



AltaGas Utilities Inc.

2005/2006 General Rate Application Phase II

October 16, 2007

ALBERTA ENERGY AND UTILITIES BOARD

Decision 2007-079: AltaGas Utilities Inc.
2005/2006 General Rate Application Phase II
Application No. 1491262

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640 – 5 Avenue SW
Calgary, Alberta
T2P 3G4

Telephone: (403) 297-8311
Fax: (403) 297-7040

Web site: www.eub.ca

Contents

1	INTRODUCTION.....	1
2	BACKGROUND	2
3	ISSUES.....	3
4	COST OF SERVICE ANALYSIS (COSA)	4
4.1	Life Cycle of a COSA	4
4.1.1	Views of the Board.....	5
4.2	Classification and Allocation of Meters and Services Costs.....	5
4.2.1	Meters Cost Allocation.....	5
4.2.1.1	Views of the Board	6
4.2.2	Meters Installation and Regulator Costs	6
4.2.2.1	Views of the Board	7
4.2.3	Services	7
4.2.3.1	Views of the Board	9
4.3	Determination of Demand Allocation Factors –Peak Demand for Rates 1/11, 2/12, and 3/13	10
4.3.1	Peak Demand for Rate Classes 1/11 and 2/12.....	10
4.3.1.1	Views of the Board	10
4.3.2	Peak Demand for Rate Class 3/13.....	11
4.3.2.1	Views of the Board	12
4.4	Diversity	12
4.4.1	Views of the Board.....	13
4.5	Analysis of Irrigation Demand and Load (Rate 4/14)	14
4.5.1	Views of the Board.....	15
4.6	Classification and Allocation of Diameter-Length Method for Distribution Mains	16
4.6.1	Views of the Board.....	18
4.7	Allocation of Customer Care and Billing.....	20
4.7.1	Views of the Board.....	21
5	RATE DESIGN	21
5.1	General – AUI’s Proposed Rates, Revenue to Cost Ratios, and Rate Shock	21
5.1.1	Views of the Board.....	24
5.2	Rate 1/11 - Small General Service	26
5.2.1	Homogeneity of Rate 1/11 Customers	26
5.2.1.1	Views of the Board	29
5.2.2	AUMA/UCA Proposals for the Division of Rate 1/11 Customers into Separate Classes.....	30
5.2.2.1	Views of the Board	33
5.3	Rate Riders	34
5.3.1	Third Party Transportation Rider (TPTR).....	34
5.3.1.1	Views of the Board	35
5.3.2	Deficiency Rider	36
5.3.2.1	Views of the Board	36
6	GAS DISTRIBUTION TARIFF	36
6.1	Retailer Distribution Service Regulations and Contracts (RDSR).....	36

6.1.1 Deposits	36
6.1.1.1 Views of the Board	37
7 REFILEING REQUIREMENTS.....	38
8 ORDER	38
APPENDIX 1 – HEARING PARTICIPANTS.....	39
APPENDIX 2 – SUMMARY OF BOARD DIRECTIONS	40
APPENDIX 3 – SUMMARY OF BOARD APPROVALS AND KEY FINDINGS	42
APPENDIX 4 –APPROVED RATE DESIGN	45
APPENDIX 5 – APPROVED RATE SCHEDULES AND RATE RIDERS	46

List of Tables

Table 1. AltaGas Proposed Rates.....	22
Table 2. Impact of Proposed Rates by Rate Class per AUI.....	25
Table 3. Natural Gas Consumption for Rate 1/11	29

ALBERTA ENERGY AND UTILITIES BOARD

Calgary Alberta

ALTAGAS UTILITIES INC. 2005/2006 GENERAL RATE APPLICATION PHASE II

Decision 2007-079
Application No. 1491262

1 INTRODUCTION

AltaGas Utilities Inc. (AUI, AltaGas or the Company) filed a 2005/2006 General Rate Application (GRA) Phase II (the Application), dated December 8, 2006, with the Alberta Energy and Utilities Board (EUB or the Board). The Application sought approvals for:

- setting appropriate 2006 distribution rates and transportation rates, corresponding rules, regulations, and charges, and other rate riders, to be effective July 1, 2007;
- compliance with Board directions set out in Board Decision [2005-029](#),¹ dated April 12, 2005; and
- compliance with Board directions regarding residual balances from the 2003/2004 GRA and the 2005/2006 GRA deficiency riders set out in Board Order [U2005-341](#),² dated August 24, 2005, and Board Order [U2006-41](#),³ dated February 21, 2006, respectively, and setting an appropriate 2006 deficiency rider that would be applied to customer statements in billing cycles for March 2007.

The Application also included a complete cost of service analysis (COSA).

The Board issued a Notice of Application on December 20, 2006 and by letter dated January 22, 2007, the Board provided a preliminary issues list for the proceeding. The letter also requested parties to provide comment by February 1, 2007 on the Board's prioritization of the issues and to include any additional issues that they considered should be added to the list. Consequently, by letter dated February 8, 2007, the Board provided the parties with a final issues list and a process schedule to deal with the Application. AUI held a post-application meeting with interested parties on February 6, 2007.

A public hearing of the Application was held on June 11, 12 and 14, 2007, in Edmonton, Alberta before a panel consisting of Mr. A. J. Berg, P. Eng. (Presiding Member), Mr. M. L. Asgar-Deen, P. Eng. (Acting Member) and Mr. M. W. Edwards (Acting Member).

¹ Decision 2005-029 – AltaGas Utilities Inc. 2003/2004 General Rate Application Phase II (Application 1359952) (Released: April 12, 2005)

² Order U2005-341 – AltaGas Utilities Inc. 2003/2004 General Rate Application(GRA) Deficiency Rider and Disposition of Residual Revenue Excesses and Gains from the 2000/2001/2002 GRA (Application 1413073) (Released: August 24, 2005)

³ Order U2006-41 – AltaGas Utilities Inc. Interim Refundable Rates and 2005 Deficiency Rider Application (Application 1436060) (Released: February 21, 2006)

The Board considers that the record for the Application closed on July 24, 2007, with receipt of all reply arguments. Parties that participated in the proceeding are listed in [Appendix 1](#).

2 BACKGROUND

AUI's 2003/2004 GRA Phase II (Application No. 1359952) was approved by the Board effective May 1, 2005, in Decision 2005-029. The Decision also included a direction requiring AUI to submit a compliance filing to update its Terms and Conditions of Service. The Board approved that compliance filing (Application No. 1399882) in Order U2005-211, dated June 1, 2005. AUI's application (No. 1413073) for approval to set a deficiency rider to collect the net 2003/2004 revenue deficiency and eliminate of the residual balance remaining from the disposition of residual revenue excesses and other gains from its 2000/2001/2002 GRA was approved by the Board in Order U2005-341.

In Decision [2005-127](#)⁴ on AUI's 2005/2006 GRA Phase I (Application No. 1378000) dated November 29, 2005, the Board directed AUI to submit a re-filing. In Decision [2006-034](#),⁵ dated April 4, 2006, the Board approved AUI's 2005 and 2006 forecasts as re-filed in Application No. 1436063. In Order U2006-41, the Board also approved AUI's application (No. 1436060) to set a 2005 deficiency rider and 2006 interim refundable rates.

In Application No. 1426643, AUI sought approval of a \$30 million debenture issue for 2005. In Decision [2006-049](#),⁶ dated May 24, 2006, the Board approved the debenture issue and an embedded cost of 5.44%, which replaced the 6.70% placeholder used in the 2005/2006 Phase I GRA.

A second compliance filing (No.1474463) for the Phase I portion of its 2005/2006 GRA was necessary to:

1. Replace fixed capitalized overhead amounts that should not have been removed in the first compliance filing,
2. Incorporate a correction to the Large Corporations Tax,
3. Update revenues to reflect the interim rates approved in Order U2006-41, and
4. Update debt costs based on Decision 2006-049.

The Board approved AUI's second compliance filing in Decision [2006-117](#),⁷ dated November 21, 2006. AUI's revenue requirements, net of gas costs, were set at \$32.971 million for 2005 and \$33.100 million for 2006, which, with existing rates, resulted in before tax revenue deficiencies of \$3.326 million for 2005 and \$0.341 million for 2006.

⁴ Decision 2005-127 – AltaGas Utilities Inc. 2005/2006 General Rate Application – Phase I (Application 1378000) (Released: November 29, 2005)

⁵ Decision 2006-034 – AltaGas Utilities Inc. 2005/2006 General Rate Application – Phase I Compliance Filing (Application 1436063) (Released: April 4, 2006)

⁶ On July 31, 2007, the Board denied AUI's October 31, 2006 application for Review and Variance of Decision 2006-049. AUI's application for leave to appeal that decision to the Alberta Court of Appeal remains outstanding.

⁷ Decision 2006-117 – AltaGas Utilities Inc. 2005/2006 General Rate Application Phase I Second Compliance Filing (Application 1474463) (Released: November 21, 2006) (Errata Released: November 22, 2006)

AUI determined that total revenue for a full year at interim rates would result in a revenue excess of approximately \$0.312 million⁸ and that total revenue for a full year at proposed rates would result in a revenue excess of approximately \$1.3 thousand.⁹

3 ISSUES

The Board has reviewed the Evidence, Argument and Reply Argument and considers the main issues to be dealt with in the Decision are as follows:

1. COSA
 - a. Life Cycle of a COSA
 - b. Classification and Allocation of Meters and Services Costs
 - c. Determination of Demand Allocation Factors – Peak Demand for Rates 1/11, 2/12, and 3/13
 - d. Diversity
 - e. Analysis of Irrigation Demand and Load (Rate 4/14)
 - f. Classification and Allocation of Distribution Mains Diameter-Length Methodology for Distribution Mains
 - g. Allocation of Customer Care and Billing
2. Rate Design
 - a. Distribution Rates
 - i. Rate 1/11 - Small General Service –Homogeneity of Rate Class 1/11; and AUMA/UCA Proposals for the Division of Rate 1/11 Customers into Separate Classes
 - ii. Rate 2/12 - Large General Service
 - iii. Rate 3/13 - Demand/Commodity General Service
 - iv. Rate 4/14 - Irrigation Pumping Service
 - b. Rate Riders
 - i. 2006 Deficiency Rider
 - ii. Third Party Transportation Cost Recovery
 - c. Revenue to Cost Ratios
 - d. Rate Shock
3. Gas Distribution Tariff
 - a. Retailer Distribution Service Regulations and Contracts

In reaching the determinations contained within this Decision, the Board has considered the record of this proceeding, including the Evidence and Argument provided by each party. Accordingly, references in this Decision to specific parts of the record are intended to assist the reader in understanding the Board's reasoning relating to a particular matter and should not be taken as an indication that the Board did not consider other relevant portions of the record with respect to that matter.

⁸ Response to information request (IR) BR-AUI-1(a)

⁹ Response to IR BR-AUI-1(b)

4 COST OF SERVICE ANALYSIS (COSA)

AUI stated that its COSA was predominantly based on principles approved by the Board in Decision 2005-029 and prior decisions to ensure consistency and predictability. However, AUI made certain refinements to the COSA that included:

- An update to the Diameter-Length method for the classification of distribution mains, as a result of using data from the Geographic Information System (GIS). This change classifies a *smaller* component of mains as customer, compared to what the Board approved in Decision 2005-029.
- An improvement to the allocation of meter reading costs. The method used in the 2003/2004 Phase 2 GRA relied on a site-based allocator weighted for the average per-meter rate of contractor meter reads. In the current COSA, capital and operating expenses are allocated based on detailed allocation and direct assignment of un-bundled meter reading expenses.¹⁰
- A change to the allocator for customer-related distribution mains, from site months to sites alone. This reflects the rationale that the number of times that a site is billed has no bearing on mains costs.

A number of specific aspects of the COSA were at issue in this proceeding and they are presented along with the Board's determinations and directions in the following sections.

4.1 Life Cycle of a COSA

In response to AUI-AUMA/UCA 3(a) AUMA/UCA stated:

It has been the experience of the AUMA/UCA consulting team that well reasoned costing methodologies have a five to eight year life cycle before an evaluation review is required. In many cases, this review has indicated that a well devised costing methodology can continue over a period of one or two reviews before a full evaluation of cost drivers, demand units, diversity and load factors cause a need for full re-evaluation and recommendations for change. The development of well defined costing methodologies and principles dramatically reduces the time and effort required to conduct a Phase II proceeding over an extended period of time. These savings under the Alberta regulatory paradigm will be inured to the benefit of rate payers.

AUI submitted that AUMA/UCA's proposed multi-process assessment of AUI's COSA is an overly burdensome regulatory process instead of a more standard one-step compliance filing. Well-defined costing principles, rather than having a finite life should determine the appropriateness of a COSA and related results. AUI was of the view that it is essential to be pragmatic when developing the COSA and suggested that "if it isn't broken, don't fix it".

AUMA/UCA submitted there are several problematic areas of the COSA. These include the determination of all class demands (Coincident Peak or CP and Non-Coincident Peak or NCP), removal of load serving cost from the customer component of mains, classification and allocation of services, recognition of the need for homogeneity, and recognition of intra and inter class diversity in line with utilized design criteria.

¹⁰ Exhibit 002-01 Application, COSA, Table 16

4.1.1 Views of the Board

The Board considers that a well-defined COSA based on cost causation principles is central to providing appropriate price signals to customers and to assuring each rate class that it is paying its fair share of a utility's revenue requirement.

The Board agrees with CCA's submission that approval of a COSA allocation method must be based on the evidence filed at a particular time. Because there is no limitation on the Board or parties to scrutinize the underlying fundamentals of an existing COSA and related results, allocation checks can be performed at the time of a Phase II proceeding and appropriate determinations with respect to the need for a new COSA study can be made.

If it is found in any Phase II proceeding that the existing COSA does not fairly reflect current cost causation principles, then conducting another COSA would be warranted. In the absence of such concerns, the continued use of the existing COSA would be appropriate. In this kind of check and rebalance framework, it is possible that the results of a particular COSA could endure for many years if its fundamentals continue to remain appropriate. In such a situation, conducting a COSA simply because a pre-determined time had expired would be inefficient and wasteful.

Accordingly, the Board finds that it is not necessary to set a finite period of time for conducting a COSA.

4.2 Classification and Allocation of Meters and Services Costs

4.2.1 Meters Cost Allocation

AUI explained that the COSA allocates meters costs on the basis of sites weighted by the Reproduction Cost New (RCN) meter cost of an average site in each rate class. Direction 6 in Decision 2005-029 required AUI to review the appropriateness of a minimum system study for meters within Rate Class 1/11 (Small General Service). AUI interpreted the Board's direction to mean that it should review the appropriateness of classifying some proportion of meters costs as energy related (as determined by a minimum system study), only after those costs are allocated to Rate Class 1/11. The results of AUI's minimum system study indicated that the unit cost could be reduced by 2.7¢ per site per day. The COSA reports a 10¢ per site per day unit cost for meters allocated to Rate Class 1/11. However, the COSA indicates that the total fixed customer cost of Rate Class 1/11 is 90¢ per site per day which is higher than the proposed rate of 59.2¢ per site per day.

AUI submitted that reducing the unit cost in the COSA by 2.7¢ would make no difference to the rate charged to Rate Class 1/11, and therefore, there was no benefit to classifying some meters costs as energy related.

CCA concurred with AUI that no further action was presently required with respect to the classification of meters and services cost within Rate 1/11. However, CCA considered that the 10% handling cost or overhead charge used by AUI to arrive at the RCN of meters lacked support. CCA recommended that the Board direct AUI to address in its next GRA the adequacy of the 10% overhead rate used to calculate RCN for meters. AUI argued that for the purpose of cost allocation, it is only important that all meters RCN estimates consistently include or exclude

the 10% overhead rate. AUI explained that, mathematically, the cost allocation results are identical whether or not the 10% overhead is applied.¹¹

AUMA/UCA filed evidence to support its position that the weighted customer methodology is more reflective of the cost of metering for various sized customers than other methods, including the minimum plant method.¹² However, AUMA/UCA was prepared to accept the weighted meter method as a proxy for the weighted customer method in this proceeding provided Rate 1/11 was split into two sub-classes as recommended by AUMA/UCA. (Further discussion on Rate 1/11 homogeneity is included in section 5.2.1).

PICA did not object to the use of the sites weighted by meters RCN allocator in this proceeding, provided the Board moderated rate impacts to Rate Classes 2/12 and 3/13.

4.2.1.1 Views of the Board

The Board finds that AUI has met the Board's Direction 6 in Decision 2005-029 with respect to the appropriateness of a minimum system study for meters within Rate Class 1/11 (Small General Service). The Board accepts AUI's explanation that reducing the unit cost in the COSA by 2.7¢ would make no difference to the rate charged to Rate Class 1/11 and find that no changes are necessary.

The Board agrees with AUI that a 10% overhead charge would have no allocative impact on the results of the COSA. Given the above conclusion, the Board considers any specific concern that CCA had regarding Direction 6 is no longer applicable.

The Board approves AUI's applied for method of allocation of meters costs for the following reasons:

- changes to the COSA would have no impact to the resulting rates;
- CCA and PICA did not object to the proposal; and
- AUMA/UCA's agreement that meters was a suitable proxy for their preferred method.

Consistent with the Board's findings in Section 5.2.2.1, the onus is on AUI to support its rate class structures by a rigorous COSA. However, if any party proposes alternative rates, it is also incumbent on that party to provide equally rigorous support for its proposal. Although both AUMA/UCA and PICA have provided only conditional support for the RCN meter cost method, the Board finds that neither has provided a substantive enough case to support a change. Given the cost to review the methods, and the Board's finding that AUI has complied with the direction in Decision 2005-029, the Board considers that further analysis with respect to the classification and allocation of meters cost is not warranted at this time.

4.2.2 Meters Installation and Regulator Costs

AUI indicated that it does not record meters and installation costs by meter type¹³ and hence, an accurate estimate of RCN regulator and installation costs for each meter type cannot be determined. AUI also explained that a sample of meters and regulator costs cannot be provided

¹¹ AUI Reply Argument, page 9

¹² Exhibit 010-03-01, page 11

¹³ Transcript, Volume 1, page 22

without a change in the manner in which work orders are recorded.¹⁴ AUI claimed that, given that the installation and regulator costs are not available or recorded by meter type, or otherwise estimated with reasonable accuracy, the RCN of the meters alone is a reasonable and prudent approach, as it was approved by the Board in Decision 2005-029. AUI was uncertain whether the cost of adding this level of detail would result in any benefit, but offered to provide a cost/benefit analysis to assess required changes to the work order system to accommodate the tracking of regulator and installation costs for the next Phase II application.

Both PICA and CCA submitted that the Board should direct AUI to track meters installation and regulator costs for the next Phase II.

4.2.2.1 Views of the Board

The Board agrees that the availability of information on meters installation and regulator costs would enable a more precise allocation of meters costs. However, the Board recognizes that, because the Phase II cost allocation process is not an exact science, more precision may not necessarily result in a net benefit if the cost to track and record the additional information is excessive. Therefore, before a more detailed allocation method can be adopted, it would be prudent to review the results of a cost/benefit analysis that AUI has offered to provide to determine whether the cost and effort required for tracking and recording meters installation and regulator costs can be justified.

Accordingly, the Board directs AUI, in its next Phase II GRA, to provide a cost/benefit analysis that would allow the Board to determine whether the cost and effort associated with changes to the work order system to accommodate the tracking of meters installation and regulator costs are reasonable expenditures to incur for purposes of improving the precision of the existing meters cost allocation method.

4.2.3 Services

AUI allocates services costs on the basis of sites weighted by the RCN meter cost of an average site in each rate class. The RCN of the meters is used as a proxy for the demand component of services. This is also consistent with the treatment approved in Decision 2005-029 and prior decisions.

AUI submitted that the RCN meter cost method was reasonable because there is some demand component to each service, and it is reasonable to accept that variations in demands are reflected in the RCN weighting factor. In response to an undertaking,¹⁵ AUI contended that conducting a feasibility study to determine the average reproduction cost of a service line by rate class would be extremely time consuming and estimated the cost of such a study to be approximately \$450,000. AUI was of the view that such a study would not yield a practical solution to improving cost allocation when other viable alternatives exist.

AUI suggested that one such alternative was the Diameter-Length calculation, which assigns demand and site-related costs on the rationale that peak demand drives services costs. Although AUI had concerns with this approach,¹⁶ it agreed that the Diameter-Length method warranted further review. AUI indicated that it would be agreeable to including in its next Phase I GRA a

¹⁴ Transcript, Volume 1, page 25

¹⁵ Exhibit 011-04(b), Feasibility Study

¹⁶ Exhibit 002-19, PICA-AUI-4(a)

full cost/benefit analysis of using the Diameter-Length method for the allocation of services. It would also include a review of other reasonable alternatives.

PICA considered that the weighting of services costs by meters costs is not appropriate because there is no relationship between the average cost of meters and average cost of services. However, PICA did not object to AUI's proposed allocation of services costs for purposes of this proceeding, because the method is consistent with that used in prior proceedings. PICA's support was conditional on the assumption that the use of the RCN meter cost allocation method would be considered an interim measure for this proceeding pending completion of a services cost study as part of the next GRA.

PICA also submitted that AUI should be directed to address other methods of classifying and/or allocating services costs to reflect the cost drivers as part of its next Phase II GRA. Among the methods to be reviewed, PICA submitted AUI should be directed to investigate use of the average replacement cost of services by rate class for services cost allocations.

ASBG/PGA submitted that, because the costs of services lines are effectively leveled by AUI's contribution policy, use of a site allocator is a more appropriate method for the allocation of services costs and should be used in AUI's compliance filing. AUI noted that under this method approximately \$625,000 of costs would be transferred from Rate Classes 2/12(Large General Service-Optional), 3/13(Demand/Commodity General Service-Optional), and 4/14(Irrigation Pumping Service-Optional) to Rate Class 1/11(Small General Service) and that this proposal is not appropriate as cost causation for services likely results from both customer and demand related costs.

AUMA/UCA noted that AUI has used the RCN meters costs as a proxy to allocate services costs to customer classes. However, AUMA/UCA provided data¹⁷ to support its position that the cost of services varies significantly over Rate 1/11 and as a result small Rate 1/11 customers inappropriately subsidize larger Rate 1/11 customers. AUMA/UCA proposed to split the rate classes to reflect increased homogeneity as discussed later in this Decision.

AUI argued that its contribution policy and rate design compensate for any differences in meters' RCN estimates and the variability between small and large Rate 1/11 customers. AUI demonstrated that, all else being equal, a higher cost site will pay 100% of the incremental cost directly through a contribution.¹⁸ AUI stated that its contribution policy is intended for exactly this purpose, i.e., the incremental costs associated with the more expensive sites are recovered directly from the sites that cause these costs. AUI also observed that larger Rate Class 1/11 customers subsidize the smaller Rate Class 1/11 customers by way of the base energy charge, which recovers the portion of customer costs not recovered through the fixed charge. The result is that intra-class subsidization is mitigated and from a practical perspective, AUI proposed no change to the allocator.

However, AUI also stated that the RCN cost information does not exist for services¹⁹ and embedded cost information could never exist because a customer's contribution dollars are not assigned to specific infrastructure.²⁰

¹⁷ AUMA/UCA-AUI-27

¹⁸ Exhibit 002-26, page 7 of Chymko Consulting Rebuttal Evidence

¹⁹ Exhibit 002-20, AUMA/UCA-PICA-4(d); Transcript Volume 1, pages 25-27; Exhibit 011-04(b)

AUMA/UCA opposed this mixing of cost and revenue information in the cost of service analysis stating that is contrary to the principle that the COSA should be done with as much precision as possible and then do any mitigation through rate design. AUMA/UCA further noted that contributions are pooled and allocated on the same basis as gross plant in service in the COSA and that there is no direct connection between the contribution policy, tariffs and the cost of service study.

AUMA/UCA recommended that, until AUI can meaningfully analyze the relative services costs for the proposed two new rate classes in its next GRA, it should utilize the meters proxy data for purposes of this Phase II. This would result in larger Rate 1/11 services being priced at 4.5 times the cost incurred by those customers using under 200 GJ per year,²¹ which they claimed would be a more appropriate cost assignment. AUMA/UCA submitted that AUI did not provide any support for the \$450,000 estimate to determine average RCN cost of services lines by rate class and suggested that it may not be necessary to go back and conduct a “service by service” review to establish a weighted site or weighted customer allocator for services lines.

In Argument, AUMA/UCA reiterated its position²² that AUI should be directed to review all available information, including that used for contribution purposes and that used for GRA forecasting purposes, to determine whether a reasonable proxy for the RCN of services lines can be developed, the cost to carry out such a study and report the results to the Board at the time of its next Phase I.

4.2.3.1 Views of the Board

The Board notes that there appears to be an inconsistency between AUI’s position that contributions mitigate differing costs of services and the absence of a direct recognition of contributions in the cost of service study.

Although the matter of splitting Rate Class 1/11 (Small General Service) is addressed later in this Decision, the Board does not find a clearly superior alternative to the previously approved method of allocating services costs on the basis of sites weighted by the RCN meter cost of an average site in each rate class. Therefore, the Board approves the use of this current method for this GRA Phase II application.

However, the Board considers that there is merit in investigating other feasible alternatives. The Board notes that AUI has offered to provide in its next Phase I GRA a full cost/benefit analysis of using the Diameter-Length method for the allocation of services together with a review of other reasonable alternatives. Accordingly, the Board directs AUI, in the next Phase I GRA, to include a full cost/benefit analysis of using the Diameter-Length method and the results of its review of other reasonable alternatives for the allocation of services cost. AUI’s review should also examine the feasibility of tracking contributions more closely to the costs they are intended to offset rather than a general allocation based on multiple factors.

²⁰ Transcript, Volume 2, pages 177-178

²¹ Exhibit 010-03-01, page 14

²² Exhibit 010-03-01, page 14

4.3 Determination of Demand Allocation Factors –Peak Demand for Rates 1/11, 2/12, and 3/13

In Decision 2005-029, the Board directed AUI to use the system design temperature of minus 40 degrees Celsius (-40° C) to calculate Coincident Peak (CP) and Non-Coincident Peak (NCP) for Rate Classes 1/11(Small General Service) and 2/12(Large General Service-Optional), instead of normalized weather. At that time, the use of -40° C was determined as appropriate to align with AUI's design criterion.

Consistent with previous approvals, in the COSA, AUI used the CP calculation to allocate transmission system costs and included peak demand at -40° C for Rate Classes 1/11 and 2/12, and the sum of billing demands for Rate Class 3/13 (Demand/Commodity General Service-Optional). However, AUI excluded Rate Class 4/14 (Irrigation Pumping Service-Optional) because Rate Class 4/14 had an insignificant effect on total transmission system costs.²³ AUI used the NCP calculation to allocate distribution system costs and included peak demand estimates for all rate classes.

4.3.1 Peak Demand for Rate Classes 1/11 and 2/12

To calculate CP and NCP for Rate Classes 1/11(Small General Service) and 2/12(Large General Service-Optional), AUI relied on its forecasting model as approved in the 2005/2006 Phase I GRA (Decision 2006-117).

PICA agreed that AUI's peak demand measures for Rates 1/11 and 2/12 reflected the aggregate demands by class, by day, at the design temperature and are, therefore, a reasonable proxy for the class NCP demands.

ASBG/PGA found AUI's use of -40° C to determine the peak demand a significant improvement over the forecasts in the prior GRA where, in ASBG/PGA's view, inappropriate averaging of data masked the peak demands of temperature sensitive customers. ASBG/PGA therefore submitted that AUI had complied with Board Direction 6 from Decision 2005-029 and that the Rates 1/11 and 2/12 peak demand determinations were not overstated and should be approved for this proceeding.

AUMA/UCA questioned the need for and the validity of the district by district forecast by showing the results to be unrealistic²⁴. AUMA/UCA specifically questioned the results which showed that a zero heating degree-day produced negative load for one commercial district.

4.3.1.1 Views of the Board

The Board notes that the model was designed to reflect the Board directed -40° C peak and the Board would not necessarily expect it to be rigorous enough to provide accurate results using values that are outside of the relevant data set for predicting heating loads. Consequently, the Board directs AUI, at its next Phase II GRA, to analyze and report on the need for a region specific calculation given the uniform -40° C and revise the model calculations to be able to account for low or no heating load.

²³ Decision 2005-029, Section 6.1

²⁴ Exhibit 010-03-01 AUMA/UCA Evidence, page 17, line 23 to page 18, line 22

The Board notes that Municipal and Gas Co-Op Intervenors (MGCI) submitted the peak demands for Rates 1/11(Small General Service) and 2/12(Large General Service-Optional), are overstated by at least 7% because those rate classes are composed of temperature-sensitive loads for which AUI's model of forecasting (a simple linear model) did not adequately explain the demand behavior and suggested that the best assumption is that maximum demand occurs at the (lowest) design temperature specified in the building code. AUI argued that the position of MGCI was based upon untested evidence on which the Board should place no weight.

The Board agrees with AUI that because MGCI's proposal was submitted through cross examination and in Argument and not as evidence during the proceeding, parties have not had the opportunity to test the proposal. Therefore, the Board does not accept MGCI's submission that the temperatures specified in the building code should be used by AUI.

The Board notes that CCA recommended that the Board should direct AUI to provide, at its next GRA, a detailed cost/benefit analysis of an assessment of the hourly/daily loads of each customer class, based on a number of sampled pressure regulating stations, to determine the appropriate demand related costs of the transmission system. Further, CCA advocated that such analysis of customer usage patterns during the year would properly capture the peak loads of all customer classes, provide a more appropriate measurement of the use of the various parts of AUI's system, and thus be more reflective of cost causation. The Board notes that AUI was not opposed to providing a cost/benefit analysis for what would be required to research customer load, but stated that CCA's request would not provide the customer level detail required for customer load analysis.

Given that the change to using -40° C has been implemented in response to direction from the Board in 2005-029 for this current COSA, the Board does not agree that further analysis of changes to methods is warranted at this time. The Board considers that additional experience, demonstrating how the current method affects cost allocation over time is necessary before any changes should be considered.

In conclusion, the Board finds that that AUI has satisfactorily complied with Direction 4 in Decision 2005-029 to revise the weather normalization method in its COSA to reflect AUI's design criterion of -40° C. The Board agrees with AUI that no party presented a compelling reason to reject the -40° C direction of the Board. Further, the Board accepts that the weather-sensitive nature of Rate Classes 1/11 and 2/12 means that the individual classes will peak at the same time that the system peaks and it is appropriate to have Class Non Coincident Peak (NCP) that equals the (CP) and is used in the COSA.

4.3.2 Peak Demand for Rate Class 3/13

AUI submitted that, in determining peak demand for Rate Class 3/13(Demand/Commodity General Service-Optional), using total billing demand for each Rate Class 3/13 customer is appropriate because the sum of the billing demand represents the capacity that Rate Class 3/13 customers have contractually reserved on the system. It stated that there should be no concern with respect to Rate Class 3/13 customers exceeding contract demand, as billing demand is adjusted upward if contract demand is exceeded.

MGCI noted that, since AUI is obligated to provide the contract demand to a Rate 3/13 customer at all temperatures, Rate 3/13 peak demands appropriately reflect the design temperature. PICA

also agreed with AUI's proposed demand allocation factors based on the sum of Rate 3/13 customers' contract demands.

AUMA/UCA submitted that AUI did not demonstrate that Rate 3/13 contract demands are established using -40° C, so there is a mismatch in the determination of the Rates 1/11 (Small General Service) and 2/12 (Large General Service-Optional) demands as compared to Rate 3/13, resulting in a subsidy to Rate 3/13 by Rates 1/11 and 2/12. AUMA/UCA claimed that, even if the customer pays for exceeding the contract demand, the demand for cost of service purposes remains based on contract demand. AUI responded that, calculating peak demand using the sum of contract/billing demands reflects the design capacity reserved for Rate Class 3/13 customers, regardless of the temperature or other factors that might affect total system demand. AUI maintained that the issue of whether or not Rate Class 3/13 is temperature sensitive is irrelevant because billing capacity used for determining peak demand reflects the maximum the customer can take and AUI has the right to curtail deliveries if necessary.

4.3.2.1 Views of the Board

The Board agrees with AUI's allocation because the sum of billing demand represents the greater of the system design capacity reserved for the Rate Class 3/13(Demand/Commodity General Service-Optional) customers or the capacity used by the Rate Class 3/13 customers. It is therefore the most appropriate measure of Rate Class 3/13 demand at the system's designed -40° C peak capacity. Accordingly, the Board approves AUI's Rate Class 3/13 demand as filed in the COSA.

4.4 Diversity

AUI explained that diversity means the different times or different ways customers or classes use the system. AUI submitted that the direction in Decision 2005-029 to use -40° C as the temperature at which to calculate CP demand for Rate Classes 1/11(Small General Service) and 2/12(Large General Service-Optional) reflects diversity in the sense that, even at -40° C, not all customers in Rate Classes 1/11 and 2/12 will necessarily be peaking; although both rate classes will be peaking. AUI's forecasting model inherently reflects diversity of individual sites and diversity present in the customer base because, in forecasting the average usage per customer, reference is made to actual historic normalized customer usage by district by customer segment. In fact, each district has a different customer usage per degree day and base load, and this is taken into account in the overall forecast. Diversity that is caused by varying temperatures is not relevant because the premise of this exercise, as required by Board Decision 2005-029, was to assume that all sites experience the same -40° C condition.²⁵

ASBG/PGA noted that AUI sized and constructed its facilities on the basis of forecast demands of customer loads and sized upstream segments beyond the customer meters to accommodate the aggregate demand profiles of many customers, which took into account differences in the demand profiles of many customers and customer classes. ASBG/PGA therefore agreed that AUI recognized diversity in customer demands.

PICA submitted that the peak demand measures calculated by AUI can be expected to reflect the average diversity between individual site-level peak demands and class demand at the mains level and the transmission level.

²⁵ Exhibit 002-26, Rebuttal Evidence, page16

Based on American Gas Association (AGA) definitions²⁶ AUMA/UCA submitted in Argument that when a NCP demand and a CP demand are of the same value, there is no diversity. It clarified that there are, within the definitions, two NCP demands, the individual Customer NCP demand and the Class NCP demand. The Customer NCP demand is the sum of the maximum demands the individual customers place on the system regardless of time. The Class NCP demand is the diversified maximum class demand for a twenty four hour period beginning at 8:00 AM, the start of the gas day (in Alberta). The Class CP demand is the demand that the class contributes to the system coincident peak. AUMA/UCA further claimed that, because AUI incorporates diversity in the design criteria for mains the same inter-class diversity must be recognized in the allocation of mains costs classified as demand related in order to provide symmetry between design criteria and the cost allocator, Class NCP.²⁷

4.4.1 Views of the Board

The Board disagrees with AUMA/UCA's position that there is no diversity reflected within the class when the Class CP and Class NCP demands are the same as used in the COSA. As AUMA/UCA explained, the Class NCP demand is the diversified maximum class demand for a twenty four hour period which does reflect the diversity between customers within the class. This is consistent with the incorporation of diversity in the design criteria. This conclusion is further supported as reasonable by AUI's explanation noting that the January 2006 aggregated Rate Class 1/11 (Small General Service) load factor is 54%. Rate Class 1/11 is comprised of 61,947 sites that, by and large, consume natural gas independent of other sites in the rate class. Each site makes its own decisions as to how much to consume and when to consume, so if one could add up the peak daily demand of all of these sites, AUI expected that the customer NCP would be considerably larger. Thus, the rate class load factor would be considerably lower if diversity was not reflected in AUI's measure of Class CP. In reality, the January 2006 Rate Class 1/11 load factor is actually higher than 54% because it is based on an extreme peak (i.e. -40° C) and average daily weather normalized load.²⁸

The Board agrees with AUI's explanation that both Rate Classes 1/11 and 2/12(Large General Service-Optional) customers are temperature-sensitive. Therefore, significant diversity between these rate classes does not exist. Both rate classes will peak at -40° C. The NCP demand is the peak of the class without reference to the system peak. However, for temperature-sensitive rate classes such as Rate Classes 1/11 and 2/12, where these customers make up the majority of total system customers, the class demand at the system peak (CP) and the class peak without reference to the system peak (NCP) will be the same.

²⁶ Diversity: A characteristic of the variety of gas loads whereby individual maximum demands usually occur at different times. Therefore, the maximum coincident load of a group or individual loads is less than the sum of the individual maximum loads. Diversity among customer's loads results in a diversity among the loads of the distribution mains and regulators as well as between entire systems.

Load Diversity: The difference between the sum of the peaks of two or more individual loads and the peak of the combined load.

For example of the Class CP is 90 and the Class NCP was 100 the class is 10% diversified or 90% coincident.

²⁷ AUMA/UCA Argument, pages 10-11

²⁸ Exhibit 002-26, Rebuttal Evidence, page 16

In conclusion, the Board approves AUI's CP and NCP calculations set out in the COSA as they appropriately reflect diversity, are consistent with the design criteria, and are used correctly in the COSA.

4.5 Analysis of Irrigation Demand and Load (Rate 4/14)

In Direction 5 in Decision 2005-029, the Board directed AUI to review the method of calculating Rate Class 4/14 (Irrigation Pumping Service-Optional) peak demand.

In response to this direction, Chymko Consulting Ltd. conducted what AUI considered to be a practical review by doubling the average demand of Rate Class 4/14 in the COSA to determine the impact that such a dramatic change would have on the allocation of costs among rate classes. The result of that particular study indicated that an additional \$72,000 would need to be allocated to Rate Class 4/14,²⁹ if there was a 100% change in the demand allocator for that rate class. AUI considered the additional \$72,000 that would be allocated to Rate Class 4/14 would not provide a material benefit to the other rate classes. As a result, AUI decided that further study was not necessary and did not conduct any further analysis.

AUI proposed to continue its use of a simplifying assumption that 1/31 of the volumetric consumption is consumed each day of the month for calculation of Rate Class 4/14 peak demand.

ASBG/PGA supported the simplifying assumption but suggested that, based on five years of actual consumption data, the peak demand should be 1,230 GJ rather than 1,467 GJ. It also proposed that, for the next Phase II application, AUI investigate whether it may be appropriate to direct assign costs to the irrigation rate class as this type of special rate may encourage irrigators to continue to use natural gas service.

PICA argued that, since summer peaks in the Southeast district do occur, Rate Class 4/14 should bear a portion of transmission costs but did not take issue with the simplifying assumption used by AUI to calculate Rate Class 4/14 peak demand. AUI maintained the position that the costs Rate Class 4/14 customers contribute to the total transmission system are not material. Rate Class 4/14 sites are almost exclusively located in a relatively small geographic area in the Southeast district, and simply calculating a transmission demand allocation factor for Rate Class 4/14 is inappropriate because it would likely over-allocate a share of transmission costs attributable to all other parts of AUI's service area.

AUMA/UCA noted that the design criteria for service to irrigation customers is connected load, which is the sum of the maximum demands each irrigation site could impose on the AUI transmission and distribution system. AUMA/UCA proposed calculating a demand based upon connected load, the design criteria and volumes, and known and measurable quantities.³⁰ This analysis resulted in a recommended demand of 5,868 GJ³¹ being used for COSA purposes compared to the applied for 1,467 GJ. This demand is derived from the analyses of connected load, resulting load factors and hours of use. It also recommended that the results of the COSA be capped under the Board's maximum 10% rate increase guideline until further research can be carried out.³² AUMA/UCA further recommended that AUI research the operation of the

²⁹ Exhibit 002-01, Application, COSA, page 32

³⁰ Exhibit 010-03-02 Evidence of AUMA/UCA Attachment 4 and 4A

³¹ AUMA/UCA Evidence, page 22, line 4

³² Transcript, Volume 3, page 397

irrigation connected load and develop a demand which it submitted would be more representative of operational reality.

4.5.1 Views of the Board

The Board agrees with AUI that, in this circumstance, it is not appropriate to use average consumption data because that would disregard the fact that Rate Class 4/14 (Irrigation Pumping Service-Optional) has the potential to peak at higher rates depending upon climatic conditions.

The Board also supports AUI's view that to develop a preferential rate designed to subsidize the irrigation customers would be contrary to the approved methods of cost allocation. AUI stated that the original purpose of Rate Class 4/14 was to provide a seasonal rate that reflects cost causation, particularly given the fact that Rate Class 4/14 does not cause any material costs on the overall transmission system.

The Board approved the exclusion of Rate Class 4/14 from the allocation of transmission system costs in Decision 2005-029 and agrees with AUI that this treatment remains appropriate because Rate Class 4/14 customers do not cause any material costs to the overall transmission system and there was no specific proposal tested during the hearing for allocation of transmission costs to Rate Class 4/14.

The demand level recommended by AUMA/UCA was not calculated based on the calculations attached to its Evidence but simply four times the level proposed by AUI. The Board does not find this a rigorous enough alternative calculation to change from the status quo. The Board also rejects AUMA/UCA's recommendation that AUI be directed to do further load research related to Rate Class 4/14.

The Board acknowledges that irrigation load will vary based on numerous factors such as temperature, precipitation, climatic region, crop type, and world agriculture prices.³³ In addition the success of any survey would depend on the willingness and ability of survey participants to provide comprehensive and accurate detail. However, AUI does not have meters necessary to record this type of load data and does not possess this type of load research.³⁴

Further, if the Board imposed a 10% rate cap on all classes, the proposal by AUMA/UCA to use a higher demand level would be severely mitigated and not be a significantly better method than that proposed by AUI.

Given that the only data available is monthly consumption based on billing data and, in order to gather this type of load data, AUI would require further capital expenditures, the Board agrees that the time and cost of further research with possibly unreliable data mitigates conducting further work.

The Board finds that AUI has complied with Direction 5 of Decision 2005-029 and approves the proposed method of calculating irrigation peak demand, as was approved in Decision 2005-029, and continues to be a practical solution in light of the data constraints. The resulting peak demand level of 1,467 GJ is approved for use in the COSA.

³³ Exhibit 002-01, Application, COSA, page 31

³⁴ Exhibit 002-01, Application, COSA, page 31

4.6 Classification and Allocation of Diameter-Length Method for Distribution Mains

AUI submitted that the Diameter-Length method used for the classification of distribution system mains costs is the same method used by ATCO Gas (Minimum Plant OD Method) which was approved by the Board in Decision 2007-026. AUI noted that the customer-related component of mains costs approved for ATCO Gas was 46.1% in the South and 42.1% in the North. Use of the Diameter-Length method by AUI results in a 59% customer component of mains costs. AUI submitted that the difference is due to the geographically dispersed nature of the AUI system.

AUMA/UCA submitted that one of the underlying issues in this proceeding is the inclusion of load serving costs in the portion of mains cost classified as customer related. In AUMA/UCA's view, the literature has clearly indicated that customer costs should not reflect the cost of serving load:

Bonbright states that the customer component of cost should reflect those costs driven by the number of customers **regardless or almost regardless of consumption (emphasis added)**

American Gas Association Gas Rate Fundamentals echo's this position when it states that customer costs should reflect **nominal or minimal load conditions (emphasis added)**

Bryant & Herman acknowledged this position in 1940 when they state that customer costs should be determined **independent of his demand or amount of commodity used (emphasis added)**.³⁵

AUMA/UCA stated that the purpose of classifying mains cost between customer and demand is to identify the cost caused by customers or the existence thereof and those costs incurred to serve load. AUMA/UCA submitted that the customer component should not reflect or include the cost of serving load and any method which results in 59% of the cost of mains being customer related is immediately suspect. AUMA/UCA contended that AUI's Diameter-Length method inappropriately includes load.

In response to this issue, AUMA/UCA developed an alternative method to classify mains based upon the ratio of the minimum consumption month to the maximum consumption month. While the AUMA/UCA would have preferred to use a zero intercept method, it elected not to revisit the zero intercept issue one more time in this proceeding.³⁶ Using the minimum/maximum(min/max) month ratio, AUMA/UCA determined that 29% of the cost of mains should be classified as customer related. AUMA/UCA argued that the data in the attachment to Exhibit 011-12³⁷ clearly demonstrates that minimum system methodologies consistently classify load serving costs as customer costs. In the attachment, on average, 27% of mains cost is classified using the zero intercept as compared to 42% using minimum system methods. AUMA/UCA submitted that its recommendation of classifying 29% of mains cost is well within the range of results shown in the Attachment to Exhibit 011-12 and is fully reflective of the concepts underpinning the zero intercept method. In order to mitigate cost shift and rate impacts, AUMA/UCA recommended that the Board adopt a 29% customer classification in this proceeding and direct AUI to conduct

³⁵ AUMA/UCA Argument, page 17

³⁶ AUMA/UCA Evidence A 11 and Transcript, Volume 3, page 395, line 14

³⁷ AUMA/UCA undertaking to the Board providing methods for the classification of distribution main costs by various utilities.

minimum/maximum day analyses on Rate Classes 1/11 (Small General Service), 2/12 (Large General Service-Optional), and 3/13 (Demand/Commodity General Service-Optional) in future proceedings to develop values which reflect a customer component that serves little or nominal load.

CCA concurred with the use of the minimum/maximum load method proposed by AUMA/UCA. In CCA's view, the minimum/maximum load method attempts to capture the nominal consumption, and effectively excludes the temperature sensitive load serving capability, thereby avoiding the problem of double counting implicit in AUI's Diameter-Length method. CCA submitted that this method theoretically comes closest to deriving the customer component of mains to reflect a basic system that would be needed to serve zero, or close to zero, load. Based on the analyses undertaken by AUMA/UCA, CCA recommended that the Board direct AUI to refile the allocation of the costs of the distribution mains using a ratio of 29%, as opposed to AUI's allocation of 59% based on the number of customers or sites. CCA further submitted that AUI should use cost data in the Diameter-Length calculation.

ASBG/PGA submitted that AUI's proposal for the Diameter-Length method should be accepted for this proceeding. However, ASBG/PGA disagreed with AUI's proposed change to the Diameter-Length method which would use a site allocator instead of the existing site-months allocator. ASBG/PGA noted that the change of this allocator would result in an increase to irrigation service of approximately 6%. ASBG/PGA also disagreed that irrigation customers stay on AUI's system in the winter months, noting that the Rate 4/14 (Irrigation Pumping Service-Optional) Rate Schedule is only available to irrigation customers during the summer pumping season that ends on October 31.

PICA submitted that the zero intercept method is the theoretically appropriate method for determining the customer component distribution mains costs and addresses the concerns raised by AUMA/UCA respecting the Diameter-Length method. However, PICA rejected AUMA/UCA's min/max method as it requires:

- a great deal of judgment in how the analyst determines the appropriate minimum volume if it is approaching zero for any given class, which may result in rate instability in successive rate cases,
- the use of the minimum month to maximum month volume ratio to calculate the customer and demand components of mains costs is not consistent with planning of the system, and
- the method assumes the customer number weighted minimum volumes recorded in 2004 to 2006 are somehow reflective of the cost of the minimum size, or zero volume pipe but there is no evidence to support this theory.

PICA considered that AUI's proposed Diameter-Length method should be accepted having regard to Decision [2007-026](#),³⁸ for ATCO Gas, wherein the Board appears to have accepted the same method, as a balance, considering the two offsetting concerns with the Diameter-Length method and the current lack of cost data. PICA further submitted that AUI should be directed to address the feasibility of using a zero intercept analysis for the next GRA Phase II. PICA considered that AUI has not supported its proposed allocation of mains general costs. PICA

³⁸ Decision 2007-026 – ATCO Gas 2003-2004 General Rate Application Phase II Cost of Service Study Methodology and Rate Design and 2005-2007 General Rate Application Phase II (Application 1475249) (Released: April 26, 2007)

submitted that there is no justifiable reason why mains general should not be classified on the same basis as mains pipe. Accordingly, PICA recommended that AUI be directed to address the classification of mains general in its next Phase II GRA.

4.6.1 Views of the Board

The Board concurs with AUI's use of a site allocator instead of the existing site-months allocator as it more appropriately reflects the distribution infrastructure that is in place to serve load. Although ASBG/PGA suggests irrigation customers should only be allocated costs based on a site-month basis which would take into account the seasonal nature of their service, infrastructure is still required to provide service whether or not these customers consume gas in winter months. The Board therefore rejects ASGA/PGA's site-month allocation proposal and approves AUI's utilization of a site allocator.

In Decision 2007-026, the Board noted that, while both the minimum plant and zero intercept methods are acceptable methodologies, it has in the past identified concerns with each:

The Board acknowledges that both the minimum plant and zero intercept studies are acceptable methodologies that have been used in classification of distribution mains costs. The Board also recognizes that use of the minimum plant method could result in the inclusion of a demand-serving capability in the customer-related portion of distribution mains. On the other hand, evidence presented in rate proceedings in other jurisdictions also indicates the potential for understatement of the customer-related classification where the zero-intercept method is used.³⁹

The Board also notes that the zero intercept method could produce statistically unreliable results if the extension of the regression equation beyond the boundaries of the data intercepted the Y axis at a negative value due to some abnormality in the data. The Board also notes that PICA submitted that the determination of the zero intercept was not an exact science and required judgment.⁴⁰

In Decision 2007-026, the Board indicated its acceptance of a minimal plant (Diameter-Length) method:

The minimum plant method has been used by ATCO Gas for many years with respect to mains and the Board is not persuaded that sufficient evidence has been provided in this proceeding to require ATCO Gas to change the classification methodology. This is essentially the same conclusion reached by the Board in Decision 2000-16 where the Board stated:

As pointed out by Calgary, in Decision E84020 the Board allowed CWNG to continue using the minimum plant method, noting the Company's evidence that the minimum plant method produced smoother results over time than the zero intercept method, and was not subject to the same data gathering problems. The minimum plant approach has been used by CWNG for many

³⁹ Decision 2000-16 Canadian Western Natural Gas Company Limited 1998 General Rate Application Phase II dated June 13, 2000, at page 21

⁴⁰ PICA Reply Argument, page 2, Decision 2007-026 – ATCO Gas 2003-2004 General Rate Application Phase II Cost of Service Study Methodology and Rate Design and Decision 2005-2007 General Rate Application Phase II (Application 1475249)

years, and the Board is not persuaded that sufficient evidence has been provided in this proceeding to require the Company to change the classification methodology.⁴¹

In Decision 2005-029, the Board stated the following:

The Board considers that the use of distance-diameter method to classify the costs of distribution mains between customer-related costs and demand-related costs is reasonable, and consistent with the approved practice of other distribution utilities.⁴²

The Board continues to be of the view that the minimum plant or Diameter-Length method is more appropriate than the zero-intercept method when classifying the costs of distribution mains between customer related costs and demand-related especially given the limited data available, the variability of zero-intercept results, and the potential for understatement of the customer-related classification. Having regard to its prior determinations with respect to the zero-intercept method and the evidence on the record of this proceeding, the Board is not persuaded that there is a need for AUI to conduct a feasibility study of using a zero intercept analysis for the next GRA Phase II as recommended by PICA.

With regards to AUMA/UCA's min/max approach, the Board concurs with AUI that the min/max approach is:

- Weather-sensitive⁴³ because, as the maximum month changes due to weather, both the customer and demand component of mains will also vary.
- Essentially the "the sanity check" associated with the zero intercept, which has consistently been rejected by the Board in this jurisdiction for the last 20 years, and therefore should also be rejected.

The Board also concurs with AUI that AUMA/UCA's criticism of the Diameter-Length method including load is circumspect when AUMA/UCA admitted on cross examination that the minimum month, by definition, includes load⁴⁴ contrary to AUMA/UCA's earlier assertion that the min/max month approach reflects no load.⁴⁵ Further the Board would expect that if the zero-intercept understates customer-related classification, AUMA/UCA's min/max approach would also suffer similar weaknesses.

Although AUMA/UCA provided evidence in Exhibit 011-12 that, on average, 27% of mains cost is classified using zero intercept as compared to 42% using minimum system methodologies, the Board is satisfied that AUI's Diameter-Length method is reasonable given the Board's rejection of the zero-intercept method and AUMA/UCA's min/max approach, and the geographically dispersed nature of AUI's system. Therefore, the Board approves AUI's Diameter-Length method of allocating mains costs and the resulting 59% customer component. However, the Board agrees with CCA that further study is warranted on whether the inclusion of cost data and capacity within the Diameter-Length method is appropriate when allocating costs between demand and customers related for distribution mains.

⁴¹ Decision 2007-026, page 59

⁴² Decision 2005-029, page 12

⁴³ Transcript, Volume 3, page 503

⁴⁴ Transcript, Volume 3, page 506

⁴⁵ Transcript, Volume 3, page 406

The Board notes that PICA considered that AUI has not supported its proposed allocation of mains general costs. PICA submitted that there is no justifiable reason why mains general should not be classified on the same basis as mains pipe. Accordingly, PICA recommended that AUI be directed to address the classification of mains general in its next Phase II GRA.

The Board is of the view that there is not enough information on the record to fully consider this issue at this time, and concurs with PICA that AUI should study the appropriateness of the classification of mains general costs on the same basis as mains pipe costs in its next Phase II GRA.

In summary, the Board is satisfied with AUI's utilization of the Diameter-Length method when classifying the costs of distribution mains between customer-related costs and demand-related. However, the Board directs AUI in its next Phase II to address:

- the classification of mains general costs, particularly the appropriateness of classifying such costs on the same basis as the mains pipe costs, and
- whether the inclusion of cost data and capacity within the Diameter-Length method is appropriate when allocating costs between demand and customer-related for distribution mains.

4.7 Allocation of Customer Care and Billing

As a result of a direction arising from Decision 2005-029, AUI reviewed the method of allocating these costs by assuming that Rate Class 3/13(Demand/commodity General Service-Optional) caused zero dollar customer care costs. The result was that an inconsequential amount of only \$4,000 shifted between rate classes. Accordingly, AUI stated that any impacts as a result of a change in this allocator are immaterial.

In AUMA/UCA-AUI-9(d), AUI was asked to provide all evidence relied upon to support the allocation of credit and collections costs on the basis of site-months. The response was that the choice of allocation method relied upon the intuitive rationale that the greater the number of invoices issued to a site, the greater likelihood that the Company will incur credit and collection efforts related to that site and that the allocation method was intended to maintain the method approved by the Board in the previous GRA. AUMA/UCA did not accept that the Board had intended to maintain the status quo because it directed AUI to review whether the use of unweighted customers is the most appropriate allocator for customer care costs.

AUMA/UCA considered that all credit and collection costs are not a function of site-months billed. AUI confirmed that the billing and customer care system records arrears by specific customer account and rate class and that uncollectible accounts and collection agency fees are included in credit and collection costs.⁴⁶ AUMA/UCA submitted that the cost driver for uncollectible accounts, collection agency fees and bank charges related to non-GCRR costs should be revenues or total costs by rate class rather than site-months.

CCA noted that, as at December 31, 2006, AUI expected to have about 693 customers taking service from retailers and was concerned whether AUI had undertaken any assessment respecting the potential for future stranded costs as more customers may leave the AUI system for retailers.

⁴⁶ Transcript, Volume 2, pages 259-260

Consequently, CCA submitted that the Board should direct AUI to monitor, by way of a deferral account, any stranded or other related costs in Customer Care and Billing, arising from customers exiting the AUI system to retailers.

4.7.1 Views of the Board

The Board has reviewed AUI's compliance to Direction 7 from Decision 2005-029 and concurs with AUI that revising the allocation of customer care costs would have an immaterial impact on customers, with the costs to conduct a change in allocation significantly outweighing the benefits. The Board therefore is satisfied that AUI has complied with the Board's direction.

The Board is satisfied that AUI's explanation that the greater the number of invoices issued to a site, the greater the likelihood that the Company will incur credit and collection efforts related to that site, especially in light of the fact that AUMA/UCA's proposal to allocate these costs based on revenues or total costs is not substantively supported by evidence within the proceeding. Therefore, the Board approves the continued use of the site-month allocator for credit and collection costs consistent with the method used for other customer care costs.

With respect to CCA's concern about the potential for future stranded or other related costs in Customer Care and Billing arising from customers exiting the AUI system to retailers, the Board notes that in Decision 2005-029, it addressed the issue of whether AUI should establish a deferral account to collect stranded costs arising from directions contained in Decision 2001-075.⁴⁷ At that time, the Board found it was premature, given the state of retail market development and stated:

Therefore, notwithstanding the Board's direction in Decision 2001-75, the Board will not require the establishment of a deferral account to capture any stranded benefits or costs resulting from customer migration to retail supply at this time. The Board considers that the issue of whether or not to establish such a deferral account can be reviewed at the time of the next GRA. If the level of retail activity should increase materially prior to the next GRA, the Board would be prepared to consider an application from AUI for the establishment of such a deferral account prior to the next GRA.⁴⁸

The Board recognizes that retail market activity has increased in AUI's service area, but understands that there are still only about 700 customers, of AUI's approximate customer base of over 60,000, on retail supply⁴⁹. Accordingly, the Board remains of the view that use of a deferral account is premature given the current stage of retail market development.⁵⁰

5 RATE DESIGN

5.1 General – AUI's Proposed Rates, Revenue to Cost Ratios, and Rate Shock

AUI submitted that its proposed distribution rates are not unduly discriminatory and, in fact, represent a fair recovery of costs from each rate class. AUI noted that fixed costs are appropriately recovered through fixed charges and supported a gradual approach for aligning rate

⁴⁷ Methodology for Managing Gas Supply Portfolios and Determining Gas Cost Recovery Rates (Methodology) Proceeding and Gas Rate Unbundling (Unbundling) Proceeding

⁴⁸ Decision 2005-029, page 7

⁴⁹ Exhibit 002-20, AUMA/UCA-AUI-1(b)

⁵⁰ Transcript, Volume 2, pages 157-159

design to unit costs.⁵¹ AUI also reviewed ATCO Gas' distribution rates. In particular, the Company noted that ATCO Gas South had proposed a fixed charge of \$18.296 per month,⁵² reflecting an increase of \$1.81 from the existing fixed charge of \$16.486 per month. This proposed change indicated that AUI is not the only utility proposing changes that would transition rates towards unity by component.

As noted in response to CCA-AUI-2(a) and illustrated in the Company's analysis of long run avoided customer accounting costs, AUI's proposed Default Supply Provider (DSP) Administration Fee was corrected to \$1.659 per month from \$1.60/month. This correction required a Rate Class 1/11 (Small General Service) base energy charge of \$1.221 per GJ (previously \$1.225 per GJ) in order to maintain the same level of recovery of revenue requirement. No other rate adjustments would be necessary. For ease of recognition, the Company used 6,385 GJ per year as the Rate Class 1/11 to Rate Class 2/12(Large General Service-Optional) transition point. The transition point using the corrected DSP Administration Fee is slightly greater, at 6,433 GJ/year.

Table 1. AltaGas Proposed Rates

	Fixed Charge (\$/month)	DSP Credit (\$/month.)	Base Energy (\$/GJ)	Demand Charge (\$/month/GJ)
Rate 1/11-Small General Service	18.00	1.659	1.221	
Rate 2/12-Large General Service(optional)	300.00	1.659	0.695	
Rate 3/13-Demand/Commodity General Service(optional)	500.00	1.659	0.016	5.505
Rate 4/14 - Irrigation Pumping Service(optional)	38.00	1.659	1.078	

With respect to the Rate Class 1/11 fixed charge, MGCI submitted that the fixed charge should be increased from the \$18/month proposed rate to \$19.26/month. MGCI submitted that this would result in a recovery of 70% of the unit cost. AUI did not oppose MGCI's suggestion, but submitted that the proposed rates are still reasonable and reflect a gradual increase of the fixed charges. With respect to Rate Classes 2/12 and 3/13, MGCI proposed that the Company move the fixed charges for these rate classes to unity with fixed costs.

AUI has proposed to recover close to 100% of the fixed, variable and total costs allocated to Rates 2/12 and 3/13.⁵³ AUMA/UCA agreed with this conceptually but noted that its proposals with respect to cost of service methods would result in changes to the costs allocated to Rates 2/12 and 3/13 (i.e. classification of mains costs and the lack of temperature adjustments to Rate 3/13 demands).⁵⁴ AUMA/UCA also noted that the Rate 2/12 cost of service will change as a result of the increase in the crossover between Rate 1/11 and Rate 2/12 from 3,700 to 6,385 GJ per year which AUMA/UCA understood is not reflected in the Chymko Consulting Ltd. cost of service analysis. AUMA/UCA also considered that Rates 2/12, 3/13 and 4/14 are sufficiently homogeneous to maintain the *status quo* rate classes.⁵⁵ In summary, AUMA/UCA submitted that

⁵¹ Transcript, Volume 2, pages 211, 212

⁵² Per ATCO Gas letter to the EUB dated November 6, 2006 referenced in Exhibit 002-13, BR-AUI-9(a)

⁵³ Exhibit 002-01, pages 28-29

⁵⁴ Exhibit 010-03-01, pages 11 and 18

⁵⁵ Exhibit 010-03-01, page 23

Rates 2/12 and 3/13 should be designed to recover 100% of cost by rate and rate component subject to a 10% maximum increase cap.

ASBG/PGA submitted that, while the Board has historically attempted to set rates within a revenue to cost ratio range of 95%-105%, in a proceeding where different cost allocators are being proposed and may be approved, the revenue to cost ratio target should be relaxed to accommodate the rate shock criterion (10% rate cap increase), if required.

PICA and AUMA/UCA concurred with AUI's proposal to achieve virtually 100% revenue to cost ratios for all rates subject to mitigating rate shock through a maximum increase cap of 10%. PICA also submitted that the rate changes resulting from this Application should be implemented on a go forward basis, given the significant changes in the rate levels proposed by AUI for Rates 2/12 through 4/14. Any retroactive implementation of rates would result in significant rate shock to these classes.

While CCA accepted a 100% revenue to cost recovery on an aggregate basis for each rate class, CCA considered that the move to 100% revenue to cost ratio by rate component was not necessary. CCA considered that this rate-making practice would provide consistency for AUI and other utilities regulated by the Board where, historically, the Residential Fixed Charge has not recovered 100% of the customer-related costs. CCA noted AUI's proposal to target for 100% revenue to cost ratio for Rate 1/11 appears to be in accordance with the prior Board directive to AUI. Since Rate 1/11 comprises about 90.7% of the total of AUI's cost of service, any attempt to recover higher than 100% will yield a significant amount of revenues to the benefit of other rate classes. CCA suggested that, in the absence of any evidence suggesting these other rate classes will experience rate spikes, all rate classes be targeted to recover 100% of costs.

CCA disagreed with AUI's proposal to increase the Rate 1/11 fixed charge from \$15.36 per month to \$18.00 per month and to move directionally closer to unity on individual components of Rate 1/11, where fixed costs (customer costs) for Rate 1/11 would be \$27.52. CCA was concerned that:

- the increase in fixed charge and the resulting decrease in energy charge will benefit the larger volume customers in Rate 1/11, most of whom are commercial in nature, and will negatively impact the smaller pure residential-type customers,
- any move to more recovery from fixed charges will frustrate attempts by smaller Residential-type customers to curtail consumption,
- the move to full recovery through the fixed charge as proposed will fundamentally change the risks facing AUI compared to the risks in place when the Board approved the generic cost of capital in Decision 2004-052 dated July 2, 2004 by shifting the collection of about one-third of its revenue requirement from the variable weather-dependent earnings to the fixed non weather- dependent earnings,
- a significant shift of revenue recovery will call into question the continued appropriateness of the formula in the generic cost of capital Decision 2004-052 to recognize the significant reduction in risks of revenue recovery,
- the proposed increase in Fixed Charge has caused the break even point (BEP) as between Rates 1/11 and 2/12 to increase from 3,728 GJ to 6,385 GJ/year.⁵⁶

⁵⁶ CCA Argument

However, if the Rate 1/11 fixed charge were to be increased today to reflect a full recovery of customer costs i.e. to \$27.52/month, and assuming no changes to the proposed Rate 2/12 rate components as proposed, the break even point would be increased to a significantly higher level, creating the potential for there being only one rate class for all customers.

Further, and for the same reasons, CCA did not support the AUMA/UCA proposal to move to full recovery of customer costs through the fixed charge. Also, CCA disagreed with MGCI's proposal to increase the Rate 1/11 fixed charge yet further to \$19.26 per month, reflecting a 70% recovery of the customer charge. CCA recommended that the Board direct AUI to maintain the level of recovery of the customer costs through the Fixed Charge at \$16.55 per month, the same level as is currently reflected in existing rates.

5.1.1 Views of the Board

The Board is of the view that CCA's concern regarding consumption fails to take into consideration that the cost of gas, not distribution rates, is the main price signal for customers. CCA also did not recognize that an increase in the fixed charge to Rate 1/11 (Small General Service) customers is still significantly below the result of the COSA which calculates a fixed unit cost of \$27.52/month.

In the recent Decision 2007-026 (ATCO Gas), the Board stated the following with respect to increasing the fixed charge:

The Board considers that it would be reasonable to move toward a fixed charge for Low Use and Irrigation customers that recovers costs more in line with the COSS in order to ensure fairness within the rate classes (horizontal equity), fairness between rate classes (vertical equity) and to enhance the predictability of the utility recovering its approved revenue requirement and stabilizing revenues. However, the Board is not prepared to assign 100% of the customer component of allocated costs to the fixed charge at this time in recognition of the customer impact of any increase to the fixed charge, especially to lower and fixed income customers, and in order to mitigate potential rate shock and to reflect the rate design attributes of rate stability, certainty and predictability.

The Board considers the Low Use and Irrigation fixed charge should be limited to 90% of the COSS results.⁵⁷

The Board is not persuaded by MGCI's submission that it should increase the fixed component of rate more in line with fixed unit costs given that certain customer groups (Rate 1/11) are more adverse to higher fixed costs. The Board considers that AUI's proposed fixed charge for Rate 1/11 customers which recovers 71% of the unit cost is reasonable and consistent with Decision 2007-026.

⁵⁷ Decision 2007-026 – ATCO Gas 2003-2004 General Rate Application Phase II Cost of Service Study Methodology and Rate Design and 2005-2007 General Rate Application Phase II Application No. 1475249, page 96

The Board notes that AUI's proposed rates achieve close to 100% revenue to cost ratio for all rate classes.

Rate Class 1/11(Small General Service)	100.00%
Rate Class 2/12(Large General Service-Optional)	99.97%
Rate Class 3/13(Demand/Commodity General Service-Optional)	99.98%
Rate Class 4/14(Irrigation Pumping Service-Optional)	99.95% ⁵⁸

The Board also notes its findings from Decision 2005-029:

With respect to revenue-to-cost ratios, the Board is of the view that cost of service analysis is not an exact science, and that blind adherence to 100% revenue-to-cost ratios in the design of rates would not be appropriate. Nevertheless, the Board considers that one objective of rate design is to design rates that recover 100% of allocated costs. The Board recognizes, however, that consideration of other rate design criteria such as rate stability, mitigation of rate shock and customer acceptance, may conflict with the desire to achieve a 100% revenue-to-cost ratio. Recognizing that cost of service analysis is not an exact science, and recognizing that other rate design criteria may conflict with the desire to achieve a 100% revenue-to-cost ratio, the Board remains of the view that a revenue-to-cost ratio range of 95% to 105% generally remains an appropriate target for all rate classes. However, the Board agrees with MGCI that due to the size of the Rate 1 class, small changes in the revenue-to-cost ratio for Rate 1 would have very large impacts on the revenue-to-cost ratios for the other rate classes. Therefore, the Board considers that the revenue-to-cost ratio for Rate Class 1 should be maintained as close as practicable to 100%.⁵⁹

The Board is satisfied that AUI's proposed rates are directionally consistent with the Board's past decisions regarding revenue to cost ratios. However, the Board must be mindful of any changes in rates that might lead to rate shock to customers.

AUI argued that rate stability and rate shock criteria are more appropriately applied when taking into consideration the total charge to the rate payer, which includes the commodity costs. In the case of AUI's proposed rate structure, if one incorporates a gas cost of \$5.50 per GJ (which is considerably lower than current market prices) the maximum increase in revenue is 2.98%, as set out in the chart below:⁶⁰

Table 2. Impact of Proposed Rates by Rate Class per AUI

Rate	Change in Revenue
Rate 1/11	-0.64%
Rate 2/12	1.82%
Rate 3/13	1.07%
Rate 4/14	2.98%

AUI submitted that rate impacts are reasonable and there is no rate shock to customers.

⁵⁸ Exhibit 002-01, Application, COSA, page 26

⁵⁹ Decision 2005-029, page 12

⁶⁰ Exhibit 002-13-03, BR-AUI-9(c)

Although the Board agrees with AUI that distribution costs are a small component of a customer's overall costs when factoring in the cost of gas, the Board considers that it is appropriate to weigh the individual impact in changes in distribution rates on customers, especially given the high residential make-up of the AUI customer base. Any significant changes in distribution rates contribute to possible higher overall costs to customers, some of whom are subject to fixed incomes.

Although applying a 10% rate cap has often been utilized by the Board, the Board is of the view that it should be considered a guideline whereby the Board may determine, on a case by case basis, whether it is appropriate to increase rates above that threshold. The Board is satisfied that AUI's proposed rates are within a reasonable tolerance of the 10% rate cap, especially given that Rate Class 2/12, Rate Class 3/13, and Rate 4/14 currently recover significantly less than their costs via AUI's existing rates and would be close to unity on AUI's proposed rates. Therefore the Board approves AUI's rates as filed (Appendix 4). The Board's approval of AUI's rates also results in the Board's acceptance of the mathematically derived transition points that result from AUI's rate design.

With regard to the interim rates, the Board considers these rates approved in Order U2006-041 are approved as final rates within the period the rates were in effect. The 2006 interim rates will continue to be in place until AUI's approved rates go into effect November 1, 2007.

The Board approves all rates, rates schedules, and rates riders not specifically addressed in the Decision are approved as filed (see Appendix 5).

5.2 Rate 1/11 - Small General Service

5.2.1 Homogeneity of Rate 1/11 Customers

AUMA/UCA considered that all customers served under Rate Class 1/11 (Small General Service) were not homogenous, particularly in terms of customer size and intra-class subsidization of larger customers by smaller ones. Citing various references,⁶¹ AUMA/UCA suggested the following criteria should be used for evaluating class homogeneity and customer classes:

- the amount of service the customer uses,
- the pressure at which the customer receives service,
- the conditions under which the customer takes service, and
- the customers' load characteristics by end use.

AUMA noted that customers of an electric utility can be divided into four principal groups or classes, each of which is relatively homogeneous with respect to load characteristics and methods of taking service.⁶²

AUMA/UCA stated that the references discussed usage characteristics for evaluating homogeneity but did not discuss cost differentials. AUMA/UCA submitted that when measurable cost differentials can be demonstrated along with size and usage differentials, there is a demonstrated lack of homogeneity which should be addressed and corrected. AUMA/UCA

⁶¹ AGA Gas Rate Fundamentals, Fourth Edition, Page 132, Page 140; and Elements of Utility Rate Determination, J. M Bryant & R.R. Herrman, McGraw-Hill Book Company, 1940

⁶² Electric Utility Rate Economics, Russell E. Caywood, Sixth Printing 1972, page 67

considered that AUI's proposal to increase the point of consumption indifference from 3,728 GJ per year to 6,385 GJ per year compounded the lack of homogeneity issue. AUMA/UCA also considered that the issue was exacerbated by AUI's use of the RCN meter proxy to allocate the costs of services to rate classes.

AUMA/UCA noted that, while the RCN of meters for Rate 1/11 is shown as \$120.81, there are more meters with a RCN of \$88.00 (57,949)⁶³ than there are residential and rural customers, (57,598).⁶⁴ AUMA/UCA considered that with the 40% increase in cost from \$88.00 to \$123.00 for the RCN of meters, the commercial class is contributing some very costly meters to the costs which the entire Rate Class 1/11 is expected to bear under the AUI proposal. AUMA/UCA also noted that the other 5,012 meters had an average RCN of \$500.10 which is about 6 times the cost of a core meter required for approximately 95% of residential customers. AUMA/UCA also considered that, with 95% of the residential customers using 200 GJ/year or less, a 40% increase in meter costs did not appear to be justified, which further indicates that there are homogeneity issues in terms of customer size and related costs within the current Rate Class 1/11.

AUMA/UCA proposed two alternative solutions to remedy the lack of homogeneity in AUI's Rate Class 1/11 (refer also to Section 5.2.2).

1. Establish tariffs by end-use customer type. Residential service would be defined as single-family residences, single-family town homes, row houses, condominiums and duplexes which are individually metered. All other existing Rate 1/11 customers would fall under the commercial industrial/larger Rate 1/11 class. A single family, separately metered farm home without any farm usage would also qualify as a residential customer.
2. Separate the current Rate 1/11 between customers using up to 200 GJ per year and those using 201 – 6,385 GJ.

AUMA/UCA considered that, by establishing separate tariff classes, a higher degree of homogeneity would be achieved based upon consumption size, predominant use, load characteristics and a closer relationship between minimum and maximum use of the class members and average use of the class. Alternatively, by separating the rate at 200 GJ, a higher degree of tariff homogeneity would be achieved, as well as promoting more efficient use of natural gas. AUMA/UCA noted that there were 54,960 customers under 200 GJ and 8,766 customers in the 201-6,385 GJ/year class. AUMA/UCA argued that AUI did not provide any quantitative or qualitative evidence that Rate Class 1/11 demonstrated homogeneity, nor did it provide any evidence which refuted the AUMA/UCA analyses of the issue.

AUMA/UCA disagreed that AUI's contribution policy addressed homogeneity and, notwithstanding, considered that the history of AUI's contribution policy was uncertain with respect to its application. AUMA/UCA submitted that there is no connection between contribution policy, tariffs and the cost of service study. AUMA/UCA asserted that the policy therefore does not equalize the costs to connect to the distribution system as between the small and large customers in Rate 1/11, and more particularly where no contribution is required.

⁶³ AUMA/UCA-7(b)

⁶⁴ AUMA/UCA-7(a)

AUI submitted that Rate Class 1/11 is homogeneous with respect to characteristics that cause costs and although Rate Class 1/11 contains what might appear on the surface to be different types of customers, from a residential home to a large retail store, this surface difference does not translate into differences in cost causation. AUI also submitted that, in terms of assessing homogeneity from a cost causation perspective, the most important factors are:

- load profile (a large retail store consumes gas in a manner similar to a residential home in the sense that peak gas consumption would occur during the coldest temperatures), and
- customer cost drivers (a difference in annual energy consumption between a class of customers consuming as much as 200 GJ and a class of customers consuming greater than 200 GJ on its own does not necessarily lead to greater costs for the higher volume customer class).

AUI submitted that, while the definition of homogeneity cited by AUMA/UCA does include some of the fundamental cost drivers in a COSA, such as load characteristics and sites, it does not purport to represent a definitive guideline for the creation of new rate classes. AUI noted that its tariff represents the stand-alone distribution service costs and does not allocate the cost of gas to rate classes; therefore, the amount of service the customer uses is less relevant than it would be for a vertically-integrated utility. Accordingly, AUI further submitted that, in accordance with that definition, all of its Rate Class 1/11 customers share the same conditions of service, have similar load profiles, and receive service at similar distribution pressures. AUI consequently argued that, as the drivers of cost in a cost of service study are sites and load profile and that existing Rate Class 1/11 is weather sensitive with customers peaking at the coldest temperature (meaning customers will have similar load factors),⁶⁵ Rate Class 1/11 is homogeneous. AUI argued any lack of homogeneity requires evidence other than simply drawing inferences from higher RCN meter costs for a small number of customers within Rate Class 1/11, as suggested by CCA, and cannot be inferred by simply observing the higher consumption of a relatively small number of customers within Rate Class 1/11. AUI also noted that its rate structure has been in place for over 20 years and homogeneity for Rate Class 1/11 has not been a concern.

AUI stated that, contrary to AUMA/UCA's assertion, it never indicated that a COSA determines rate classes or measures homogeneity. AUI stated that plant, net of accumulated depreciation and net of contributions, is not used to allocate costs to rate classes, has no bearing on intra-class subsidies within Rate Class 1/11 and has no bearing on whether contributions levelize the cost of meters and other assets entering rate base within Rate Class 1/11. AUI submitted that implementing new rate classes only requires contemplation when relevant cost-of-service differences exist between two identified and defined customer groups.

AUI considered that AUMA/UCA's limited focus on transition points and meter costs, specifically meter RCN costs, to suggest that smaller Rate Class 1/11 customers are subsidizing larger Rate Class 1/11 customers failed to prove its claim. AUI argued that if AUI's contribution policy is ignored, larger Rate Class 1/11 customers subsidize the smaller Rate Class 1/11 customers because customer costs not recovered through the fixed charge are recovered by way of the base energy charge (the rates as currently proposed include recovery of only 51% of the customer and demand costs in the fixed customer charge),⁶⁶ which is opposite to the result predicted by AUMA/UCA. AUI noted that its contribution policy generally applies to more

⁶⁵ Transcript, Volume 3, pages 496-499

⁶⁶ Exhibit 002-13, BR-AUI-7(d)

costly rural services or services that require a greater investment, wherein a lower net investment for less economical services means that more economical smaller Rate Class 1/11 customers will not bear a disproportionate amount of any larger, less economical, Rate Class 1/11 customers' costs. AUI asserted that by taking AUI's rate design and contribution policy into consideration, all intra-class subsidization is mitigated.

With respect to energy, AUI submitted that usage is largely homogeneous within Rate Class 1/11. AUI noted that there are fewer than 2,500 customers that consume more than 500 GJ/year of gas within Rate Class 1/11, which represents less than 4% of customers within the Class, and consequently, any cost impacts to smaller, more numerous customers would be very limited.

5.2.1.1 Views of the Board

The Board is mindful that AUI has an extensive service territory with many small customers throughout the Province.⁶⁷ AUI mainly serves customers that consume 200 GJ or less of natural gas per year. In 2006, AUI's customer distribution for Rate Class 1/11 (Small General Service) can be grouped as follows:⁶⁸

Table 3. Natural Gas Consumption for Rate 1/11

Natural Gas Consumption (GJ/Year)	Residential	Commercial	Rural	Total	Percentage
200 or less	42,719	2,294	9,947	54,960	86.3
201 - 249	1,188	531	1,127	2,846	4.5
250 - 299	426	381	617	1,424	2.2
300 - 500	312	981	707	2,000	3.1
501 - 1,000	133	982	250	1,365	2.1
1,001 - 4,000	100	891	69	1,060	1.7
> 4,000	<u>3</u>	<u>68</u>	<u>0</u>	<u>71</u>	<u>0.1</u>
	<u>44,881</u>	<u>6,128</u>	<u>12,717</u>	<u>63,726</u>	<u>100.0</u>

This grouping would suggest that a distinction could be made between the types of customers served, particularly between the few high load customers and others, as suggested by AUMA/UCA and CCA. The Board notes the reference to the different size of meters made by AUMA/UCA and CCA in this respect. However, while AUI recognized the possible differences in types of Rate 1/11 customers, AUI also considered that these differences did not necessarily translate into differences in cost causation. The Board further notes that AUI considered all of these customers to have similar load profiles and cost drivers, and therefore, were homogenous in character. AUI's position was supported by ASBG/PGA and PICA.

However, the Board has not been convinced by either of the opposing positions. Instead, the Board agrees with MCGI that there is a lack of evidence on the record to clearly demonstrate whether or not the customers served under Rate Class 1 are sufficiently different to the extent that one or more types of customers are unjustly subsidizing others and would therefore warrant

⁶⁷ Exhibit 011-09, Map of AUI Service Area

⁶⁸ Exhibit 002-20, AUMA/UCA-AUI-7(a)

Rate 1/11 to be re-defined. As this matter affects rate design, the Board will set out its findings in section 5.2.2.1, with respect to dealing with AUMA/UCA's proposals to split Rate Class 1/11.

5.2.2 AUMA/UCA Proposals for the Division of Rate 1/11 Customers into Separate Classes

As noted above in section 5.2.1, AUMA/UCA considered that AUI's Rate Class 1/11 (Small General Service) lacked homogeneity and proposed two alternatives to address the issue as follows.

1. Establish tariffs for Residential, Small Commercial and Industrial, Large Commercial and Industrial and Irrigation classes.⁶⁹ Residential service would be defined as single-family residences, single-family town homes, row houses, condominiums and duplexes which are individually metered. All other existing Rate 1/11 customers would fall under the commercial industrial/larger Rate 1/11 class. A single family, separately metered farm home without any farm usage would also qualify as a residential customer.⁷⁰
2. Adopt General Service Tariffs breaking the current Rate 1/11 at 200 GJ per year. The Small Commercial and Industrial Class would generally cover consumption in the range of 201 – 6,385 GJ/year. Current parameters for Rates 2/12 (Large General Service-Optional) and 3/13 (Demand/Commodity General Service-Optional) would remain the unchanged as there are relatively few customers on those rates, 142 sites for Rate 2/12 and 53 sites for Rate 3/13. In order to address migration issues, a two year rolling evaluation period would be utilized.⁷¹

AUMA/UCA noted that they it did not fully develop tariffs that reflect the recommendations set forth in their evidence. However, they estimated the approximate customer costs for the small/residential Rate 1/11 customers would be \$20 per month and the approximate customer costs for the larger/commercial customers would be \$48 per month.

AUMA/UCA disagreed with AUI that the difference in energy consumption does not necessarily lead to greater costs for the higher volume user. AUMA/UCA argued that a potential \$5.5 million shift in costs is at issue if Rate Class 1/11 is split.

AUMA/UCA noted that AUI identified 155 Rate Class 2/12 customers in the 4,000 to 6,385 GJ/year consumption band under proposed rates that would be marginally better off in Rate Class 1/11. AUMA/UCA further noted that, although the 155 Rate Class 2/12 customers represent only 0.24% of the Rate Class 1/11 customers, these customers represent 90.12%⁷² of 172 Rate Class 2/12 customers. Thus, under the rate design proposed by AUI, the transition point changes enough to provide an incentive for almost all of the customers on Rate Class 2/12 to change to Rate Class 1/11 instead of staying in their current rate class. AUMA/UCA advocated that an additional rate class would ensure Rate Class 2/12 remains intact.

ASBG/PGA disagreed with AUMA/UCA's proposal to split Rate 1/11 into sub-classes and agreed with AUI's characterization of the proposal as being unduly discriminatory because

⁶⁹ Exhibit 010-03-01, page 6

⁷⁰ MGC-AUMA/UCA-2(a)

⁷¹ Exhibit 010-03-01, page 6

⁷² Exhibit 002-20, AUMA/UCA-AUI-7(a) shows 172 Rate Class 2/12 customers. $155/172 = 90.12\%$

AUMA/UCA used indirect or speculative means to identify specific sub-groups for differing treatment. ASBG/PGA was concerned with the considerable increase in costs to rural and farm customers that AUMA/UCA advocated, noting that AUMA/UCA forecast the fixed charge for the proposed over 200 GJ/year rate class to almost triple, from \$16 to \$48 per month. ASBG/PGA also agreed with AUI that the number of rate classes studied should be minimized. Consequently, ASBG/PGA submitted that Rate 1/11 should not be split into separate rate classes for this proceeding.

CCA supported AUMA/UCA's recommendation for the split of the Rate 1/11 into separate rate classes. In particular, CCA considered that the existing Rate 1/11 configuration did not reflect customers with homogeneous characteristics. However, CCA did not support the use of a volume threshold amount and instead favored one based on end-use customer types, e.g. Residential, Commercial, etc. CCA considered that all same end-use customers should be housed in the same rate class. While recognizing that the consumption in this rate class may vary from 50 GJ a month to 6400 GJ/year, given the proposed break even point for Rate 1/11, CCA submitted that appropriate rate design will provide the correct price signals.

MGCI expressed concern about certain of the customers that AUMA/UCA purported to represent. MGCI opposed both of the proposals made by AUMA/UCA to split Rate 1/11 into two new classes in that:

- AUMA/UCA Rate 1/11 proposals would shift costs to farm customers in particular and away from residential customers, without evidence clearly demonstrating that farm customers are more costly to serve than residential customers,
- AUMA/UCA failed to demonstrate any significant points of dissimilarity between residential and farm customers, whereas there appears to be several points of similarity between them, and
- splitting Rate 1/11 as proposed by AUMA/UCA under either proposal would be more expensive to administer and monitor than would following the rate structure proposed by AUI.

MGCI believed that before the Board approves the creation of new rate classes, and the allocation of less costs to one of the new rate classes and more costs to the other, as proposed by AUMA/UCA, the Board should have before it clear and comprehensive evidence that the proposed new cost allocations are fair and that one homogenous group of customers was clearly causing more costs than the other. MGCI stated that it was not prepared to countenance creating winners and losers amongst the individual customers it represents, without clear and convincing evidence that a defined and discernable group is subsidizing another. Accordingly, MGCI asserted that the proposals are neither just nor reasonable and should be rejected. Similar to PICA, MGCI submitted that the evidence on the record is not sufficient to support a split of Rate Class 1/11.

PICA submitted that AUMA/UCA's recommendation to split Rate 1/11 should not be accepted in this proceeding as there is no evidence of any undue cross-subsidy between smaller and larger customers within Rate 1/11. PICA considered that, if such a split were to be considered in the future, then a full COSA showing the revenues and costs for each of the sub-groups within Rate 1/11 should be made available for examination and assessment by all parties.

AUI submitted that there was no evidence to support AUMA/UCA's proposals to split Rate Class 1/11 or that the proposals would result in more appropriate rates. AUI considered that splitting Rate Class 1/11 based on the AUMA/UCA's proposals would not reflect an evidence-based approach to rate making and noted that PICA, MGCI, and ASBG/PGA opposed the AUMA/UCA proposal.

AUI noted that the general trend over the last several decades has been to simplify rate structures. AUI stated that it previously had a complicated rate structure with area specific block rates but that the efforts of AUI, the Board, and interveners resulted in the current simplified rate structure and conditions of service. AUI viewed its current tariff as being a significant improvement over previous tariffs and as having a rate structure that is simple, transparent, and practical to administer. AUI asserted that, since its service territory is adjacent to its competitors' in numerous areas, making changes to its rate design and rate class structure that make them significantly different than those of its competitors will have a detrimental effect on its competitiveness and potential growth opportunities.

AUI set out the following issues that it asserted will arise if either AUMA/UCA proposal is adopted:⁷³

- A clear and detailed definition of 'residential' is required and a mechanism would be required to continually ensure that customers are properly categorized by segment.
- Accounts would have to be monitored to ensure customers are served under the appropriate rate, the cost for which would be driven by the number of sites monitored, not the number of sites that switch between rate classes.
- System modifications would be required to accommodate either proposal.
- Changes to system processes would be required to accommodate either proposal.
- Educational and communication efforts would be necessary to ensure customers and industry understands the changes and how the changes affect them.
- Inter-generational inequities exist without the ability to link contributions to customers.
- Creating new customer segments or rate classes from existing ones means that new data will be incongruous with old records, which will impact the AUI's ability in many ways, including developing forecasts and comparative reporting.
- Tariffs, including rates and terms and conditions of service, will have to be thoroughly reviewed and modified in accordance with the new rate structure.

AUI noted that both proposals would also put an end to AUI's current voluntary or optional rate classes and likely lead to customer resistance, a matter which AUMA/UCA did not consider.⁷⁴

More specifically, AUI submitted that the proposal to split Rate Class 1/11 at the 200 GJ/year level should be rejected as splitting the rate class at that level still leaves a remaining non-homogeneous rate class (i.e., 201 to 6,385 GJ/year). AUI considered that AUMA/UCA did not adequately consider this aspect of its rate structure proposal. AUI further submitted that there are significant monitoring and other issues associated with this proposal. With respect to a two year trial period, concerns arise in respect of:

⁷³ Exhibit 002-26, AUI Rebuttal Evidence, page 1

⁷⁴ Transcript, Volume 3, pages 492, 493

- the possibility of two unusually cold winters in a row within the two year trial period,
- customers who move within the service territory or who are new to AUI's service territory as AUMA/UCA's proposal is unclear whether the customer or the site is designated as being in the over or under 200 GJ/year rate class, and
- ongoing monitoring for a significantly larger number of customers will be required.

AUI also noted the relative magnitude of customers affected by a rate class defined by a limit of 200 GJ per year in that over eleven thousand customers consumed between 150 and 250 GJ/year; whereas, just over two hundred customers, served under Rates 1/11 and 2/12, consumed 4,000 GJ/year or more. Consequently, AUI argued that the switching of customers back and forth across the 200 GJ/year threshold can be reasonably expected, especially smaller consumers who are typically most sensitive to changes in weather. AUI further noted that the increase in the fixed charge for the over 200 GJ/year class to \$48 is approximately three times the current Rate Class 1/11 fixed charge, which will likely lead to significant customer opposition given the magnitude of the change if a cross-over of the 200 GJ/year threshold involves a relatively small volume.

AUI argued that the proposal to create several new rate classes, including residential, small commercial and industrial is very problematic with respect to definitions. AUI submitted that this proposal would be extremely difficult to implement, given that its rates are currently general service rates, and a method of identifying residential, commercial and industrial customers would need to be formulated in a way that is robust enough for billing purposes. AUI was concerned that significant billing related problems are probable if such a proposal is approved by the Board.

5.2.2.1 Views of the Board

The Board understands AUI's reluctance to effect changes to Rate Class 1/11 (Small General Service) given the demographics involved and potential administrative issues and added costs that AUI expects may arise as a result. The Board also notes that the composition of the Rate Class has not been contentious in the past and the Rate Class has been in effect for some time.

The Board has reviewed the proposals made by AUMA/UCA. Theoretically, either proposal appears to have some merit given the different types of customers, and their respective load factors, served within the class. The Board notes that CCA supported a division of the class based upon customer type, while ASBG/PGA, PICA and MGCI opposed AUMA/UCA's proposals.

The Board considers that the proposals were not supported by sufficient evidence to persuasively demonstrate to the Board that the current structure of the rate class includes any inherent degree of bias to one type of customer over another. The Board notes that AUMA/UCA referred to estimates and potential cost savings, which are not conclusive in nature.

The Board also considers that AUI similarly has not fully demonstrated that there is not undue subsidization of certain customers by others within the Rate Class. In this situation, the Board agrees with MGCI and PICA that a split of Rate Class 1/11 at this time would be premature and that any changes to the structure of the Class should otherwise be subject to a proper COSA, which should be made available for examination and assessment by all parties. The Board considers that this issue needs to be resolved but recognizes that a COSA can be time consuming and costly.

Notwithstanding, the Board believes that the onus should be on AUI to support the appropriateness of its rate class structure, particularly where there is concern and disagreement by interested parties that represent customers affected by its rates. Accordingly, the Board directs AUI, at its next Phase 2 GRA, to prepare a report that demonstrates that the customers served in Rate Class 1/11 are reasonably homogenous and that the tariffs applied in Rate Class 1/11 are fair and reasonable to the customers within that Class. At that time, the Board will reconsider whether there should be any changes to the composition of Rate Class 1/11.

5.3 Rate Riders

5.3.1 Third Party Transportation Rider (TPTR)

AUI proposed a TPTR for the recovery of upstream transportation charges. Currently, these charges are subject to deferral account treatment in the Deferred Gas Account (DGA), because they are currently and have been historically included in the cost of gas used in the determination of AUI's regulated gas cost recovery rate (GCRR).⁷⁵ The TPTR was proposed by the Company to ensure that all gas distribution customers pay for these transportation charges and not just default supply customers. AUI submitted that the proposal to administer these costs in a deferral account is appropriate because it is consistent with Board practice. As a result, transportation costs have not impacted forecast risk for the Company. To now include them in distribution rates would unfairly increase the Company's risk. If the TPTR is not approved by the Board, the Company submitted that the status quo should prevail and these costs should continue to be recovered through the DGA.

AUI noted that Direct Energy Regulated Services,⁷⁶ which also uses a DGA in the determination of its regulated gas cost flow-through (recovery) rate, includes third party transportation costs. The main difference between DERS and AUI is that DERS, as the default supply provider for ATCO Gas and Pipelines Ltd. (AGPL), sells gas to customers in AGPL's natural gas distribution service areas, whereas AUI both distributes and sells the gas to customers in its service areas. Therefore, cost recovery by way of a rider ensures that costs are fairly recovered by all customers who use and benefit from having upstream transportation capacity.

CCA, PICA, and AUMA/UCA supported AUI's proposed TPTR and the deferral account nature of the proposed rider. However, AUMA/UCA submitted that any transportation services obtained from AltaGas Operating Partnership (AOP) should be at fair market value as required under *AltaGas Utilities Inc. Inter-Affiliate Code of Conduct*. MGCI submitted that recovering these third party costs from an affiliate by a flow-through approach is inappropriate because AUI is in a position of conflict of interest.

Although CCA disagreed with MGCI's suggestion that the TPTR should be recovered through the Revenue Requirement, CCA agreed with the MGCI's concerns as to the need for a deferral account. CCA noted that the Board's past practice has been to approve deferral account treatment only for those items that are difficult to forecast and have demonstrated significant volatility from year to year.

MGCI considered that the TPTR is similar to the GCRR in that a true-up account is involved, and is similar to base rates in that it is paid by all customers (including both default supply and

⁷⁵ Decision 2001-075

⁷⁶ DERS is a regulated business unit of Direct Energy marketing Limited

retail). MGCI submitted that maintaining the true-up nature of the collection of third party transportation costs is not warranted and disagreed that, as a result of Decision 2001-75, the Board strictly considered such costs to be subject to deferral treatment. MGCI considered that the Board, in Decision 2001-75, merely stated that transportation costs upstream of utilities' pipeline systems, among other costs, should be transferred from the utility cost of service to the GCRR. MGCI's position was that third party transportation costs should not remain as part of the GCRR.

MGCI considered that, since there is significant forecasting involved in determining third party transportation costs, their automatic collection by AUI on a flow-through basis is not appropriate because, under the flow-through proposal, customers will bear 100% of the risk for any over-forecast of demand. MGCI therefore submitted that a practical and sensible sharing of the risk between customers and AUI is warranted by transferring third party transportation costs to revenue requirement where they could be scrutinized as part of the GRA review process and collected through base rates. MGCI noted that transportation costs were similar in 2005 and 2006 and that AUI did not expect them to be significantly different in 2007. Consequently, MGCI further submitted that the TPTR was unnecessary.

5.3.1.1 Views of the Board

The Board notes AUI's submission that transactions between AUI and AOP for third party transportation services are appropriate and consistent with *AltaGas Utilities Inc. Inter-Affiliate Code of Conduct*. The Board also notes AUI's submission that the materiality of the third party transportation service provided by AOP (10% of third party transportation costs).⁷⁷ Based on 15.8 million GJ/year of delivery volumes, AUI submitted that the affiliate transaction equates to only \$1.16 for a small user consuming 126 GJ in one year.⁷⁸

The Board notes that AUI is mandated by legislation to obtain upstream transmission capacity. Section 4 of the *Roles Relationships and Responsibilities Regulation* A.R. 186/2003 states:

4(1) A gas distributor must do the following:

- (a) ...
- (b) make decisions about building, upgrading and improving the gas distribution system for the purpose of providing safe, reliable and economic delivery of gas to customers in the service area served by the gas distribution system;
- (c) arrange for adequate upstream transmission capacity for the purposes of clause (b) (emphasis added).⁷⁹

The Board notes AUI's submissions that its proposed TPTR that includes a deferral account adequately balances AUI's forecast risk and AUI's responsibility to provide safe, reliable and economic delivery of gas to customers.

⁷⁷ Exhibit 002-13, AUI response to BR-AUI-13(b), attachment page 1 of 1

⁷⁸ $\$146,000 \div 15,800,000 \text{ GJ/y} = \$0.009/\text{GJ/y}$. $\$0.009/\text{GJ/y} \times 126 \text{ GJ/y} = \1.16

⁷⁹ Gas Utilities Act -Roles, Relationships and Responsibilities Regulation outlines the functions of gas distributors, retailers, and default supply providers.

The Board concurs with AUI that ensuring adequate supplies for customers may be somewhat at odds with its management of forecast risk. The Board considers that third party transportation service and adequacy of gas supply is a key concern of customers. Further the rider also ensures that both retail and default supply customers pay their share of third party transportation service costs.

Therefore, the Board approves AUI's TPTR as filed, effective November 1, 2007, including deferral account treatment.

5.3.2 Deficiency Rider

AUI has requested recovery of outstanding balances from the 2003/04 Deficiency Rider, the 2005 Deficiency Rider and the 2006 Deficiency Rider totaling \$543,857.⁸⁰ AUI had estimated that each customer should pay a one-time charge of 1.735% of their 2006 billed revenues on the March billing cycle, albeit this percentage would be adjusted to reflect 2006 actual billed revenues. The estimated one-time charge for a residential customer is based on consuming 126 GJ/year in 2006.

5.3.2.1 Views of the Board

The Board considers that AUI's one-time deficiency rider recovering outstanding balances from the 2003/04 Deficiency Rider, the 2005 Deficiency Rider and the 2006 Deficiency Rider totaling \$543,857 is appropriate. The Board approves AUI's Deficiency Rider effective November 1, 2007.

The approved Rate Schedules and Riders are attached in [Appendix 5](#) to this Decision.

6 GAS DISTRIBUTION TARIFF

6.1 Retailer Distribution Service Regulations and Contracts (RDSR)

6.1.1 Deposits

AUI has not requested a deposit from retailers operating in its service territory because, in terms of revenues, the vast majority of gas distribution service provided to retailers is to those who are not required to provide a deposit. Under the *Natural Gas Billing Regulation* A.R. 185/2003, three of the six retailers currently operating in the AUI service territory have at least a triple B (BBB) bond rating. As a result, they would qualify under that regulation for a \$10,000,000 reduction in the deposit. Given the size of this reduction, these three retailers would not be required to post any security. AUI is in the process of determining deposit requirements from the other three retailers.

By way of information request BR-AUI-15 and in testimony at the hearing,⁸¹ AUI stated it is prepared to incorporate wording in AUI's proposed Retailer Distribution Service Regulations that is acceptable to the Board that would have AUI recover retailer arrears only from the retailer, rather than from the customer.

⁸⁰ Exhibit 002-01, pages 37-38

⁸¹ [1] Transcript, Volume 2, pages 372-374

Regarding the impact on a customer of any failure of a Natural Gas Retailer, CCA submitted that AUI would seek to be kept whole but that the unfairness of the interplay between the Natural Gas Utility Services Rules (NGUSR) and RDSR may result in the customer paying more than once for the service or gas it received and used. CCA was concerned that this outcome illustrated an imbalance in the position of AUI and the customer and considered that there should be rules and terms for also balancing the interests of customers to insure the customer does not suffer any adverse impacts such as paying more than once for gas received. CCA submitted that AUI should not be allowed to draft its rules or terms of service with customers and retailers to manage its way out of risks for which it is compensated, either in return for business risk or by way of a bad debt expense amount.

CCA submitted that Article 8.1 (1) of the Retailer Distribution Service Regulations and Contracts requires the addition of a clause (3) which should state:

(3) The customer may be relieved of an obligation to pay AUI pursuant to this article if they are able to show payments in good faith to the retailer. Such relief to the customer shall not exceed the amount billed to the customer by the retailer, paid to the retailer by the customer but not advanced to AUI by the retailer.⁸²

CCA argued that this clause would prevent any excess recovery by AUI from the customer, that is, it would remedy the unfairness of the customer having to potentially pay twice. CCA suggested that Part 8 (7)⁸³ could be added and state:

(7) AUI recommends customers keep a record of all payments to retailers as these may assist you, the customer, in case of any disputes. AUI will not bill a customer for the same delivery service or gas if you have paid a retailer in good faith.

6.1.1.1 Views of the Board

The Board considers the current wording in Section 8.1 of the draft Retailer Distribution Service Regulations could result in the customer paying twice for AUI charges, if the customer has made payment to its retailer and the retailer defaults with AUI. AUI has the ability to monitor its retailers to ensure it has reasonable deposits in place to avoid the need to seek payment from customers of retailers. The Board considers AUI should be diligent in avoiding the need to seek payment from customers due to retailer default, and is not satisfied that the additional protection provided by Section 8.1 encourages AUI to be diligent in this matter.

The Board believes that any risk associated with retailer default should be kept to a minimum for customers. The Board therefore considers it would be appropriate to make changes to the wording of AUI's Retailer Distribution Service Regulations to minimize cases of customers being required to pay twice for AUI charges. The suggestions made by CCA would provide some protection for customers from double billing and should provide sufficient incentive to AUI to avoid relying on the provisions of Section 8.1 for payment.

Therefore, the Board directs AUI, in its refile, to either incorporate the changes recommended by CCA for both AUI's Retailer Distribution Service Regulations and AUI's Natural Gas Utility Service Rules, or make its own revisions to serve this purpose that provide some protection for customers from double billing.

⁸² Retailer Distribution Service Regulations, pages 17-18

⁸³ Retailer Distribution Service Regulations, page 20

7 REFILING REQUIREMENTS

The Board directs AUI to provide its Refiling to the Board and all parties on or before October 29, 2007. Further, AUI shall advise all parties that reply comments are due to the Board on or before November 7, 2007.

8 ORDER

IT IS HEREBY ORDERED THAT:

- (1) AltaGas Utilities Inc.'s rates are approved as filed, effective November 1, 2007.
- (2) AltaGas Utilities Inc. is required to comply with all directions and approvals contained in this Decision.

Dated in Calgary, Alberta on October 16, 2007.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

A. J. Berg, P.Eng.
Presiding Member

(original signed by)

M. L. Asgar-Deen, P.Eng.
Acting Member

(original signed by)

M. W. Edwards
Acting Member

APPENDIX 1 – HEARING PARTICIPANTS

Name of Organization (Abbreviation) Counsel or Representative	Witnesses
AltaGas Utilities Inc. (AltaGas, AUI or the Company) G.R. Jeerakathil	E. Tuele, President, AUI A. Mantei, Vice-President Controller, AUI R.J. Koizumi, CMA, Manager, Regulatory Affairs, AUI N. Chymko Chymko Consulting Ltd. M. Turner Chymko Consulting Ltd.
The Alberta Urban Municipalities Association (AUMA) and The Office of the Utilities Consumer advocate (UCA) J.A. Bryan, Q.C.	R.L. Bruggeman Robert L. Bruggeman Regulatory Consulting Ltd. M.B. Lively Independent Consultant H.J. Vander Veen Energy Group, Inc.
The Public Institutional Consumers of Alberta (PICA) N.J. McKenzie R. Retnanandan	
The Aboriginal Communities (ABCOM) J. Graves, P.Eng.	
The Municipal and Gas Co-op Intervenor (MGCI) T.D. Marriott	
The Consumers Coalition of Alberta (CCA) J.A. Wachowich	
The Alberta Sugar Beet Growers (ASBG) and The Potato Growers of Alberta (PGA) J.H. Unryn	
Alberta Energy and Utilities Board Board Panel A. J. Berg, P.Eng., Presiding Member M. L. Asgar-Deen, P.Eng., Acting Member M. W. Edwards, Acting Member Board Staff R. Marx, Counsel M. McJannet H. Grenz, B.Comm., CMA D. R. Weir, CA	

APPENDIX 2 – SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. Accordingly, the Board directs AUI, in its next Phase II GRA, to provide a cost/benefit analysis that would allow the Board to determine whether the cost and effort associated with changes to the work order system to accommodate the tracking of meters installation and regulator costs are reasonable expenditures to incur for purposes of improving the precision of the existing meters cost allocation method..... 7
2. However, the Board considers that there is merit in investigating other feasible alternatives. The Board notes that AUI has offered to provide in its next Phase I GRA a full cost/benefit analysis of using the Diameter-Length method for the allocation of services together with a review of other reasonable alternatives. Accordingly, the Board directs AUI, in the next Phase I GRA, to include a full cost/benefit analysis of using the Diameter-Length method and the results of its review of other reasonable alternatives for the allocation of services cost. AUI's review should also examine the feasibility of tracking contributions more closely to the costs they are intended to offset rather than a general allocation based on multiple factors..... 9
3. The Board notes that the model was designed to reflect the Board directed -40° C peak and the Board would not necessarily expect it to be rigorous enough to provide accurate results using values that are outside of the relevant data set for predicting heating loads. Consequently, the Board directs AUI, at its next Phase II GRA, to analyze and report on the need for a region specific calculation given the uniform -40° C and revise the model calculations to be able to account for low or no heating load..... 10
4. In summary, the Board is satisfied with AUI's utilization of the Diameter-Length method when classifying the costs of distribution mains between customer-related costs and demand-related. However, the Board directs AUI in its next Phase II to address:..... 20
 - the classification of mains general costs, particularly the appropriateness of classifying such costs on the same basis as the mains pipe costs, and..... 20
 - whether the inclusion of cost data and capacity within the Diameter-Length method is appropriate when allocating costs between demand and customer-related for distribution mains. 20
5. Notwithstanding, the Board believes that the onus should be on AUI to support the appropriateness of its rate class structure, particularly where there is concern and disagreement by interested parties that represent customers affected by its rates. Accordingly, the Board directs AUI, at its next Phase 2 GRA, to prepare a report that demonstrates that the customers served in Rate Class 1/11 are reasonably homogenous and that the tariffs applied in Rate Class 1/11 are fair and reasonable to the customers within that Class. At that time, the Board will reconsider whether there should be any changes to the composition of Rate Class 1/11. 34
6. Therefore, the Board directs AUI, in its refiling, to either incorporate the changes recommended by CCA for both AUI's Retailer Distribution Service Regulations and AUI's Natural Gas Utility Service Rules, or make its own revisions to serve this purpose that provide some protection for customers from double billing..... 37

7. The Board directs AUI to provide its Refiling to the Board and all parties on or before October 29, 2007. Further, AUI shall advise all parties that reply comments are due to the Board on or before November 7, 2007. 38

APPENDIX 3 – SUMMARY OF BOARD APPROVALS AND KEY FINDINGS

This section is provided for the convenience of readers. In the event of any difference between the Approvals in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. The Board agrees with AUI that a 10% overhead charge would have no allocative impact on the results of the COSA. Given the above conclusion, the Board considers any specific concern that CCA had regarding Direction 6 is no longer applicable. 6
2. The Board approves AUI's applied for method of allocation of meters costs for the following reasons: 6
 - changes to the COSA would have no impact to the resulting rates;..... 6
 - CCA and PICA did not object to the proposal; and..... 6
 - AUMA/UCA's agreement that meters was a suitable proxy for their preferred method. .. 6
3. Although the matter of splitting Rate Class 1/11(Small General Service) is addressed later in this Decision, the Board does not find a clearly superior alternative to the previously approved method of allocating services costs on the basis of sites weighted by the RCN meter cost of an average site in each rate class. Therefore, the Board approves the use of this current method for this GRA Phase II application..... 9
4. Given that the change to using -40° C has been implemented in response to direction from the Board in 2005-029 for this current COSA, the Board does not agree that further analysis of changes to methods is warranted at this time. The Board considers that additional experience, demonstrating how the current method affects cost allocation over time is necessary before any changes should be considered. 11
5. The Board agrees with AUI's allocation because the sum of billing demand represents the greater of the system design capacity reserved for the Rate Class 3/13(Demand/Commodity General Service-Optional) customers or the capacity used by the Rate Class 3/13 customers. It is therefore the most appropriate measure of Rate Class 3/13 demand at the system's designed -40° C peak capacity. Accordingly, the Board approves AUI's Rate Class 3/13 demand as filed in the COSA..... 12
6. In conclusion, the Board approves AUI's CP and NCP calculations set out in the COSA as they appropriately reflect diversity, are consistent with the design criteria, and are used correctly in the COSA..... 14
7. The Board agrees with AUI that, in this circumstance, it is not appropriate to use average consumption data because that would disregard the fact that Rate Class 4/14 (Irrigation Pumping Service-Optional) has the potential to peak at higher rates depending upon climatic conditions..... 15
8. The Board approved the exclusion of Rate Class 4/14 from the allocation of transmission system costs in Decision 2005-029 and agrees with AUI that this treatment remains appropriate because Rate Class 4/14 customers do not cause any material costs to the overall transmission system and there was no specific proposal tested during the hearing for allocation of transmission costs to Rate Class 4/14..... 15
9. The Board finds that AUI has complied with Direction 5 of Decision 2005-029 and approves the proposed method of calculating irrigation peak demand, as was approved in Decision

- 2005-029, and continues to be a practical solution in light of the data constraints. The resulting peak demand level of 1,467 GJ is approved for use in the COSA..... 15
10. The Board concurs with AUI's use of a site allocator instead of the existing site-months allocator as it more appropriately reflects the distribution infrastructure that is in place to serve load. Although ASBG/PGA suggests irrigation customers should only be allocated costs based on a site-month basis which would take into account the seasonal nature of their service, infrastructure is still required to provide service whether or not these customers consume gas in winter months. The Board therefore rejects ASGA/PGA's site-month allocation proposal and approves AUI's utilization of a site allocator..... 18
11. The Board continues to be of the view that the minimum plant or Diameter-Length method is more appropriate than the zero-intercept method when classifying the costs of distribution mains between customer related costs and demand-related especially given the limited data available, the variability of zero-intercept results, and the potential for understatement of the customer-related classification. Having regard to its prior determinations with respect to the zero-intercept method and the evidence on the record of this proceeding, the Board is not persuaded that there is a need for AUI to conduct a feasibility study of using a zero intercept analysis for the next GRA Phase II as recommended by PICA..... 19
12. The Board is satisfied that AUI's explanation that the greater the number of invoices issued to a site, the greater the likelihood that the Company will incur credit and collection efforts related to that site, especially in light of the fact that AUMA/UCA's proposal to allocate these costs based on revenues or total costs is not substantively supported by evidence within the proceeding. Therefore, the Board approves the continued use of the site-month allocator for credit and collection costs consistent with the method used for other customer care costs. 21
13. The Board recognizes that retail market activity has increased in AUI's service area, but understands that there are still only about 700 customers, of AUI's approximate customer base of over 60,000, on retail supply. Accordingly, the Board remains of the view that use of a deferral account is premature given the current stage of retail market development. 21
14. Although applying a 10% rate cap has often been utilized by the Board, the Board is of the view that it should be considered a guideline whereby the Board may determine, on a case by case basis, whether it is appropriate to increase rates above that threshold. The Board is satisfied that AUI's proposed rates are within a reasonable tolerance of the 10% rate cap, especially given that Rate Class 2/12, Rate Class 3/13, and Rate 4/14 currently recover significantly less than their costs via AUI's existing rates and would be close to unity on AUI's proposed rates. Therefore the Board approves AUI's rates as filed (Appendix 4). The Board's approval of AUI's rates also results in the Board's acceptance of the mathematically derived transition points that result from AUI's rate design..... 26
15. With regard to the interim rates, the Board considers these rates approved in Order U2006-041 are approved as final rates within the period the rates were in effect. The 2006 interim rates will continue to be in place until AUI's approved rates go into effect November 1, 2007. 26
16. However, the Board has not been convinced by either of the opposing positions. Instead, the Board agrees with MCGI that there is a lack of evidence on the record to clearly demonstrate whether or not the customers served under Rate Class 1 are sufficiently different to the extent that one or more types of customers are unjustly subsidizing others and would therefore warrant Rate 1/11 to be re-defined. As this matter affects rate design, the Board will set out

its findings in section 5.2.2.1, with respect to dealing with AUMA/UCA’s proposals to split Rate Class 1/11. 29

17. Therefore, the Board approves AUI’s TPTR as filed, effective November 1, 2007, including deferral account treatment..... 36

18. The Board considers that AUI’s one-time deficiency rider recovering outstanding balances from the 2003/04 Deficiency Rider, the 2005 Deficiency Rider and the 2006 Deficiency Rider totaling \$543,857 is appropriate. The Board approves AUI’s Deficiency Rider effective November 1, 2007..... 36

APPENDIX 4 –APPROVED RATE DESIGN



Appendix 4 - Rate
Design Summary.xls

(consists of 1 page)

APPENDIX 5 – APPROVED RATE SCHEDULES AND RATE RIDERS

RATE SCHEDULES



Appendix 5 - Rate
01.doc

AUI Rate No. 1 – Small General Service
(consists of 1 page)



Appendix 5 - Rate
02.doc

AUI Rate No. 2 – Large General Service (Optional)
(consists of 1 page)



Appendix 5 - Rate
03.doc

AUI Rate No. 3 – Demand/Commodity General Service (Optional)
(consists of 1 page)



Appendix 5 - Rate
04.doc

AUI Rate No. 4 – Irrigation Pumping Service (Optional)
(consists of 1 page)



Appendix 5 - Rate
06.doc

AUI Rate No. 6 – Standby, Peaking, and Emergency Service
(consists of 1 page)



Appendix 5 - Rate
10a.doc

AUI Rate No. 10a – Producer Transportation Service ‘Closed Rate’
(consists of 1 page)



Appendix 5 - Rate
10b.doc

AUI Rate No. 10b – Producer Transportation Service ‘Closed Rate’
(consists of 1 page)



Appendix 5 - Rate
10c.doc

AUI Rate No. 10c – Producer Transportation Service ‘Closed Rate’
(consists of 1 page)



Appendix 5 - Rate
11.doc

AUI Rate No. 11 – Small General Service for Retailer
(consists of 1 page)



Appendix 5 - Rate
12.doc

AUI Rate No. 12 – Large General Service (Optional) for Retailer
(consists of 1 page)



Appendix 5 - Rate
13.doc

AUI Rate No. 13 – Demand/Commodity General Service (Optional) for Retailer
(consists of 1 page)



Appendix 5 - Rate
14.doc

AUI Rate No. 14 – Irrigation Pumping Service (Optional) for Retailer
(consists of 1 page)



Appendix 5 - Rate
30.doc

AUI Special Contract Rate No. 30 – Transportation Service ‘Closed Rate’
(consists of 1 page)

RATE RIDERS



Appendix 5 - Rider
A.doc

AUI Rider A - Franchise Tax Riders
(consists of 3 pages)



Appendix 5 - Rider
B.doc

AUI Rider B – Municipal Property Tax Riders
(consist of 1 page)



Appendix 5 - Rider
C.doc

AUI Rider C – Deemed Cost of Gas Rider
(consists of 1 page)



Appendix 5 - Rider
D.doc

AUI Rider D – Gas Cost Recovery Rate Rider
(approved monthly in a separate application)
(consists of 1 page)



Appendix 5 - Rider
E.doc

AUI Rider E – Unaccounted-For Gas Rider
(approved yearly in a separate application)
(consists of 1 page)



Appendix 5 - Rider
F.doc

AUI Rider F – 2006 Deficiency Rider Placeholder Rate
(consists of 1 page)



Appendix 5 - Rider
G.doc

AUI Rider G – Third Party Transportation Cost Rider
(consists of 1 page)

2006 Proposed Rate Design

	Billing Determinants				Interim Approved Rates Per Order U2006-41				Revenues at Existing Rates (\$)			
	Billings Units	Energy Units (GJ)	Demand Units (GJ)	Days	Fixed Charge (\$/mo.)	DSP Credit (\$/mo.)	Base Energy (\$/GJ)	Demand Charge (\$/mo./GJ)	Fixed Charge	Base Energy	Demand Charge	Total
Rate 1/11	743,366	11,568,601		365	\$ 15.36	\$ 1.55	\$ 1.450		12,564,508	16,774,472	-	29,338,980
Rate 2/12	1,740	1,186,700		365	\$ 275.67	\$ 1.55	\$ 0.612		482,358	726,260	-	1,208,619
Rate 3/13	660	2,932,163	182,916	365	\$ 414.29	\$ 1.55	\$ 0.017	\$ 5.156	274,166	49,847	945,828	1,269,841
Rate 4/14	1,939	120,711		214	\$ 32.82	\$ 1.55	\$ 0.950		66,984	114,675	-	181,660
	<u>747,705</u>	<u>15,808,175</u>	<u>182,916</u>	<u>1,309</u>					<u>\$ 13,388,017</u>	<u>\$ 17,665,254</u>	<u>\$ 945,828</u>	<u>\$ 31,999,099</u>

	Proposed Rates				Revenues at Proposed Rates (\$)			
	Fixed Charge (\$/mo.)	DSP Credit (\$/mo.)	Base Energy (\$/GJ)	Demand Charge (\$/mo./GJ)	Fixed Charge	Base Energy	Demand Charge	Total
Rate 1/11	\$ 18.00	\$ 1.659	\$ 1.221		14,620,723	14,125,262	-	28,745,985
Rate 2/12	\$ 300.00	\$ 1.659	\$ 0.695		524,910	824,756	-	1,349,667
Rate 3/13	\$ 500.00	\$ 1.659	\$ 0.016	\$ 5.505	330,796	46,915	1,007,029	1,384,739
Rate 4/14	\$ 38.00	\$ 1.659	\$ 1.078		76,884	130,126	-	207,010
					<u>\$ 15,553,313</u>	<u>\$ 15,127,060</u>	<u>\$ 1,007,029</u>	<u>\$ 31,687,401</u>

	Allocated Cost of Service (\$000)			
	Customer	Energy	Capacity	Total
Rate 1/11	20,457	101	8,189	28,747
Rate 2/12	544	10	796	1,350
Rate 3/13	352	26	1,007	1,385
Rate 4/14	133	1	73	207
	<u>21,486</u>	<u>138</u>	<u>10,065</u>	<u>31,689</u>

	Unit Costs		
	Customer	Energy	Capacity
Rate 1/11	\$ 27.52	\$ 0.717	
Rate 2/12	\$ 312.64	\$ 0.679	
Rate 3/13	\$ 533.33	\$ 0.009	\$ 5.505
Rate 4/14	\$ 68.59	\$ 0.613	

	Proposed Rates		Existing Revenue to Cost Ratios
	Revenue to Cost Ratios	Percentage Change	
Rate 1/11	100.00%	-2.02%	102.06%
Rate 2/12	99.98%	11.67%	89.53%
Rate 3/13	99.98%	9.05%	91.69%
Rate 4/14	100.00%	13.95%	87.76%

			Transition Points Annual GJ
Rate 1			
Fixed Charge	\$ 19.659	\$ 235.91	
Energy Charge		\$ 1.221	
			6,433 Rate 1 vs Rate 2
Rate 2			
Fixed Charge	\$ 301.659	\$ 3,619.91	
Energy Charge		\$ 0.695	
			13,264 Rate 2 vs Rate 3 (100 GJ Demand)
Rate 3			
Fixed Charge	\$ 501.659	\$ 6,019.91	
Energy Charge		\$ 0.016	
Demand Charge	\$ 5.505	\$ 6,606.00	

RATE NO. 1	SMALL GENERAL SERVICE
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Description:

Available to all customers except those customers who do not purchase their total natural gas requirements from the Company or who utilize the Company's facilities only for standby, peaking or emergency services.

Charges:

Fixed Charge:

Base	\$ 0.592/Day
Default Supply Provider Administration Fee	\$ 0.055/Day

Variable Energy Charge:

Base	\$ 1.221/GJ
Gas Cost Recovery	Rate Rider "D"

The minimum daily charge will be the Fixed Charge.

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: March 1, 2006 Order U2006-41	SGS
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RATE NO. 2	LARGE GENERAL SERVICE (OPTIONAL)
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Description:

Available to all customers except those customers who do not purchase their total natural gas requirements from the Company or who utilize the Company's facilities only for standby, peaking or emergency services.

Charges:

Fixed Charge:

Base	\$ 9.863/Day
Default Supply Provider Administration Fee	\$ 0.055/Day

Variable Energy Charge:

Base	\$ 0.695/GJ
Gas Cost Recovery	Rate Rider "D"

The minimum daily charge will be the Fixed Charge.

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: March 1, 2006 Order U2006-41	LGS
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RATE NO. 3	DEMAND/COMMODITY GENERAL SERVICE (OPTIONAL)
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Description:

Available to all customers except those customers who do not purchase their total natural gas requirements from the Company or who utilize the Company's facilities only for standby, peaking or emergency services.

Charges:

Demand Charge \$ 0.181/Day/GJ
of Billing Demand

Fixed Charge:

Base \$ 16.438/Day
Default Supply Provider Administration Fee \$ 0.055/Day

Variable Energy Charge:

Base \$ 0.016/GJ
Gas Cost Recovery Rate Rider "D"

The minimum daily charge will be the Demand Charge and Fixed Charge.

Determination of Billing Demand:

The Billing Demand shall be the greater of:

1. 100 GJ, or
2. The Contract Demand, or
3. The greatest amount of gas (GJ) delivered in any consecutive 24-hour period during the current and preceding eleven billing periods provided that the greatest amount of gas delivered in any 24 consecutive hours in the summer period (April 1 to October 31, inclusive) shall be divided by 2.

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: March 1, 2006 Order U2006-41	DCGS
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RATE NO. 4	IRRIGATION PUMPING SERVICE (OPTIONAL)
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Description:

Available only to customers for the use of natural gas as a fuel for engines pumping irrigation water from **April 1 to October 31**, inclusive.

Charges:

	<u>April 1 to October 31</u>
Fixed Charge:	
Base	\$ 1.243/Day
Default Supply Provider Administration Fee	\$ 0.055/Day
Variable Energy Charge:	
Base	\$ 1.078/GJ
Gas Cost Recovery	Rate Rider "D"

The minimum daily charge will be the Fixed Charge.

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: March 1, 2006 Order U2006-41	IPS
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RATE NO. 6	STANDBY, PEAKING, AND EMERGENCY SERVICE
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Description:

Available only at the option of the Company.

Charges:

Demand Charge \$ 0.181/Day/GJ
of Billing Demand

Fixed Charge:

Base \$ 16.438/Day
Default Supply Provider Administration Fee \$ 0.055/Day

Variable Energy Charge 1.3 times the Variable Base Charge of Rate No. 3
plus the greater of:
(a) 1.3 times the GCRR; or
(b) 1.3 times the actual cost of gas purchased

The minimum daily charge will be the Demand Charge and Fixed Charge.

Determination of Billing Demand:

The Billing Demand shall be the greater of:

1. 100 GJ, or
2. The Contract Demand, or
3. The greatest amount of gas (GJ) delivered in any consecutive 24-hour period during the current and preceding eleven billing periods provided that the greatest amount of gas delivered in any 24 consecutive hours in the summer period (April 1 to October 31, inclusive) shall be divided by 2.

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: May 1, 2005 Decision 2005-029	SPES
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RATE NO. 10a	PRODUCER TRANSPORTATION SERVICE 'CLOSED RATE'
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Description:

Transportation service is available to the Rate 10a customer subject to the terms and conditions specified in the contract.

Charges:

	<u>1 Year</u>	<u>Term 2 Years</u>	<u>3 Years</u>
Fixed Charge per Month	\$ 250.00	\$ 250.00	\$ 250.00
Demand Charge per GJ of Billing Demand per Month.....	\$ 1.418	\$ 1.333	\$ 1.248
Energy Charge per GJ	\$ 0.019	\$ 0.019	\$ 0.019

- a) The minimum monthly charge will be the fixed plus demand charge.
- b) The Company and customer shall determine receipt and delivery locations for transportation service by consultation and agreement.
- c) Service under Rate 10a is subject to available system capacity.
- d) The Company reserves the right to restrict the amount of gas received and delivered up to the Contract Demand.
- e) Billing demand will be the higher of: contracted demand, the greatest amount of gas (GJ) transported in any consecutive 24-hour period, during the current or the previous 11 months.
- f) The rates do not include costs payable by the Customer for specific facilities at the point(s) of receipt or delivery provided by the Company for the Customer.

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: May 1, 2005 Decision 2005-029	Page 1 of 1 PTS10a
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RATE NO. 10b	PRODUCER TRANSPORTATION SERVICE 'CLOSED RATE'
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Description:

Transportation service is available to the Rate 10b customer subject to the terms and conditions specified in the contract.

Charges:

Variable Energy Charge \$ 0.085/GJ

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: May 1, 2005 Decision 2005-029	PTS10b
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RATE NO. 10c	PRODUCER TRANSPORTATION SERVICE 'CLOSED RATE'
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Description:

Transportation service is available to the Rate 10c customer subject to the terms and conditions specified in the contract.

Charges:

Demand Charge \$ 0.020/Day/GJ of Billing
Demand

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: May 1, 2005 Decision 2005-029	PTS10c
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RATE NO. 11	SMALL GENERAL SERVICE FOR RETAILER
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Description:

Distribution service is available to retailers under contract for the delivery of retail supply.

Charges:

Fixed Charge:

Base \$ 0.592/Day

Variable Energy Charge:

Base \$ 1.221/GJ

The minimum daily charge will be the Fixed Charge.
This service is not available for standby, peaking or emergency services.

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: March 1, 2006 Order U2006-41	SGS-R
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RATE NO. 12	LARGE GENERAL SERVICE (OPTIONAL) FOR RETAILER
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Description:

Distribution service is available to retailers under contract for the delivery of retail supply.

Charges:

Fixed Charge:

Base \$ 9.863/Day

Variable Energy Charge:

Base \$ 0.695/GJ

The minimum daily charge will be the Fixed Charge.
 This service is not available for standby, peaking or emergency services.

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: March 1, 2006 Order U2006-41	LGS-R
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RATE NO. 13	DEMAND/COMMODITY GENERAL SERVICE (OPTIONAL) FOR RETAILER
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Description:

Distribution service is available to retailers under contract for the delivery of retail supply.

Charges:

Demand Charge \$ 0.181/Day/GJ
of Billing Demand

Fixed Charge:

Base \$ 16.438/Day

Variable Energy Charge:

Base \$ 0.016/GJ

The minimum daily charge will be the Demand Charge and Fixed Charge.

Determination of Billing Demand:

The Billing Demand shall be the greater of:

1. 100 GJ, or
2. The Contract Demand, or
3. The greatest amount of gas (GJ) delivered in any consecutive 24-hour period during the current and preceding eleven billing periods provided that the greatest amount of gas delivered in any 24 consecutive hours in the summer period (April 1 to October 31, inclusive) shall be divided by 2.

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: March 1, 2006 Order U2006-41	DCGS-R
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RATE NO. 14	IRRIGATION PUMPING SERVICE (OPTIONAL) FOR RETAILER
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Description:

Distribution service is available to retailers under contract for the delivery of retail supply. Available to retailers only for the use of natural gas as a fuel for engines pumping irrigation water from **April 1 to October 31**, inclusive.

Charges:

	<u>April 1 to October 31</u>
Fixed Charge:	
Base	\$ 1.243/Day
Variable Energy Charge:	
Base	\$ 1.078/GJ

The minimum daily charge will be the Fixed Charge.
This service is not available for standby, peaking or emergency services.

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: March 1, 2006 Order U2006-41	IPS-R
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SPECIAL CONTRACT RATE NO. 30	TRANSPORTATION SERVICE 'CLOSED RATE'
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Description:

Transportation service is available to the Rate No. 30 customer for the term and conditions specified in the contract.

Charges:

Fixed Charge	\$ 250.00/Month
Energy Charge	\$ 0.230/GJ

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: May 1, 2005	
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RATE RIDER “A”	FRANCHISE TAX RIDERS
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Municipalities

Additions to be made to the rates of customers resident in municipalities that have agreed to accept a percentage of gross revenue of the special franchise tax in lieu of a property tax pursuant to Section 360 of the Municipal Government Act, 1994, c. M-26.1 (previously Section 14(7) and 14(8) of the Municipal Taxation Act).

The percentage shown is to be applied as an addition to the total billings calculated.

Municipality	District	Type	Rate (%)	Board Order
Athabasca ¹	Athabasca	Town	6.0	U97149
Barrhead	Barrhead/Westlock/ Morinville	Town	3.1	U98152
Delia	Hanna	Village	4.0	E92122
Donalda	Stettler	Village	4.0	E92122
Elk Point	St. Paul	Town	7.0	U99062
Grande Cache	Grande Cache	Town	6.952	U99084
Hairy Hill ²	St. Paul	Village	5.0	E95078
Hanna	Hanna	Town	3.1	E76087
New Sarepta	Leduc	Village	5.5	U98138
Radway	Westlock	Village	3.0	E90046
Sunset Beach ³	Athabasca	Summer Village	6.1	U97151
Three Hills	Three Hills	Town	4.75	U98033

¹ Periodic changes to franchise tax rates have been pre-approved by the Board.

² Periodic changes to franchise tax rates have been pre-approved by the Board.

³ The Municipality has elected to have the percentage of gross revenue from the special franchise tax collected on distribution revenue, gas costs, and a deemed value for gas applied to volumes distributed for retailers.

EFFECTIVE DATE: November 1, 2007		Rider “A”
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Métis Settlements

Additions to be made to the rates of customers resident in Métis Settlements that have by bylaw approved Utility Services Agreements providing for the payment of annual utility service fees calculated as a percentage of gross revenues.⁴ The percentage shown is to be applied as an addition to the total billings calculated.

Métis Settlement	District	Rate (%)	Board Order
Buffalo Lake	St. Paul	7.0	U2000-236
Fishing Lake	St. Paul	5.0	U97153
Gift Lake	Wabasca	7.0	U2003-378
Kikino	St. Paul	7.0	U2000-107

⁴ The *Métis Settlements Act* (S.A. 1998 Chapter M-14.3) enables the Métis Settlements General Council to legislate by Policy and Settlement Councils to legislate by bylaw on matters related to the operations of utilities within the settlement areas, including the granting of interests in land, the assessment and taxation of these interests, and the licencing of related activities. [s.222(1); Sch.1, ss.14, 19]. Under *Métis Settlements General Council Public Utilities Policy* (GC-P9804; Alberta Gazette, Nov.30, 1998, p.2221) a Settlement may enter into Utility Service Agreement allowing a utility to use land and provide utility services in the Settlement Area and providing for the utility to pay an all inclusive annual service fee. The fee may be determined as a percentage of gross revenue received from services provided in the Settlement Area. Each of the listed Settlements has entered into a Utility Service Agreement with AltaGas Utilities. Under the *Public Utility Policy* [s.2.3(3)] the Service Agreement takes effect on being approved by bylaw and by the Alberta Energy and Utilities Board.

EFFECTIVE DATE: November 1, 2007		RIDER "A"
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Municipalities Governed by Standardized Franchise Agreement

For each calendar year the franchise fee will be calculated as a percentage of the Company's actual total revenue derived from the Gas Distribution Tariff, including without limitation the fixed charge, base energy charge, demand charge but excluding the cost of gas (being the calculated revenues from the gas cost recovery rate rider or the deemed cost of gas) in that year for Gas Distribution Service within the Municipal Area.

Municipality	District	Type	Rate (%)	Board Order
Beaumont	Leduc	Town	21.20	2005-287
Bonnyville	Bonnyville	Town	20.00	2003-068
Bonnyville Beach	Bonnyville	Summer Village	0.00	2005-321
Botha	Stettler	Village	10.00	2004-260
Calmar	Leduc	Town	20.00	2004-244
Crystal Springs	Leduc	Summer Village	0.00	2005-117
Drumheller	Drumheller	Town	27.00	2004-440
Glendon	St. Paul	Village	4.62	2004-264
High Level	High Level	Town	27.50	2004-274
High Level	Rate 23 Customers only		35.00	2004-274
Island Lake	Athabasca	Summer Village	0.00	2005-085
Leduc	Leduc	City	27.00	2005-276
Leduc	Rate 3/13/23 Customers only		35.00	2005-276
Mewatha Beach	Athabasca	Summer Village	6.00	2005-207
Morinville	B/W/M	Town	19.00	2005-142
Munson	Drumheller	Village	11.00	2004-291
Pincher Creek	Pincher Creek	Town	20.00	2004-293
St. Paul	St. Paul	Town	22.00	2004-289
Stettler	Stettler	Town	18.00	2004-247
Two Hills	St. Paul	Town	10.00	2005-135
Waskatenau	B/W/M	Village	8.00	2004-421
Westlock	B/W/M	Town	0.00	2004-232
Willingdon	St. Paul	Village	6.00	2005-5

EFFECTIVE DATE: November 1, 2007		RIDER "A"
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RATE RIDER “B”	MUNICIPAL PROPERTY TAX RIDERS
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Additions to be made to the rates of customers resident in municipalities that receive a property tax assessed pursuant to Section 353 of the *Municipal Government Act*, R.S.A. 2000 c.M-26. The addition is an estimated percentage of distribution revenues required to provide for the tax payable each year. To the extent that this percentage may be more or less than that required to pay the tax, the percentage of distribution revenue in the rider will be adjusted on an annual basis. The percentages are filed with the Alberta Energy and Utilities Board.

Rate Rider "B" is to be applied as an addition to the total billings calculated for the following areas:

<u>Districts</u>	<u>Rate (%)</u>	<u>Municipalities</u>	<u>Rate (%)</u>
Athabasca	5.51250	Village of Morrin	2.31538
Barrhead, Westlock, Morinville	3.11660	Zama City	4.50480
Bonnyville	1.56700	Town of Bonnyville	6.58270
Drumheller	0.00500	Village of Waskatenau	4.69100
Grande Cache	n/a	Town of Westlock	2.13460
Hanna	1.55840	Town of Calmar	11.13190
High Level	5.93780	Town of Stettler	4.76900
Leduc	0.49960	Town of Pincher Creek	6.91380
Pincher Creek	1.27880	Town of High Level	4.88000
St. Paul	4.22720	Village of Glendon	10.62520
Southeast	3.07860	Village of Botha	5.94130
Stettler	1.84190	Town of St. Paul	0.72270
Three Hills	1.66610	Town of Drumheller	7.46100
Two Hills	4.21530	Village of Munson	2.41050
		Village of Willingdon	11.48720
		Summer Village of Island Lake	2.52280
		City of Leduc	4.09390
		Summer Village of Crystal Springs	1.68240
		Town of Two Hills	8.96940
		Town of Beaumont	1.91050
		Summer Village of Bonnyville Beach	2.48380
		Town of Morinville	3.78700
		Summer Village of Mewatha Beach	0.72060

EFFECTIVE DATE: November 1, 2007		RIDER “B”
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RATE RIDER "C"	DEEMED COST OF GAS RIDER
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**TO ALL RETAILER DISTRIBUTION SERVICE RATES IN THE DETERMINATION OF THE
DEEMED COST OF GAS FOR CALCULATING RATE RIDER "A"**

To be applied to the amount of natural gas delivered under Retailer Distribution Service in the determination of municipal franchise tax payable (Rider "A") to municipalities that have agreed to accept payment of a percentage of gross revenues of the special franchise pursuant to Section 360 of the *Municipal Government Act* R.S.A. 2000, c. M-26.

The Deemed Cost of Gas Rider is equal to Rider "D" as amended from time to time and approved by the Alberta Energy and Utilities Board.

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE: May 1, 2005 Decision 2005-029	RIDER "C"
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RATE RIDER “D”	GAS COST RECOVERY RATE RIDER
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TO ALL DISTRIBUTION RATES THAT INCLUDE GAS COST RECOVERY

To be applied to the energy sold to all customers receiving default supply unless otherwise specified by specific contracts.

The recovery of gas costs is subject to reconciliation based on actual experienced gas costs as approved by the Alberta Energy and Utilities Board.

Gas Cost Recovery Rate:

October 1, 2007 to October 31, 2007: \$5.213 per GJ

EFFECTIVE DATE: Acknowledged Monthly	REPLACING RATE EFFECTIVE: September 1, 2007	RIDER “D”
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RATE RIDER "E"	UNACCOUNTED-FOR-GAS RIDER
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FOR THE DETERMINATION OF UNACCOUNTED-FOR GAS

The Unaccounted-For-Gas Rider shall be used in the calculation of the Gas Cost Recovery Rider "D" and to determine the amount of Unaccounted-For-Gas as defined in AltaGas Utilities Inc.'s terms and conditions of service.

Unaccounted-For-Gas Rider:..... 0.730%

EFFECTIVE DATE: November 1, 2006	REPLACING RATE EFFECTIVE: November 1, 2005	RIDER "E"
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RATE RIDER “F”	2006 DEFICIENCY RIDER PLACEHOLDER RATE
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Description:

This rider applies to all distribution service customers’ actual billed distribution revenue, excluding gas charges, on statements processed in the January 2006 through December 2006 billing cycles.

Rate:

2006 Deficiency Rider 1.735%¹

Application:

To be collected over the billing cycles of November 2007.

¹ This percentage of 1.735% serves as a placeholder until AUI files an update to Rate Rider “F” and receives approval from the Alberta Energy and Utilities Board on a final rate.

EFFECTIVE DATE: November 1, 2007		RIDER “F”
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RATE RIDER “G”	THIRD PARTY TRANSPORTATION COST RIDER
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**TO ALL DISTRIBUTION SERVICE RATES FOR THE RECOVERY OF
 THIRD PARTY TRANSPORTATION COSTS**

To be applied to the energy delivered to default supply and retail supply distribution service customers.

The recovery of third party transportation costs is subject to reconciliation based on actual experienced third party transportation costs as approved by the Alberta Energy and Utilities Board.

Third Party Transportation Cost Recovery Rate:

October 1, 2007 to October 31, 2007: \$0.0953 per GJ

EFFECTIVE DATE: November 1, 2007	REPLACING RATE EFFECTIVE:	RIDER “G”
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