's term sheets with Minnesota Power and Wisconsin Public Service into binding contracts, leading to the "in service" date of Keeyask and Conawapa being delayed a year — the in-service date for Bipole III was previously set back five years, it is now expected to be in service in MH's 2017/18 fiscal year;

k) The Board has approved new interim rates for four isolated northern communities provided electricity by means of diesel generation, and, in doing so, has directed the absorption in MH's general accounts of the accumulated deficit on past diesel generation operations; indicated an intention to reduce the "tail block" rate for service to the communities over the next several years; and recommended that the grid be extended to the communities; and

l) The recession followed by a major pulp and paper company's closure, the announced closures of one mining company's smelter, and the announced planned closure of another smelter and a refiner in Northern Manitoba have contributed to reduced domestic load forecasts, resulting in delays in the requirement for Keeyask and/or Conawapa in service dates for domestic load requirements. MH has advised that it has already spent $400 million on its Keeyask Generation Station project, which is carried on the Utility's balance sheet as an asset — within the category 'construction work in progress', and that Hydro's ongoing present level of expenditures on its overall major development plans approximate $1 million a day, with that level of daily expenditure expected to rise considerably as the plans mature and further work is undertaken.

123 All of these expenditures are classified as "assets" (generally construction in progress) on the Utility's balance sheet, and the value of those assets going forward depends on the conversion of MH's term sheets with American counterparties into firm contracts containing adequate volumes, profitable pricing and other significant terms; a favourable outcome at an expected Needs and Justification Review (yet to be conducted), and the development of transmission in the United States, funded by either MH's American counterparties or the utilities of the region acting in concert.

124 While MH has indicated that economic conditions have improved in both Manitoba and in the MISO market overall, it has also reported, as indicated above, that a) its domestic load forecasts for future years have been scaled back, b) MH has withdrawn its application for Energy Intensive Industry Rates (EIIR), though the Utility has indicated continued consultations with industrial customers and a plan to make a new application at some point in the future, c) the term sheets entered into with MH's major American counterparties have been extended (MH has testified that negotiations are "going well" and the Utility anticipates the conditions required for successful sales will be met), and, d) that the Utility's projected "in service" dates for the two major generation projects, Keeyask and Conawapa, have been delayed a year.

125 Furthermore, and as indicated above, the Utility's forecasts for the costs of what it portrays as its "decade of investment" have increased significantly, with new higher cost forecasts for Keeyask and Conawapa and serious outstanding questions as to the expected cost of Bipole III (MH's current forecast for the construction of Bipole III is $2.2 billion, though other "unofficial" estimates, yet to be tested and/or confirmed by external experts engaged by MH, have ranged to $4.1 billion).

126 Until the GRA unfolds further, the Board sees MH's current GRA filings and evidence in a similar light to the Utility's prior interim rate request and Board Order 18/10 (which provided for a 2.9% interim rate increase, 2.8% when the exemption of Area and Roadway Lighting is taken into account, as of April 1, 2010): that is, replete with issues and concerns

with numerous risk factors.

127 These risk factors include drought; changes in accounting standards, IFRS; illiquid equity — MH's balance sheet includes intangible assets, deferred and capitalized costs that may be subject to adjustment or expensing under IFRS; extensive capital plans — with rising cost estimates; decreased short-term and spot export sales prices; term sheets that are subject to renegotiation, to mention but a few.

128 The Board is not, at least yet, comfortable with either the Utility's methodology of determining its debt:equity ratio, which is one of the cornerstones of MH's alleged financial strength, or that the established target of 75:25 is adequate when the plans made would, if implemented, more than double the Utility's assets and debt obligations.

129 The Board notes that the present and forecast debt:equity ratio, agreed by MH as being important to credit rating agencies and lenders, also involves the inclusion of Accumulated Other Comprehensive Income (formed by unrealized gains on foreign exchange — debt outstanding in American currency). Those "gains" may well be "offset" by reduced export sales, as export prices are also in U.S. dollars.

130 Furthermore, MH has testified that if intangible assets, rate regulated assets and contributions in aid of construction were deducted from its equity, its debt:equity ratio would increase from the present 75:25 to approximately 80:20.

131 As well, the Board has concerns with the present circumstances of the term sheets; the ongoing spending of a million dollars a day based on the premise adequate firm export contracts will be developed; and whether intergenerational equity is represented in current rates, where current ratepayers are, in a sense, engaged in plans that involve risk, with the "cost" of those risks deferred to another generation of ratepayers.

132 With respect to the funds spent to-date and ongoing spending on the planned Keeyask generating station, those funds will be eventually "recovered" only if Keeyask is built and the export contracts that provide for its "advancement" (of its in service date) are adequate to avoid period losses. That said, the evidence to-date suggests that if built Keeyask may be expected to generate $500 million per year in costs but, as its entire output will, at first, expect to be exported, as domestic load growth is not expected to require Keeyask for well past its expected in service date, export sales revenue may develop only $300 million per year for at least the initial years, leaving $200 million to be met by domestic revenues.

133 A similar situation appears to apply to Conawapa, where the currently expected annual cost, once it is in service, is $700 million while MH currently forecasts only $550 million of revenue, leaving a further $150 million of annual deficit in the initial years to be, presumably, covered by domestic revenue.

134 As to Bipole III, dependent upon what the final cost to construct is, these costs will also need to be recovered from additional revenue. If the cost ends up in the range of $2 billion, the annual initial additional costs to be absorbed by additional revenue appears to be in the range of $200 million; if the cost is in the order of $4 billion, then the annual cost in the initial years will be in the $400 million range.

135 Clearly, the long anticipated “Needs and Justification” review is required. Neither a date for that review has yet been set, nor an agency assigned to undertake that responsibility.

136 Such a review may require the commitment of MH’s American export counterparties to new firm contracts and the building of new transmission in the United States to connect to MH’s transmission at the border — the cost of the new American transmission may be $2 billion.

137 Again, the Board is concerned with meeting the need for intergenerational equity, with MH taking risks on behalf of current ratepayers that could contribute to higher rates (in comparison with inflation) rather than lower rates for future generations.

138 The Board is of the view that other development plans need to be considered as well as MH’s present preferred development plan. While MH has assured the Board that its Preferred Development Plan will be implemented only if it proves out to be economically feasible, and that other development plans have been considered — such as building Conawapa but not Keeyask, or deferring both projects and constructing a combined cycle natural gas generation station in southern Manitoba — such alternative scenarios have not been fully tested.

139 One of the yardsticks by which various development scenarios should be tested is the implications for domestic rates. It is possible that MH’s preferred development approach will not prove out to be the most optimal approach for its domestic customers; many of them lower income and many of them using electricity to heat their homes.

140 Looking out a decade, the Board notes that MH’s forecasts assume 3.5% annual rate increases, commencing with April 2012, those projected increases being approximately twice the expected rate of inflation.

141 Based on the evidence before the Board at this stage in the Hearing, the Board is not “comfortable” or confident that MH’s estimated series of annual 3.5% rate increases, although basically twice the rate of inflation, would recover the costs and meet the Utility’s revenue requirements into the future, if the present development plan is implemented.

142 In the very short-term, MH has advised that it does not expect to achieve its most recent forecast net income for fiscal 2011, despite continuing good water conditions (above average), the shortfall largely attributable to lower than expected export sales prices for MH’s short term and spot export market sales. In closing, while the Board appreciates that MH’s revenues and expenses have not yet been fully tested, and that the GRA process, now underway, will afford the Board and Interveners the full opportunity to do so, there is more than enough evidence and “concern” to justify a further 2.0% interim increase. To avoid this interim increase would only increase the risk that a larger rate increase will be required after the hearing is concluded, providing the risk of rate shock for consumers.

143 As to the delays in concluding this hearing, the timing of the GRA process has been significantly extended from the usual duration of past experience, primarily due to the increased attention now being paid to MH’s risks, that the result of a whistleblower’s allegations and the resultant Board’s review of MH’s risk and risk management issues.

144 The concerns of the Board with respect to MH's risks go back at least to 2004, and have last been fully enumerated in a number of Orders, including Orders 32/09 and 116/08. Despite the Board's focus on risks and directions to MH to file independent reports reviewing and quantifying its risks, MH has moved slowly, initially withholding risk reports received from their former NYC consultant, and failing to undertake the full risk review sought by the Board through MH's engagement of KPMG.

145 The extended timelines of the ongoing GRA is not an effort to deliberately delay 'just and reasonable rate increases'. The extended timeline is necessary to ensure all issues are properly explored, thereby, it is hoped, protecting the public interest in the long-term.

146 When the most important "commercial" asset of the Province, MH, is planning to, largely through debt (that debt to be guaranteed by the Province and likely represent more than 50% of the overall debt of the Province), engage in a "decade of investment" involving commitments to export customers that, in themselves, involve risk, setting rates so as to achieve just and reasonable rates for not only this generation of customers but also the ones that will follow is very important.

147 The Board considers it highly likely that public hearings will carry over at least into the summer of 2011, thereby delaying a final decision, not only with respect to the interim rates that took effect April 1, 2010 but also the further rate increases sought by MH for April 1, 2011.

148 Even without having the benefit of the full GRA, the Board does not accept the premise that ratepayers would be better off with delaying a further "relatively modest" (compared to future forecasts) increase on April 1 of this year.

149 This Board has repeatedly indicated that the financial health of the Utility is a factor to be considered in the Board's deliberations as to setting rates that are in the public interest. To the credit of all Interveners, they too value and support rates to sustain a financially solid Utility.

150 While the GRA is far from completed, the Board has sufficient information to see the increasing significance and importance of domestic (Manitoba) revenue, and the Utility's reliance on rate increases to support annual net income results and its overall capital structure.

151 That said, the interests of consumers are another factor that the Board must, and does, take into consideration in assessing the public interest. The economic conditions of the past year, and now, consist of trying times and challenges for consumers. That weighs heavy on the mind of the Board, which still awaits evidence in this hearing on measures and viable options towards addressing the particular payment and energy efficiency problems of lower income consumers.

152 While financial challenges lie ahead for MH, with its ambitious capital plans, those challenges and issues need to be reviewed taking into account the long-term and such a review has yet to be held. Yet, and despite prior Board Directives, MH has not pursued the required review of its capital plans and export intentions, all of which impact domestic rates. At this point in time, the Board is not confident that MH's preferred and forecast capital expenditure plans for the "decade of investment" represent the approach most likely to ensure the lowest rates possible for domestic Manitoba customers.

153 And, if the further interim rate increase to be granted as of April 1, 2011 was to be deferred until the conclusion of the GRA, the rate increase required to recover the additional revenues would mathematically need to be higher to recover the additional revenues in the remaining months of MH's fiscal year 2011/12. The Board has previously stated its disapproval of "retroactive" rates or rate riders.

154 By this interim rate approval, the Board is protecting the short-term financial status of MH with the maintenance of adequate retained earnings. Examining MH's financial forecasts clearly disclose that domestic rate increases are required to keep MH producing annual net income results, without those regular increases, the forecasts suggests a string of annual deficits, even before the coming into service of major new generation and transmission assets, that with further rate implications.

155 After hearing all of the evidence and submissions in the GRA, the Parties to the hearing and ratepayers generally may be assured that if the Board concludes that the facts do not justify the imposition of the rate increases provided on an interim basis, the Board will adjust rates downward in the final GRA Order. Any amount collected found to be in excess of the rate in the final Order may be refunded/credited back to domestic customers, this to ensure consumers are protected in the longer term.

156 Interim increases to rates do not bind the Board, in any way, in making its final GRA rulings and directives. MH still bears the onus in its GRA to show that interim rate increases are just and reasonable.

157 The Board expects all Interveners to collectively explore and test fully all rate increase issues through the remainder of the GRA, together with all cost of service and rate design issues. The interim rate adjustments are to have no prejudicial affect on the ability of Interveners to argue, at the conclusion of the GRA hearing, that the rate increases and/or rate design, quite different from that awarded, ought to be approved by the Board in its final rate Order(s).

158 MH is to file Rate Schedules to conform with the directions of this Order.

159 Board decisions may be appealed in accordance with the provisions of Section 58 of The Public Utilities Board Act, or reviewed in accordance with Section 36 of the Board's Rules of Practice and Procedure (Rules). The Board's Rules may be viewed on the Board's website at www.pub.gov.mb.ca.

9.0 It Is Therefore Ordered That:

160

1. Manitoba Hydro's request for a 2.9% average rate increase, for all domestic customer classes (except Area and Roadway Lighting) served by MH, effective April 1, 2011, BE AND IS HEREBY DENIED;

2. Manitoba Hydro is to implement a 2.0% average and interim rate increase for all domestic customer classes (except Area and Roadway Lighting) through an increase to the energy portion of consumer rates, and, with respect to Residential rates, the rate increase is to be applied to the first energy block rate to eliminate the inversion and, then, keep

the two energy blocks equal;

3. Manitoba Hydro is to provide the Public Utilities Board with revised interim Rate Schedules for all electricity consumed on and after April 1, 2011, together with Proof of Revenues, prepared in accordance with the directives in this Order;

4. This Order shall remain interim until confirmed, varied or otherwise dealt with by further Order of the Board.

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