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

April 26, 2007

Alberta Energy and Utilities Board

**ALBERTA ENERGY AND UTILITIES BOARD**
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

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# 1 INTRODUCTION

The Alberta Energy and Utilities Board (the Board) received an application (the Application) on August 18, 2006 from ATCO Gas requesting Board approval of the following:

- a Cost of Service Study (COSS) methodology for the North and South,
- rate groups and rates for the ATCO Gas North and ATCO Gas South distribution systems subject to any refiling associated with the approved 2007 revenue requirements and the decision for the Application; and
- rates for the costs related to Carbon to be identified separately on the South rate schedules subject to a decision on outstanding jurisdictional matters.

The Division of the Board assigned to this Application was B.T. McManus, Q.C. (Presiding Member), J. I. Douglas, FCA and G. J. Miller. A hearing was held in Edmonton from December 11-14, 2006. Written argument and reply argument were received on January 15 and January 31, 2007, respectively.

Submissions subsequent to reply argument were received from The City of Calgary (Calgary), Alberta Urban Municipalities Association and the City of Edmonton (AUMA/EDM) and ATCO Gas, the last of which was received on February 16, 2007.

The Board considers the record for the Application closed on February 16, 2007.

# 2 BACKGROUND

## 2.1 Background Summary

Application 1416346 was filed with the Board by ATCO Gas on August 31, 2005, for the approval of a 2003-2004 General Rate Application (GRA) Phase II (the Original Application).

The Original Application was advanced utilizing four workshop Topics:

1. Final approval of 2003 and 2004 rates
2. Transmission Service Rider
3. Terms and Conditions of Service
4. Establishment of concepts and principles, including the notion of uniform North and South distribution rates, to be used for the 2005-2007 GRA Phase II leading to rates effective January 1, 2007

Topics 1 and 3 were dealt with by the Board in Decisions 2006-062[1] and 2006-075,[2] respectively. Topic 2 was addressed in Decision 2006-083,[3] as well as through the commitment[4] of ATCO Gas to further address the collection and analysis of data required to allocate transmission costs in relation to the demand created by customer class in its next GRA process subsequent to 2007.

Topic 4, dealing with concepts and principles associated with future rate design and COSS, was advanced in a series of workshops. In the final workshop on July 28, 2006, it was determined that ATCO Gas would file the Application by August 18, 2006. The Application dealing with Topic 4 is the subject of this proceeding. In this proceeding, ATCO Gas updated the initial COSS submitted in the Original Application to incorporate 2007 revenue requirements, as of March 17, 2006 in association with the ATCO Gas 2005-2007 GRA Phase I Decision 2006-004.[5] In the Application, ATCO Gas submitted that, for expediency, it would not pursue the notion of uniform North and South rates at that time, but would instead pursue this objective by way of a separate application which would propose a combined North and South revenue requirement with distinct North and South rates determined using the COSS methodology. Hence, the Original Application has evolved from establishing future cost of service and rate design methodologies to include a 2005-2007 GRA Phase II. The outcome of this process will lead to the establishment of 2007 rates in the final year of the 2005-2007 GRA test period.

After considering submissions from parties, the Board determined in a letter of October 26, 2006 that an oral hearing would be appropriate to provide for the expressed desire of interveners to more fully test the Application.

## 2.2 Decision Overview

Traditionally, a GRA Phase II decision will consider and determine how to apply the appropriate rate design criteria for the determination of just and reasonable rates to collect the utility's approved revenue requirement, determine the rates for the proposed services and establish the appropriate terms and conditions for these services. Certain of those rate design criteria address the accuracy of the cost allocation methodologies used to support the collection of a share of revenue requirement from each class through rates. The primary tool utilized in determining an appropriate cost allocation is a COSS. A COSS will ordinarily analyze the costs incurred in providing regulated services, categorize or functionalize these costs, classify the costs into customer, commodity and demand related components and then determine an appropriate set of methodologies for the allocation of the costs among the several customer classes. An appropriate allocation may be done in one of any number of ways, including on a fully allocated cost basis for all costs or by way of a mixed allocation, with costs that can not be attributed to a single customer class (general system costs for example) being allocated on a fully allocated basis and costs that can be attributed to a single customer class being direct assigned to that class.

[1] Decision 2006-062, ATCO Gas 2003-2004 GRA Phase II Part 1 Rates as Final, June 27, 2006
[2] Decision 2006-075, ATCO Gas 2003-2004 GRA Phase II Terms and Conditions, July 27, 2006
[3] Decision 2006-083, ATCO Gas 2005-2007 General Rate Application – Phase I Compliance Filing to Decision 2006-004 Part B, August 11, 2006
[4] Reference Application 1475249, ATCO Gas letter to the Board dated October 19, 2006, pages 4 & 9
[5] Decision 2006-004 – ATCO Gas 2005-2007 General Rate Application Phase I (Application No. 1400690) (Released: January 27, 2006)

In the Application, ATCO Gas has filed COSSs with a proposed allocation of costs and the resulting rates flowing there from.

Given the importance of a COSS in the process leading to an appropriate rate design, Section 5 of this Decision will review ATCO Gas's proposed COSS for the North and South and if necessary direct adjustments to the methodologies employed to achieve the appropriate allocation of costs among rate classes.

Section 6 will consider the rate design criteria that are not primarily focused on the allocation of costs and consider whether an appropriate balancing of these criteria would result in any adjustments to the rates that would otherwise result from the determinations made in Section 5.

In reaching the determinations contained within this Decision, the Board has considered all relevant materials comprising 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 all relevant portions of the record with respect to that matter.

## 3 2007 REVENUE REQUIREMENTS

In the Application, ATCO Gas proposed that, for the purpose of establishing an approved COSS methodology and rate design principles, it would use the 2007 revenue requirement as filed by it on March 17, 2006[6] in compliance with Decision 2006-004. In response to information request (IR) CAL-AG-02 (dated September 15, 2006) ATCO Gas confirmed that it had taken into account the effect of Decision 2006-075 regarding the Schedule C charges adjustment. ATCO Gas also stated that it reconciled the numbers except for the Carbon related assets which it indicated could not be reconciled because of different tax treatment.

In its Rebuttal Evidence,[7] dated November 24, 2006, ATCO Gas stated that in its compliance filing for the decision related to this proceeding, it would use the most current approved revenue requirement forecast available for the determination of the 2007 final rates. ATCO Gas anticipated that the available revenue requirement would incorporate the effect of any further compliance filing decisions related to:

- Phase I of the 2005 – 2007 GRA
- the Common Matters decision[8], and
- the 2007 impact of the Daily Forecasting and Settlement System (DFSS) from the Retailer Service decision.[9]

[6] First compliance filing (Application No. 1452948) resulting in Decision 2005-083, 2005-2007 General Rate Application – Phase I, Compliance Filing to Decision 2006-004 Part B, dated August 11, 2006.

[7] ATCO Rebuttal Evidence, pp. 6-7/22

[8] Decision 2006-100, ATCO Utilities, 2005-2007 Common Matters Application, dated October 11, 2006.

[9] Decision 2006-098, ATCO Gas Retailer Service and Gas Utilities Act Compliance Phase 2 Part B Customer Account Balancing and Load Balancing, dated October 10, 2006, and Errata, dated November 7, 2006 (Application No. 1411635)

ATCO Gas stated that in several previous decisions (the most recent being Decision 2006-083), the Board had directed ATCO Gas to defer the impact related to the finalization of all outstanding placeholder amounts and address the disposition of such amounts at a future time. ATCO Gas would therefore defer the impact related to any remaining outstanding placeholders for the years 2003 - 2007. The Board notes that ATCO Gas' 3rd GRA Phase I Compliance filing[10] submitted February 14, 2007 in response to Decision 2006-133,[11] dated December 28, 2006, indicated the placeholders that remained outstanding were those in conjunction with the benchmarking of ATCO I-Tek and ATCO I-Tek Business Services and the lease rate for Carbon Storage capacity.

Generally the interveners agreed with ATCO Gas' proposal or had no comment.

**Views of the Board**

The Board agrees that the revenue requirement used to establish final rates for 2007 will be that approved by the Board in the decision that completes the 2005-2007 GRA Phase I. The Board also confirms its understanding that the outstanding placeholders, which will be dealt with in a subsequent process, are those previously noted.

## 4 RATE GROUPS

ATCO Gas proposed elimination of certain old rate schedules that it considered were no longer applicable. The rate schedules proposed to be eliminated were:

- North - Rate 13b, 40, 41, 42, 43, 50
- South - Rate 40, 41, 43, 50[12]

ATCO Gas proposed combining certain other rate groups and renaming another rate group so that only three new rate groups would remain. These three new groups were:

- North and South
  - Low Use < 8000 GJ [gigajoule] & 2 part rate (fixed and variable (commodity) charges[13]) – combination of existing Rates 1 and 11
  - High Use > 8000 GJ & 3 part rate (fixed, commodity[14] and demand[15] charges) combination of existing Rates 3 and 13,
- South only
  - Irrigation – same as current Rate 5 structure (fixed and variable charges)

10 Application 1502769
11 Decision 2006-133 – ATCO Gas 2005-2007 General Rate Application - Phase I Second Compliance Filing to Decision 2006-004 Part B (Application 1478363) (Released: December 28, 2006)
12 Rate 13b was for an optional Retailer Delivery Service – Large Use, which incorporated a balancing charge; Rates 40, 41, 42 and 43 were for various Buy/Sell Services; and Rate 50 was a Balancing Service for Transportation Customers.
13 Any costs assigned on the basis of demand are combined with those of commodity.
14 At present there are no costs proposed to be recovered on the basis of commodity in the North and therefore that component has a zero value. In the South the commodity portion relates to the Production and Storage component.
15 The greater of Nominated Demand or the greatest amount of gas 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 consecutive 24 hours in the summer period shall be divided by 2.

### 4.1 Elimination of Old Rates

In Section E.2 of Exhibit 003 and in Section 2.2.2 of the attachment to Exhibit 055, ATCO Gas outlined its proposals with respect to Rate Groups, including the elimination of Rate Groups that were no longer required. ATCO Gas proposed to eliminate the previously noted Rate Groups.

AUMA/EDM agreed with ATCO Gas' proposal to eliminate the rates that were for Buy/Sell, Retailer Delivery Service and Balancing Service, seeing no reason to retain these rates.

No other party submitted comments regarding the elimination of the rates as proposed by ATCO Gas.

**Views of the Board**

The Board considers it appropriate to eliminate rates which are no longer applicable or in use and accordingly approves the elimination of the rates as proposed by ATCO Gas, specifically Rates13b, 40, 41, 42, 43, and 50 in the North and Rates 40, 41, 43, and 50 in the South.

### 4.2 Creation of New Rate Groups

ATCO Gas proposed three new rate groups, namely Low Use Rate Group (North and South, High Use Rate Group (North and South) and Irrigation Rate Group (for the South only) effectively replacing current rate groups by combining them. Rate 1 and Rate 11 Rate Groups would be combined into one Rate Group called Low Use and Rate 3 and Rate 13 Rate Groups would be combined into one Rate Group called High Use. The breakpoint between these new Rate Groups would continue to be at the 8,000 GJ per year level. ATCO Gas submitted that the combination of these Rate Groups was appropriate as the distribution service received was the same,[16] the only difference being whether a Retailer or the Default Supply Provider (DSP) was the supplier of the natural gas. ATCO Gas was not proposing any change to the current Irrigation Rate Group for ATCO Gas South, but it would no longer be referred to as Rate 5.

The Board notes that in proposing to combine the rate groups, the changes proposed by ATCO Gas in the Application were not extensive. In response to submissions by Calgary and Public Institutional Consumers of Alberta (PICA), ATCO Gas included in its proposal the use of a minimum system method for classifying and allocating meter costs for the design of the rates.[17] Also, to accommodate combining Rates 3 and 13, the billing demand used in Rate 13 would be replaced with the 24-hour billing demand as determined in Rate 3.

Calgary's evidence was that fairness in conducting a COSS depended on individual classes being homogeneous in terms of size, load characteristics and cost causation relationships.[18] Calgary submitted that its proposal for new rate classes would reduce historical inequities and subsidies and achieve a required level of homogeneity.

Calgary submitted that based on two primary considerations for meeting the homogeneity requirements for the selection of appropriate size of customers in a class, customer size (annual

[16] Transcript Pages 389 and 390
[17] AG Evidence, August 18, 2006, pp. 5-8
[18] Calgary Evidence p.6/35

gas consumption[19]) and load (using meter costs as a reflection of load[20]) the Low Use and High Use Rate Groups proposed by ATCO Gas should both be separated into two classes of service (referred to as A and B) with the Low Use breakpoint at 300 GJ per year[21] (for both North and South) and High Use (A and B) breakpoint at 50,000 GJ per year. Calgary also submitted that if ATCO Gas could demonstrate a recognition of cost differentials at the 50,000 GJ per year level within its proposed large use class through rate design, utilizing concepts such as stepped demand charges or multiple customer charges based on size, the need to split the High Use class into two classes could be mitigated or eliminated.[22]

Calgary submitted that it had conducted a multi-faceted analysis as to the lack of homogeneity[23] within the current Rate Groups of Rates 1/11 and 3/13. This lack of homogeneity had caused a long history of cross subsidies between high and low use customers within each class. Calgary's evidence contended that the subsidy within the Rate 1/11 class for customers using 300 GJ per year or less amounted to $243 per year for metering cost alone.[24] Calgary submitted that the record was clear[25] that there was a fundamental lack of homogeneity in the existing classes of service and the changes advocated by Calgary was the only evidence to address this issue.

Calgary argued that the issue of class homogeneity was clearly on the record[26]. The issue could not be addressed through artificial cost classification of meters between demand and customer as proposed by ATCO Gas. Calgary submitted that ATCO Gas had not presented any evidence to support that there were demand cost drivers associated with meter costs, particularly in the low use Rate 1/11 proposed class of service. Conversely, Calgary's evidence[27] set forth the regulatory frame work for the requirement to recognize the need for homogeneity. In both its evidence and IR responses Calgary set forth the criteria it used to demonstrate that currently there was a fundamental lack of homogeneity in both the Rate 1/11 and 3/13 classes. Factors included meter costs, annual usage compared to average usage, the number of standard 250 CFH [cubic feet per hour] meters and the capturing like size customers within each class. While ATCO Gas indicated in its rebuttal[28] that there were more breakpoints than those advocated by Calgary, Calgary submitted that for the present time its recommendations would address the current class deficiencies. Calgary submitted that its proposal for dividing the proposed low and high use rate

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19 Calgary noted that in using workshop information, annual average consumption in the Low Use group was 173 GJ while the range was from 50 GJ to about 8,000 GJ. Calgary also noted that 95% of the Low Use customers use 300 GJ or less. (using AGS 2006 data) Calgary noted that in the South and North respectively, the percentage of High Use customers using over 50,000 GJ was 8.6% and 7.6%.

20 Calgary noted that in using workshop materials, the per customer unit "replacement" meter costs increase from $237 to $308 (30% increase) between an annual consumption range of 250 and 300 GJ and from $308 to $451 (46% increase) for an annual consumption of 300 versus 350 GJ. Calgary also submitted that meter cost also begin to increase in cost starting at over 50,000 GJ in the High Use group.

21 Calgary Evidence p. 6/35, "…95% of all Rate 1 customers use 300 GJ or less on an annual basis."

22 Calgary evidence pp.4-8

23 As noted at page 4 of Exhibit 24-01 homogeneity is a primary criterion of rate design.

24 Calgary evidence p. 22 "As can be seen in response to CAL-AG-1(b) Attachment 1 the results of the methodology provide for a metering cost per customer of:

| | |
|---|---|
| Low Use A | $33.01 |
| High Use A | $275.87…" |

a difference of $243.

25 ATCO's rebuttal evidence (Ex. 56) confirmed the lack of homogeneity in the rate classes

26 Ex.24-01 Evidence of Calgary and Exhibit 56 AG Rebuttal evidence

27 Ex. 24-01 Calgary evidence pages 4 – 6

28 Ex 56 AG Rebuttal pages 10 – 11 and TR3 page 480 line 11

classes would meet the long established regulatory paradigm of class homogeneity while maintaining the practical attributes[29] of rate design.

AUMA/EDM concurred with Calgary that the Low Use Rate Group was too broad and lacked homogeneity and should therefore be split. However, AUMA/EDM argued that while a breakpoint at 300 GJ would address that problem, there could be a practical alternative approach by dividing residential and commercial users within the Low Use rate class. AUMA/EDM noted that ATCO Gas acknowledged that the majority of customers in the first 6 strata of Item 4.2 Attachment[30] were residential customers[31] and that Item 4.2 could be broken down to provide the meter costs for residential customers separately.[32]

AUMA/EDM noted that ATCO Gas acknowledged that other Canadian utilities, Terasen, Saskatchewan Energy, Union and Enbridge, had separate residential gas distribution rates.[33] Calgary witness, Mr. Vander Veen, agreed that grouping of customers into residential, commercial, industrial and seasonal would constitute homogeneous groups. He also indicated that other Canadian utilities have had residential and commercial rates for close to 100 years.[34] AUMA/EDM argued that separate residential rates should reduce the switching problem[35] associated with the breakpoint.

AUMA/EDM considered that the differentials in metering costs for Rate 3 were far less dramatic than for Rate 1[36] and accordingly could be more easily addressed through rate design.

AUMA/EDM also considered that a minimum system method for classifying and allocating meter costs produced a distorted allocation of meter costs to the under 300 GJ per year group and thus should not be utilized as a means of addressing meter costs without creating additional rate groups.

In response to AUMA/EDM's recommendation to split the Low Use Rate Group ATCO Gas submitted that it must be rejected. ATCO Gas argued that AUMA/EDM had not addressed this matter in the workshop process and chose not to file evidence with respect to this recommendation. There was therefore no comprehensive evidence in this proceeding with respect to AUMA/EDM's new concept, which was presented by AUMA/EDM for the first time in Argument as a recommendation to be implemented for the compliance filing.

Calgary argued with respect to AUMA/EDM's proposal that AUMA/EDM had provided no definition of what constitutes a residential or commercial customer. Before making this type of recommendation, Calgary argued that it was incumbent on the party proposing the change to at least define their terms and address the potential issues which must be considered.[37] Calgary

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[29] Bonbright, J.C., Danielsen A.L., Kamerschen D.R. *Principles of Public Utility Rates*, Second Edition, Arlington, Virginia, Public Utilities Reports, Inc., 1988, page 384.
[30] Application, Tab - July 28, 2006 Meeting, Item 4.2 Attachment, July 14, 2006
[31] T30
[32] T31
[33] T36 and 154
[34] T440-441
[35] T36
[36] Application, Item 4.2, Ex 003
[37] TR 3 page 440 regarding issues which need to be addressed under this proposal

submitted that the record in this proceeding was devoid of the required analyses to institute this type of proposal.

The Alberta Irrigation Projects Association (AIPA) did not see the merit of further dividing rate classes due to potential customer switching problems and cost considerations outlined by ATCO Gas.

AIPA submitted that the ATCO Gas methodology for cost classification and allocation for the Low Use rate to include minimal meter costs classified as customer-related costs with the balance classified as demand costs mitigated any cross-subsidization. Customer costs would be recovered through a customer charge and demand costs were recovered through the variable commodity charge. Therefore higher cost metering costs would be recovered from the higher use customers in the class through higher variable charges.

AIPA was concerned that the 300 GJ per year breakpoint for the Low Use Rate Group was not readily apparent from the Calgary analysis and particularly if farm services were spanning this proposed breakpoint. AIPA also had concerns that a split at the 300 GJ annual consumption level could cause significant customer rate shifting around this point. For instance Rate 1 customers that receive farm service could see an inexplicable difference in the monthly fixed charge whether annual consumption is above or below 300 GJ.

AIPA was concerned with the potential switch to three part rates and the potential additional cost implications of installing automatic meter reading (AMR) devices for all of these customers.

AIPA was also concerned with Calgary’s suggestion for an open-ended, principle based approach to cost of service analysis without any consideration of the cost of implementation. AIPA considered it fundamental that a regulated service be provided at the lowest cost of service consistent with reliability and safety considerations. The accuracy and precision associated with implementation of a principle must be weighed against the cost of that implementation to ensure that the costs do not outweigh the benefits.

For the above reasons AIPA recommended that the proposed Low Use rate class for 0 – 8,000 GJ per year consumption level be approved by the Board for this proceeding.

PICA submitted it had not been demonstrated the existing two part tariff for Rate 1 was unduly discriminatory or unfairly preferential to any one consumption range within Rate 1 for the purposes of this proceeding. A similar comment would apply to Rate 3.

It was PICA’s submission that the test of whether Rates 1 and 3 should be split ought to be based on whether the costs were tracking cost recovery within each rate class under the present rate structure. If the rate recoveries were not tracking costs for different consumption levels and the corresponding revenue to cost ratios were materially outside tolerances, there might be reason to consider changing the rate components or even splitting the rate classes.

In PICA’s view, the grouping of the majority of customers under the 300 GJ per year consumption range was not, in its self, indicative that the present cost recovery was unreasonable for Rate 1.

PICA noted the main reason for Calgary's proposal to split Rate 1 appeared to relate to differences in meter costs at different consumption ranges and, in particular, with respect to residential customers versus other customers within Rate 1. PICA noted there was no evidence ATCO Gas would be able to assign services costs by customer class and consumption ranges within customer classes in the same manner as it did for meters. Consequently, it could not be determined whether there was any disparity between different consumption ranges within rate classes due to differences in services costs. As an alternative, and for purposes of this proceeding, PICA submitted any perceived inequities due to meter costs within Rate 1 could be addressed through the level of the Rate 1 fixed charge.

PICA agreed with the principle that the level of fixed charges should closely reflect the customer related costs. While it was appropriate to recover 100% of customer related costs by way of fixed charges; PICA submitted that a Rate 1 fixed charge designed to reflect meter costs applicable to the minimum size of meters would ensure residential customers are not over charged for meter costs. It appeared to PICA that ATCO Gas' proposed design of the Rate 1 fixed charge already reflected this principle as ATCO Gas used a minimum system method to classify meter costs. Although PICA recommended the weighted meter costs method be used for allocation of meter costs; PICA supported the use of the minimum meter cost for design of the Rate 1 fixed charge for purposes of this proceeding.

PICA argued that it had not been demonstrated that the existing tariff structures for Rates 1 and 3 were unduly discriminatory or unfairly preferential to any one consumption range. Accordingly, PICA suggested that any move to split Rates 1 and/or 3 should not be implemented at this time. Rather, ATCO Gas should be directed to address whether the rate recoveries are tracking costs for different consumption levels and comment on corresponding revenue to cost ratios at the time of the next GRA Phase II.

The Rate 13 Group (R13 Group) supported ATCO Gas' proposal and did not believe it was the appropriate time to further delineate rate classes based on low/high use characteristics.

The R13 Group submitted that ATCO Gas was clear that it did not believe the idea of splitting the Rate 13 customers further was warranted on the basis of better cost allocation, primarily because of the relatively small numbers of these customers and the "setup" and "administration" costs that would be incurred by ATCO Gas.

The R13 Group agreed that the concerns expressed by ATCO Gas[38] and AIPA regarding the determination of the appropriate breakpoint, the appropriate rate structure and the administrative rules around switching customers from one rate to another were legitimate concerns. The R13 Group submitted that ATCO Gas' rate class proposal should be approved by the Board.

The Consumers Coalition of Alberta (CCA) saw some merit in the further dividing of rate classes because of the over allocation of costs through classification of costs to customer. The issue could be addressed through the change in costing methodologies to reduce costs being classified to demand or adjusting the fixed charge/variable charge ratio in the design of the Low Use rate.

[38] Ex. 3, AG Application, p. 7

The CCA disagreed with ATCO Gas and agreed with Calgary that that the low use rate group lacks homogeneity. CCA noted that 95% of the low use customers use less than 300 GJ annually. CCA argued that the only homogeneity of band 0 to 8,000 GJ annual use customers was that they were connected to the ATCO Gas system and they appeared to have similar load factors.

Although Calgary focused on meters in its analysis, the CCA considered that the same could be said of services and mains. Larger customers needed higher customer components for services, meters and mains. Minimum system methodologies assigned costs to customer based on the minimum system. The minimum system was sufficient to serve small customers, both the customer component and the load component. CCA argued that simply because a 300 or 350 GJ customers may have meter replacement costs that were close in dollar terms did not mean that a 300 GJ customer had similar meter costs to an 8,000 GJ customer. CCA noted that ATCO Gas did agree that, based on meter replacement costs, the 300 – 8,000 GJ per year customers were not homogenous.[39]

The CCA supported Calgary's proposal that the High Use Rate Group should be split using a breakpoint of 50,000 GJ per year. The CCA considered that not only were meter replacement costs different across the customers of the high use rate but also services and main costs attributable across the customer class. The fundamental reason that there were only 80 customers, as ATCO Gas argued,[40] was not a reason to assume homogeneity across the rate group.

The Aboriginal Communities (ABCOM or First Nations) noted that there were, at the moment, two rate classes, however, if the principle could be established, then there would be no reason why a myriad of rate classes might not be applicable. From the First Nations perspective a rate that provided for a lower fixed charge plus a demand charge modulated by the elimination of the mains component might be more appropriate for First Nations customers.

The First Nations proposed that the Board should direct ATCO Gas to provide, as part of its next Rate Application, a cost allocation that considers rural residences. ATCO Gas should be directed to further differentiate into Low Use A (urban) and Low Use A (rural).

First Nations submitted that the distinction should be based on urban (a service in an incorporated town or city) and rural (being everything else). ABCOM also suggested it might be helpful to separate Low Use B into rural/urban as well.

ABCOM argued that ATCO Gas had admitted in evidence that the rural system was not serviced by the feeder mains system. For those reasons it appeared appropriate that rural customers should not have the cost of the feeder system allocated to them. First Nations submitted that this distinction should be captured in ATCO Gas' cost allocation methodology at the time of the next hearing.

ATCO Gas disagreed with Calgary's proposal to separate the proposed Low Use Rate Group into two separate Rate Groups referred to as Low Use A and Low Use B using a breakpoint of 300 GJ per year. ATCO Gas understood Calgary's recommendation was based on its perception

[39] AG Argument p. 4
[40] AG Argument p. 5

that ATCO Gas' proposed Low Use Rate Group lacked homogeneity.[41] It appeared to ATCO Gas that Calgary had come to the conclusion that its proposed Rate Groups would be more homogenous on the basis of meter related matters, load factors and annual usage.[42]

With respect to annual consumption, ATCO Gas considered that while Calgary indicated that 95% of ATCO Gas' Rate 1 customers use less than 300 GJ annually and that 5% of these customers use more than 300 GJ annually,[43] Calgary had not indicated the significance of the 95%/5% split. ATCO Gas submitted that this in itself did not demonstrate a lack of homogeneity in the existing Rate Group, nor did it demonstrate the appropriateness of the breakpoint at 300 GJ per year as suggested by Calgary.

With respect to Load Factors, as was noted in the ATCO Gas Rebuttal Evidence, the customers in ATCO Gas' proposed Low Use Rate Group are homogenous.[44]

ATCO Gas noted that Calgary also relied on meter costs to suggest that its proposed Rate Groups would be more homogenous than ATCO Gas' proposed Low Use Rate Group. It appeared that Calgary had determined that the 300 GJ per year breakpoint for its proposed Low Use – A Rate Group was appropriate on the basis of two factors, namely increasing meter replacement costs and its review of CFH ratings for meters. ATCO Gas believed it had shown in Item 4.2 Attachment to its Rebuttal Evidence that replacement meter costs were similar for the 0-200 GJ group of customers. After 200 GJ, meter costs increase consumption block over consumption block. Therefore, a breakpoint of 300 GJ per year was not obvious on the basis of meter replacement cost increases. The breakpoint could just as easily have been at a number of different places on the basis of meter cost increases. Based on meter replacement costs, the 300-8000 GJ annual use customers were not homogenous. ATCO Gas agued that Calgary's proposal would still result in low use customers paying a disproportionate share of meter costs.

ATCO Gas observed that with respect to CFH ratings for meters, Calgary noted that there were 435,973 meters rated at 250 CFH in the south, and the customer count at its recommended 300 GJ breakpoint was 427,233 (a similar comparison was made for the North).[45] Given that the number of customers in the Low Use – A Rate Group (427,233) was considerably lower than the number of minimum size meters (435,973), the reliance by Calgary on a breakpoint of 300 GJ per year continued to be unclear. ATCO Gas argued that its minimum system calculations incorporated the fact that on a replacement cost basis, 435,973 customers in the south would only require the minimum size meter.[46] ATCO Gas argued that its recommended treatment for meter costs (see Section 5.2.12 of this Decision) results in better differentiation of costs for customers based on consumption levels without the issues and incurrence of costs.

In its Rebuttal Evidence, ATCO Gas addressed Calgary's proposal to split the High Use Group into two Rate Groups using a breakpoint of 50,000 GJ per year.[47] ATCO Gas argued that there was no rationale for Calgary's suggested breakpoint of 50,000 GJ. ATCO Gas identified in its Rebuttal Evidence that meter replacement costs in the North were in fact lower for the 50,000-

41 Exhibit 024-01 Page 6, Lines 12-13
42 Exhibit 024-01, Pages 6 and 7; Exhibit 048-10 R13-CAL.1
43 Exhibit 024-01 Page 6, Lines 19-20
44 Exhibit 056, Page 11, Lines 11-17
45 Exhibit 048-06, BR-CAL-2(b)
46 Refer to Item 4.8(a) Attachment 2 from the workshops.
47 Exhibit 056, Page 13, Lines 3-12

100,000 GJ block than the 40,000 – 50,000 GJ block. ATCO Gas submitted that there was no justification for the creation of a new Rate Group for approximately 80 customers given that ATCO Gas' proposed classification methodology for meters addresses the cost inequity issue.

ATCO Gas also noted that the reference to contract demand was only applicable to the current Rate 13 Rate Group.[48] ATCO Gas indicated that the use of contract demand in the context of the current Rate 13 Rate Group would not exist under the ATCO Gas proposal and that as per its proposal the current Rate 13 customers would be treated the same as the Rate 3 Rate Group.[49]

ATCO Gas claimed Calgary was not correct[50] in its submission that the creation of new Rate Groups would not impose undue costs and work effort for ATCO Gas.[51] The creation of additional Rate Groups would result in an increase in costs, additional administration and confusion for customers.

ATCO Gas indicated that the current rate migration process was a relatively simple manual process that was used to review customers with annual consumptions around the 8,000 GJ per year breakpoint. At this level, AG noted that it was required to monitor less than 1000 customers annually. At around the 300 GJ per year breakpoint, ATCO Gas submitted that it would need to monitor about 24,000 customers. As a result, ATCO Gas submitted that the creation of a new rate group as proposed by Calgary would require computer system changes first to create the new Rate Group and second to develop automated rate migration programs. The estimated cost of these system changes would be in the order of $0.5 million.[52]

ATCO Gas proposed a change in the classification methodology for meter costs on the basis of a minimum system method. ATCO Gas addressed this methodology in greater detail in Section 4.2.13 (Distribution Meters) of its Argument. The solution by ATCO Gas was to fix the classification problem and not create additional rate groups.[53]

**Views of the Board**

In summary, the Board notes there were two proposals filed in evidence in respect of establishing new rate groups which were as follows:

- ATCO Gas proposed to combine Rates 1 and 11 into a Low Use Rate Group, combine Rates 3 and 13 into a High Use Rate Group, where the breakpoint between the groups would remain as 8000 GJ per year, and call Rate 5 an Irrigation Rate. A minimum system method would be used for classifying meter costs for the design of the rates.

- Calgary proposed to split the Low Use Rate Group into Group A and Group B with a breakpoint at 300 GJ per year, and split the High Use Rate Group into a Group A and Group B with a breakpoint at 50,000 GJ per year. Calgary did not propose changes for the Irrigation Rate.

48 Transcript Page 44, Lines 3-5
49 Transcript Page 44, Lines 6-9
50 Exhibit 056, page 11, Lines 18-21 and Page 12, Lines 1-21
51 Exhibit 024-01, Page 9, Lines 1-10
52 AG Rebuttal evidence pp. 11-12/22
53 Transcript Page 48, Lines 18-25

Both proposals were made to address a perceived problem in the lack of homogeneity of the rate groups. While ATCO Gas did not acknowledge the problem was as severe as argued by Calgary, ATCO Gas did introduce a minimum system method for classifying meter costs in an effort to address Calgary's homogeneity concerns.[54] ATCO Gas believed that a better differentiation of costs for customers based on consumption levels would result from this proposal without the incurrence of additional costs and the burdens of monitoring the cross-over breakpoint.

Calgary submitted that the problem of homogeneity could only be addressed by splitting the rates, and that this was necessary in order to correct a long standing cross-subsidization issue.

The AUMA/EDM appeared to accept ATCO Gas' position that Calgary's changes would cause unnecessary administrative problems and cost. However, they also agreed with Calgary that there was a homogeneity problem that required a solution. AUMA/EDM believed a proposal could be implemented without the same level of administrative concerns or cost and that it would also address the homogeneity issue satisfactorily.

ABCOM appeared to agree that a split of the Low Use Rate Group proposed by ATCO Gas was desirable but did not make a specific recommendation for implementation in this GRA.

The Board notes that, for their own noted reasons, PICA, the R13 Group and AIPA all supported ATCO Gas' proposal. In particular, PICA was satisfied that the minimum system method to be applied by ATCO Gas to meter costs would mitigate the homogeneity problem.

The CCA was supportive of Calgary's proposal to split both the Low Use Rate Group and the High Use Rate Group. In essence, Calgary, AUMA/EDM, ABCOM and CCA all considered there was a homogeneity problem that required something different in the grouping of customers than what was proposed by ATCO Gas.

The Board notes that the interveners representing the broadest cross section of customers, particularly in the Low Use category, were in favour of some changes to the rate groupings proposed by ATCO Gas. To highlight the issue with the Low User Rate Group, evidence was provided that showed 95% of the customers in that rate grouping used less than 300GJ annually and that the cost of meters above and below this point differ enough to be significant when assessing homogeneity. The Board tends to agree with Calgary that splitting the rates at or near the 300 GJ point would improve the homogeneity of the groupings with respect to consumption. The Board also notes that the evidence demonstrates that the bulk of the residential customers (taken to mean individual dwellings with their own delivery meters) would use less than 300 GJ per year.

The Board is persuaded that there is a homogeneity problem with the Low Use Rate Group that needs to be further considered. However, the Board would prefer a solution that would not be administratively complex, nor unnecessarily impose additional costs. The Board is concerned that the Calgary proposal may be administratively complex and impose additional costs and notes that the Calgary proposal did not garner wide support from those interveners requesting a change. ATCO Gas has indicated an implementation cost of at least $500,000 and that the number of accounts to be monitored would be approximately 24,000 with attendant ongoing expense. ATCO Gas has argued that because it will use the minimum system method for

[54] AG Evidence, August 18, 2006, pp. 5-8

classifying meter costs, the homogeneity issue was adequately resolved without the imposition of the administrative efforts and cost. While the ATCO Gas' solution may partially address the homogeneity concern, the Board is unconvinced that this measure is sufficient. While the Board may be prepared to consider other proposals directed at splitting the Low Use Rate Group, they must be properly supported by evidence and subject to full testing by parties. In this regard, the Board notes that the proposals put forward by AUMA/EDM and ABCOM in argument were unsupported by evidence and accordingly the Board has afforded them little weight.

Before making any further change splitting the Low Use Rate Group, the Board is prepared to test ATCO Gas' position that the change to a minimum system method for classifying meter costs will be a satisfactory option (refer to Section 5.2.12.1 of this Decision for further discussion). Therefore, the Board will approve ATCO Gas' proposal for a new Low Use Rate Group as presented.

However, the Board also directs ATCO Gas to come forward at the next GRA Phase II proceeding with an analysis and evaluation of the methods mentioned by Calgary, AUMA/EDM and ABCOM. The Board believes it will be advisable for ATCO Gas to meet with these parties to discuss the details and definitions to assist in addressing the proposals. These proposals should be compared, on a pro and con basis and assessed with respect to the incremental benefits, if any, which could result over and above the benefits demonstrated through the implementation of the minimum system method for allocating meter costs. The analysis should be in sufficient detail to demonstrate the difference in cost to customers over different annual consumptions.

In respect of the High Use Rate Group proposed by ATCO Gas and the splitting of it into two groups using a breakpoint of 50,000 GJ per year as proposed by Calgary, the Board notes that the topic did not receive the same degree of discussion. Calgary also noted that the split may not be necessary if ATCO Gas could address the issue in rate design. It appears only the CCA specifically supported Calgary's proposal to split the rate. ATCO Gas could not see the benefit of making the change where only 80 customers would form a rate group. ATCO Gas felt that the issue of inequity would be adequately addressed by applying a minimum system method to the meter costs.

The Board does not consider that there has been sufficient benefit demonstrated by the proposed split of the High Use Rate Group and accordingly approves the new High Use Rate Group as proposed in the Application.

There were no objections to the new Irrigation Rate Group and the Board approves it as submitted. However, while the Board notes the new group is essentially the existing Rate 5, the Board also notes that the companion Rate 18 was not discussed. The Board directs ATCO Gas to provide an explanation in the Compliance Filing of its proposal with respect to Rate 18.

The above Board approvals of the new rate groups, especially those that combine two previous rate groups are expressly made subject however to ATCO Gas being able to demonstrate to the satisfaction of the Board in the Compliance Filing how Rider D for unaccounted for gas (UFG) will be handled while the DSP is still in the position of carrying out load balancing activities for the distribution system, which is expected to continue until at least November 2007. Also, it will be necessary in the Compliance Filing for ATCO Gas to describe how, with the combining of the existing rates; it intends to handle the different load balancing and accounting rules[55] that are currently being used.

Accordingly, the Board directs ATCO Gas to discuss the details of the proposed administration of the UFG Rider D for the Low Use, High Use and Irrigation Rate Groups in the short term as well as subsequent to the transition of load balancing activities from the DSP to ATCO Gas in the Compliance Filing to assist the Board with respect to the practicality of immediately eliminating the existing rates differentiating between default supply and competitive gas supply.

Additionally the Board directs ATCO Gas to discuss the conceptual approach of the proposed administration of load balancing and account balancing practices for the Low Use, High Use and Irrigation Rate Groups in the short term as well as the transition process envisioned in association with the Retailer Service process in the Compliance Filing to assist the Board with respect to the practicality of immediately eliminating the existing rates differentiating between default supply and competitive gas supply.

To be clear, the Board is hereby approving in principle the combining of the rate groups as proposed by ATCO Gas, but not the implementation. The Board considers it may be necessary to continue with four rather than two rate schedules until after ATCO Gas has taken over all activities associated with load balancing. Consequently, the implementation of the new rate classes will be delayed until ATCO Gas can demonstrate to the Board that all the provisions as stated in rate schedules of Rates 1 and 11 and in Rates 3 and 13 (also Rates 5 and 18 in the South) are appropriately and completely addressed in the rate schedules of the Low Use Rate and the High Use Rate, respectively (and Irrigation Rate in the South).

## 5 COST OF SERVICE STUDIES

ATCO Gas indicated it used the traditional three steps in preparing its fully distributed COSS. The three steps in sequence are the functionalization of costs, the classification of costs and the allocation of costs to rate groups. The classification of costs is determined by whether the costs vary based upon the existence of a customer (customer costs), the costs that vary based upon the customers maximum requirements (demand costs), and costs that vary based upon consumption (commodity costs).

ATCO Gas claimed that the preparation of the Application was based on cost of service methodologies previously reviewed and approved by the Board in Decision 2000-16.[56] A few changes to the approved methodologies were being proposed by ATCO Gas where it believed it was clear that a change was warranted. For ATCO Gas North, the COSS was filed as Exhibit 018-12 (the Proposed North COSS) and for ATCO Gas South, the COSS was filed as Exhibit 018-15 (the Proposed South COSS) (collectively the Proposed COSSs). ATCO Gas considered its COSS methodologies were practical and easy to implement. They did not result in rates that were unduly discriminatory and did not result in increased costs to customers as a result of additional administration.

55 Transcript, pp. 389-390
56 Decision 2000-16 – Canadian Western Natural Gas Company Limited 1998 General Rate Application Phase II (Application 980413) (Released: June 13 2000)

Issues identified by ATCO Gas were that the methodologies proposed by interveners would not result in any cost allocation improvements; would incur a higher level of work and associated costs; required information not currently available and that the benefit to the average residential customer was only $0.29 on an annual basis.[57]

Issues introduced by Calgary were which of three "demands"[58] was the appropriate one to use; what was the appropriate quantum of demand for each rate; and that the rate components in each rate class be allowed to vary by +/-10% in relationship to cost determination".

Calgary noted that over 25 years had passed since the GURDI [gas utility rate design inquiry] Report identified the need for change in the cost allocation and classification methodologies of ATCO Gas and its predecessors. Calgary claimed that subsequent rate cases had repeated the need for ATCO Gas to revise its data collection and management practices to accommodate change. Calgary referenced the GURDI decision where the Board said "The Board does not consider the lack of readily available data to be sufficient reason not to consider a particular method."[59]

Calgary considered it a major issue that ATCO Gas appeared to have not responded to previous Board directions' that required ATCO Gas to review costs and cost causations, the review of which would have provided much of the detail that ATCO Gas now claimed did not exist.

**Views of the Board**

The Board believes that what appears to be at the heart of the differences between ATCO Gas and the interveners who propose changes to the Application is the level of detail of the available data that would be used in a COSS. ATCO Gas has historically gathered data in a certain way and with a certain precision that has been satisfactory for the purpose of conducting a COSS as viewed by ATCO Gas. Interveners and Calgary in particular, are recommending changes that require a significant change in the detail gathered. The question that the Board must ultimately answer is whether or not the rates that result from the COSS will be significantly improved by the change from the status quo. Further, if changes are required, can improvements be accomplished with minimal additional expense. The Board notes there are several specific issues that will be addressed later in the decision as the Board reviews some of the component parts of the COSS. The review of the individual items will be discussed first before the Board comments further on the matter of the data detail.

## 5.1 Functionalization of Costs

ATCO Gas utilized the following 15 functions in its COSS and stated they were established in two previous proceedings related to rate unbundling.

- Administration
- Consumer Information
- Billing
- Call Centre
- Credit and Collections

57 Transcript Page 511, Lines 8-18
58 Class Non Coincident Demand, Customer Non Coincident Demand and Coincident Demand
59 Public Utilities Board Report No. E80100, GURDI, p. 136

- Meter Reading
- Load Balancing
- Load Settlement
- Gas Supply
- Production and Gathering
- Storage
- Transmission
- Distribution Meters
- Customer Service
- Distribution Mains and Services

**Views of the Board**

The Board notes that other than AIPA, no other intervener filed an objection to the ATCO Gas functions. AIPA recommended a separate function for feeder mains. ATCO Gas noted that the costs for all mains were recorded in the same account (#475) and as such all mains costs are functionalized to the Distribution Mains and Services Function. ATCO Gas considered the separation of feeder mains from distribution mains a "classification issue".

Notwithstanding ATCO Gas' assertion that the functions were established in previous proceedings, the Board notes that the Customer Service function is new. The Board also observes that previously Load Balancing and Load Settlement had been combined as one function. Also the functions of Customer Enrollment and Customer Information System were identified in the unbundling process,[60] but have not been carried forward as separate functions. Further, the Board notes that there are no costs associated with the Gas Supply function and therefore questions its continued purpose. Finally, in the same way Distribution Meters are considered a separate function, could Services and Distribution Mains be considered separate functions? The Board directs ATCO Gas to provide the rationales that address these matters when it files a Compliance Filing to this Decision.

Upon review of the filed material it appears to the Board that ATCO Gas has not filed a summary as directed in Decision 2003-108,[61] which stated as follows:

> The Board therefore directs ATCO Gas to add to its COSS a summary of the costs of each of the functions in a rate format.[62]

ATCO Gas is directed to file the summary in the Compliance filing.

### 5.1.1 Functionalization of Asset-Related Expenses

In the Application ATCO Gas proposed to utilize the existing methodology[63] (which allocated utility income tax to all fixed asset accounts and necessary working capital (NWC) components based on the mid-year rate base including NWC.) For each asset account and NWC item, ATCO Gas then functionalized the Asset-Related Expenses (total of Return, Income Tax and Depreciation) to the 15 functions noted previously.

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60 Decision 2003-108
61 Decision 2003-108 – ATCO Gas 2003 Gas Rate Unbundling (Application 1303682) (Released: Dec 18, 2003)
62 Decision 2003-108, Direction 3, p. 54
63 ATCO Gas revised its proposal of August 2005 when it submitted the update in August 2006

**Views of the Board**

As noted previously, there were no opposing views to the functionalization of Asset Related Expenses, other than that of AIPA recommending a separate function for feeder mains, which will be dealt with later. ATCO Gas' submission in respect of functionalization of Asset Related Expenses is hereby accepted pending the Board's finding with respect to AIPA's issue.

### 5.1.2 Functionalization of Operating Expenses

In the Application, ATCO Gas stated that it functionalized the operating expenses in each account to one or more of the 15 functions noted previously based on various rationales.[64]

**Views of the Board**

The Board notes that no opposing views were submitted and therefore approves ATCO Gas' submission in respect of the functionalization of Operating Expenses.

## 5.2 Classification of Functionalized Costs

ATCO Gas indicated that after revenue requirement approved costs were functionalized to the operating functions, the costs of each function were classified as customer, commodity or demand related costs based on various supporting rationale based on cost causation principles.

ATCO Gas submitted that customer-related costs were costs which related directly to the number of customers served. Commodity-related costs were costs which vary with annual throughput and demand-related costs were costs associated with meeting the maximum gas flow sizing (capacity) requirements of the distribution system.

The following tables show for each function, the magnitude of 2007 revenue requirement dollars that ATCO Gas proposed to classify as customer related, commodity related and demand related for the North and South respectively. The data in the tables was compiled from the noted data sources.

[64] As outlined in ATCO Gas' August 2005 application pp. 37-43 and resubmitted by letter November 23, 2006

Table 1. ATCO Gas North – Proposed Classification by Function

| Function | Customer ($000s) | Commodity ($000s) | Demand ($000s) | Total ($000s) |
|---|---|---|---|---|
| Administration | 13,485 | 20 | 8,936 | 22,441 |
| Consumer Information | 1,829 | 2 | 1,209 | 3,040 |
| Billing | 13,239 | 637 | | 13,876 |
| Call Centre | 2,185 | | | 2,185 |
| Credit and Collections | 767 | 1 | 506 | 1,274 |
| Meter Reading | 14,228 | | | 14,228 |
| Load Balancing | 144 | | | 144 |
| Load Settlement | 145 | | | 145 |
| Gas Supply | | | | 0 |
| Production and Gathering | | | | 0 |
| Storage | | | | 0 |
| Transmission | | | 37,658 | 37,658 |
| Distribution Meters | 16,158 | | 11,177 | 27,335 |
| Customer Service | 14,462 | | | 14,462 |
| Distribution Mains and Services | 45,155 | 115 | 48,954 | 94,224 |
| Income Credits | (5,304) | (9) | (3,575) | (8,888) |
| Total | 116,493 | 766 | 104,865 | 222,124 |

Data Source: Exhibit 018-12 (CAL-AG-19)

Table 2. ATCO Gas South – Proposed Classification by Function

| Function | Customer ($000s) | Commodity ($000s) | Demand $000s) | Total ($000s) |
|---|---|---|---|---|
| Administration | 13,933 | 43 | 8,310 | 22,286 |
| Consumer Information | 1,830 | 5 | 1,088 | 2,923 |
| Billing | 13,584 | 583 | | 14,167 |
| Call Centre | 2,128 | | | 2,128 |
| Credit and Collections | 680 | 1 | 408 | 1,089 |
| Meter Reading | 11,060 | | | 11,060 |
| Load Balancing | 140 | | | 140 |
| Load Settlement | 141 | | | 141 |
| Gas Supply | | | | 0 |
| Production and Gathering | | 1,919 | | 1,919 |
| Storage | | 11,655 | | 11,655 |
| Transmission | | | 27,286 | 27,286 |
| Distribution Meters | 15,898 | | 7,125 | 23,023 |
| Customer Service | 11,966 | | | 11,966 |
| Distribution Mains and Services | 39,162 | 288 | 39,897 | 79,347 |
| Income Credits | (3,428) | (352) | (2,179) | (5,959) |
| Total | 107,094 | 14,142 | 81,935 | 203,171 |

Data Source: Exhibit 018-15 (CAL-AG-19)

### 5.2.1 Administration

In its Argument, ATCO Gas stated that all costs in the Administration function were classified based on a composite classification of the costs for all distribution service functions. ATCO Gas submitted that there was no evidence supporting an alternative classification method for these costs and on that basis, ATCO Gas argued that its proposed methodology should be approved as filed.

Calgary stated that in its experience, Administrative and General (A&G) costs were typically classified in proportion to all other costs absent the ability to implement direct assignment of dedicated A&G costs. Calgary indicated that in the Proposed South COSS, ATCO Gas implemented this general principle exclusive of the recognition of production and gathering and storage costs.

AUMA/EDM stated that ATCO Gas' position in Argument was not consistent with its views in the Application wherein ATCO Gas agreed that it was not appropriate to include the costs related to billing or ATCO I-Tek Call Centre costs in the composite classification of distribution service function costs. AUMA/EDM submitted that the Billing function costs and Call Centre costs should be excluded from the distribution service function costs for classification purposes for the Administration function.

While ATCO Gas indicated that all costs in the Administration function were classified based on the composite classification of the costs for all distribution service functions, the Board notes that in the Proposed COSSs, the actual composite classification of distribution service functions used to classify the Administration function accounts excluded the Billing function and certain Call Centre function costs related to ATCO I-Tek.[65]

Calgary indicated that, while it did not investigate the classification and allocation of administrative costs in detail, further direct assignment of A&G costs could improve the classification of costs in this function.

**Views of the Board**

While the Board notes that Calgary provided in its Argument an example of further direct assignment of costs that it claimed could improve the classification of accounts for the Administration function, the Board agrees with ATCO Gas that the Calgary position should have been properly supported by evidence with specific recommendations in order to be properly tested and considered by the Board and parties.

The Board notes that no other party commented on the classification of costs under this function.

At this time, the Board considers the methods to classify the Administration function accounts as outlined in the Proposed COSSs to be reasonable and approves them accordingly. However, in its next GRA Phase II, the Board suggests that ATCO Gas consider whether further direct assignment of Administration function costs is feasible.

[65] The Board also notes that the total Distribution Service costs, as shown on p. 1/86 of the Proposed COSSs, included the following functions: Distribution Mains and Services, Distribution Meters, Billing, Customer Service, Meter Reading, Call Centre, Load Settlement, Load Balancing, Administration, Credit and Collections and Consumer Information. However, the costs associated with the Administration function, the Credit and Collections function and the Consumer Information function have been shown separately and were not used in the actual composite classification methodology proposed by ATCO Gas.

### 5.2.2 Consumer Information

ATCO Gas indicated that in historical COSS, the costs related to Consumer Information were included under the function of Marketing and treated as an overhead. ATCO Gas stated that in Decision 2001-75, the Board defined this function as Marketing and Customer Information. ATCO Gas noted that in the Application, the function was renamed Consumer Information as the majority of the costs related to providing customers with information related to such items as energy use, safety, home service, etc. ATCO Gas indicated that the majority of the costs functionalized to Consumer Information were advertising, demonstrating and selling expense, and home service**.**

In its Argument, ATCO Gas stated that all costs in the Consumer Information function were classified based on a composite classification of the costs for all distribution service functions. ATCO Gas submitted that there was no evidence supporting an alternative classification method for these costs and on that basis, ATCO Gas argued that its proposed methodology should be approved as filed.

Calgary indicated that it did not investigate the classification and allocation of Consumer Information function costs in detail, and until such time as general principles of cost of service study methodology were firmly established, the level of effort in the classification of non capital intensive costs would be best addressed in future proceedings under sound regulatory principles which Calgary expected to emerge from this proceeding.

AUMA/EDM stated that ATCO Gas' position in Argument was not consistent with its views in the Application wherein ATCO Gas agreed that it was not appropriate to include the costs related to billing or ATCO I-Tek Call Centre costs in the composite classification of distribution service function costs.

While ATCO Gas indicated that all costs in the Consumer Information function were classified based on the composite classification of the costs for all distribution service functions, the Board notes that in the Proposed COSSs, the actual composite classification of distribution service functions used to classify the Consumer Information function accounts excluded the Billing function and certain Call Centre function costs related to ATCO I-Tek.

AUMA/EDM supported the classification of Consumer Information function costs as outlined in the Proposed COSSs.

#### Views of the Board

The Board notes that the composite classification of distribution service functions used to classify the Consumer Information function accounts is consistent with the method used to classify the Administration function accounts as outlined in the Proposed COSSs.

The Board considers the method to classify the Consumer Information function accounts as outlined in the Proposed COSSs to be reasonable and approves it accordingly.

### 5.2.3 Billing

ATCO Gas indicated that in historical COSS, billing was part of the Customer Accounting function. However, in the process of unbundling functions, billing was treated as a unique function. ATCO Gas noted that in the Application, the Billing function included costs related to billing, customer information systems, and customer enrollment. ATCO Gas indicated that the majority of the costs functionalized to Billing were developed software and customer billing and accounting.

The Board notes that in the Proposed COSSs about 95% and 96% of the total Billing function costs in the North and South, respectively, are classified as customer related and the balance are classified as commodity related.

Calgary did not take issue with the fact that ATCO Gas proposed to classify most of the Billing function costs as customer related. Instead, Calgary stated that the classification issue related to the Billing function revolved around the issue of demand related costs for those rate groups which are billed on three-part rates. Calgary submitted in Argument that the cost of fixed monthly billing and commodity billing should be the same for all classes of service and that the only remaining issue was the additional cost of demand billing. In order to address this issue, Calgary submitted that the use of the weighted customer approach[66] for the distribution of meter costs and billing costs to the rate classes could adequately address this issue under the Calgary proposal which was to split Rate Groups 1/11 and 3/13 into four stand alone Rate Groups.

ATCO Gas submitted that it addressed the costs related to demand billing in the response to Item 4.4 of the workshop process.[67] In that response, ATCO Gas noted that, based on the original I-Tek Business Services (ITBS) forecast provided in the ATCO Gas GRA for 2003 and 2004, the annual billing costs related to the complex service accounts represented approximately $95,000 on a total billing cost of approximately $15.7 million. ATCO Gas stated that bills were no longer rendered on a basis which would allow the identification of these costs. ATCO Gas submitted that no weight should be given to Calgary's comments because the comments constituted new evidence, the matter was reviewed in the workshops and the amounts under review were immaterial.

ATCO Gas argued that there was no evidence in this proceeding that would indicate that its proposed classification of the Billing function costs was not appropriate and on that basis, ATCO Gas requested that the Board approve the classification as filed.

### Views of the Board

The Board does not consider Calgary’s comments with respect to the distribution of Billing function costs to be very clear and it would have been helpful if these views were provided in evidence so that these views could have been tested and better understood. It is not clear to the Board whether Calgary, in referring to billing costs, is referring to all costs classified as customer related under the Billing function or whether Calgary is referring to Customer Billing and Accounting (account 713) costs which were classified as customer related. The Board agrees with ATCO Gas that it appears that the annual billing costs related to complex service accounts are not substantial.

[66] Weighted customer approach is a mechanism to determine relative costs to serve customers in current dollars. Weighted customer factors are derived based on the results of a meter and regulator cost study performed by the company in an effort to assign reasonable costs to the rate groups with larger meters. The calculation was provided in Tab G, page 86 of the Original Application.

[67] Workshop June 13 & 14, 2006 Meeting, Topic 4 Information Response, 2003/2004 GRA – Phase II, Application 1416346, p. 6 of 17, dated June 8, 2006

The Board notes that no other party provided comments on this matter.

The Board considers the methods to classify the Billing function accounts as outlined in the Proposed COSSs to be reasonable and approves them accordingly.

### 5.2.4 Call Centre

ATCO Gas proposed that the costs included under the Call Centre function be classified as customer related costs because these costs were directly related to the number of customers served.

Calgary did not take issue with the fact that ATCO Gas proposed to classify the Call Centre function costs as customer related. Calgary stated that these costs were distributed to the rate classes based on the forecast number of customers. Calgary indicated that, while it did not investigate this matter in detail, these costs could be directly assigned in proportion to the rate class source of a call if the rate class of the caller could be determined at the time of the call.

ATCO Gas submitted that Calgary's comments constituted new evidence which ATCO Gas had no opportunity to explore. ATCO Gas stated that the suggestion of Calgary does not stand up to close scrutiny. ATCO Gas indicated that it was classifying forecast costs in this process, not actual costs. ATCO Gas also stated that there was nothing on the record of this proceeding to indicate that the number and length of calls from different rate groups in one year would necessarily be indicative of another year. ATCO Gas argued that the comments of Calgary should be disregarded and given no weight by the Board. ATCO Gas submitted that there was no evidence in this proceeding that would indicate that the classification of Call Centre function costs was not appropriate and on that basis, ATCO Gas requested that the Board approve the classification as filed.

**Views of the Board**

The Board concurs with ATCO Gas that the costs being classified are forecast costs rather than actual costs. The Board notes that there was no analysis in relation to the practicality, appropriateness or potential cost implications in association with the Calgary suggestion that costs could be directly assigned on the basis of designating calls on the basis of which rate class was making the calls. Additionally there was no analysis of whether the costs ought to be considered as to the use of the Call Centre or the general availability of the Call Centre to all customers.

Accordingly the Board approves the ATCO Gas proposal that the costs included under the Call Centre function be classified as customer related costs because these costs were directly related to the number of customers served by ATCO Gas.

### 5.2.5 Credit and Collections

ATCO Gas stated in Argument[68] that that all costs in the Credit and Collections function were classified based on the composite classification of all distribution service function costs. In the Application, however, ATCO Gas stated that it was not appropriate to include the costs related to

[68] Argument, p. 8

billing or ATCO I-Tek Call Centre costs for purposes of this classification and that the cost of service was modified accordingly.[69] The Board agrees with AUMA/EDM[70] that it appears that the ATCO Gas Argument misstated ATCO Gas' position.

The Board considers the Proposed COSSs are consistent with the views expressed by ATCO Gas in the Application and notes that AUMA/EDM supports this view. In the Proposed COSSs, the actual composite classification of distribution service functions used to classify the Credit and Collections function accounts excluded the Billing function and certain Call Centre function costs related to ATCO I-Tek.

Calgary did not take issue with the proposed classification of Credit and Collections function costs but it also claimed that it did not investigate the classification of these costs in detail.

With respect to the distribution of these costs to the rate classes, Calgary stated that to the extent that these costs could be identified by rate schedule, there was the potential to directly assign these costs to the appropriate classes of service.

ATCO Gas submitted that Calgary's comments constituted new evidence which ATCO Gas had no opportunity to explore. On that basis, ATCO Gas argued that such comments should be disregarded and given no weight by the Board.

**Views of the Board**

The Board notes that no other party commented on the distribution of costs under this function.

The Board considers that it would have been helpful if Calgary's views were provided earlier in this proceeding so that these views could have been explored further.

The Board notes that the composite classification of distribution service functions used to classify the Credit and Collections function accounts was consistent with the method used to classify the Administration function accounts and Consumer Information function accounts as outlined in the Proposed COSSs.

At this time, the Board considers the method to classify the Credit and Collections costs as outlined in the Proposed COSSs to be reasonable and approves it accordingly. However, in its next GRA Phase II, the Board suggests that ATCO Gas comment on whether these costs are or can be tracked by rate class.

### 5.2.6 Meter Reading

ATCO Gas proposed that the costs included under the Meter Reading function be classified as customer-related costs because these costs were directly related to the number of customers served. ATCO Gas submitted that there was no evidence in this proceeding that would indicate that the classification of Meter Reading function costs was not appropriate and requested that the Board approve the classification as filed.

[69] Application, p. 5
[70] Reply Argument, p. 3

Calgary did not take issue with the fact that ATCO Gas proposed to classify the Meter Reading function costs as customer related. Calgary stated that these costs were distributed to the rate classes based on the forecast number of customers. Calgary indicated that in its distribution methodology, ATCO Gas did not reflect the fact that Rate 3/13 customers may incur more or less cost for meter reading than the Rate 1/11 class because all Rate 3/13 customers have AMR devices.

ATCO Gas submitted that Calgary's comments constituted new evidence which ATCO Gas had no opportunity to explore. ATCO Gas argued that such comments should be disregarded and given no weight by the Board.

**Views of the Board**

The Board considers that it would have been helpful if Calgary's views were provided earlier in this proceeding so that these views could have been explored further. However, in its next GRA Phase II, the Board suggests that ATCO Gas comment on whether its method for distributing these costs to the rate classes should be modified in light of Calgary's comments above. The Board notes that no other party commented on the classification of costs under this function.

At this time, the Board considers the method to classify the Meter Reading function costs as outlined in the Proposed COSSs to be reasonable and approves it accordingly.

### 5.2.7 Load Balancing and Load Settlement

In the Original Application, ATCO Gas proposed that the costs under the Load Balancing and Load Settlement functions be classified as commodity related. However, in the Application, ATCO Gas stated that upon further review of the nature of the costs that are expected to be incurred related to these functions, it would be more appropriate to classify costs under these functions as customer-related costs.

ATCO Gas stated that historically, load balancing costs were contained within the retail function performed by ATCO Gas as the activities related to load balancing were an indistinguishable component of the retail function.

ATCO Gas indicated that it no longer performs a retail function and that the functions that will be performed by ATCO Gas under load balancing and load settlement will be completely unique to anything ATCO Gas has previously performed.

ATCO Gas indicated that the most significant costs that will be assigned to the Load Balancing and Load Settlement functions will be the system costs related to DFSS and Gas Transportation Information System (GasTIS)[71] as well as the staff costs. ATCO Gas submitted that none of these costs will be affected by the magnitude of gas consumed by customers.

[71] In Decision 2006-098, p. 43, the Board noted that the requirements for a GasTIS would be established in Module 3 and that ATCO Gas indicated that the purpose of GasTIS was to provide retailers with direct access to their accounts in order to observe their customer's aggregate consumptions, issue nominations and observe their account balances. GasTIS will also provide ATCO Gas with the aggregation of supply nominations necessary to manage its distribution system load balancing and that the aggregation of supply nominations would be accomplished through an interface between ATCO Gas' GasTIS and ATCO Pipelines' TIS.

ATCO Gas stated that it was proposing to classify the load balancing costs as customer related because the cost driver for these costs will be the number of accounts, or customers, that need to be processed. ATCO Gas also stated that load settlement processes for a small residential account will be similar to the processes required for a commercial account.

The Board notes that the costs included under these two functions in the Proposed COSSs are split equally between the two functions and shared equally between the North and South. The costs under these two functions include some minor labour costs and other assigned expenses.

The Board also notes that in its compliance filing for this Decision, ATCO Gas is expected to use the most current approved revenue requirement forecast available for the determination of the 2007 final rates and that it is expected that this revenue requirement would incorporate the 2007 impact[72] of the DFSS in addition to other items.[73]

In Decision 2006-098,[74] the Board accepted ATCO Gas' proposal to proceed immediately with Module 3,[75] which forms part of Phase 2 Part B of the Retailer Service and Gas Utilities Act Compliance process,[76] while working with customers to test the DFSS. The Board also agreed that a one year test period was desirable and the Board directed ATCO Gas to conduct a one year test of the DFSS system commencing November 1, 2006.

PICA, AIPA and the R13 Group supported ATCO Gas with respect to its proposed classification of the costs under the Load Balancing and Load Settlement functions.

PICA submitted that although load balancing and settlement functions deal with gas volumes, these activities are specific to each customer. In this regard, PICA argued that the same activities concerning load settlement and balancing have to be performed whether a specific customer consumes 100,000 GJ or 100 GJ per annum.

AUMA/EDM submitted that based on the definition of load balancing, as outlined in Decision 2006-098, load balancing involves "the sale or acquisition of volumes required to balance gas that has largely physically flowed on the ATCO Gas distribution systems." AUMA/EDM submitted that it involved both physical load balancing and load balancing administration which were commodity issues.

72 In Decision 2006-098, and its Errata, the Board determined that there would be no revenue requirement impact in 2005 or 2006, and that the net 2007 revenue requirement impact would be a credit to ATCO Gas South customers of $110,000 and a credit to ATCO Gas North customers of $113,000.

73 ATCO Gas Rebuttal Evidence, dated November 24, 2006, pp. 6-7 of 22

74 Decision 2006-098 – ATCO Gas Retailer Service and Gas Utilities Act Compliance Phase 2 Part B Customer Account Balancing and Load Balancing (Application No. 1411635) (Released: October 10, 2006) (Errata released: November 7, 2006), pp. 38-39

75 As outlined in Decision 2006-098, Appendix 5, p. 6 of 7, the objective of Module 3 is to develop and implement information systems to forecast consumption and establish final end-use customer consumption, to aggregate the end-use customer data into accounts for respective retailers, self-retailers and the DSP so they can monitor and nominate gas supplies into their accounts and to establish details of customer account balancing implementation procedures.

76 This was in response to directions from the Board in a letter of July 26, 2005, which was issued in conjunction with Decision 2005-081. In the Application ATCO Gas proposed a consultative process to advance topics related to customer account balancing and load balancing procedures using modules

AUMA/EDM submitted that load balancing costs were a function of the magnitude of gas consumed by customers - in other words, a requirement by ATCO Gas to physically match the customer's supply receipts into the system with the delivery volumes consumed by that customer. AUMA/EDM argued that the costs of load balancing were not driven by or a function of the number of customers but, rather, their relative consumption and should be assigned on a commodity basis.

AUMA/EDM submitted that, although it might be argued that load settlement functions "are specific to each customer", there was no basis for suggesting that load balancing functions could be interpreted in that matter. AUMA/EDM submitted that PICA's interpretation flew in the face of the Board's definition which stated that load balancing involves "… the sale or acquisition of volumes required to balance gas that has largely physically flowed on the ATCO Gas distribution system."[77]

AUMA/EDM submitted that PICA appeared to base its conclusion on an inappropriate hypothetical comparison between a customer consuming 100,000 GJ and a customer consuming 100 GJ per annum. AUMA/EDM argued that such a comparison should be based on the out-of-balance volumes which, in turn, involves "… the process of acquisition or disposition of gas supplies by the utility to maintain the pipeline system pressures in balance."[78]

AIPA submitted that load balancing costs were caused by customers' load imbalances on a monthly basis. On this basis, AIPA argued that load balancing costs should be classified as customer costs to reflect the costs being caused by the average number of customers in a particular month. AIPA also submitted that load settlement costs were caused by the average number of customers in the month. On this basis, AIPA argued that the classification of these costs should be 100% customer-related.

In response to AIPA's submission that load imbalances occur on a monthly basis, AUMA/EDM stated that was not correct because imbalances occur on a real-time basis and, in any event, the timing of the event should not dictate the manner in which the cost should be classified.

The R13 Group argued that ATCO Gas' proposed classification method should be approved. The R13 Group submitted that the correct approach for evaluating load balancing and load settlement costs was to evaluate what factor causes these costs to increase or decrease. On this basis, the R13 Group suggested that the following questions should be considered:

- Will load balancing costs be any different for a small residential customer and a large residential customer?
- Will load balancing costs increase if there is no growth in the number of customers in the system, but the existing customers' load increases?
- If the number of customers increases but ATCO Gas experiences no net load growth, will load balancing costs increase?
- Will the cost of resolving a small imbalance for a residential customer be any different than the cost for resolving a large imbalance?

[77] AUMA/EDM Argument, pp. 8-9
[78] Decision 2005-081, p. 2, Footnote 4

The R13 Group claimed that Calgary's argument addressed none of these issues, but simply relied on the vague idea that load balancing involves load and must be classified and allocated accordingly. The R13 Group submitted that in effect like meters costs, balancing costs were incurred for each customer who needs to be balanced; they were not affected by the magnitude of the consumption of individual customers.

The R13 Group suggested that the systems-related aspects of load balancing and load settlement cost appeared to be conceptually similar to billings costs, which Calgary appeared to agree should generally be classified as customer-related.[79]

AUMA/EDM was not opposed to ATCO Gas' proposed method of classification of the costs under the Load Settlement function.

Calgary and the CCA did not agree with the ATCO Gas position with respect to the classification of costs under the Load Balancing and Load Settlement functions, and instead proposed that the costs under these functions be classified as commodity related.

Calgary submitted that the proposed Load Balancing and Load Settlement function costs were entirely driven by the volume differentials between gas delivered by the DSP and Retailers and the gas consumed by their customers. Calgary indicated that if deliveries equal consumption, irrespective of the number of customers, there was no imbalance and thus no settlement. On that basis, Calgary argued that the load balancing and load settlement costs should be classified as commodity.

ATCO Gas submitted that Calgary's position ignored the fact that the system and staff costs will be incurred regardless of whether every retailer balances perfectly each day. ATCO Gas argued that it will still be required to provide information to retailers on a daily basis, perform monitoring functions and have the ability to perform load balancing as required.

Calgary stated that deliveries from the DSP and Retailers were based on a forecast over which customers have neither control nor input. Calgary indicated that it was the responsibility of the DSP and Retailers to manage their deliveries in proportion to their customers' consumption, not the number of customers served by them. On that basis, Calgary argued that the cost driver was volume, not the number of customers served.

ATCO Gas submitted that the deliveries from the DSP and Retailers do not have any relation to the costs ATCO Gas will incur for these functions and that the costs exist because the customers exists, not because of any relationship to throughput on ATCO Gas' system.

With respect to load balancing, Calgary submitted that it was the accuracy of the forecasts and the methodology employed that drive load balancing costs, not the number of customers. Calgary argued that a large customer with a large volume could create as large an imbalance as a number of small customers and on that basis, the costs of load balancing should be classified as commodity.

[79] Calgary Argument, p.17.

The CCA agreed with Calgary that the proposed costs under the Load Balancing and Load Settlement functions should be classified as commodity related because the cost driver was volume. The CCA argued that out of balance volumes caused imbalances which were completely unrelated to the number of customers on the system.

The CCA submitted that the DFSS and GasTIS were computer programs used to balance the energy requirements on the ATCO Gas system. The CCA indicated that the systems needed to be in place no matter how many customers were on the ATCO Gas system. The CCA argued that simply because ATCO Gas stated that none of the costs will be affected by the amount of gas consumed by customers does not mean the costs should be allocated to customer. The CCA submitted that the number of customers does not drive load balancing and settlement costs.

The CCA claimed that distribution customers, particularly residential, were not the customers who would utilize the load balancing and settlement systems. The CCA submitted that the data would be utilized by Rate 13 customers, natural gas retailers and the DSP. The CCA indicated that there would only be a handful of customers who utilize the output of the load balancing and settlement systems. The CCA submitted that the systems were needed to ensure energy costs were allocated to the natural gas retailers and the default supplier. On that basis, the CCA argued that the costs of the process should be classified as energy, not customer.

ATCO Gas indicated that the parties advocating classification of these costs on the basis of 100% commodity were confusing the cost of the load balancing activities (i.e. the Y-day instrument) with the costs functionalized to these functions. ATCO Gas submitted that the cost of performing load balancing itself will be recovered through the Load Balancing Rider, not cost of service delivery rates. ATCO Gas indicated that the costs being functionalized in the COSSs were mainly system and staff costs. ATCO Gas argued that these costs were fixed and will not vary with consumption.

ATCO Gas submitted that these costs should be shared equally by all ATCO Gas customers because these systems provide the same service regardless of consumption. ATCO Gas argued that it would not be fair to have a 1,000 GJ customer pay more for these systems than the 100 GJ customer, which would be the result if load balancing or load settlement costs are classified as 100% commodity related.

**Views of the Board**

Based on the views from parties on this matter, it appears to the Board that there is a certain amount of confusion related to the Load Balancing and Load Settlement functions with respect to definition and scope. This confusion may have been caused by the titles of these functions in relation to the concepts of customer account balancing, load balancing and load settlement that were recently discussed in the proceeding which led to Board Decision 2006-098. This confusion may also have been caused by the fact that ATCO Gas' role in relation to these functions and concepts is still evolving.

With respect to the Load Balancing and Load Settlement functions, ATCO Gas indicated that the costs being functionalized in the COSSs were mainly system and staff costs and that these costs were fixed. ATCO Gas indicated that the system costs were related to the DFSS and GasTIS. While ATCO Gas has focused the discussion on its vision for the Load Balancing and Load Settlement functions, the Board notes that at this time, the Board has only approved 2007 revenue requirements associated with the DFSS. The proposed GasTIS has yet to be tested in a regulatory proceeding.

Since the current decision is establishing new rates based on 2007 revenue requirements, the Board considers it appropriate to focus primarily on the classification of costs for the Load Balancing and Load Settlement functions for 2007 and the costs expected to be included under this function in 2007.

At this time, the Board does not consider it appropriate to make a determination with respect to the classification of costs that ATCO Gas expects to include under the Load Balancing and Load Settlement functions in the future because the scope of these functions is still evolving, GasTIS has not been tested and the Board has not yet made final determinations with respect to customer account balancing, load settlement and load balancing, as described in Decision 2006-098. However, as outlined further below, the Board has provided some preliminary views on this matter.

In regard to 2007, the expected revenue requirement associated with these functions is only expected to be about $170,000 in the North[80] and South.[81] The Board notes that most of the costs are labour related and that these costs are partially offset by costs associated with the DFSS. ATCO Gas was directed to conduct a one year test of the DFSS commencing November 1, 2006.

With respect to the DFSS, the Board notes that this system is expected to support load balancing, customer account balancing and load settlement.

> In Attachment 7 to its written evidence, p. 4, AG indicated that DFSS will provide daily forecasts and backcasts for non-SCADA distribution interconnections which AG submitted was necessary for load balancing.[82]
>
> Each morning, a backcast for the previous gas day is proposed to be completed for each retailer. This daily backcast is envisioned as the best available estimate (prior to settlement) of the retailer's customers' consumption for the previous gas day. ATCO Gas proposes to utilize a complex DFSS model, involving numerous forecasting procedures, to calculate the previous gas day's usage by using actual temperatures in a backcasting model. After the meter has been read, the consumptions allocated to each retailer's end-use site each day are referred to as settlement. ATCO Gas considered that the difference between the backcast and settlement, or backcast/settlement variance, is an important consideration in the determination of the minimum range for the imbalance window.[83]
>
> In its written evidence, p. 62, AG submitted that the One Bill Model processes allow retailers to enroll customers on a daily basis and this requires the utility to set up its settlement processes on a daily basis to ensure that it matches the retailer to the site correctly. AG indicated that the DFSS was developed to meet these settlement processes and was required regardless of which customer account balancing methodology was put in place.[84]

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[80] North: Load Balancing $144k + Load Settlement $145k + DFSS ($113k) = $176k.
[81] South: Load Balancing $140k + Load Settlement $141k + DFSS ($110k) = $171k.
[82] Decision 2006-098, p. 36, footnote 50
[83] Decision 2006-098, p. 32
[84] Decision 2006-098, p. 36, footnote 51

Since the revenue requirements associated with the Load Balancing and Load Settlement functions are not significant for 2007, the Board is prepared to accept ATCO Gas' proposal to classify these costs as customer related for the purposes of this proceeding.

While most parties referred to load balancing and load settlement in their views with respect to the classification of costs under the Load Balancing and Load Settlement functions, it appears to the Board that the parties were actually structuring their argument around the concepts of load balancing, load settlement and customer account balancing.

Regardless of the terminology, the Board considers it appropriate to provide the following views in order to assist ATCO Gas and other parties with respect to future Phase II matters that are anticipated since it appears that ATCO Gas will request approval of future revenue requirements associated with the DFSS and GasTIS.

It appears that the functionality of the DFSS is expected to support load balancing, load settlement and customer account balancing. It also appears to the Board that the GasTIS is also expected to support load balancing, load settlement and customer account balancing and that it is expected that the GasTIS would interface with the DFSS.

> ATCO Gas Written Evidence, p. 78. The Board notes that the requirements for a Gas Transportation Information System (GASTIS) will be established in Module 3 and that AG indicated that the purpose of GasTIS is to provide retailers with direct access to their accounts in order to observe their customer's aggregate consumptions, issue nominations and observe their account balances. GasTIS will also provide AG with the aggregation of supply nominations necessary to manage its distribution system load balancing and that the aggregation of supply nominations would be accomplished through an interface between AG' GASTIS and AP' TIS.[85]

Given the above, it appears to the Board that future costs under the scope of the Load Balancing and Load Settlement functions are expected to be incurred in order to allow ATCO Gas to load balance its distribution system and to ensure that Retailer and DSP accounts can be settled. Costs are also expected to be incurred so that Retailers and the DSP can manage their respective accounts.

In regard to load balancing, the Board notes the following excerpt[86] from Decision 2006-098.

> With respect to load balancing, the Board will consider incorporating both a physical or operational component as well as an associated administrative or supply component into the definition of 'load balancing' for purposes of this Decision. **As indicated above, the physical quantity of gas required to load balance the distribution system in real time is obtained from the ATCO Pipelines system. The amount of gas required to balance the ATCO Gas FSU [Firm Service Utility] accounts on ATCO Pipelines is the difference between the amount of gas received by or delivered to the distribution systems and the amount of gas made available to the distributor by retailers and the DSP for any given time period for the respective systems. In addition the imbalance in the ATCO Gas FSU accounts must be dealt with in accordance with the prevailing administrative policies for customer accounts on the ATCO Pipelines system**.

[85] Decision 2006-098, p. 43, footnote 79
[86] Decision 2006-098, p. 11

Based on the evidence in this proceeding and the Board's findings in Decision 2006-098, the gas purchases and sales required by ATCO Gas to balance its FSU accounts are not expected to be part of revenue requirements used to determine ATCO Gas' delivery rates, rather they will be recovered through a deferral account mechanism.

While ATCO Gas claims that the costs expected to be included in the Load Balancing and Load Settlement functions will be fixed, the Board directs ATCO Gas to provide further explanation in this regard. In particular, the Board is interested in understanding whether ATCO Gas expects any variable cost component associated with the DFSS and GasTIS and any other costs functionalized to these functions. This explanation should be provided in the future proceeding wherein ATCO Gas requests approval for DFSS and GasTIS related costs.

ATCO Gas proposed to share costs equally between the Load Balancing and Load Settlement functions in the Proposed COSSs and it also appears that ATCO Gas has a desire to continually share the costs between the two functions in some manner in the future. ATCO Gas also indicated that the main costs to be included in these functions are related to the DFSS and GasTIS. The Board notes that the DFSS and GasTIS are both expected to not only support load balancing and load settlement, but these systems are also expected to support customer account balancing. Given the above, ATCO Gas may want to consider renaming or restructuring the Load Balancing and Load Settlement functions so that the resulting function(s) and associated costs are consistent with the scope of the included activities.

### 5.2.8 Gas Supply

ATCO Gas noted that it did not functionalize any costs to this function.

ATCO Gas stated that with the transfer of its retail business to Direct Energy Regulated Services (DERS) costs were no longer functionalized to this function. ATCO Gas also stated that the cost related to the buying and selling of gas for load balancing will be included in the Load Balancing function in future applications.

### 5.2.9 Production and Gathering

ATCO Gas proposed to classify all costs under the accounts in this function as commodity related. ATCO Gas noted that the benefits of production and gathering were provided to South customers through the Company Owned Production Rate Rider (COPRR)[87] which was provided on a commodity rate basis. ATCO Gas indicated that no party took issue with the classification of these accounts. ATCO Gas requested that the Board approve the classification as filed.

Calgary stated that ATCO Gas' proposed classification method was for all practical purposes, a universally accepted methodology in all North American regulatory jurisdictions. Calgary noted that it took no issue with this approach.

[87] The COPRR relates to the difference between the market value of the gas produced from the south production facilities owned by ATCO Gas South and the royalty cost of gas.

**Views of the Board**

The Board notes that costs under this function are only applicable to the South. The Board notes that no other parties provided comments with respect to the classification of costs for this function.

The Board considers the proposed method to classify the Production and Gathering function accounts to be reasonable and approves it accordingly.

### 5.2.10 Storage

ATCO Gas proposed to classify all costs under the accounts in this function as commodity related. ATCO Gas stated that this commodity classification was consistent with the fact that the Company Owned Storage Rate Rider (COSRR)[88] was implemented on a commodity basis.

Calgary stated that it has taken issue with the classification of storage costs as commodity related going back to Decision 2001-075. Calgary submitted that the fixed cost of storage were no more commodity driven than the fixed cost of mains. However, at this time, Calgary indicated that issues surrounding the classification of Carbon should be deferred until such time that all regulatory and appeal decisions were rendered on the Carbon issues.

**Views of the Board**

The Board notes that costs under this function are only applicable to the South. The Board also notes that the classification of storage was dealt with in Decision 2003-028[89] wherein, the Board determined it appropriate to classify the costs as commodity related.

> The Board also notes Calgary's concern that capital and operating costs of Carbon storage were allocated, in Decision 2000-16, to Rate classes 1 and 3 on the basis of demand, but allocated to all classes on the basis of throughput in the COSS. With respect to Calgary's observation that this change in cost allocation has not been tested in any proceeding, the Board notes that the change in cost allocation was subject to examination by parties and by the Board in the written process dealing with the change to a monthly GCRR, which was approved in Decision 2002-034. The Board agrees with ATCO that the allocation of Carbon storage costs appropriately reflects the impact of the treatment of Carbon storage costs, as approved in Decision 2002-034.[90]

The Board notes that no other parties provided comments with respect to the classification of costs for this function.

The Board considers the proposed method to classify the Storage function accounts to be reasonable and approves it accordingly.

[88] The COSRR relates to the ATCO Gas South owned storage facility used by third parties.
[89] Decision 2003-028: ATCO Gas South, 2001/2002 General Rate Application, Evaluation of the Need for 2002 Phase II, Application No. 1286129
[90] Decision 2003-028, p. 4

### 5.2.11 Transmission

ATCO Gas proposed to classify the costs under this function as demand related. ATCO Gas submitted that the driver of these costs was the peak demand of the distribution system. ATCO Gas requested that the Board approve the classification as filed.

Calgary indicated that it had no issue with ATCO Gas' proposed classification.

**Views of the Board**

The Board notes that no other parties provided comments with respect to the classification of costs for this function.

The Board considers the method to classify the Transmission function costs to be reasonable and approves it accordingly.

### 5.2.12 Distribution Meters

The Distribution Meter function includes direct asset-related expenses for meters, regulating and meter installations and developed software[91], direct cash expenses for removing and resetting meters, meters and regulators and supervision[92] and it also includes other assigned asset-related and cash expenses.

This section will first review the classification of two of the direct asset-related expenses (meters and regulating & meter installations) and then the classification of the remaining accounts under this function will be reviewed.

#### 5.2.12.1 Accounts 474 and 478

In Decision 2000-16, the Board accepted that the costs in accounts 474 (regulating and meter installations) and 478 (meters) should be classified as customer related and that the costs should be distributed to the rate groups using a weighted customer approach[93] (Weighted Customer Meter Approach). The Board also determined that the costs for the other Distribution Meter and Regulator related accounts would also be classified as customer related and distributed to the rate groups using the Weighted Customer Meter Approach.

In the Original Application, ATCO Gas proposed that the costs in these accounts continue to be classified as customer related and distributed to the rate groups using the Weighted Customer Meter Approach. ATCO Gas stated that the types of meters and associated costs vary from a small house meter to a large commercial/industrial meter and to simply distribute these costs on the basis of average customers would not assign reasonable costs to the rate groups with larger meters.

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[91] Accounts 478, 474 and 402 respectively

[92] Accounts 673, 678 and 670 respectively

[93] ATCO Gas determined the replacement cost of meters and regulators for each rate group and then determined a replacement cost per customer for each rate group (the Weighting Factors). The Weighting Factors were then divided by the lowest Weighting Factor to determine an adjusted weighting factor for each rate class. The adjusted weighting factor for each rate class was then multiplied by the forecast customer count for each rate class to determine a weighted customer count for each rate class. In order to distribute the meter and regulator related expenses to the rate classes, the applicable cost was multiplied by the ratio of weighted customer count for each rate class to the total weighted customer count.

ATCO Gas stated that subsequent to the Original Application and during workshop discussions, it was highlighted that differentiation in meter costs also occurs (although not to the same degree) within the current Rate 1 rate group since there was a range of different meter costs for a residential customer to a small commercial/industrial customer. Calgary prepared an analysis that illustrated that meter replacement costs increased as consumption increased. This analysis led to a suggestion by Calgary that the Low Use Rate Group (Rates 1 and 11) be split at a break point of 300 GJ and the High Use Rate Group (Rates 3 and 13) be split at a break point of 30,000.[94] This suggestion led to discussions about a minimum system method to classify meter costs as customer related and demand related.

In the Proposed COSSs, ATCO Gas proposed to use a minimum system method to classify the costs under accounts 474 and 478 (the Meter Minimum System Method). ATCO Gas stated that the Meter Minimum System Method established the customer-related costs by applying the 2007 forecast costs under accounts 474 and 478 to a ratio which was derived by taking the cost to replace all existing meters with the minimum sized meter and dividing this cost by the cost to replace all existing meters with the same size meter. ATCO Gas noted that the remaining costs were classified as demand-related costs.

The Proposed COSSs show that for ATCO Gas South, about 68% of the costs in these accounts would be classified as customer related and for ATCO Gas North, about 58% of the costs would be classified as customer related.

Based on ATCO Gas's proposal, CCA claimed that residential and other small customers in the low use rate would be overcharged for meters because the residential customer would pay all its required meter costs in the fixed charge plus additional amounts in the variable charge.

ATCO Gas noted that the CCA calculated the annual fixed charge billings and variable charge billings based on the average residential consumption for the North and South using ATCO Gas' proposed rates. ATCO Gas also noted that it appeared that the CCA then compared the replacement cost for the minimum size meter and the annual fixed charge billings noted above to come to the conclusion that all of the meter costs for a residential customer were recovered in the fixed charge.

### Views of the Board

The Board agrees with ATCO Gas that the CCA analysis was not appropriate because the referenced meter replacement costs were not the meter costs included in the Proposed COSS and were only used as part of the Meter Minimum System Method to classify the costs as customer related and demand related.

The CCA stated that it agreed with ATCO Gas that as the annual consumption increases, the meter replacement cost increases. The CCA indicated that meters vary by demand and energy usage. The CCA considered that the use of an energy or demand cost classification would be fairer to small customers.

[94] Exhibit 003, Application, p. 6

As noted above, in Decision 2000-16, the Board approved costs in accounts 474 and 478 as being customer related since these costs would appear to vary based on the number of customer served by ATCO Gas. While further below the Board will give consideration to whether it is appropriate to now classify a portion of these costs as demand related, the Board does not consider it appropriate to classify these costs as 100% energy related or demand related as suggested by CCA. The Board does not consider the CCA reasoning on this point to be persuasive.

Calgary submitted that for this proceeding, meter costs should be classified as customer related and allocated to high and low use Rate Group 1/11 and all Rate Group 3/13 on the basis of weighted customers based upon the replacement costs of meters used to serve each class of customers (the Calgary Meter Proposal).

Calgary submitted that for many years ATCO Gas has classified meters as customer related and allocated these costs on the basis of weighted customers. Calgary stated that ATCO Gas did not provide any studies or analyses that indicated that demand drives the cost of metering and therefore ATCO Gas had failed to provide sufficient support for its proposed classification change.

Calgary also stated that it was common practice in the industry to classify metering costs as customer related, even for customers with demand meters. Calgary argued that the primary driver of the need for a meter is a customer.

AUMA/EDM also appeared to support that meter costs should be classed as customer related and distributed to the rate classes using a weighted customer approach but instead of splitting the proposed Low Use Group into groups based on consumption, AUMA/EDM suggested that the Low Use group should be split into residential and commercial groups (the AUMA/EDM Meter Proposal).

ATCO Gas submitted that it appropriately addressed cost causation through the classification of meter costs into customer and demand components rather than through the creation of additional rate groups.

In regard to the Calgary Meter Proposal and AUMA/EDM Meter Proposal, the Board notes that in Section 4.2, the Board determined it appropriate to accept ATCO Gas' proposed rate groups (Low Use and High Use) for this proceeding and not split these groups.

PICA stated that, given the availability of data to directly assign meter costs,[95] it considered the weighted customer approach for allocating meter costs to rate classes preferable to the minimum system method. PICA also noted that while it recommended the weighted meter costs method be used for allocation of meter costs, PICA supported the use of the minimum meter cost for design of the Rate 1 fixed charge for purposes of this proceeding.

95 PICA claimed that as outlined in PICA-AG-4(b), ATCO Gas could directly assign each of the meters by size to different consumption ranges within each rate class. PICA also claimed that based on replacement cost of meters, ATCO Gas could determine the relative weight of meter costs applicable to different consumption ranges within each class and by rate class.

ATCO Gas stated that it did not understand the relationship implied by PICA of directly assigning costs to different rate groups versus the classification of those costs between customer and demand. ATCO Gas submitted that the direct assignment of these costs would still not address the issue regarding the range of meter replacement costs within the existing Rate Groups 1/11. ATCO Gas stated that even if the meter costs were direct assigned to the various Rate Groups, there would still be cross-subsidization within the Rate Groups if the costs are classified as 100% customer.

ATCO Gas stated that Calgary did not provide evidence to substantiate its assertions nor did it indicate in evidence why the ATCO Gas Proposal was not an acceptable solution. ATCO Gas argued that the fact that other utilities may or may not classify these costs as 100% customer was irrelevant.

ATCO Gas submitted that based on evidence[96] in the proceeding, as annual consumption per customer increases, the replacement cost of the meter to serve those customers also increases. This relationship demonstrates the shortcomings of classifying meter costs as 100% customer, which allocates the same meter costs to each customer within a Rate Group.

ATCO Gas stated that its methodology recognized that not all customers within a Rate Group have the same type of meters or related costs. ATCO Gas submitted that its classification methodology for Meter costs provides a more appropriate differentiation of costs for customers within a Rate Group based on consumption levels.

ATCO Gas indicated that its evidence[97] clearly demonstrates that there is a demand component to meter cost because as the annual consumption increases, the meter replacement cost increases.

In regard to its approach for investing in meters, ATCO Gas stated that there was a minimum size meter which was identified as the smallest practical size of meter that would need to be installed to serve a customer, regardless of load. ATCO Gas indicated that no consideration of customer specific load was required in the determination of its minimum size meter which was a 250 CFH meter. ATCO Gas submitted that on this basis, some portion of meter costs should be classified as customer related. ATCO Gas also indicated that as the capacity requirement for customers exceeded the limits of this minimum size meter, larger capacity meters are installed. On this basis, ATCO Gas argued that some portion of meter costs should be classified as demand related to recognize this fact.

ATCO Gas also indicated that the following evidence of Calgary also appears to support the classification of some portion of meter costs as Demand.

> *Meters are sized on the customers' maximum scf/h flow requirements. Thus, the meter cost is reflective of the load the customer places on the system.*[98]

96 Exhibit 003 under the Workshop Tab July 28, 2006 Meeting. Schedules labeled Item 4.2 Attachment (Revised) and Item 4.8(a) Attachment 2 (Revised), both dated July 14, 2006
97 Item 4.2 Attachment
98 Exhibit 024-01, p. 7, Question 5

ATCO Gas submitted that it was appropriate to consider that meters have a demand component since meters have capacity ratings[99] and since the capacity of meters installed and associated meter costs increase with annual consumption.[100]

ATCO Gas stated that the Meter Minimum System Method took into consideration the number of customers that would only require the minimum size meter, but it also took into consideration that there was a relationship between demand, meter size and cost.

The Board notes that both Calgary[101] and AUMA/EDM[102] considered that there was potential for consideration of a demand component of cost for meters used to serve high use customers, in Rate Group 1/11 and all Rate Group 3/13 customers.

AIPA indicated that the Meter Minimum System Method with the classification of meter costs into customer-related costs and demand-related costs provided for an increasing charge for metering costs for higher use customers and was therefore compatible with a single Low Use and High Use groups without any rate class split.

AIPA stated that the Weighted Customer methodology classified all meter costs as customer-related and does not take into account increasing meter costs with increasing consumption levels within a rate group. Therefore, AIPA considered that meter costs should be classified on the basis of the minimum system methodology as advocated by ATCO Gas in this proceeding.

While the Board has previously accepted that all Distribution Meter and Regulator expenses should be classified as 100% customer related, the Board is persuaded by the arguments by ATCO Gas and AIPA that some component of the costs under accounts 474 and 478 should be classified as demand related.

Given that the Board has determined to accept ATCO Gas' proposed Low Use and High Use classes and given that the evidence in this proceeding shows generally increasing meter costs with increasing consumption levels within these rate groups, the Board approves the Meter Minimum System Method proposed by ATCO Gas for accounts 474 and 478. The Board considers it appropriate that the classification reflect the fact that larger-usage customers require more expensive metering related equipment. Implicit in this approval is the fact that the Board considers it acceptable that meter replacement cost data was used in the Meter Minimum System Method. The Board considers that in relation to estimated replacement costs for distribution mains and services, less judgment is required to estimate meter replacement costs. The Board also notes that meter replacement cost data was also used by ATCO Gas in the previously approved Weighted Customer Meter Approach.

### 5.2.12.2 Other Accounts

In regard to accounts 673, 678 and 670 (removing and resetting meters, meters and regulators, and supervision, respectively), ATCO Gas submitted that these costs were related to the operation and maintenance of meters.

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[99] Exhibit 003, Workshop Information, July 28, 2006, Item 4.8(a) Attachment 2 (Revised)
[100] Exhibit 056, Item 4.2 Attachment (Revised)
[101] Argument, p. 20
[102] Reply Argument, p. 6

ATCO Gas proposed that the costs in these accounts be classified as customer related and demand related using the same percentages it determined for accounts 478 and 474 (meters and regulating, and meter installations, respectively). ATCO Gas claimed that this was consistent with past COSS.

For accounts 478 and 474, ATCO Gas proposed to classify about 68% of the costs in the South as customer related and about 58% of the costs in the North as customer related. The remaining costs were classified as demand related.

ATCO Gas submitted that the costs in accounts 673, 678 and 670 can vary with the size of meter being serviced, and therefore, the costs were to some extent driven by demand. The CCA agreed with ATCO Gas that costs related to the operation and maintenance of meters vary with the size of meter.

Calgary argued that the costs in these accounts were not driven by demand and that there was a lack of analysis regarding the development of cost drivers to support ATCO Gas' classification. Calgary submitted that cost associated with meter expenses were primarily driven by the number of meters, which was more closely associated with the number of customers than it was the demand of those customers.

The CCA did not support classifying these costs as customer related.

**Views of the Board**

The Board accepts ATCO Gas' claim that costs related to the operation and maintenance (O&M) of meters can vary with the size of meter being serviced. This is consistent with the conclusions accepted by the Board with respect to accounts 474 (regulating and meter installations) and 478 (meters) where the Board determined it appropriate that a portion of the costs in these accounts should be classified using a demand component to reflect that larger-use customers require more expensive metering equipment.

Therefore, the Board approves the classification method proposed by ATCO Gas for accounts 673, 678 and 670.

In regard to the remaining accounts under the Distribution Meter function, ATCO Gas submitted that there was no evidence that would indicate that the classification of these accounts was not appropriate. No other party provided comments. The Board considers that ATCO Gas' proposed classification methods are reasonable and on that basis, approves them as filed.

### 5.2.13 Customer Service

ATCO Gas stated that the Customer Service function included services provided on customer premises including emergency calls for gas odors, carbon monoxide, no heat, etc. ATCO Gas submitted that the costs under this function were classified as customer costs because the driver of these costs was the number of customers served.

**Views of the Board**

The Board considers the proposed classification of Customer Service function costs to be reasonable and notes that no other party commented on the classification of costs under this function. Accordingly, the Board approves the classification of these costs as proposed by ATCO Gas.

### 5.2.14 Distribution Mains and Services

ATCO Gas stated that the Distribution Mains and Services function identifies all asset and non-asset related costs attributable to the mains and services, and regulating stations that provide distribution service in the ATCO Gas service territory.

ATCO Gas stated that in its proposal, the majority of the Distribution Mains and Services costs were classified based on minimum plant studies. ATCO Gas submitted that the basic premise of a minimum plant study was that the commonly used minimum sized pipe was the minimum size installation necessary to provide service to a customer. ATCO Gas indicated that an investment of at least this magnitude was required regardless of volume and demand and was, therefore, dependent on the number of customers served.

This section will first determine the appropriate classification method for Distribution Mains followed by determination of the appropriate classification method for Distribution Services. The appropriate classification for other related accounts will then be determined.

#### 5.2.14.1 Account 475 – Distribution Mains

ATCO Gas proposed that all distribution mains costs for account 475 be classified utilizing a minimum plant study based on the outside diameter (OD) analysis (the Mains Minimum Plant OD Method) for various distribution main line pipe sizes.

Certain parties in the proceeding suggested, however, that feeder main costs should be separated from the remaining distribution main costs and classified separately. Therefore, in the following section, the Board will first consider whether feeder main costs should be classified separately.

***Feeder Mains***
Calgary, AUMA/EDM, CCA and AIPA suggested that feeder mains costs should be separated from the remaining distribution main costs and classified separately.

AUMA/EDM submitted that there was sufficient information on the record to arrive at the proportion of mains costs represented by feeder mains. AUMA/EDM argued that Account 475 - Distribution Mains should be separated into feeder mains and other mains based on the evidence[103] that 23% of total costs were attributable to feeder mains (the Feeder Main Evidence). AIPA supported this approach and absent any better information, Calgary also supported this approach.

While some parties take the position that costs associated with feeder main can be identified and separated with sufficient certainty from other mains, the Board does not agree. It appears to the Board that as the design of the ATCO Gas distribution system has evolved, the definitions of

[103] AUMA/EDM-AG-03

feeder main and main have become less clear and are likely to continue in this direction. In the hearing, ATCO Gas noted in an exchange with Board Counsel that:

> Historically, lower-pressure gas was delivered to customers' homes and businesses and feeder mains had IP [intermediate pressure] gas flowing through them. So our gas would come from a transmission line to a station; **the pressure would be reduced to IP, would flow through a feeder main**, and then it would hit another station, a district station, where the pressure would be reduced again, and then the gas would flow through even lower pressure gas to the homes and businesses of customers. So we had a nice clean distinction. **But now there is no more new district stations being planned and we delivered IP pressure to -- directly to people's homes and businesses** and the effect of that is that we're able to use smaller pipes for mains and services than we did historically, so while the 23 percent may be representative -- well, is representative of our seven-year spending history where we've been delivering IP gas directly to people's homes, we don't think it would be -- well, we aren't sure whether or not it would be representative of the entire spending history in that mains and feeder mains account.[104] [**emphasis added**]

ATCO Gas was further questioned by Board Counsel on the ability to distinguish feeder mains and mains as follows:

> Q. Thank you, sir. Mr. Feltham, I would like to go back to a discussion we were starting to have earlier with respect to understanding the difficulty in identifying feeder mains versus mains both with respect to physically identifying them and from a cost perspective. Nomenclature in the workshops and this proceeding seems to have been very important, and developing an understanding of the views of the parties on common terms has shown itself to be fairly critical. Just to get the nomenclature straight, could you give me ATCO's definition of what a feeder main is?
> A. MR. FELTHAM: ATCO's understanding of a feeder main is a pipe that goes from a gate station to an area where we deliver gas to customers. Typically there would not be a service coming off a feeder main.
> Q. Thank you, sir. And I understand from your earlier testimony that a feeder main could be a variety of sizes depending on the circumstances; is that correct, sir?
> A. MR. FELTHAM: That's correct, sir.
> Q. And you would not have one feeder main connecting to another feeder main? It has to go from a gate station to an area where customers are being serviced?
> A. MR. FELTHAM: A feeder could connect one feeder main to another feeder main.
> Q. Do you want to retry your definition then, sir?
> A. MR. FELTHAM: I guess the reason we're having a little bit of trouble is when we started delivering gas from -- to people's homes at IP pressure, that removed the district station, **so historically we would have been able to say the feeder mains were the pipe or network of pipes that connected the gate stations to the district stations** and then the district stations reduced the pressure again, delivered the gas into mains and that was then delivered to customers. **So in the absence of that district station node, I was trying to describe the feeder mains as those pipes that still perform that same function, deliver gas from the gate stations to the areas where we deliver gas to customers**. **So it may come directly from a gate station but it could also conceivably, that feeder main could also conceivably be connected to another feeder main**.[105] [**emphasis added**]

[104] Tr 366-367
[105] Tr 382-383

ATCO Gas confirmed that some of its facilities were clearly feeder mains, clearly mains and clearly services but there was also a portion of its facilities which could not be clearly defined.[106]

ATCO Gas indicated that the Feeder Main Evidence was based on a seven year[107] history of feeder mains costs and that its calculations determined that feeder mains comprised an average of 23% of the total capital expenditures on mains for these years, based on certain assumptions. ATCO Gas also stated, as quoted above, that while the 23% was representative of its seven-year spending history when ATCO Gas delivered IP gas directly to people's homes, it was not sure whether or not it was representative of the entire spending history in the mains and feeder mains account.[108][109]

ATCO Gas also stated that although it can identify the cost of its feeder mains in the year installed, there was no way to adjust that cost for the fact that the function of a feeder main can change to a main over time because it was unable to track specific costs to specific sections of pipe.

ATCO Gas stated that it does track feeder main costs separately in the year that the costs are incurred but when the costs go into its asset account numbers, there was no way to isolate the costs.[110] ATCO Gas stated that it does not track the costs of its feeder mains by asset account.

> So what we did is we took seven years of spending history and tried to approximate what our historical -- well, seven-year historical average spend history was and that turned out to be about 23 percent. But when we did the analysis, we had to move away from looking at the asset accounts because the dollars weren't tracked that way; and then we had to move into these appropriations that are referenced in Exhibit No. 62.
>
> And then that data is not clean either, because we have rural main extensions and services, obviously having mains and services in that, so we had to try and figure out what portion. So we looked at a couple years of history in that rural main extension and approximated the split between mains and services and that particular appropriation at 50 percent. And that comes to the calculation that's detailed in the IR response.[111]

In addition, ATCO Gas indicated that splitting costs based on pipe diameter was not possible. ATCO Gas stated that while feeder mains were generally larger than mains, this was not always the case.

ATCO Gas submitted that with no actual historical record, no pipe size distinction and no practical way to approximate the historical record, the net book value of feeder mains and mains cannot be distinguished. On that basis, ATCO Gas argued that there was no meaningful way to classify the cost of feeder mains differently from the cost of mains.

106 Tr 387-388
107 1999-2005
108 Tr 366-367
109 AUMA/EDM-AG-03(a)
110 Tr 29
111 Tr 232

ATCO Gas also indicated that the Feeder Main Evidence clearly showed a significant amount of variability in the percentage of urban feeder main costs in relation to all main costs over the seven year period, ranging from a low of 18% to a high of 31%.

AUMA/EDM disagreed with ATCO Gas' position and argued that there was sufficient information available on the record to distinguish the percentage of and cost of feeder mains as opposed to other mains.

In regard to the year-to-year variability in urban feeder main costs, in relation to all main costs, AUMA/EDM submitted that this should not be surprising since the bulk of the work done in Edmonton and Calgary was done by contractors. AUMA/EDM stated that at any given time, the cost would be a reflection of market conditions, contractor availability, size of contract and the nature of the work to be done.

AUMA/EDM submitted that since actual data was recorded and available, it should not be simply discarded out of hand. AUMA/EDM argued that a seven or nine year average should tend to normalize the ratio of feeder mains to total distribution mains.

AUMA/EDM noted that ATCO Gas provided a 5 year historic and forecast of urban feeder mains expenditures in its Phase I Application.[112] AUMA/EDM submitted that, since ATCO Gas records actual and forecast urban feeder mains expenditures and has provided 7 years of data showing the relative percentage of urban feeder mains to total distribution extensions (being 23% on average), there was no reason why this information should not be used for cost allocation purposes. AUMA/EDM argued that it was clearly the best information available and was useful to this proceeding. AUMA/EDM submitted that this additional information if added to the Feeder Main Evidence would result in the percentage of feeder mains to total mains expenditures over the 9-year period[113] of 24% (the Modified Feeder Main Approach).

AUMA/EDM submitted that the currently available data was a reasonable proxy for the percentage of urban feeder mains to total mains.

In response, ATCO Gas submitted that it was concerned that there was nothing to indicate the appropriateness of using a seven year history as a proxy to determine the percentage of rate base costs related to feeder mains versus mains.

ATCO Gas also stated that, while the cost of a feeder main could be identified in the year installed, AUMA/EDM have not addressed how to adjust the feeder main cost when required to reflect a change in the function of a feeder main.

While it appears to the Board that it would be possible to estimate the historical costs for feeder mains in older portions of the distribution system and may be possible to estimate costs for somewhat equivalent mains in the newer portions of the distribution system, the Board is not convinced that this exercise would be practical or cost effective to do for the entire system. Further, this exercise would also be problematic for specific sample portions of the system, given the amount of estimating that would be required and the difficultly in determining representative samples. The Board is especially concerned about directing such an exercise when the results of

[112] AG 2005-2007 GRA Phase I, Tables 2.2.11 and 2.2.12, p. 2.2-5(May 2005)
[113] 1999-2007

this exercise are unclear. The Board notes that parties do not even agree on how feeder main costs should be classified. Calgary and AUMA/EDM argued that feeder mains costs should be classified as 100% demand related while PICA and AIPA claimed that in addition to a demand component, these costs should also be classified with a customer related component. Accordingly, the Board does not consider it appropriate for ATCO Gas to undertake to estimate the historical costs related to feeder mains for its entire system nor on a sample system basis.

In addition, the Board believes the record is clear that ATCO Gas is unable to accurately identify and distinguish feeder mains from the rest of its distribution mains. Further, this difficulty becomes more severe as time passes and the system continues to grow. Accordingly, a cost methodology that is dependent on correctly identifying feeder main costs separately from mains costs is problematic, unreliable and is likely to be even more so in the future.

For the above reasons, the Board does not consider it appropriate to use the Feeder Main Evidence or Modified Feeder Main Approach to separate the costs of feeder mains from the costs of other mains. The Board agrees with ATCO Gas that there is nothing to support the appropriateness of using this evidence as a proxy to determine the percentage of rate base costs related to feeder mains versus mains.

As a consequence of the reality of the evolution of the distribution system and the increasing difficulty to distinguish feeder mains from mains, the continuing use of revenue requirement terms and cost allocations terminology that distinguishes between feeder mains versus mains becomes questionable. Therefore, ATCO Gas is directed to provide an assessment on whether it is still appropriate to continue to separately identify feeder mains in its capital program and/or whether a modified term and definition should be used. This assessment should be filed as part of its next GRA.

***Classification Alternatives for Distribution Mains***

Given that the Board determined in the section above that an estimate of feeder main costs would not be separated out from account 475, the Board will determine in this section how to classify all costs under account 475, distribution mains.

In this regard, the Board notes that Calgary recommended that feeder main costs should be classified as 100% demand related and that the remaining mains should be classified as customer and demand related.

The CCA considered that main costs should be allocated to demand because the classification of mains costs into customer and demand components would cause significant problems in the rate design for small customers. The CCA claimed that small customers would absorb an excessive amount of excess system costs and would be double allocated costs. CCA submitted that classifying mains costs as demand related was appropriate because it was the only allocation factor which was relatively consistent over Rate 1.

PICA submitted that all main costs (including feeder mains) should be classified as customer and demand related.

In regard to its approach for currently investing in distribution mains, ATCO Gas stated that there was a minimum size main which was identified as the smallest practical size of main that would need to be installed to serve a customer, regardless of load. ATCO Gas indicated that no consideration of customer specific load was required in the determination of its minimum size main which was 42 mm (millimetre) (with some minimal exceptions). ATCO Gas submitted that on this basis, some portion of mains costs should be classified as customer related. ATCO Gas also indicated that as the capacity requirement for customers exceeded the limits of this minimum size main, larger capacity mains would be installed. On this basis, ATCO Gas argued that some portion of mains costs should be classified as demand related to recognize this fact.

The R13 Group also recommended that the Board classify all mains costs, including feeder mains, into demand and customer components. The R13 Group stated that when a gas distribution utility such as ATCO Gas expands its distribution network to serve a set of new customers, it must accomplish two objectives. First, it must install enough mains footage to interconnect the customers. Second, each main must have sufficient capacity to meet the peak demands of all customers downstream of that main.

After considering the views of the parties above, the Board considers it appropriate to classify the costs under account 475 as customer related and demand related. The Board considers it appropriate to assume that mains are required to provide service to individual customers and to also meet the demand requirements of customers. The Board notes that no parties suggested that any mains costs be classified as commodity related. The Board also notes that it has traditionally classified mains costs as customer and demand related.

***Customer/Demand Classification Methods***

In the section above, the Board determined it appropriate to classify the costs under account 475 (distribution mains) as customer related and demand related. This section of this Decision first reviews the suggested methods for determining the amount of distribution mains costs that should be classified as customer and demand related.

ATCO Gas' proposal is reviewed first. Other proposals submitted by the various parties in this proceeding are subsequently outlined. The zero intercept method, which most interveners recommended in some form, is reviewed after each intervener proposal is outlined.

The section that reviews the zero intercept method also includes a discussion of the minimum system method since some parties have expressed similar comments with respect to both classification methods. These comments are also generally applicable to use of these methods for both distribution mains and services.

In the final subsection below, the Board makes a determination on the appropriate method to use for determining the amount of distribution mains costs that should be classified as customer and demand related.

***The Mains Minimum Plant OD Method***

ATCO Gas proposed to use the Mains Minimum Plant OD Method[114] to determine the amount of distribution mains costs (account 475) that should be classified as customer related and demand related. ATCO Gas stated that this methodology was approved in Decision 2000-16 and that it was not proposing a change from this Board approved methodology.

[114] The Mains Minimum Plant OD Method is shown on p. 77 of the Proposed COSSs

PICA noted that the Mains Minimum Plant OD Method was a variation of the minimum system method. PICA stated that under ATCO Gas's proposed method, the notional unit cost of the minimum diameter pipe applied to the entire system was considered to represent the customer component of costs for the system.

The R13 Group noted that in contrast to most standard cost classification methodologies, the Mains Minimum Plant OD Method relied on no cost information at all.

The R13 Group stated that the Mains Minimum Plant OD Method relied on the proposition that the installed per-meter cost of mains capacity was linearly proportional to the diameter of the main, and that there were no decreases in the average cost per meter as diameter increases. The R13 Group indicated that the Mains Minimum Plant OD Method was a traditional minimum system method that assumed there were no economies of scale associated with mains diameter.

ATCO Gas submitted that the results of its Mains Minimum Plant OD Method for the most part were within the 95% confidence interval[115] of Calgary's zero intercept study. ATCO Gas stated that it believed this was sufficient corroboration to support the continued use of the Mains Minimum Plant OD Method.[116]

ATCO Gas stated that the information used in the Mains Minimum Plant OD Method was readily available, and produced reasonable, stable, and consistent results over time.

AUMA/EDM and Calgary submitted that the Mains Minimum Plant OD Method was arbitrary and lacked in any theoretical or cost underpinning.

ABCOM stated that the Mains Minimum Plant OD Method was fraught with inconsistencies and inaccuracies and assumptions that rendered it difficult to feel much comfort about the allocations that flow from it. ABCOM submitted that the most glaring assumption was the minimum pipe sizes used by ATCO Gas and the impact this had on rural customers.

ABCOM claimed that the minimum mains size in rural areas was 26 mm in contrast with the remainder of the ATCO Gas system which was characterized as having a minimum of 42 mm. ABCOM also outlined typical urban[117] and rural sizes[118] of mains. ABCOM submitted that this was a significant difference that the application of the minimum system method in this case failed to consider.

In response, ATCO Gas submitted that ABCOM did not provide any references or support for its assertions other than to list a number of different pipe sizes for rural versus urban customers, all of which are considered in the ATCO Gas analysis (except for 73 mm which ATCO Gas claimed it did not use). ATCO Gas submitted that the assertions of ABCOM on this matter should be ignored as no evidentiary basis was provided.

The CCA submitted that the Mains Minimum Plant OD Method over allocated costs to residential and other small customers because classifying costs as customer and demand related

[115] Exhibit 016-01, CAL-AG-4(c)
[116] Argument, p. 27
[117] 42 mm, 60 mm, 88 mm, 114 mm, 168 mm, 219 mm, 273 mm, and 312 mm
[118] 42 mm, 48 mm, 60 mm, 73 mm and 88 mm

required small customers to pay for the minimum plant in the fixed charge plus additional costs in the form of demand charges. The CCA claimed that the minimum plant served all the demand needs for the small customer.

ATCO Gas stated that it was quite evident from a review of the CCA argument that its focus was to ensure that no significant costs were classified as customer related so that the resultant fixed charge and costs for low use customers would be minimized. ATCO Gas claimed that its methodology provided a fair treatment of costs across the whole range of customers from 0 to 8,000 GJ annually and argued that the CCA were focusing on only one faction of that Rate Group.

PICA submitted that the minimum system method was not an appropriate method for classifying mains costs. PICA stated that the mains connect the services to the transmission tap and that generally, each main was connected to several services and there was demand diversity on the distribution mains. PICA submitted that since mains could be shared by more than one service, the minimum system method tends to overstate the customer component of costs for distribution mains. This concern was supported by Calgary.

In this regard, ATCO Gas noted that the percentage of mains costs classified as customer related under its proposal for the South was 46.1% while Calgary's proposal of classifying 23% of mains costs (deemed to be feeder mains) as 100% demand related and the balance on the basis of the zero intercept study resulted in 65% of total mains costs classified as customer related. ATCO Gas submitted that if its methodology overstated the customer component, one must conclude that Calgary's zero intercept method was highly suspect.

The R13 Group claimed that the zero intercept study provided in the proceeding actually implied a higher customer component of costs than that produced by the Mains Minimum Plant OD Method under virtually all scenarios.[119] The R13 Group submitted that not only had Calgary failed to offer any evidence that the Mains Minimum Plant OD Method resulted in a customer component that was too high, the actual results of the only zero intercept method on the record in this respect indicated that the customer component was too low.

PICA and AUMA/EDM submitted that the Mains Minimum Plant OD Method did not recognize that the cost of each size of pipe does not increase in the same proportion as the increase in pipe size. PICA argued that economies of scale associated with larger pipe sizes should be expected because certain fixed costs associated with the pipeline and cost of installation do not vary with pipe size.

Calgary submitted that the primary failure of the Mains Minimum Plant OD Method was its lack of use of any form of cost data.[120] This concern was supported by AUMA/EDM and AIPA.

ATCO Gas acknowledged that no direct cost assumptions were made in its analysis and that indirectly, it assumed that a linear relationship existed between the costs of pipe installed and pipe size. However, ATCO Gas submitted that given the reasonability of its results in

[119] Application p. 13
[120] TR3 p. 348 line 8

comparison to the zero intercept study when compared to the 95% Confidence Interval,[121] it did not consider this to be inappropriate.

The R13 Group agreed that a system that was based on the minimum-sized pipe had some load carrying capability and that on this basis, it could be argued that the Mains Minimum Plant OD Method overstated the customer component of costs.

However, the R13 Group also submitted that the Mains Minimum Plant OD Method tended to understate the customer component of costs because it failed to recognize that per-meter mains costs could decline with mains size.

The R13 Group suggested that these objections were both credible and potentially significant in terms of cost allocation. The R13 Group stated that ideally, an alternative approach that eliminated or mitigated both of these objections would be preferred. The R13 Group stated, however, that these errors tend to offset one another. As such, the R13 Group indicated that it was not obvious that ATCO Gas' proposed method was necessarily biased in a particular direction. The R13 Group stated that while ATCO Gas' method was not ideal and in the absence of any better analysis, the Mains Minimum Plant OD Method should be retained and it should continue to apply to all mains, including feeder mains.

PICA submitted that while the R13 Group's suggestion above may have some superficial attraction, the biases in the Mains Minimum Plant OD Method were not offsetting. PICA claimed that the use of 26 mm pipe as the minimum size pipe for mains in the Mains Minimum Plant OD Method in place of 42 mm pipe, which was the minimum size pipe used under current planning assumptions, would tend to understate the customer component of mains costs. PICA submitted that this factor was not considered by the R13 Group in weighing the biases.

***The AIPA Mains Proposal***

AIPA recommended that account 475 (distribution mains) be separated into feeder mains and distribution mains.[122]

AIPA submitted that the feeder mains portion be classified between customer-related costs and demand-related costs on the basis of the zero intercept methodology. AIPA stated that this classification would recognize that a minimum system with zero throughput was required to connect a load area to the transmission tap on the ATCO Pipelines system. AIPA claimed that the zero intercept methodology based on pipe size squared as developed in Schedule C[123] would be appropriate. AIPA stated that this schedule utilized six data points commencing at a pipe size of 42.2 mm which was appropriate for feeder mains.

For distribution mains, AIPA recommended that the classification be based on the zero intercept methodology with the pipe size squared regression as per Schedule C except that 26 mm pipe should be included in the regression, since distribution mains include 26 mm pipe size, and consideration should be given to removal of the largest pipe size of 219.1 mm. AIPA claimed

[121] ATCO Gas Argument, p. 21
[122] 23% feeder mains and 77% distribution mains
[123] Exhibit 003, Application, Schedule C, Classification of Distribution Mains, Zero Intercept and Minimum System Methods

that this would still leave 6 data points for the regression but would reflect the smaller size range of distribution mains as compared to the larger feeder mains.

ATCO Gas submitted that AIPA provided no meaningful justification for its recommendations and on that basis, no weight should be given to these submissions.

***The AUMA/EDM Mains Proposal***

AUMA/EDM indicated that the best and most reasonable information available should be used to perform a zero intercept study for mains. AUMA/EDM submitted that ATCO Gas should be directed to conduct a more detailed review of the unit costs for various pipe sizes including representative sampling and file that information in its compliance filing. AUMA/EDM stated that if the best available information continues to be that filed in this proceeding,[124] then that information should be utilized to run the zero intercept methodology.

ATCO Gas stated that, while AUMA/EDM acknowledged the several concerns that ATCO Gas had with the zero intercept methodology, AUMA/EDM did not provide recommendations for how these short-comings could be overcome. ATCO Gas indicated that it had no idea what it was expected to sample given that the costs were not recorded by pipe size in its records. ATCO Gas argued that the comments of AUMA/EDM on this matter should be ignored as there was no evidentiary support provided.

The R13 Group submitted that it would be wholly inappropriate to direct ATCO Gas to conduct and implement new, complex and detailed studies, such as a zero intercept study, in its compliance filing for this proceeding. The R13 Group argued that such an approach would only result in either re-litigating in the compliance stage what has already been a long and somewhat tortured process, or limiting the due process rights of the participants by imposing a methodology that parties have not had an opportunity to evaluate or critique. Neither of those results would constitute sound regulatory policy.

***The Calgary Mains Proposal***

In evidence, Calgary recommended classifying 23% of mains costs (deemed to be feeder mains) as 100% demand related and that the remaining mains costs be classified based on the zero intercept methodology.

In argument, Calgary stated that if the customer component was to reflect the illustrative pilot light (the straw to connect all customers or the true minimum system), then the regulatory principle should acknowledge that the customer classified costs do not serve load.

Calgary claimed that the zero intercept method was one methodology that could be used to determine customer classified costs independent of load and that it was preferable to the method advocated by ATCO Gas which reflected an assumption of a minimum load and did not use actual cost information.

Calgary submitted that ATCO Gas should be required to come forth with analyses of all data bases in its possession concerning the use of the zero intercept methodology or provide interveners with all applicable data bases in its possession which would allow interveners to conduct the studies.

[124] Replacement unit costs provided in CAL-AG-05(a)

***The CCA Mains Proposal***

The CCA submitted that all mains should be classified as demand related because this was the only appropriate method. The CCA indicated that the average load factors were relatively constant across all strata within the Rate 1 group and CCA appeared to indicate that these load factors were equivalent to demand.

***The PICA Mains Proposal***

PICA stated that it considered the zero intercept method to be the conceptually appropriate method for classifying mains costs. However, PICA also considered that for the purposes of this proceeding, the Mains Minimum Plant OD Method with an adjustment for economies of scale to reflect declining unit costs with increasing pipe diameter (the PICA Mains Proposal[125]), would produce similar results to a properly carried out zero intercept study.

PICA indicated that under current planning assumptions, ATCO Gas uses 42 mm pipe as the minimum size pipe for distribution mains. Based on this information and other evidence in the proceeding, PICA determined that under a zero intercept method, the pipe size at zero volume, as measured by pipe diameter squared, would be a theoretical 30.8 mm diameter pipe.

PICA submitted that since the 26 mm pipe approximated a zero intercept pipe size of 30.8 mm, and since ATCO Gas used 26 mm pipe as the minimum system pipe in the Mains Minimum Plant OD Method, the Mains Minimum Plant OD Method effectively approximated a zero intercept method for distribution mains using current planning assumptions.

PICA performed a regression analysis to determine the percentage change in pipeline costs with changes in pipe size. Based on this analysis, the impact of changes in pipe costs with size was reflected in the classification percentages recommended by PICA. PICA submitted that it was appropriate to use the unit costs for various sizes of pipe provided by ATCO Gas to estimate the economies of scale relative to various pipe sizes and to reflect the impact of costs on the results of the Mains Minimum Plant OD Method.

In its evidence,[126] PICA showed its proposed method for making an adjustment for declining unit costs with increasing pipe diameter.

While PICA stated that the PICA Mains Proposal would be acceptable for the purposes of this proceeding, PICA also submitted that for the next GRA, ATCO Gas should conduct a comprehensive zero intercept study for distribution mains.[127]

ATCO Gas indicated that it did not support the PICA Mains Proposal because it utilized the same unit cost data (replacement cost estimates for various pipe sizes) that was used in developing the zero intercept studies in this proceeding.

The CCA did not support the PICA Mains Proposal because the CCA considered that the issue of declining unit cost with increasing pipe diameter was similar to an issue ruled on by the Board in

125 Relative to AG' proposal, the PICA proposal increased the customer related share of distribution mains costs from 42.2% to 47.7% in the North and from 46.1% to 58.8% in the South.
126 Exhibit 023-02, PICA Evidence Appendix 1
127 PICA Evidence pp. 7-8

the CWNG 1998 Phase II hearing with respect to the demand to be used for distributing demand related costs to the various rate groups.

Calgary stated that the Board should be very concerned with the PICA Mains Proposal because it appeared to include a large amount of load serving capability in the customer component of mains.

The R13 Group submitted that the PICA Mains Proposal would correct only one of the biases inherent in the Mains Minimum Plant OD Method and on that basis, would result in a demonstrably biased methodology. The R13 Group claimed that the PICA Mains Proposal would adjust the Mains Minimum Plant OD Method only for its failure to recognize economies of scale but it would not adjust the Mains Minimum Plant OD Method for the other common critique of minimum system methods, namely that they incorporate some of the demand component of costs because the minimum system has load carrying capability. The R13 Group did not recommend adoption of the PICA Mains Proposal for this proceeding.

***Zero Intercept and Minimum System Methods for Mains and Services***

In this proceeding, ATCO Gas proposed to use minimum plant OD methods to determine the amount of mains costs and services costs that should be classified to the customer and demand components. Two other methods were examined during the workshops associated with this proceeding: the zero intercept method and the minimum system method. PICA noted that ATCO Gas' proposed minimum plant OD methods were variations of the minimum system method.

ATCO Gas stated that when applying the zero intercept method, distribution system costs were not based on installing the smallest-sized asset but rather were determined through regression analysis to determine the hypothetical cost of installing a zero-sized pipe. ATCO Gas indicated that the distribution system could then be re-priced at the cost of installing the zero-diameter asset. ATCO Gas stated that the percentage of customer-related costs was the cost of installing the zero-sized pipe as a percent of the actual system.

ATCO Gas indicated that when applying the minimum system method, distribution system costs were determined using the smallest (actual) size pipe in the regression analysis to determine the hypothetical cost of installing a pipe size. ATCO Gas stated that the percentage of customer-related costs was the cost of installing the minimum system as a percent of the actual system.

PICA indicated that the data for these analytical methods was usually based on representative sampling of the system. While the zero intercept method and minimum system method usually rely on historical costs for distribution plant of a utility, the Board notes that ATCO Gas filed COSSs in this proceeding that used the zero intercept method and minimum system method that relied on estimated unit replacement costs for various sizes of mains and services. ATCO Gas stated that it does not track its actual costs by pipe size and on that basis it could not determine the historical unit costs for various size mains and services.

Calgary submitted that there were two fundamental advantages to the zero intercept method as compared to the minimum plant OD methods. Calgary stated that the zero intercept method takes into account a cost component associated with its implementation and the zero intercept method holds true to the basic concept or definition of customer costs in segregating demand costs from customer costs.

The R13 Group submitted that the zero intercept method was probably the best theoretical method for classifying costs into demand and customer components because it reflected the actual economies of scale experienced by the utility in constructing mains plant while insuring that the customer component did not double count any demand-related costs.

In the Application, ATCO Gas indicated that, since the last workshop meeting, it had examined the unit replacement costs used in the analysis for the zero intercept and minimum system studies. ATCO Gas noted that four additional COSS were filed in the Application based on these methods and which included revised unit replacement costs and revised regression analysis. ATCO Gas stated that a review with its engineering group resulted in revised unit replacement costs that ATCO Gas claimed provided more consistent assumptions in the development of the costs between the various operational groups.

Calgary indicated that it was concerned with the magnitude of the changes in values of the unit replacement costs of mains and services. Calgary stated that based on the absolute dollar values, as well as percentage change, ATCO Gas fundamentally changed the dynamics of the replacement cost of mains. Calgary also stated that a review of the replacement costs for services indicated a similar trend, however, replacement costs were adjusted upwards and downwards. Calgary argued that the magnitude of the changes in replacement costs raised concerns as to the quality of all values contained in the COSS.

In comparison to the minimum plant OD methods, ATCO Gas indicated that it had a number of concerns[128] with the use of the zero intercept and minimum system methodologies for classifying mains and services costs.

ATCO Gas stated that it did not take issue with the theoretical basis for the use of the minimum system and zero intercept methodologies but there were practical issues related to the data that was the driver of these methodologies.

ATCO Gas indicated that it had to two primary concerns with above noted methodologies.[129]

- the number of data points.
- the quality of data points.

These data concerns were related to the estimated unit replacement costs for mains and services.

ATCO Gas submitted that the development of the unit replacement costs required a considerable amount of estimation and judgment and that there was no opportunity to test the data points against actuals.[130]

ATCO Gas stated that the regression used in the zero intercept study and minimum system study in this proceeding was being performed on only six estimated data points. ATCO Gas also stated that the estimates were based on a number of underlying assumptions that may or may not be representative of the true replacement cost of the system.

[128] Application pp. 11-12
[129] Tr 54-56
[130] Tr 55

ATCO Gas stated that the number of data points was directly related to the number of pipe sizes. ATCO Gas submitted that additional data points were not going to be readily available because it did not believe additional pipe sizes were going to materialize.

ATCO Gas also submitted that the range of possible intercepts at the 95% confidence interval for services was very wide and this called into question the appropriateness of relying on the results of the regression analysis. ATCO Gas stated that while the range for mains was not as wide, when the upper confidence interval value was used in the south, more than 100% of the costs would be classified as customer related. ATCO Gas submitted that this was not a reasonable result and argued that the range of possible intercepts at the 95% confidence interval was being influenced by the lack of data points in the regression analysis.

PICA indicated that the problems encountered by ATCO Gas with respect to the regression analysis were not the result of inadequate data points but instead, the result of a lack of understanding of the data points selected and the results that ATCO Gas obtained.

PICA submitted that the purpose of regression analysis was to understand the relationship between two or more variables. PICA submitted that ATCO Gas did not carry out any further analysis to understand the reasons for the results it obtained.

PICA also stated that ATCO Gas did not consider which sizes of pipe should be included or excluded from the zero intercept study. PICA submitted that in order to determine a theoretical zero capacity pipe, the pipe sizes closest to the minimum size pipe would be most relevant. PICA noted that for the mains analysis, ATCO Gas included pipe sizes ranging from 42 mm to 219 mm.

ATCO Gas stated that it did not understand the rationale PICA used to conclude that only certain pipe sizes should be included in the regression analysis. ATCO Gas also stated that further limiting of the number of data points in the regression analysis would only increase its concerns. ATCO Gas submitted that PICA's recommendations on this matter were difficult to understand and did not appear to be based on well understood methodologies.

With respect to the zero intercept method, Calgary stated that, while it appreciated ATCO Gas' concern over the number of data points available for this exercise, over time, ATCO Gas should be able to develop additional data points to enhance the analyses and allay its concerns.

ATCO Gas noted that under cross-examination, Calgary suggested that ATCO Gas could run regressions just on the cost of pipe in an attempt to address data problems. [131] ATCO Gas stated that while Calgary's proposal may appear reasonable on its face, it could in fact produce very different results through elimination of the installation cost component from the regression analysis. ATCO Gas submitted that there were no economies of scale associated with pipe costs and when the pipe diameter doubles, the cost per meter of pipe more than doubles.[132] ATCO Gas claimed that this was not the case for installation costs. ATCO Gas stated that Calgary did not clarify how the results of the regression analysis would be used given that ATCO Gas' historical rate base value included installation costs.

[131] Transcript page 450, lines 2-9 and pages 498-499
[132] PICA-AG-6(b)

ATCO Gas stated that PICA indicated that ATCO Gas should be looking at whether the zero intercept study was producing reasonable results and that one of the corroborations PICA believed ATCO Gas should be able to use was a comparison of the actual cost of 42 mm pipe versus the cost produced through regression analysis. ATCO Gas stated that while it was unclear what cost would be produced through the regression analysis, which could be corroborated against the actual cost, there appeared to be some circularity in relying on the results of a regression analysis to confirm the appropriateness of the numbers used to perform the regression analysis.

ATCO Gas indicated that PICA also discussed a further corroboration in its evidence.[133] ATCO Gas stated that the calculations performed by PICA for this corroboration relied on a regression analysis performed with four data points and ATCO Gas noted that one data point was a pipe size that ATCO Gas did not use anymore. ATCO Gas indicated that a review of the 95% confidence interval[134] indicated a pipe size ranging from 21.6 mm to 39.9 mm. ATCO Gas stated that it was unclear what corroboration PICA believed could be obtained from a regression analysis of only four data points with this wide a confidence interval. ATCO Gas argued that PICA appeared to rely on a questionable analysis to corroborate other questionable information.

In response, PICA submitted that the determination of zero intercept was not an exact science and required judgment. PICA submitted that this was the reason why corroboration was needed between the zero intercept in relation to the minimum size main currently used in designing the system. PICA stated that if the minimum size mains used under current design assumptions was less than the zero intercept pipe size, the pipe sizes used in the regression as data points would need to be re-examined.

The R13 Group stated that in practice and for the specific purposes of this proceeding, the available data were not of sufficient quantity or quality to allow for a reasonable zero intercept study.

PICA stated that since 42 mm pipe represented the commonly used minimum size pipe under current planning assumptions, it was appropriate to use 42 mm pipe in minimum system or zero intercept studies for classification of distribution mains.

ATCO Gas indicated that it currently uses 42 mm OD polyethylene pipe as the minimum size plant for urban distribution mains system expansion and that a 26 mm OD main may be used to serve the last anticipated customer in a rural system. ATCO Gas also noted that 26 mm steel mains were used extensively historically and comprised the bulk of the 26 mm mains in ATCO Gas' inventory.[135]

ATCO Gas also stated that it was concerned with the potential variability in estimated replacement unit costs that could occur over time because unit costs were influenced both by changes in economic conditions and contractor bidding practices.

133 P. 8
134 Exhibit 023-01. ATCO Gas stated that the confidence interval information could be obtained by double clicking on the table in PICA's Evidence at page 8.
135 PICA-AG-06(c)

In response, PICA submitted that the use of replacement cost new for determining the unit costs of various sizes of pipe was appropriate and consistent with the approach adopted by other utilities, such as ENMAX Power Corporation (ENMAX). PICA noted that ENMAX classified primary distribution taps and transformers based on a zero intercept method using replacement cost new.

PICA submitted that there was always potential variability of costs over time and steps could be taken to smooth out such variability, such as averaging of contractor rates. PICA stated that methods of construction and costs do vary from time to time and each successive cost study would reflect the costs based on the current planning assumptions.

In response, ATCO Gas submitted that PICA could not have it both ways. ATCO Gas stated that either an averaging method would have to be used or the Board should be prepared for fluctuations in the results from study to study, which could be significant.[136]

**Views of the Board**

In this section, the Board will make a determination in regard to the method to be used for determining the amount of distribution mains costs that should be classified as customer related and demand related.

In this regard, the Board notes that parties in this proceeding have provided various recommendations.

The CCA suggested that all mains should be classified 100% as demand related. In Section 5.2.14.1 Account 475 – Distribution Mains (Classification Alternatives for Distribution Mains**)**, the Board determined that this was not appropriate.

AIPA, AUMA/EDM and Calgary recommended that feeder mains should be separated out from other mains in account 475 for the purposes of cost classification. In Section 5.2.14.1 Account 475 **–** Distribution Mains (Feeder Mains**)**, the Board determined that it was not appropriate to use the Feeder Main Evidence or Modified Feeder Main Approach to separate the costs of feeder mains from the costs of other mains. The Board also determined that it was neither appropriate for ATCO Gas to undertake to estimate the historical costs related to feeder mains for its entire system nor to estimate the historical costs on a sample system basis.

AIPA, AUMA/EDM and Calgary recommended that the remaining mains, after feeder mains were removed, should be classified using some form of the zero intercept method. For this proceeding, PICA suggested using the Mains Minimum Plant OD Method with a cost adjustment and for ATCO Gas' next Phase II GRA, PICA recommended that ATCO Gas should use the zero intercept method. Each of these suggested methods rely on mains cost data while the ATCO Gas proposed Mains Minimum Plant OD Method does not.

AIPA's proposal and the PICA Mains Proposal rely on estimated unit replacement costs filed in this proceeding. The Calgary recommendation appeared to rely on historical cost data since Calgary was concerned with the quality of replacement cost data provided in this proceeding. AUMA/EDM suggested that ATCO Gas should determine its unit mains costs through

[136] Argument, p. 28

representative sampling of historical data and that it should file these estimates in the compliance filing. AUMA/EDM also stated that the estimated unit replacement costs filed in this proceeding should be used if the historical estimates were not as good as the replacement cost data.

The R13 Group recommended that ATCO Gas be directed to undertake an effort to compile data on a work order by work order basis regarding the cost of installing new mains of different diameters, and to present the results of this analysis at its next Phase II proceeding.

While some parties in this proceeding have suggested that ATCO Gas should determine its historical unit costs for various pipe sizes, the Board notes that ATCO Gas stated that it does not track its actual costs by pipe size. Therefore, ATCO Gas would be required to estimate its historical unit costs. While some parties have suggested that ATCO Gas should do some representative sampling and that ATCO Gas should compile data on a work order basis, the Board does not consider this appropriate, especially when the results of this exercise are unknown.

Given that ATCO Gas does not track its actual costs by pipe size, the Board considers that excessive judgment would be required to estimate the unit costs. The Board also believes that it would not only be difficult to determine a representative sample of its distribution system, given the evolution of its systems with respect to design, pipe sizes and pipe types, but it would also be controversial. In addition, it would still be unknown whether these estimates properly reflect actual costs.

In regard to ATCO Gas implementing a system to track actual unit costs for various mains and services, the Board notes that ATCO Gas indicated that a considerable amount of estimation and judgment would be required for the identification of costs by pipe size without any indication that the result would be an improvement to the allocation methodology.[137] ATCO Gas indicated that crews currently charge their time, material and equipment to one services work order or one mains work order and these charges are not allocated by pipe size. ATCO Gas also indicated that in order to track costs by pipe size, it would have to establish work orders for each size of service and main in a particular geographic area and have crews allocate time, material and equipment to each work order. ATCO Gas also noted that until the required tracking changes were implemented, it was uncertain whether an improved cost classification would result.[138] The Board concurs with this comment. The Board also considers that a tracking system would have to be in place for many years before it would be of much value because of the relative weighting between existing distribution systems and new systems built after implementation of the appropriate tracking measures. Therefore, the Board will not direct ATCO Gas to implement any tracking systems.

In regard to estimated unit replacement cost data, ATCO Gas submitted that the development of the unit replacement costs required a considerable amount of estimation and judgment and that there was no opportunity to test the data points against actuals.[139] ATCO Gas also stated that it was concerned with the potential variability in estimated unit replacement costs that could occur over time because units costs were influenced both by changes in economic conditions and contractor bidding practices.

[137] Tr 56
[138] Tr 55-56
[139] Tr 55

While AIPA appeared willing to use the estimated unit replacement costs for mains filed in this proceeding, the Board notes that Calgary expressed its concern with the quality of replacement data provided in this proceeding. The R13 Group also stated that for the specific purposes of this proceeding, the available data were not of sufficient quantity or quality to allow for a reasonable zero intercept study.

In its evidence, PICA stated that ATCO Gas failed to provide the unit costs for all of the different pipe sizes constituting the distribution system and that a zero intercept study using the limited number of pipe sizes might not result in reliable results. PICA goes on to state that ATCO Gas should conduct a comprehensive zero intercept study for distribution mains in its next GRA having regard to unit costs for significant pipe sizes. PICA also outlined the PICA Mains Proposal given the limited information for carrying out a reliable zero intercept study in this proceeding.[140]

Later in its argument, PICA stated that the data necessary to carry out a proper zero intercept study for mains was available in this proceeding and that there was no need to incur significantly higher costs to perform a zero intercept study in future proceedings.[141]

While the quality of the estimated unit replacement cost data filed in this proceeding for distribution mains appears to be in dispute, the Board considers that significant judgment was required to estimate the mains costs. The Board notes that the assumptions with respect to trenching[142], installation techniques, extent of development, installation rates, and other factors would generally be required to estimate replacement costs. The Board also notes that the replacement cost estimates varied significantly between the ATCO Gas business units.[143]

While ATCO Gas expressed its concern with respect to whether these estimates and underlying assumptions would be representative of the true replacement cost of the system, the Board is also concerned whether these estimates would be representative of the historical costs on a proportional basis. Therefore, the Board does not consider it appropriate to use the estimated unit replacement cost data for mains filed in this proceeding.

Given the potential variability in estimated unit replacement costs and required judgment involved in estimating unit replacement costs for mains, the Board also does not consider it necessary for ATCO Gas to undertake to perform these estimates for future Phase II proceedings.

The Board notes that it accepted ATCO Gas' proposed method for classifying distribution meter costs and that this method relied on replacement cost data. However, in relation to distribution mains, the Board considers that less judgment is required to estimate meter replacement costs.

While the Board understands the theoretical merits of utilizing methods to classify customer and demand costs that rely on some form of cost data (either historical or replacement), the Board considers this to be too problematic with respect to the ATCO Gas distribution system for the

[140] PICA Written Evidence, pp. 7-8
[141] PICA Argument, p. 23
[142] In PICA-AG-07(c), ATCO Gas stated that the difference in installation costs between the North and South were driven primarily by the use of common trenching which is for the most part only prevalent in the City of Calgary.
[143] CAL-AG-05(b) Attachment

reasons outlined above. Accordingly, the Board does not consider it appropriate to classify mains costs using customer/demand classification methods, like the zero intercept method, which rely on cost data.

ATCO Gas proposed to classify distribution mains costs using the Mains Minimum Plant OD Method which ATCO Gas submitted was approved in Decision 2000-16.

The R13 Group submitted that ATCO Gas presented credible evidence that no reasonable information was available in this proceeding for conducting the statistical analysis necessary to evaluate a zero intercept or minimum system study. Therefore, the R13 Group argued that it was not unreasonable to adopt ATCO Gas' proposal for this proceeding.

The R13 Group also stated that in the absence of any better analysis, the Mains Minimum Plant OD Method should be retained and it should continue to apply to all mains, including feeder mains.

The Board notes the concerns expressed by parties with respect to the Mains Minimum Plant OD Method. In particular, the implicit assumption of a linear relationship between pipe size and unit cost (the Linear Relationship Assumption). The Board notes that the Linear Relationship Assumption would tend to understate the customer component of costs. Under the Mains Minimum Plant OD Method, the customer component of mains costs is determined by multiplying the total mains cost times the ratio of the minimum size mains cost to total mains costs (the Ratio)[144] under the Linear Relationship Assumption. The Ratio determined under the Linear Relationship Assumption would be smaller (and therefore, understate the customer component of the mains costs) than the Ratio determined if the unit cost ($ per metre) per millimetre of pipe size decreased with increasing mains diameter. No party took exception to the conclusion that the Linear Relationship Assumption would tend to understate the customer component of mains costs.

The Board also notes the traditional concern with respect to minimum system methods in that the minimum sized pipe has some load carrying capability and therefore, the customer component of costs would tend to be overstated.

The R13 Group suggested that these objections were both credible and potentially significant in terms of cost allocation. The R13 Group stated, however, that these errors tended to offset one another. As such, the R13 Group argued that it was not obvious that ATCO Gas' proposed method was necessarily biased in a particular direction.

PICA submitted that the biases in the Mains Minimum Plant OD Method were not offsetting because ATCO Gas used 26 mm pipe as the minimum size pipe for mains in its analysis in place of 42 mm pipe, which was the minimum size pipe used under current planning assumptions. PICA argued that this factor would tend to understate the customer component of mains costs.

The Board notes that it is unclear to what extent the above concerns would be offsetting.

[144] The Ratio can also be determined by taking the minimum size pipe (26.7 mm) times the total mains length for all pipe sizes and dividing by the total of each pipe size times its respective mains length.

While the Mains Minimum Plant OD Method is not ideal, the Board does not consider that, under the circumstances, there is a solid alternative method to classify mains costs to customer and demand components. The Board notes that while both the minimum plant and zero intercept methods are acceptable methodologies, it has in the past determined fault 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.[145]

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.[146]

Further, the Board also found in Decision 2000-16 that the zero intercept method "….. has the effect of shifting costs from the customer component to the demand component".[147]

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 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. [148]

The Board continues to believe that this method will provide a reasonable classification of distribution mains between the customer and demand components. The Board also finds the Mains Minimum Plant OD Method to be appealing because of ATCO Gas' claim that this method would produce stable and consistent results over time.

Accordingly the Board approves the Mains Minimum Plant OD Method as proposed by ATCO Gas.

[145] Decision 2000-16 Canadian Western Natural Gas Company Limited 1998 General Rate Application Phase II dated June 13, 2000, at page 21
[146] Reply Argument, p. 2
[147] Decision 2000-16 Canadian Western Natural Gas Company Limited 1998 General Rate Application Phase II dated June 13, 2000, at page 21
[148] Decision 2000-16 Canadian Western Natural Gas Company Limited 1998 General Rate Application Phase II dated June 13, 2000, at page 21

Given that the Board has determined the Mains Minimum Plant OD Method to be satisfactory and that it has found in this Decision and in Decision 2000-16 that it remains unconvinced that it would be appropriate for ATCO Gas to develop the necessary data to conduct a comprehensive zero intercept study, and that a zero intercept study conducted on existing data has insufficient support to prefer it to the Mains Minimum Plant OD Method, the Board considers this matter as resolved. Accordingly, the Board would not expect to see intervener evidence in the next ATCO Gas Phase II proceeding advocating the zero intercept methodology. The Board would expect to see substantial new evidence as to the benefits of the zero intercept methodology or any other alternative classification approach for mains costs before it would be prepared to reexamine this matter.

In response to PICA's submission that it was appropriate to use 42 mm pipe in minimum system or zero intercept studies for classification of distribution mains, since 42 mm pipe represented the commonly used minimum size pipe under ATCO Gas' current planning assumptions, the Board directs ATCO Gas to file, as part of its next GRA Phase II, its views on why 26 mm pipe continues to be the appropriate size pipe to use as the minimum system pipe in its Mains Minimum Plant OD Method.

#### 5.2.14.2 Account 473 - Distribution Services

ATCO Gas proposed that North and South[149] distribution service costs for account 473 be classified utilizing a minimum plant study based on the outside diameter analysis for various distribution service line pipe sizes (the Services Minimum Plant OD Method).[150] ATCO Gas noted that, based on this methodology, 64.9% of its services costs were classified as customer related and the remaining 35.1% as demand related.[151]

ATCO Gas indicated that the use of the Services Minimum Plant OD Method was a change from the methodology referred to as the "Representative Year methodology" (the Rep Year Analysis) approved in Decision 2000-16 for ATCO Gas South. ATCO Gas also indicated that the Services Minimum Plant OD Method was used in the past for ATCO Gas North.

ATCO Gas stated that the principal reason for the proposed change was that the Rep Year Analysis produced inconsistent results between Phase II applications. ATCO Gas noted that the Rep Year Analysis classified 44.7% of the costs as customer-related costs in the Canadian Western 1998 Phase II Application but by the year 2002, this classification percentage had changed to 61.0%.[152]

For the unbundled 2004 analysis, ATCO Gas indicated that it calculated both alternatives (the Services Minimum Plant OD Method and Rep Year Analysis). ATCO Gas stated that the Rep Year Analysis was dependant on the cost of installing the minimum sized service line and that it

149 ATCO Gas also recommended using the north analysis as a surrogate for the south, as the service line installation and disconnection by size data necessary to perform a south analysis was not available. ATCO Gas stated that it compared the only data that was maintained in the south (2003 and 2004 service line installations by size of pipe) and submitted that the surrogate approach was reasonable

150 The Services Minimum Plant OD Method is shown on p. 76 of the Proposed COSSs.

151 ATCO Gas claimed that these percentages were consistent with the previous classifications for both ATCO Gas (North) using OD analysis (62% customer and 38% demand) and ATCO Gas (South) using rep year analysis (61% customer and 39% demand).

152 Tr 380-381 and 351

discovered that the Rep Year Analysis was producing significant changes from previous years. On investigation, ATCO Gas indicated that it found that the cost to install services was volatile and inflationary during the 1970's and 1980's. In addition, ATCO Gas found that the use of contractors to perform service installations and the different methods of contractor pricing was causing significant swings in results.

ATCO Gas submitted that the Services Minimum Plant OD Method was not affected by pricing and that this method compared the number of installations of the minimum sized pipe for services to the number of installations of all sizes of pipe for services to determine the percentage to classify as customer-related costs. ATCO Gas stated that this method was more consistent and reliable during a time of volatile prices because this method did not incorporate any cost to install the pipe.

PICA submitted that the Services Minimum Plant OD Method was a variation of the minimum system method but that it did not recognize changes in unit costs of pipe with changes in pipe size; whereas a typical minimum system method would take the unit cost of various pipe sizes into consideration.

Calgary submitted that ATCO Gas had an obvious conflict within its position. Calgary claimed that ATCO Gas indicated that services were designed on the basis of connected load and that the related costs should be allocated on the basis of design, but that it classified the capital cost of services with both customer and demand components.

The R13 Group stated that Calgary misinterpreted the fundamentals of the services cost classification. The R13 Group claimed that any particular service line must be of sufficient size to meet the maximum connected load of the customer that it served and that there were economies of scale associated with service lines. The R13 Group submitted that in effect, service lines have a demand component and a customer component.

The R13 Group submitted that economies of scale can be reflected in a COSS in two ways. The first way would be by a utility developing a customer weighting factor based on the relative cost of services for each rate class when a utility has accurate data of the services cost by rate class. The R13 Group indicated that the utility could then classify costs as customer-related and allocate those costs on a weighted customer basis. The R13 Group indicated that in effect, the weighting factor implicitly recognized the demand component of services.

The R13 Group submitted that ATCO Gas provided a second approach in this proceeding, namely an explicit split of services costs into demand and customer components. The R13 Group claimed that in the absence of solid data regarding actual services costs by class, this was a conceptually reasonable method.

The R13 Group stated that both the weighted customer approach and the ATCO Gas approach attempted to recognize the same cost causation factors. The R13 Group argued that since Calgary did not offer any specific alternative to ATCO Gas' proposal, there was no reason to reject ATCO Gas' proposed approach in this proceeding.

The R13 Group also stated that ATCO Gas' method might be improved by applying a zero intercept method to these costs. The R13 Group noted that ATCO Gas' analysis suggested that applying a zero intercept method would result in a significant increase in the customer component of services costs.[153]

The CCA submitted that under a customer and demand cost classification, residential and other small customers would be double charged for distribution service costs. The CCA stated that the minimum system was sufficient to serve a small customer and that this cost would be collected in the customer charge. The CCA stated that additional amounts would also be collected in the demand or energy component but it was not needed to serve the residential customer.

AIPA indicated that it was concerned with the Services Minimum Plant OD Method because this methodology did not consider the cost of the pipe by different sizes. AIPA also submitted that, while this methodology was based on the implicit assumption that pipe cost had a linear relationship with pipe size, the ATCO Gas data showed that this relationship did not exist.

***AIPA Proposal***

AIPA submitted that the alternative COSS based on the minimum system method and pipe size squared regression (the AIPA Proposal) provided the best methodology to correspond with the design and costs of the system. AIPA claimed that pipe size squared corresponded to the area of the pipe and hence volume or flow, which was an essential consideration in the minimum system to be assessed. AIPA stated that the AIPA Proposal took into account the replacement costs of various sized distribution services to ensure an appropriate cost at the minimum pipe size.

AIPA indicated that since ATCO Gas has all of this data, based on the best engineering estimates at this time, the results of this analysis were credible and sufficient to be applied in this proceeding. AIPA argued that in the compliance filing, ATCO Gas should be directed to classify distribution services as customer and demand related costs on the basis of the AIPA Proposal.

In response to the AIPA Proposal, ATCO Gas indicated that it did not understand the methodology being referred to by AIPA. ATCO Gas submitted that the AIPA Proposal was new evidence that parties have not had an opportunity to review and understand nor was there any evidence that such a recommendation was at all credible. ATCO Gas stated that the comments of AIPA on this matter should be ignored.

The CCA submitted that under a customer and demand cost classification, residential and other small customers would be double charged for distribution service costs.

***AUMA/EDM Proposal***

AUMA/EDM indicated that the best and most reasonable information available should be used to perform zero intercept study for services. AUMA/EDM submitted that ATCO Gas should be directed to conduct a more detailed review of the unit costs for various pipe sizes including representative sampling and file that information in its compliance filing. AUMA/EDM stated that if the best available information continues to be that filed in this proceeding[154], then that information should be utilized to run the zero intercept methodology.

[153] Application, p. 13
[154] Replacement unit costs provided in CAL-AG-05(a)

***The Calgary Proposal(s)***

In its evidence, Calgary recommended that services be classified based upon the zero intercept methodology.

PICA submitted that the zero intercept method was not an appropriate method for classifying services costs because it had the effect of understating the service costs associated with the customer classification. PICA indicated that the customer related component for services costs determined through a zero intercept study could result in a zero demand pipe cost being lower than the 15 mm economic pipe sizing determined by ATCO Gas which would not be feasible from an engineering point of view. In addition, PICA stated that a customer classification based on zero demand pipe size would not reflect the fact there was a certain amount of demand associated with each customer and that it varies with number of customers. Accordingly, PICA submitted that the use of the zero intercept method for classification of services should not be accepted.

In Argument, Calgary stated that historically, it supported the classification of costs related to services as customer related. Calgary stated, however, that with the disclosure by ATCO Gas that service costs were incurred on the basis of connected load, it was difficult to argue for the use of a customer component of costs. Calgary stated that, should the Board accept ATCO Gas' contention that services costs were incurred on the basis of load, then these costs should be classified as 100% demand related.

AIPA considered that the statement "that service costs are incurred with connected load" simply implied that larger loads required larger sized pipe for the service connection. AIPA stated that this variation in the size of the service connection did not impact the principle that customer-related costs should reflect the minimum sized service connection to any customer. With this principle, AIPA argued that only costs associated with larger services, above the minimum sized service, should be classified as demand-related. AIPA submitted that the Calgary's suggestion of classification of 100% of the service costs as demand-related ignored the minimum system concept.

PICA indicated that it failed to understand why the use of connected load or any other load for designing services had anything to do with the classification of services. PICA submitted that services were essentially customer related costs. PICA stated that according to the definition of services, one service line serves one customer. PICA claimed that the purpose of the minimum system analysis for services was to determine the relative cost of different pipe sizes serving different load sizes.[155] PICA submitted that the way the services were sized had no relationship to how services should be classified.

In reply, Calgary stated that there was a conflict in ATCO Gas' position for the classification of services. Calgary stated that it continued to believe that services should be allocated on a weighted customer approach (the Weighted Approach). Calgary stated, however, that ATCO Gas did not retract its position of basing service design solely on connected load.

In response, AIPA submitted that that the Weighted Approach did not explicitly recognize that within a rate class the cost to serve larger customers required larger sized service facilities (design on the magnitude of connected load). On that basis, AIPA submitted that the Weighted

[155] Tr 663

Approach did not align properly with cost causation or would require many weightings for different strata of consumption.

ATCO Gas submitted that it would be inappropriate to classify services as 100% customer related and it would be inappropriate to classify services as 100% demand related. ATCO Gas stated that the record showed that the 15 mm pipe size service adequately provided the needs of a wide range of customers. ATCO Gas claimed that the determination of this pipe size did not require any consideration of load on the part of ATCO Gas and on that basis, it was a customer-related cost. ATCO Gas also indicated that the record also showed that 15 mm was not the only pipe size used by ATCO Gas for the installation of services. ATCO Gas noted that larger pipe sizes were required to address increased demand. ATCO Gas submitted that, similar to meters and mains, there was a minimum system aspect to service lines that required costs to be classified as both customer and demand related.

Calgary submitted that if the Board adopted a change in the classification of services, it should be in line with the Calgary proposal to split Rate 1 / 11 into two rate groups. Under the proposed split, Calgary submitted that there was no demand component for low use Rate 1 customers and there may be a demand component for larger customers. Calgary indicated that it has long supported the use of the zero intercept method to classify service lines. However, if the Board adopted the cost causation standard / cost utilization standard, Calgary stated that it was prepared to adopt the Board's decision to classify services as 100 percent demand related based upon the adoption of the Calgary recommendation of separating the existing Rate 1 / 11 into low and high use classes, based on an annual consumption of 300 GJ per year.

Calgary noted that there were 391,556 service lines for 15 and 26 mm pipe sizes in the South[156] and that the customer count in the South for those using 300 GJ or less was 427,413.[157] On that basis, Calgary indicated that it appeared that the bulk of these customers were served from a 15 or 26 mm service. Based upon unit costs, Calgary submitted that it did not appear that these services had a demand component as 26 mm services had a lower cost per metre than 15 mm services.

PICA noted that as a future refinement, it would not be opposed to excluding the demand units for customers served from minimum size service lines for the purposes of demand cost allocations.

Calgary stated that, if the Board does not adopt either the cost causation / cost utilization standard and Calgary's split of the Rate 1 / 11 class, the appropriate classification of service should be based on the zero intercept method in order to provide some recognition that smaller services were primarily used to serve smaller customer.

The CCA submitted that under a mixed customer and demand cost classification, residential and other small customers would be double charged for distribution service costs.

[156] Item 4.10(d) Attachment 1 Page 2
[157] Exhibit 24-01 Calgary Evidence p. 7 of 35, Footnote 12

***The CCA Proposal***
The CCA submitted that distribution services should be classified as demand related. The CCA considered that average load factors were approximately the same across the eleven strata of Rate 1 and on that basis, a demand classification would be a fair. The CCA considered that distribution services were sized to meet connected load and that connected load was more associated with demand than customer.

***The PICA Proposal***
PICA submitted that unlike the distribution mains, there was little or no demand diversity on the service lines because, by definition, service lines connect a customer to the distribution mains. On that basis, PICA submitted that the use of a minimum system method, such as the Services Minimum Plant OD Method, was appropriate for service lines except that certain adjustments for economies of scale were required (the PICA Proposal).[158] PICA recommended that the classification percentages for distribution services account 473 should be adjusted for declining unit costs with increasing pipe diameter.[159]

Calgary stated that services were designed upon connected load and argued that the PICA Proposal did not reflect either cost causation or cost utilization. Calgary submitted that the PICA Proposal was fundamentally at odds with the concept that the customer component of cost does not serve load. Calgary stated that the magnitude of the PICA classification of customer costs for services clearly indicated that load serving costs were included in its proposal for the classification of services.

PICA submitted that the minimum system method was the appropriate method for classifying service line costs.[160] PICA stated that there was one service according to the definition of services for each customer so services were essentially 100 percent customer related. PICA also stated, however, that all services were not the same size and that some services were minimum size and other services were larger. PICA submitted that the minimum system was the lowest-cost approach to serving the smallest customer. Having determined the minimum system, PICA indicated that the cost of serving a customer larger than a minimum system customer must be determined. On that basis, PICA argued that the minimum system method was appropriate for classifying service costs.

In addition, PICA submitted that the use of a minimum system method for classifying services was not unfair to smaller customers using minimum size services because the 15 mm pipe was the smallest pipe feasible for serving a customer from an engineering and economics point of view.

PICA submitted that the minimum OD method, with suitable adjustment for economies of scale, was appropriate for classification of services because the objective was to arrive at the relative costs of different sizes of services serving different classes of customers. In other words, the minimum OD method was used as a proxy for a weighted customer allocation of services costs.

[158] Relative to ATCO Gas' proposal, the PICA proposal increased the customer related share of distribution services costs from 65.4% to 76.0% in the North and from 65.4% to 69.5% in the South.
[159] Exhibit 23-03 shows the adjustment of the Services Minimum Plant OD Method to recognize the declining costs with increasing pipe size
[160] BR.PICA-3(b)

The R13 Group submitted that the PICA Proposal would correct only one of the biases inherent in the Services Minimum Plant OD Method and on that basis, would result in a demonstrably biased methodology. The R13 Group claimed that the PICA Proposal would adjust the Services Minimum Plant OD Method only for its failure to recognize economies of scale but it would not adjust the Services Minimum Plant OD Method for the other common critique of minimum system methods, namely that they incorporate some of the demand component of costs because the minimum system has load carrying capability. The R13 Group did not recommend adoption of the PICA Proposal for this proceeding.

**Views of the Board**

In this section, the Board will make a determination in regard to how distribution services costs should be classified.

In this regard, the Board notes that certain parties in this proceeding suggested that these costs should be classified as customer and demand related while other parties have suggested that these costs should be classified as demand related only.

ATCO Gas, the R13 Group, AIPA, AUMA/EDM and PICA have suggested that distribution services costs should be classified as customer and demand related.

The CCA suggested that distribution services should be classified as demand related because distribution services were sized to meet connected load and the CCA considered that connected load was more associated with demand than customer.

Calgary also suggested that it was prepared to classify services as 100 percent demand related if the Board adopted a cost causation standard / cost utilization standard and based upon the adoption of the Calgary recommendation to separate the existing Rate 1 / 11 into low and high use classes.

PICA submitted that the way the services were sized had no relationship to how services should be classified.

ATCO Gas stated that the record showed that the 15 mm pipe size service adequately provided the needs of a wide range of customers. ATCO Gas claimed that the determination of this pipe size did not require any consideration of load on the part of ATCO Gas and accordingly, it was a customer-related cost. ATCO Gas also indicated that the record also showed that 15 mm was not the only pipe size used by ATCO Gas for the installation of services. ATCO Gas noted that larger pipe sizes were required to address increased demand. ATCO Gas submitted that, similar to meters and mains, there was a minimum system aspect to service lines that required costs to be classified as both customer and demand related.

AIPA stated that the variation in the size of the service connection did not impact the principle that customer-related costs should reflect the minimum sized service connection to any customer. With this principle, AIPA argued that only costs associated with larger services, above the minimum sized service, should be classified as demand-related.

The R13 Group claimed that any particular service line must be of sufficient size to meet the maximum connected load of the customer that it served and that there were economies of scale associated with service lines. The R13 Group submitted that in effect, service lines have a demand component and a customer component.

No parties suggested that any services costs be classified as commodity related.

After considering the views of the parties above, the Board considers it appropriate to classify the costs under account 473 as customer related and demand related for the reasons outlined by ATCO Gas above. The Board also notes that it has previously classified ATCO Gas services costs as customer and demand related.

The parties that recommended that distribution services costs be classified as customer and demand related have not all agreed upon the method to use to determine the amount that should be classified to the respective customer and demand components.

AIPA suggested a minimum system method and AUMA/EDM supported a zero intercept method. Calgary also supported a zero intercept method if the Board did not adopt the cost causation / cost utilization standard and Calgary’s proposed split of the Rate 1 / 11 class. PICA suggested using the Services Minimum Plant OD Method with a cost adjustment. The Board notes that all of these alternate proposed methods rely on service line cost data.

The AIPA Proposal and the PICA Proposal rely on estimated unit replacement costs filed in this proceeding. AUMA/EDM suggested that ATCO Gas should determine its service line costs through representative sampling of historical data and that it should file these estimates in the compliance filing. AUMA/EDM also stated that the estimated unit replacement costs filed in this proceeding should be used if the historical estimates were not as good as the replacement cost data.

In regard to development of historical service line cost data, the Board notes that ATCO Gas stated that it does not track its actual costs by pipe size. Therefore, ATCO Gas would be required to estimate its historical unit costs. The Board does not consider this appropriate because significant judgment would be required to estimate the unit costs and it would still be unknown whether these estimates properly reflect actual costs.

In regard to ATCO Gas implementing a system to track actual unit costs for various size pipe, the Board determined in the previous section of this decision that it would not direct ATCO Gas to undertake to implement such a system at this time.

In regard to estimated unit replacement cost data, the Board notes ATCO Gas’ concerns with respect to the Rep Year Analysis, which relied on replacement cost data. In this regard, ATCO Gas stated that it found that the cost to install services was volatile and inflationary during the 1970’s and 1980’s and that the use of contractors to perform service installations and the different methods of contractor pricing was causing significant swings in results.

While PICA questioned whether the percentage cost differentials between different sizes of plant would remain stable from year to year, even though the absolute unit costs of pipes may change from year to year, ATCO Gas submitted that in practice this may not be the case. ATCO Gas noted that there were many components in a pipe installation contract and the method used by the successful bidder to approach its bid may vary from year to year. ATCO Gas stated that while it provides bidders with the opportunity to bid different installation rates for different pipe sizes, not all contractors do so.[161]

ATCO Gas also submitted that the development of the unit replacement costs required a considerable amount of estimation and judgment and that there was no opportunity to test the data points against actuals.[162]

While AIPA and PICA appeared willing to use the estimated unit replacement costs for services filed in this proceeding, the Board notes that, as outlined in the Section 5.2.14.1 Account 475 - Distribution Mains (Zero Intercept and Minimum System Methods for Mains and Services), Calgary expressed its concern with the quality of replacement data provided in this proceeding.

While the quality of the estimated unit replacement cost data filed in this proceeding for services appears to be in dispute, the Board considers that, while less judgment was involved in estimating services costs in relation to mains costs, significant judgment would still be required to estimate the services costs. The Board also notes that the replacement cost estimates varied quite a bit between the ATCO Gas business units.[163]

While ATCO Gas expressed its concern with respect to whether these estimates and underlying assumptions would be representative of the true replacement cost of the system, the Board is also concerned whether these estimates would be representative of the historical costs on a proportional basis. Therefore, the Board does not consider it appropriate to use the estimated unit replacement cost data for services filed in this proceeding.

Given the apparent volatility in service line pricing and required judgment involved in estimating unit replacement costs for service lines, the Board also does not consider it necessary for ATCO Gas to undertake to perform these estimates for future Phase II proceedings.

The Board notes that it accepted ATCO Gas' proposed method for classifying distribution meter costs and that this method relied on replacement cost data. However, in relation to distribution mains and services, the Board considers that less judgment is required to estimate meter replacement costs.

While the Board understands the theoretical merits of utilizing methods to classify customer and demand costs that rely on some form of cost data (either historical or replacement), the Board considers this to be too problematic with respect to the ATCO Gas distribution system for the reasons outlined above. Accordingly, the Board does not consider it appropriate to classify services costs using customer/demand classification methods, like the zero intercept method, which rely on cost data.

ATCO Gas proposed to classify distribution services costs using the Services Minimum Plant OD Method instead of the Rep Year Analysis because the Rep Year Analysis, which relied on service line installation cost data, was producing significant changes in the percentage of services costs classified as customer related. In this regard, the Board observes the following passage from Decision 2000-16.

[161] PICA-AG-07(d)
[162] Tr 55
[163] CAL-AG-05(b) Attachment

> CWNG stated that it had noted PICA's observation about the representative year methodology to determine the classification of distribution services between customer and demand. Specifically, PICA noted that the results of the study for 1998 had produced a significant change in the classification percentages when compared to the results of the 1993 study. CWNG stated that it recognized the concern, and would be reviewing the methodology prior to filing its next COS study.[164]

The R13 Group submitted that in the absence of solid data regarding actual services costs by class, the Services Minimum Plant OD Method was a conceptually reasonable method.

The Board notes the concerns expressed by parties with respect to this method. In particular, the implicit assumption of a linear relationship between pipe size and unit cost. The Board notes that this linear relationship assumption would tend to understate the customer component of costs.

The Board also notes the traditional concern with respect to minimum system methods in that the minimum sized pipe has some load carrying capability and therefore, the customer component of costs would tend to be overstated.

The Board notes that it is unclear to what extent the above concerns would be offsetting.

While the Services Minimum Plant OD Method is not ideal, the Board does not consider that, under the circumstances, there is a solid alternative method to classify services costs to customer and demand components. The Board also finds the Services Minimum Plant OD Method to be appealing because of ATCO Gas' claim that this method would be more consistent and reliable during a time of volatile prices. Further, as stated in relation to mains above, the Board would not expect to see interveners file evidence in respect of the zero intercept methodology in the next ATCO Gas Phase II proceeding and that parties would need to file substantial new evidence as to the benefits of the zero intercept methodology or any other alternative classification approach for mains costs before the Board would be prepared to reexamine this matter.

Accordingly, the Board approves ATCO Gas' proposal to use the Services Minimum Plant OD Method to classify North and South distribution service costs for account 473.

No party expressed concern with the fact that ATCO Gas used North service line installation and disconnection data as a surrogate for the South, and at this time, the Board is prepared to accept this approach for the purposes of this proceeding. However, in order to determine whether this surrogate approach will be accepted in the future, ATCO Gas is directed, as part of the Compliance Filing, to provide an estimate of the cost to gather the necessary historical South data (number of service lines by pipe size) required to perform the Services Minimum Plant OD Method separately for the South.

### 5.2.14.3 Other Distribution Mains and Services Accounts

ATCO Gas proposed to classify certain accounts under the Distribution Mains and Services function as outlined in the table below.

[164] Decision 2000-16, p. 15

Table 3. ATCO Gas Proposals for Classification of Accounts for Distribution Mains and Services

| Account # | Account Name | Expense Type | Basis of Classification |
|---|---|---|---|
| 471 | Land Rights | Direct Asset | 100 % customer |
| 472 | Structure & Improvements | Direct Asset | 100 % demand |
| 477 | Measuring & Regulating Equipment | Direct Asset | 100 % demand |
| 305 | Property Taxes | Cash | Account 477 |
| 675 | Distribution Mains & Services | Cash | Sum of accts 473 & 475 |
| 677 | Measuring & Regulating | Cash | Account 477 |

The CCA submitted that all accounts outlined in the table above, except for account 675, should be classified as demand related. The CCA also submitted that account 675 should be classified in the same percentages as the related asset accounts.

For purposes of this proceeding, PICA recommended that all accounts whose classification was dependent on accounts 473 and 475 be adjusted for declining unit costs with increasing pipe diameter, as set out in the PICA evidence.

With respect to accounts 471, 472, 477, 305 and 677, Calgary argued that at a minimum, these accounts should be classified as all other mains and services expense. However, Calgary also stated that a better approach would be to analyze the costs to determine the drivers and why they are incurred.[165]

Calgary argued that Account 471 was not driven by demand but by the need for mains and services.

Calgary submitted that account 472 was not driven by demand but generally by the number of customers or the overall number of facilities and therefore staff.

Calgary stated that account 477 may have a demand component to it to the extent the measuring and regulating equipment related to the transmission expense, but ATCO Gas provided no evidence of this.

With respect to account 305, Calgary stated that municipal and other taxes were related to facilities and to the extent that they were not driven by commodity cost, these items would be driven by the dollar cost of the facilities which Calgary argued was not demand driven.

In regard to account 677, Calgary submitted that these costs were not driven by demand but by the volume and the number of facilities which Calgary argued was driven by the number of customers.

ATCO Gas indicated that it would not be opposed to adopting Calgary’s proposed treatment for these accounts which was a classification on the basis of prime accounts 473 and 475. Although, given the immateriality of the amounts in question, ATCO Gas stated that it did not believe that a change in classification was necessary.

[165] Calgary Evidence, pp. 32-35

**Views of the Board**

The Board considers it reasonable to approve the classification of these remaining accounts based on the sum of the classification of prime accounts 473 (services) and 475 (mains).

### 5.2.15 Income Credits

ATCO Gas proposed that the Board should approve the treatment of income credits as proposed in the COSS.

Calgary indicated that while it did not have any comments on the classification of income credits, it noted that the decisions reached by the Board in regard to cost classification and allocation in this proceeding might impact the current classification of income credits. Calgary also suggested that there was an inconsistency of treating two[166] of the income credits related to storage in these cost of service studies when the Board denied Calgary's request to have all the storage related income credits included in the revenue requirements and treated as income credits to be applied against the storage costs included in the COSS.

No other parties commented on the treatment of income credits.

**Views of the Board**

While the Board notes Calgary's comments, it considers that although ATCO Gas has tracked the storage related costs separately, ATCO Gas has generally complied with the intent of the Board's directions as set out in Order U2005-133.[167]

The Board considers the ATCO Gas approach to income credits is reasonable and approves that treatment.

## 5.3 Distribution of Costs to Rate Groups

Costs are included in rates traditionally on the basis of a COSS which attempts to allocate costs on the basis of cost causation principles.

Costs are functionalized and then classified by cost driver as:

- customer (driven by the number of customers served)
- commodity (driven by throughput)
- demand (driven by how the system is sized in order to accommodate the maximum load on the system)

Classified costs are then allocated to various rate classes generally as follows.

- Customer related costs are allocated on the basis of the number of customers in each rate class
- Commodity related costs are allocated on the basis of throughput of each class
- Demand related costs are allocated on the basis of coincident peak demands or non-coincident peak demands of each class.

[166] Deferred storage revenue and condensate revenue (page 31 of 86).
[167] Order U2005-133 ATCO Gas South 2005/2006 Carbon Storage Plan, dated March 23, 2005.

For each function, ATCO Gas distributed (or allocated) the expenses and credits (direct asset expenses, direct cash expenses, total assigned expense and income credits) that were classified to customer, commodity or demand, to its proposed rate groups (Low Use, High Use and Irrigation in the south only). This allocation was based on each rate group's respective proportion of such costs. In general, customer related costs are distributed to rate classes on the basis of number of customers, commodity related costs are distributed on the basis of throughput and demand related costs are distributed on the basis of coincident peak demands or non-coincident peak demands. The methodologies used in distributing costs classified as customer, commodity and demand are discussed in the following section.

### 5.3.1 Methodologies for Distributing Costs

The cost distribution methodologies associated with number of customers, annual throughput and peak demand are discussed in the following sections. The amounts associated with these methodologies are utilized to distribute costs to rate groups.

#### 5.3.1.1 Customers

ATCO Gas indicated that for the COSS it used the average number of customers for 2007 slightly modified from the number approved by the Board in Decision 2006-004 for the 2005-2007 GRA Phase I. ATCO Gas considered that this was consistent with previous COSS to use the average number of customers in the last year of the test period.

Table 4 shows the 2007 average customer numbers from the GRA Phase I in comparison to the customer numbers used in this Phase II Application.

Table 4. Comparison of Phase I and Phase II Average 2007 Customer Numbers

| | Phase I[168] | Phase II[169] |
|---|---|---|
| North | | |
| Low Use (1&11) | 485,702 | 485,685 |
| High Use (3&13) | 1,148 | 1,148 |
| Total | 486,850 | 486,833 |
| South | | |
| Low Use (1&11) | 485,291 | 485,291 |
| High Use (3&13) | 1,079 | 1,079 |
| Irrigation | 671 | 671 |
| Total | 487,042 | 487,041 |

Calgary expressed some concerns with the number of customers that ATCO Gas used in the COSS study. Calgary was concerned that consumption data for only about 92% of the group was being used to determine the cost allocation factors for the total group, thereby resulting in some question as to the reliability of the cost allocators. ATCO Gas pointed out that the regression analysis only used customer data if the customer had been active for at least 12 months. Consequently, ATCO Gas indicated in response to concerns from Calgary, that at least 12,571 customers were excluded from the regression analysis which would explain the variance with the number of customers in the 2005-2007 GRA forecast.

[168] Reference Tab 7.5 North and South GRA Phase I Application 1400690
[169] Reference ATCO Gas Exhibits 18-12 and 18-15

Calgary also questioned in their evidence whether the forecast number of customers used in the COSS would be achieved in 2007 based on the data provided. The Board considers the explanation provided by ATCO Gas with regard to its treatment of the number of customers used in the regression analysis is reasonable and notes that Calgary did not provide any alternative solution other than to identify that the results of the data in aggregate may be less than perfect.

CCA suggested that ATCO Gas should utilize the number of customers approved by the Board for the 2007 test year.

Although the Board understands the rationale used by ATCO Gas in altering the average number of customers approved in the Phase I decision, the Board considers the same data should be utilized for allocating costs that was used in approving costs. Accordingly, the Board considers that ATCO Gas should utilize the same numbers approved in the Phase I process in its refiling.

The Board directs ATCO Gas to utilize the average customer numbers approved in the Phase I proceeding in its refiling.

#### 5.3.1.2 Annual Throughput

ATCO Gas indicated that it used the approximate annual throughput reviewed and approved in the Phase I portion of the ATCO Gas GRA.

Table 5 shows the 2007 annual throughput from the GRA Phase I in comparison to the annual throughput used in this Phase II Application.

Table 5. Comparison of Phase I and Phase II 2007 Annual Throughput (TJs)

| | Phase I[170] | Phase II[171] |
|---|---|---|
| North | | |
| Low Use (1&11) | 94,217 | 94,180 |
| High Use (3&13) | 25,276 | 25,276 |
| Total | 119,493 | 119,456 |
| South | | |
| Low Use (1&11) | 84,051 | 84,051 |
| High Use (3&13) | 27,918 | 27,918 |
| Irrigation | 627 | 627 |
| Total | 112,596 | 112,596 |

No parties expressed concerns with the annual throughput proposed by ATCO Gas. The Board observes that while the South throughput is consistent, ATCO Gas has utilized a lower throughput in the Phase II for the North.

The Board directs ATCO Gas to utilize the throughput approved in the Phase I proceeding in its refiling.

[170] Reference Tab 7.5 North and South GRA Phase I Application 1400690
[171] Reference ATCO Gas Exhibits 18-12 and 18-15

#### 5.3.1.3 Peak Demand

**Background**

The concept of peak demand is an important consideration in the distribution of demand related costs among rate classes as it reflects the apportionment of costs associated with categories of facilities that are utilized by all rate classes.

The distribution of costs to rate groups incorporating the concept of demand can be a complex regulatory issue with differing alternative approaches frequently considered. Complexity and controversy in analysis can arise because different customer classes create demand on the distribution system at varying times in accordance with variables such as load characteristics associated with heating, processing or some heating/processing combination; temperature; season; day of the week; duration of peak demand; varying geographic location within a distribution territory; concentration of customers; and distance from points of supply. Inconsistent connotations among parties with regard to the use and interpretation of peak demand related terminology can also readily contribute to disagreement and misunderstandings.

In general, an important analysis tool in the determination of the amount of costs that ought to appropriately be distributed among rate classes can include studying the demand placed on the distribution system on a coincident basis for the time duration when the system experiences its maximum aggregate demand. On a natural gas distribution system with a large proportion of heating load, this coincident peak demand is generally expected to occur on the coldest winter day. However, some customer classes such as irrigation customers may create their maximum demand on the system at time periods that may be unaligned or non-coincident with the maximum aggregate system peak demand. Additionally, certain individual customers who fall within a specific rate class (for example asphalt plants) will expectedly experience their peak demand at a time period that is non-coincident with the balance of customers in their rate class. These types of non-coincident peaking requirements must also be weighed and incorporated into determinations with regard to the distribution of costs related to system capacity among rate classes.

**Method for Determination of Demand for Each Rate Class**

ATCO Gas indicated that the appropriate method to consider peak demand on its distribution system is through an analysis of the relationship between temperature and actual consumption data. ATCO Gas undertook this review by conducting a regression analysis to determine the slope and intercept for a given set of data to obtain a linear relationship between temperature and demand. ATCO Gas utilized a peak demand at a design temperature of -40°C which was determined by extrapolation using a linear equation.

ATCO Gas referred to coincident peak demand (CP) as the demand by rate group when the system was at its peak demand. Non-coincident peak demand (NCP) was referred to by ATCO Gas as the maximum demand of all the rate groups regardless of when they occur. The CP used by ATCO Gas in its COSS was the NCP excluding seasonal customers.

ATCO Gas proposed that CP would be used solely to allocate demand costs by rate group in the Transmission function, whereas NCP was proposed by ATCO Gas to be used to allocate demand costs by rate group in each function except the Transmission function.

ATCO Gas noted that the NCP as used in the ATCO Gas COSS was based on the sum of the individual customers' estimated 24 hour consumption expressed in GJ's based on the following methodologies:[172]

- for Low Use and High Use temperature sensitive customers, the NCP is the estimated 24 hour consumption at the ATCO Gas design temperature of -40˚C;
- for Low Use Industrial customers, the NCP is based on the average day consumption of the maximum monthly consumption in the 12 month period;
- for High Use non-temperature sensitive customers, the NCP is the maximum measured 24 hour billing demand;
- for Irrigation customers, the NCP is based on an analysis of monthly consumption records for the Rate Group as a whole.

ATCO Gas used an approach to ascertain temperature sensitivity by examining the R squared coefficient, which is a statistical measure of the strength of the regression, wherein ATCO Gas assumed that customers with an R squared less than 0.50 were non-temperature sensitive.

Differing approaches used by ATCO Gas in the determination of NCP for each rate group created disagreement among parties which is discussed further in a subsequent section.

In CAL-AG-19 (dated September 25, 2006), ATCO Gas noted that it reviewed its original calculations of CP and NCP and found an error. Consequently ATCO Gas updated and refiled its schedules.

ATCO Gas proposed the following CP and NCP amounts by rate group[173]:

Table 6. 2007 Coincident and Non-Coincident Peak Demand Proposed by ATCO Gas

| | CP (GJ/day) | NCP (GJ/day) |
|---|---|---|
| ATCO Gas South | | |
| Low | 946,674 | 946,674 |
| High | 211,774 | 214,911 |
| Irrigation | n/a | 10,233 |
| | | |
| ATCO Gas North | | |
| Low | 1,029,513 | 1,029,513 |
| High | 198,402 | 202,111 |

Before assessing the CP/NCP on a quantitative basis, the Board considers that it is appropriate to first discuss the concept of diversity.

**Concept of Diversity**

The concept of diversity and how it ought to be incorporated into system design and cost allocation was the subject of significant evidence and argument in this proceeding with both Calgary and PICA offering alternative approaches to the ATCO Gas proposals.

[172] Exhibit 018-18, AIPA-AG-001 (a) Attachment 1
[173] Reference Exhibit 18-18

As referenced by Calgary, The American Gas Association Natural Gas Glossary defines diversity as:

> 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 of individual loads is less than the sum of the individual maximum loads. Diversity among customers' loads results in a diversity among the loads of distribution mains and regulators as well as between entire systems.[174]

The Board considers the Rate 13 Group described diversity appropriately as it applies to the ATCO Gas distribution system:

> In considering diversity, however, it is important to recognize that the maximum diversity of demand for distribution systems is at the tap to ATCO Pipeline. This diversity at the tap is not class coincident peak demand and it is not class non-coincident peak demand. It is simply the non-coincident peak demand at that tap and on the feeders from that tap for that particular distribution sub-system.[175] While this demand must reflect some diversity between the types of customers served downstream, and it must reflect the diversity that comes from not all customers' water heaters being on in exactly the same hour, it has significantly less diversity than any province-wide (or half-Province-wide) measure of CP or class NCP demand. Any comparison of diversity between customer demands in Lethbridge with those in Edmonton have no cost causation effect on distribution mains at all. (T. 626) AG has over 4,000 taps into ATCO Pipelines. Each distribution sub-system that is served downstream from that tap will not reflect any significant weather-related diversity.[176]

The Board agrees that the maximum diversity will be observed at the tap from ATCO Pipelines, diversity will diminish through the mains, and diversity will be least at the services.

ATCO Gas described that it includes the concept of diversity into the design of its distribution mains by applying a "demand factor" into the design of its systems serving more than 100 residential customers by reducing the residential customer design demand from 4.5 $m^3$/hour to 3 $m^3$/hour. For non-temperature sensitive customers the system is designed to accommodate peaking at the same time as temperature sensitive customers. ATCO Gas emphasized its position that the costs ought to be recovered on the basis of how the system is designed[177], rather than how customers might choose to use the system in any given year.

The Board considers the following exchange between ATCO Gas witnesses and Board Counsel, Mr. McNulty, is informative from a number of perspectives, including the approach that ATCO Gas utilized to establish its proposed allocation on the basis of design.[178]

> Just to confirm, when designing a portion of
> the distribution system which is forecast to serve Rate 3 and
> Rate 13 customers, I think we heard that the design is done
> on a design demand basis with respect to the mains, correct,

[174] Exhibit 66
[175] Ex.056 AG Rebuttal at 15
[176] R13 Group Argument, page 13
[177] Reference ATCO Gas Application, page 700 and Rebuttal, page 4
[178] Reference Transcript pages 324-331

sir?

A. MR. FELTHAM: That's true, with the one exception that when we design the system we generally don't know whether or not it's going to be a Rate 3 or Rate 13.

Q. Okay. And design demand basis is a function of the demand factor applied to the estimated heating load, correct?

A. MR. FELTHAM: That is -- that approach is typical for residential customers, not for the Rate 3 or 13 customers.

Okay, fair enough. And when ATCO states that recovery should be on a design basis in the portion of the rebuttal evidence I just referred to, what does that mean with respect to Rate 3 and Rate 13 customers, as I think you mentioned that you are not able to allocate demand classified costs on a design demand basis?

A. MR. FELTHAM: I think my comments can probably be used to -- for all of our rate classes. So because the design demand is not available as a tool to allocate the demand-related costs on a customer-by-customer basis, that's the reason that the NCP is used to -- as a representative of the design demand. And in the case of a Rate 3 or Rate 13 or perhaps, more appropriately, a nontemperature-sensitive customer, when the design is -- when the design is performed, that's based on the best information we have, and hopefully that's -- that information gives us some idea about what its peak flow, that particular customer's peak flow will be, and when -- in the calculation of the NCP that customer's actual peak 24-hour consumption is used in the NCP, and that's what's used to allocate demand costs.

Q. Sir, is it possible to do any type of correlation to determine whether the NCP as representative as a demand design basis is an accurate one to use?

A. MR. FELTHAM: We've been struggling with that question because I think to do that correlation you're suggesting requires us to have both numbers, both the design demand and the actual peak 24-hour consumption of that -- of that customer. But if we had the design demand, then we'd be using that to allocate the costs. So we don't have the design demand, so we can't do the correlation.

Q. Which is the subject of the future work element that you may be pursuing.

A. MR. FELTHAM: Actually, the future work element will hopefully let us do a little bit better job of allocating the demand portion of our costs by better approximating the design demand. The design demand, to be clear, is a one-hour forecast peak flow rate, and the 24-hour peak consumption is what's used to allocate the costs. And so hopefully the future work will let us use a one-hour consumption instead of a 24-hour consumption.

Q. So, sir, if the correlation between the design demand and the NCP is not clear, is it accurate to say, then, that the system -- that the cost allocation methodology is based

on design demand as opposed to use?
A. MR. FELTHAM: Again, the system is designed prior to the customer arriving, and then the arrival of the customer and its actual use trended to the design conditions gives us what we think -- gives us our NCP that we think is representative of the ~~NCP~~ design demand. And, quite frankly, it's the best method that we've devised that uses the information that is available.
Q. So, sir, I'm just wondering, then, how much of an assumption is built in to saying that because the system is designed and built around design demand but that NCP is used in cost allocation methodology that that then means that allocations are done on the basis of design?
A. MR. FELTHAM: I guess there is a couple of components of NCP that are similar to the way we design our system. The temperature-sensitive customers, we take their actual use and trend it to the design conditions, minus 40, and because we're using actual consumption, diversity is incorporated into that measurement because we are measuring actuals. And when we design the system for our temperature-sensitive customers, we -- particularly those residential customers, we've already gone over that, how we do it for -- to minus 40 and incorporate diversity into design. And then when we have a nontemperature-sensitive customer, we don't know when they will peak. So when we design the system, we design the system so that they could experience their peak at the same time that our temperature-sensitive customers can experience the peak. And when we calculate our NCP, we've got our temperature-sensitive customers' actual consumption brought to design conditions, and then we take the actual peak, 24-hour peak, of our nontemperature-sensitive customers where that's available, and then -- and that's what goes into our NCP.
Q. So, sir, those additional steps and that analysis that you went through, I take it, lend you the comfort that you feel is appropriate to make the conclusion that the system -- the cost allocation is done on the basis of design?
A. MR. FELTHAM: That's correct.
Q. … For nontemperature-sensitive customer demand classified costs it would be allocated on maximum billing demand and temperature sensitive would be allocated on noncoincident demand at minus 40 degrees; would that be fair?
A. MR. TROVATO: Let me try that one, Mr. McNulty. The NCP that we use to distribute demand-related costs is the sum of for nontemperature-sensitive customers their maximum 24-hour measured demand or billing demand. For the temperature-sensitive customers, it's the sum of their estimated 24-hour usage at minus 40.
Q. Thank you, sir. I think we're fairly close. You helped to put in the 24-hour parameter around that which helped a lot. Thank you, sir.

Sir, does that, then, mean that there may be some costs not allocated on the basis of billing demand being those equal to the difference between costs incurred when the system was designed and built on a design basis, and those recovered on a billing demand basis?

A. MS. WILSON: I think you'll have to run that by us again, Mr. McNulty. It is getting late in the day.

Q. The system is designed and built on design basis, and for nontemperature sensitive loads, the demand classified costs are recovered on maximum billing demand with the 24-hour parameters that you specify; does that then mean there is a differential in costs between the costs incurred when it's built versus the costs that are recovered through the maximum billing demand?

A. MR. FELTHAM: Because we don't have the design demand available, it's difficult to make that comparison. So I guess we don't know the answer to that.

Q. Would it be logical to think that there would be a differential?

A. MR. FELTHAM: There could be a differential. I'm not sure of the direction of it. But on a customer-by-customer basis, the bill demand could be higher or it could be lower than what the -- the basis for which the system was designed.

Q. Fair enough. To the extent that those costs -- that the billing demand recovered less of a cost associated with what the costings of the system actually were incurred and designed and built -- as designed and built, would that then mean that those additional costs would be recovered through billings to temperature-sensitive loads, primarily Rates 1 and 11?

A. MR. FELTHAM: I think, again, all rates would share in the impact of that.

Q. Well we're talking, here, about a situation where you've got nontemperature loads, which would be primarily Rates 3 and 13, although not exclusively; and in a situation where cost incurred on design and building of the system were not recovered through the billing demand from those customers, would it not, then, be implied that those costs have to go somewhere and they would go to the other customers which are primarily Rates 1 and 11?

A. MS. WILSON: The starting point of our NCP calculations are based on how the system is being used by both temperature-sensitive and nontemperature-sensitive customers. We then take that information and we bring it to design conditions.

Now for a nontemperature-sensitive customer, the assumption is made that their billing peak will be the same at a design condition or at a minus 40 degrees. So we simply assume that it won't vary as a result of taking it to minus 40 degrees. But for all rate groups, we unfortunately do not have the specific design demand information. Even when we design our system, we don't design it with specific

> rate groups in mind.
> Q. What I'm trying to get at through these series of questions is to understand whether there is any potential unfairness with allocating -- with costs reallocated to Rates 1 and 11 being on a different basis, namely, on a temperature-sensitive basis than customers who are primarily in Rates 3 and 13 that would be in a nontemperature basis billed on maximum billing demand.
> A. MS. WILSON: We don't believe so. As I indicated, the assumption is that for a nontemperature-sensitive customer, their peak at minus 40 would be the same as their maximum actual peak. When we design our systems, although those peaks may occur at different times for different temperature-sensitive versus a nontemperature-sensitive customer, when we design our systems we have to allow for the capability for both sets of customers to peak at the same time.

The Board understands that ATCO Gas estimates the NCP for temperature-sensitive customers by utilizing a peak demand study that incorporates monthly billing information to extrapolate peak demand at the design temperature. The design temperature has been previously established in GRA Phase I processes as -40°C in the North and -36°C in the South. Notwithstanding that -36°C is used by ATCO Gas in the South peak demand study, ATCO Gas has utilized a temperature of -40°C to calculate NCP in both the North and South using the rationalization that the one hour peak volume used for design is based on -40°C in both the North and South[179] as follows:

> ATCO Gas designs its distribution system based on a one hour peak volume occurring at -40C. A full explanation of the ATCO Gas calculation of the one hour peak volume was previously provided in the 2003/2004 ATCO Pipelines Phase 2 GRA in Information Response BR-AP-26 (Supplemental). In summary, historical individual service point consumption is used to determine a linear relationship for temperature sensitive customers. In the south, this relationship is extrapolated to -36C to determine a peak day volume. In the north, this relationship is extrapolated to -40C to determine a peak day volume. Peak Hour factors are then applied to the peak day volumes to determine one hour peak volumes. In the case of both the south and the north, the one hour peak volume assumes a temperature of -40C for that one hour. The peak volumes determined in this process are used for the sizing of major distribution facilities, specifically gate stations and large diameter feeder mains. Individual service lines are sized for the connected load at that service point. For example, there is a high likelihood that all gas burning appliances in an individual house could be active at one point. Therefore, the facilities immediately upstream of a house must be sized for the connected load. In installing facilities, ATCO Gas utilizes the next largest commercially available size of equipment.
>
> So while a -36 ° C temperature is used in the south for the development of a peak day volume, the one hour peak volume in both the south and north, which is used in the design of facilities, is based on a temperature of -40 ° C.

[179] Reference Calgary Evidence, page 10 referencing AG attachment to letter of December 22, 2005, Application 1416346, responding to Calgary's communication of December 12, 2005 regarding December 2, 2005 meeting Page 13.

The Board notes that Calgary inquired into the ATCO Gas use of -40°C, rather than -36°C for the South and requested analyses from ATCO Gas at a temperature of -36°C. These analyses at -36°C were provided by ATCO Gas.[180]

The peak demand data that is initially estimated as a 24 hour peak is converted into a one hour peak and a four hour peak by ATCO Gas for each of the North and South, for differing applications by utilizing adjustment factors of 1.1 and 1.08, respectively, established in the GRA Phase I process. However, for cost allocation purposes, the NCP determination for temperature sensitive customers, ATCO Gas utilizes the data in the format of a 24 hour peak demand based on actual consumption, trended to design conditions at -40°C. For non-temperature sensitive customers NCP determination is done with an estimated 24 hour demand utilizing maximum billing demand, contract maximum or average amount in the highest use month. In this respect, the Board considers that while ATCO Gas is attempting to establish NCP for temperature-sensitive and non-temperature-sensitive customers on a comparative basis, the approaches are different wherein the end results may fall short of being consistent. This leads to a probable bias toward understating the non-temperature sensitive demand under peak conditions. In particular, the Board is concerned the following assumption referred to in the transcript quote provided previously, could lead to an understatement of the non-temperature sensitive peak demand:

> Now for a nontemperature-sensitive customer, the assumption is made that their billing peak will be the same at a design condition or at a minus 40 degrees. So we simply assume that it won't vary as a result of taking it to minus 40 degrees.

ATCO has argued that the demand that the system is designed for is the cost driver for demand related costs. Since the system design demand can not be determined for each customer (and therefore it can not be determined for each customer class) because of a lack of data, ATCO argues that the next best thing to use is a process taking actual usage of the system for temperature sensitive customers and then trending it to design temperature conditions.

Calgary considered that ATCO Gas had failed to incorporate diversity into its rate design in an appropriate fashion. Calgary suggested that to properly assess diversity it is critical to clearly distinguish between customer NCP and class NCP, and that the Board had failed to provide those definitions in Decision 2000-16. Calgary suggested that the class NCP must be determined for each rate class. However, the approach utilized by ATCO Gas was to add the individual customer NCP amounts to determine the NCP amount for each class. Calgary was concerned that this would overstate the class NCP, which it considered ought to be lower after taking the effect of diversity into account.

In order to make an adjustment for diversity in the determination of class NCP, Calgary proposed to determine a reduced value of NCP. The method proposed by Calgary to determine a reduced NCP for all[181] temperature sensitive customers was to use a proxy methodology to reflect diversity. Calgary suggested that NCP for temperature sensitive customers be determined[182] at a

[180] Reference Exhibit 16-01, CAL-AG-01(a) Attachment 5 and CAL-AG-01(b) Attachment 3
[181] Reference AIPA.Calgary-8 (d)
[182] Calgary argument, page 31, submits that, as a reasonable compromise, the Board should direct ATCO Gas to use -34°C to determine the Customer NCP for Rate 1/11. The Board understands this Calgary compromise

temperature of -34°C, rather than -40°C as had been calculated by ATCO Gas. In its evidence,[183] Calgary provided data analyses examining the ratio of peak hour to average hour wherein it observed intra-day diversity occurrences from 10% to 18%. The 10% diversity was based upon an analysis of peak hour to average hour from an hourly metered location shown in CAL-WP-4. The 18% diversity evaluation was based upon CAL-WP 5 which also showed that there is considerable intra-day diversity based upon actually metered hourly load. Taking the lower end of the diversity range, 10%, Calgary provided evidence that a 10% diversity adjustment would be reflective of a demand determination at approximately -34°C. In cross examination[184] Calgary indicated its recommendation of -34°C was based upon the professional judgement of Mr. Vander Veen and Mr. Johnson who considered it to be a reasonable compromise starting point. That judgement incorporated aspects of diversity, data reliability, differences in determination of demand for different customers and appliance consumption characteristics. Calgary recommended this approach should be utilized as a base to be used in conjunction with SCADA data, load research data and historic temperature data to develop a methodology reflective of actual customer usage at -34°C. Calgary's assessment was that the -36°C assessments completed by ATCO Gas would not provide an adequate adjustment and in its judgement -34°C would be more appropriate.

CCA agreed with the -34°C proposal, but did not provide explanation.

ATCO Gas did not agree with Calgary's perspectives and considered that because the NCP calculations it performs are based on peak day (i.e. 24 hour) demands for a group of customers who are experiencing the same weather, no diversity can be assumed to exist between temperature-sensitive customers. ATCO Gas did consider that it would be appropriate to incorporate diversity in some fashion if the NCP calculations were based on the peak hour instead of the peak day.

Further, ATCO Gas pointed out that Calgary was under the apparent understanding that ATCO Gas was utilizing the connected load for design of its distribution mains, which Calgary considered would result in excessive demand. ATCO Gas clarified that it does not incorporate connected load for design for any portion of its distribution system other than the service lines and meters.

PICA indicated that although ATCO Gas appears to recognize diversity for planning purposes, diversity may not be properly recognized for cost allocation purposes. Although PICA disagreed with the Calgary approach respecting the methodology to incorporate diversity into the determination of class NCP, PICA considered that the diversity concern could be evaluated by ATCO Gas undertaking sampling studies. These sampling studies would be utilized to assess the contribution to peak demand by rate classes on the basis of their contribution to individual distribution main demand and individual transmission tap peaks. The contemplated outcome would be that coincident demands by rate class at the time of individual feeder peaks would be utilized to allocate demand related mains costs to rate classes. Similarly, transmission demand costs would be allocated to rate classes based on contribution to transmission tap demands by each rate class at the individual transmission tap level.

recommendation would utilize the ATCO Gas approach to set CP equal to NCP for Rate 1/11 in this proxy determination.

183 Reference Calgary Evidence, Exhibit 024-01, page 13

184 Reference Transcript 444 and Transcript 543

The R13 Group suggested that the PICA proposal had some theoretical appeal; however, the R13 Group expressed concern with the PICA sampling proposal from a cost/benefit perspective indicating it would entail significant costs with unclear benefits. The R13 Group considered that no sampling proposal should be contemplated prior to examining a detailed cost assessment in a subsequent GRA process. AUMA/EDM concurred with the R13 Group that more analyses regarding the benefits of such sampling would be required before proceeding with this type of expenditure.

The R13 Group also expressed concern with the Calgary proposal to develop an estimate of NCP at -34°C, indicating the method to be speculative and not based on any specific analysis of demand diversity at the level of distribution sub-systems. The R13 Group suggested that the Calgary proposal failed to recognize the PICA perspective that diversity should be examined for the individual distribution sub-systems, and instead endeavoured to apply system-wide diversity benefits which the R13 Group considered would be irrelevant for cost allocation purposes. Consequently, the R13 Group considered that Calgary has not demonstrated that the solution would be an improvement over the ATCO Gas proposal. AIPA also indicated it did not see any basis for the Calgary proposed adjustment.

The R13 Group supported the position that design condition demand is the primary cost causation factor for the ATCO Gas demand-related costs. While the R13 Group did not consider that the ATCO Gas NCP demand reflects a perfect proxy for design demand conditions, it considered that the method presents a reasonable approximation which it considers probably overstates diversity at the level of services, but probably understates diversity at the feeder mains level.

**Views of the Board**

The Board concurs with the R13 Group assessment that the ATCO Gas method most likely does overstate some elements of diversity while understating others. In this respect the ATCO Gas NCP determination method could be considered to overstate diversity at the level of services from the perspective that the meter and service line may on occasion be subject to a peak demand approaching the connected load, at least in comparison to the peak demand study methodology which uses monthly consumption data to determine an average monthly usage which would expectedly generate an NCP lower than the connected load after extrapolation to the design temperature. It would appear therefore, that an element of diversity in relation to connected load is built into the individual customer calculation. Similarly, although the ATCO Gas method incorporates an element of diversity into its design through its design demand factor for larger numbers of customers, it could be considered to understate diversity further upstream at the feeder mains level or transmission taps as the method might not accurately capture the diversity associated with multiple customers utilizing the system in differing fashions.

The Board concurs with Calgary and PICA that an opportunity may exist; at least on a theoretical level; to more effectively incorporate the concept of diversity into the cost allocation process. The Calgary proposal would reflect a possible proxy mechanism although it lacks a completely definitive rationale and might have a tendency to over-adjust from the perspective that it appears to make an adjustment on a total system basis which does not recognize the existence of many independent systems in the ATCO Gas distribution system. Nonetheless, the adjustment mechanism could reflect some improvement over that used by ATCO Gas. The PICA proposal would introduce an alternative that would require further study, would introduce incremental costs and might or might not ultimately be more accurate to some degree.

As referenced by Calgary and PICA, there would appear to be merit in verification of some of the demand data through actual data if it could be made available. Additional data might also help to address concerns with the ATCO Gas peak demand studies using monthly billing data which is extrapolated to obtain peak demand amounts at the design temperature.

The Board agrees that the demand for which the system is designed for is the primary cost driver for the demand component of costs. Some elements of diversity are built into the system design through the use of a demand factor in planning mains and certain other parts of the system. Design demand data however, is not directly available on a customer by customer basis and therefore is unavailable on a class by class basis, in order to allocate demand classified costs. Accordingly, some proxy methodology must be employed to emulate the cost allocations that would occur if the system design demand data were available.

The Board is concerned that the methodology utilized by ATCO Gas in allocating the demand component of costs does not accurately translate the costs driven by system design into a fair cost allocation among the classes as a result of some of the issues referred to above. In particular, the Board notes issues associated with:

- using NCP which is based on a peak 24 hour consumption while design demand is based on a one hour peak consumption
- determining NCP based on a regression analysis which assumes an hourly design temperature of -40°C in both the north and the south given that the peak day volume is determined for design purposes at -40°C only in the North. The peak day volume temperature used for design purposes in the south is -36°C;
- A possible disconnect between the demand related costs generated by a system design (which incorporates design temperature parameters) and how those costs are allocated among the classes resulting from a cost allocation methodology which allocates costs:
    - to non-temperature sensitive Low Use industrial customers, based on the average day consumption of the maximum monthly consumption in the 12 month period without reference to system design temperatures;
    - to non-temperature sensitive customers in the high use class on the basis of billing demand without reference to system design temperatures;
    - while temperature sensitive customers are allocated costs using extrapolations based on system design temperatures,

  which may have the effect of underestimating the NCP, and therefore the demand related costs, allocated to non-temperature-sensitive customers;
- the categorization of some loads as non-temperature sensitive in determining NCP primarily for the high use rate class when it not clear to the Board that temperature is totally irrelevant to so called “non-temperature sensitive” customers; and
- the utilization of billing demand in determining NCP for non-temperature-sensitive customers. Billing demand may be exceeded at any time and may therefore result in the NCP being understated in a given year while this is not possible with respect to temperature-sensitive customers whose demand is extrapolated to a design temperature.

These concerns lead the Board to the conclusion that the ATCO Gas allocation methodology for demand classified costs does not accurately emulate the allocation of demand classified costs that would occur if the system design demand data were available on a customer by customer or class by class basis. In particular, the Board is concerned that an appropriate level of diversity has not adequately been reflected in the cost allocation process and may not have been adequately captured on a consistent basis between rate classes.

The Board notes that all interveners appear to agree that diversity is not adequately reflected in the present ATCO Gas cost allocation proposal.

In assessing how best to reflect diversity, the Board has considered the proposal put forward by Calgary and the proposals put forth by PICA calling for further study and analysis.

The Board is in favor of making an adjustment at this time to the allocation of the demand component of costs to offset the above concerns associated with the proposal put forward by ATCO Gas and to better reflect diversity in the cost allocation process. However, the Board is concerned that the evidence as to the appropriate quantum of an adjustment is not as robust as the Board would like to see before settling on an appropriate adjustment.

The Board has considered Calgary's proposal and notes the objections to this proposal raised by ATCO Gas. The Board is concerned that the 10% diversity adjustment factor and the -34°C proxy adjustment to emulate the effect of that degree of diversity and other factors are dependant to a significant degree on the judgement of the Calgary experts and lacking in detailed definitive analysis. Accordingly, the Board is of the view that the full adjustment advocated by Calgary is not certain enough to be implemented at this time.

Given the Board's conclusion that an adjustment to the ATCO Gas methodology to better reflect diversity in the allocation of demand related costs as it relates to temperature sensitive customers is appropriate and the Board's concerns that the Calgary proposal lacks sufficient evidentiary support to support a 10% adjustment, the Board has determined to utilize the Calgary proxy approach but to make adjustment using -36°C rather than -34°C. Accordingly, the Board will require an adjustment to the allocation of the demand component of costs by directing ATCO to incorporate the temperature of -36°C into its NCP determination for temperature-sensitive customers in its refiling for both the North and the South. The Board cautions that this adjustment is solely for the purpose of determining the NCP for cost allocation purposes and notes that it is not proposing in this Decision any adjustment to the one hour design temperature of -40°C for the purposes of system design criteria.

ATCO Gas is directed to assess the appropriateness of using the -36°C adjustment directed by this Decision as a proxy for diversity and to report on this analysis in the next Phase II proceeding. In addition, ATCO Gas is directed to consider alternative methods of reflecting diversity in allocating the demand component of costs in the next GRA. In particular, ATCO Gas is directed to include in its next Phase I application a program designed to collect a representative sample of diversity measurements across the North and South distribution systems. The results of this program, if approved by the Board in the next Phase I proceeding, will be provided in the next Phase II proceeding.

Further, as indicated above, the Board is not convinced that the rationale to utilize -40°C as the criteria for NCP determinations for both the North and South is reasonable given that the assumed peak day volume average minimum design temperature for the North is -40°C versus -36°C for the South. Instead the Board might expect that if a 24-hour temperature of -36°C in the South reflects a minimum hourly design temperature of -40°C, then -40°C in the North might correspondingly reflect a minimum hourly design temperature in the order of -44°C in the North. The Board considers that clarification respecting the appropriate North and South design temperature is required in this regard as the temperature assumptions may have implications in the distribution system design as well as the upstream transmission system design and associated costs, which are addressed in Phase I proceedings.

Accordingly, the Board directs ATCO Gas to provide further review and analysis supporting its minimum design temperatures in association with the determination of NCP in its next GRA in both the Phase I and Phase II.

**NCP Determination for Different Rate Groups**

While the Board has provided direction above with respect to the incorporation of diversity in the determination of cost allocation for demand related costs, the following section provides additional direction with respect to particular calculation issues with respect to quantitatively determining demand for the Low Use, High Use and Irrigation rate groups.

**Low Use**

For the temperature-sensitive Low Use (currently Rate 1/11) Rate Group, ATCO Gas described that the NCP was based on a 12 month linear regression analysis determined on an individual customer basis. For each customer, the NCP was calculated at the system design temperature of -40°C.

ATCO Gas performed the 2007 NCP calculation[185] by using the relationship between peak demand, load factor and annual consumption[186] to establish a CP value at -40°C. To do this ATCO Gas established an average rate group load factor based upon a three-year historic relationship between annual sales and the sum of the peak demands[187] (CP and NCP) for the years 2004, 2005 and 2006. Then, ATCO Gas divided the 2007 approved GRA Phase I throughput by this historic average rate group load factor to calculate the 2007 peak demand. ATCO Gas utilized this CP value as the NCP.

The Board understands that this calculation utilized the best-available data, but notes that the input data and methodology results in some disparities. In this regard, Calgary expressed concerns[188] with respect to the integrity of the data and mechanics used for determination of NCP. In response to the Calgary concerns, ATCO Gas noted that it had made certain assumptions to deal with anomalies in the data records and that the concerns expressed by Calgary would have minimal, if any impact on the results of the analysis.

As another example respecting the integrity of data, the Board notes that the resultant South 2006 CP/NCP was less than the 2005 CP/NCP calculation, which the Board considers improbable.

[185] Reference Exhibit 18-18, AIPA-AG-001 (a) Attachment 1
[186] ATCO Gas defined Load Factor = Annual Consumption / 365 days / Peak Demand
[187] Reference revised methodology described in Exhibit 22, CAL-AG-21(a)
[188] Reference Exhibit 24-01, Calgary Evidence, pages 16-18, examples such as temperature data, calendarized consumption data, service territory temperature variations, completeness of data and reliability of regression analysis

Calgary also inquired[189] regarding verification of the peak demand results using actual data. ATCO Gas indicated that it had not done that verification as it did not have the relevant data.

The Board recognizes that the data records may contain certain anomalies that must be dealt with in a fashion such as described by ATCO Gas. However, the Board is concerned with the apparent lack of data reconciliation using actual data. In this respect, the Board believes that ATCO Gas also shares these concerns from the following comments[190]:

> The information available to ATCO Gas today for the determination of the CP and NCP is limited. While ATCO Gas is obtaining additional information from sources such as the SCADA taps, it requires time to review and determine how best to use that information.
>
> ATCO Gas hopes that at a future time, it will be able to estimate the contribution of each rate group to the design demand for purposes of cost allocation.
>
> In order to do this, ATCO Gas will require the following:
>
> - Hourly flow data at the system level (gate stations) for a large enough number of points to represent the total system;
> - Hourly flow data from a sample of each rate group that accurately represents the total system;
> - Tests of the new methodologies to use this data.
>
> Through the use of the information discussed above, ATCO Gas hopes to be able to propose an improvement to the methodology used to allocate demand related costs (including transmission) between rate groups at a future Phase II.

The Board directs ATCO Gas to provide a feasibility assessment for verification of the peak demands that are established from billing data through extrapolation to the design temperature with actual metered data and report on the progress in the next GRA.

For the customers that ATCO Gas considered to be non-temperature-sensitive Low Use Industrial customers, ATCO Gas indicated the NCP was assumed to be found in the month with the largest throughput and was determined by dividing the highest month throughput by the number of days in that month. The Board considers that this approach is more of an average demand in the highest use month that probably introduces some understatement of the peak demand for these customers. In addition, as discussed above, the Board shares a concern expressed by Calgary that the ATCO Gas assessments that these customers are non-temperature-sensitive may also be questionable and may also tend to understate the peak demand for customers designated as Low Use Industrial. Again, the Board considers the estimation process presents an opportunity for enhancement by cross-verification with actual data as directed earlier in this Decision.

For this Decision, the Board approves the use of the ATCO Gas methodology to determine NCP as the CP amounts adjusted for seasonal use. In the case of the temperature sensitive customers in the Low Use Rate Group, the CP and NCP will be equal using the proxy approach of -36°C.

[189] Reference Exhibit 18-29, CAL-AG-20 (a)
[190] Reference ATCO Gas Rebuttal, page 22

**High Use**

For the High Use (Rate 3/13) Rate Group, two methods were utilized to determine the individual customer NCP. For temperature sensitive customers, the linear regression analysis based on actual daily consumption for a 5 month winter period was used to determine NCP at the system design temperature of -40°C. For non-temperature sensitive customers, the NCP was based on the maximum 24 hour Billing Demand. ATCO Gas used an assumption that if the R squared for the individual linear regression analysis for a customer was less than 0.50, the customer was assumed to be non-temperature sensitive.[191]

AUMA/EDM took issue with the use of 5 month data rather than 12 months of data to be consistent with the treatment of the Rate 1/11 customers. AUMA/EDM referenced the results when 12 months of data was considered as outlined in the response to AUMA/EDM-AG-04(b) as follows.[192]

Table 7. Comparison of High Use CP and NCP using 5 Month and 12 Month Regression Analysis[193]

2007 Coincident and Non-Coincident Demand Calculations:

| | (1) Throughput GJ | (2) Load Factor % | (3) Coincident Peak Demand GJ Per Day (1) / 365 / (2) x 100 | (4) Non-Coincident (GJ/Day) | (5) Non-Coincident Peak Demand (GJ/Day) (3) + (4) | |
|---|---|---|---|---|---|---|
| AGS High Use | | | | | | |
| South | 27,918,000 | 37.4 | 204,681 | 3,137 | 207,818 | Note (1) |
| South | 27,918,000 | 33.3 | 229,693 | 3,137 | 232,830 | Note (2) |
| AGN High Use | | | | | | |
| North | 25,276,000 | 36.8 | 188,001 | 3,709 | 191,710 | Note (1) |
| North | 25,276,000 | 33.2 | 208,582 | 3,709 | 212,291 | Note (2) |

(1) based on 5 month regression analysis ending March 31, 2006 as filed on August 18, 2006
(2) based on 12 month regression analysis ending March 31, 2006

While the Board understands that the calculations for the Rate 1/11 customers utilize a system of data testing and adjustment that may not have been utilized in the analysis completed by ATCO Gas for the Rate 3/13 customers, AUMA/EDM does raise an interesting perspective in association with the overall reliability and integrity of the data given the approximate 10% variation. Additionally, the Board anticipates that the meter reading data associated with the Large Use customers is of higher quality than that associated with the Low Use customers which tends to support the ATCO Gas methodology using the five winter months. Nonetheless, the Board considers that this potential underestimation of Large Use customer demand should be taken into consideration in the overall assignment of demand related costs and considers that, for the purpose of this Phase II decision, it will be somewhat offset between rate classes with the use of -36°C for the NCP determination of temperature sensitive demand. The Board considers that ATCO Gas should address any potential underestimation of Large Use customer demand in its next GRA Phase II.

191 Exhibit 018-18, AIPA-AG-001 (a) Attachment and Exhibit 022, CAL-AG-23

192 The Board anticipates that the CP and NCP in this table would be subject to updates associated with the ATCO Gas COSS corrections made in response to CAL-AG-19.

193 AUMA/EDM-AG-04(b) Attachment, page 1 of 1

PICA expressed a concern that ATCO Gas was making an assumption that for industrial and non-temperature sensitive customers, the time of peak consumption coincides with the time of the lowest temperature when the rest of the system would be peaking. Instead PICA considered that the industrial and non-temperature sensitive customers can peak at any time. As a result, PICA suggested that the contribution to CP for the industrial and non-temperature sensitive customers would tend to be overstated since they might not be making the full contribution on the system peak day. PICA also argued that the non recognition of diversity for these customers results in the CP calculation being closer to an NCP calculation than a coincident peak.

While ATCO Gas concurred that a non-temperature sensitive customer can peak at any time, ATCO Gas pointed out that the system design makes provision for that non-temperature sensitive customer to be able to peak during conditions of peak demand on the rest of the system. ATCO Gas considered that the costs ought to be recovered on the basis of how the system is designed, rather than how customers might choose to use the system in any given year.

PICA also expressed an additional concern wherein it suggested that ATCO Gas had failed to adjust for the degree of variability among customers with a low R squared (near 0.50) versus those with a high R squared (near 1.0). PICA suggested that the failure by ATCO Gas to consider this perspective would also result in potential overstatement of the coincident peak demand. The Board considers that PICA was endeavoring to introduce an element of utilizing the R squared results into some form of continuum for varying adjustment as a function of the R squared values. While the PICA suggestion may have some degree of notional merit, the Board does not consider that there is any evidence in this proceeding supporting the suggestion or analyzing the reliance or reliability that ought to be placed upon the R squared methodology for that purpose. Overall, the Board does not consider this PICA concern to have a practical application in this circumstance.

For this Decision, the Board approves the use of the ATCO Gas methodology to determine NCP as the CP amounts adjusted for seasonal use for the High Use Rate Group.

**Irrigation**

ATCO Gas noted above that the NCP for Irrigation customers was based on the maximum consumption month for the Rate Group as a whole. ATCO Gas utilized a five year historical average (2001-2005) to develop the NCP.[194] In this process, ATCO Gas divided the peak month irrigation sales for each year by the number of days in that month. ATCO Gas used this number as the peak demand. Then ATCO Gas calculated the load factor (based upon a 6 month April – September period) for each year and determined the average load factor for those five years. That average load factor was applied to the 2007 approved throughput to determine the NCP for Irrigation customers.

AIPA introduced an analysis of the calculation of NCP for the Irrigation Rate Group using a 5, 6 and 7 year time period incorporating a regression analysis.[195] All the AIPA alternatives resulted in a higher load factor than calculated by ATCO Gas, consequently each of these alternatives proposed a lower value of NCP associated with Irrigation customers. The 6 year analysis disregarded data for 2002 which appeared anomalous. ATCO Gas submitted that there is no

[194] Reference Exhibit 18-18, AIPA-AG-001 (a) Attachment 1
[195] Exhibit 064

"right" answer as to what is the best time period to use; rather, it is more important to be consistent from one COSS to another for this analysis. ATCO Gas submitted that a 5 year average has been used historically and that there is no compelling reason to use a different time period for determining the average in this COSS.

Calgary considered that that the NCP for Irrigation customers is understated as the NCP is based on the average use for the peak month. Calgary also submitted that an adjustment should be made to reflect the actual days of irrigation use in a month; not all days in the month.[196] However, AIPA pointed out that Calgary had not expressed a similar concern for the Low Use industrial customers; therefore AIPA considered that Calgary was inconsistent in its approach.

ATCO Gas agreed that the current methodology used could tend to understate the NCP for Irrigation customers. However, ATCO Gas indicated there is no way of knowing how many days in a month the irrigation accounts have been on in a particular month without having ATCO Gas staff go out and check every account to see if it is irrigating or installing AMR devices on all Irrigation customers.

Similar to the circumstance with Low Use industrial customers, the Board considers the Irrigation approach used by both ATCO Gas and AIPA is more of an average demand in the highest use month that probably introduces some understatement of the NCP for these customers.

AIPA proposed further approaches to reduce its lowest calculated NCP value by a further factor of 50% on the basis that approximately half of the Irrigation systems have a summer peak and half of them have a winter peak. AIPA rationalized that since the summer peaking systems would not cause a winter design impact, they would not contribute to the NCP and should be excluded from the NCP. AIPA submitted that this adjustment is required to account for where Irrigation customers do not contribute to winter peaking systems.[197] AIPA also submitted that Irrigation customers should not share in feeder main costs.[198]

No parties agreed with AIPA with regard to the 50% reduction. ATCO Gas indicated that whether Irrigation customers currently impact the system design or not, they receive service from all of these systems and that changes can also occur over time which could change a winter peaking system to a summer peaking system. ATCO Gas also noted that Irrigation customers currently do not receive any transmission charges, yet the information provided by AIPA itself makes reference to transmission taps serving only irrigation customers.[199] ATCO Gas considered its original proposal to be reasonable, but concluded that if a change is warranted the change should likely be to increase the NCP for the Irrigation Rate Group, for the reasons cited by Calgary.

AUMA/EDM concurred with Calgary that the irrigation NCP was understated and suggested that to be consistent with the -40°C design criteria for temperature sensitive loads, it would be more reasonable for the Irrigation customers to utilize the maximum peak day which occurred in 2001 (11,088 GJ/day), rather than the ATCO Gas proposal (10,233 GJ/day) or any of the AIPA

[196] Calgary Argument, Pages 28-29
[197] AIPA Argument, Page 18
[198] AIPA Argument, Page 18
[199] AIPA Argument, Page 17

alternatives (9366, 8767, 8339 or 50% of 8339 GJ/day). AUMA/EDM considered that the system must have been designed to meet that 2001 conservatively calculated peak demand.

The Board is not persuaded that the 50% reduction to the NCP proposed by AIPA is warranted. The Board considers the Irrigation customers are sharing service among other customers and ought to contribute towards that utilization of infrastructure. Additionally, the Board concurs with ATCO Gas that the amount of demand placed on the system can vary over time, as both the design criteria and actual utilization may be variable.

While the Board considers the average demand calculated by ATCO Gas may tend to understate the NCP, the Board is also mindful of potentially offsetting variations in precipitation levels and data anomalies such as the unusually low load factor experienced in 2002. In weighing these perspectives, the Board considers the ATCO Gas proposal to utilize the amount of 10,233 GJ/day as the NCP reflects a reasonable demand.

Accordingly, for ATCO Gas South, the Board approves an Irrigation customer NCP of 10,233 GJ/day for 2007.

**Use of CP and NCP Amounts for Distribution and Transmission Costs**
The Board approvals in relation to CP and NCP are summarized in the following table.

Table 8. 2007 Coincident and Non-Coincident Peak Demand as Proposed by ATCO Gas and as Approved by the Board

| | Proposed CP (GJ/day) | Approved CP[200] (GJ/day) | Proposed NCP (GJ/day) | Approved NCP[201] (GJ/day) |
|---|---|---|---|---|
| ATCO Gas South | | | | |
| Low | 946,674 | 881,808 | 946,674 | 881,808 |
| High | 211,774 | 204,165 | 214,911 | 207,302 |
| Irrigation | n/a | n/a | 10,233 | 10,233 |
| | | | | |
| ATCO Gas North | | | | |
| Low | 1,029,513 | refiling[202] | 1,029,513 | refiling[203] |
| High | 198,402 | 190,202 | 202,111 | 193,911 |

ATCO Gas proposed to utilize the CP amounts for distribution of transmission related costs from ATCO Pipelines and to utilize the NCP amounts for the distribution of costs associated with demand related components for meters, services and mains. ATCO Gas referenced that its proposed approach was consistent with Decision 2000-016.

PICA considered that CP should be utilized for mains instead of NCP. PICA took this position on the rationale that ATCO Gas uses an NCP demand which is the sum of individual customer demands adjusted for temperature and does not incorporate diversity between the meter and the mains. PICA also considered that the CP demands utilized by ATCO Gas to allocate transmission costs were NCP demands minus seasonal loads which also failed to incorporate

200 Obtained at -36°C from Exhibit 16-01, CAL-AG-01(b) Attachment 3
201 Obtained at -36°C from Exhibit 16-01, CAL-AG-01(b) Attachment 3
202 Subject to adjustments from customer numbers and throughput consistent with Phase I determinations
203 Subject to adjustments from customer numbers and throughput consistent with Phase I determinations

diversity. AUMA/EDM did not support PICA in that regard and considered that NCP is reflective of system design and should be used to allocate mains costs to rate classes.

The Board notes that the differences between NCP and CP relate to the addition of the seasonal irrigation load plus adjustments in the High Use class for other seasonal customers. The Board also is not persuaded by the PICA argument that the referenced treatment of diversity between the meter and the mains warrants use of CP for mains.

Calgary proposed that customer NCP would be used to distribute demand costs related to services. Class NCP would be used to distribute non-feeder mains costs and costs deemed to be associated with non-interconnected feeder mains. Class CP would be used for all interconnected feeder mains and transmission costs.

ATCO Gas noted the difficulty of separating feeder mains from total mains and did not consider that process to be practical.

The Board considers there would be some theoretical merit in the Calgary proposal to use class CP for feeder mains. However, there appear to be two concerns in that regard. First, ATCO Gas has indicated it is unable to definitively ascertain which mains are feeder mains.[204] Second, the data aggregated by ATCO Gas is a summation of individual customer data which is not reflective of a class NCP as it does not incorporate diversity through the mains and feeder mains. At this point in time, the data to move toward a high-quality class NCP determination appears to be lacking without further study, regarding which ATCO Gas has proposed to undertake[205] and the Board has provided previous direction earlier in this Decision. The Board does not consider that it would be timely or particularly effective to endeavour to ascertain high-quality class NCP data in a refiling process associated with the Application.

After assessing the evidence and perspectives of parties, the Board considers that it is appropriate to continue to utilize CP for transmission costs and NCP for meters, services and mains as proposed by ATCO Gas. For clarity the referenced NCP is the summation of the individual customer NCP amounts, given that high-quality class NCP amounts are not currently available.

# 6 RATES

In the Application, ATCO Gas recommended that in the design of each component of the rates for each Rate Group, the Board should approve a rate design methodology that closely reflects the cost components that result from the COSS. ATCO Gas proposed that the rates should be designed to recover 100% of the costs allocated to Customer, Commodity and Demand for each rate group.

Table 9 compares the rates proposed by ATCO Gas to the rates in place on January 1, 2005[206] at the commencement of the 2005-2007 test period for ATCO Gas North.

204 Reference Exhibit 71 and cross examination by Mr. McNulty at Transcript 382-387.
205 Reference ATCO Gas Rebuttal, page 22
206 Reference Order U2004-443 approving interim rates effective January 1, 2005 for the North and South on a comparative basis unencumbered by riders.

Table 9. ATCO Gas North Comparison of January 1, 2005 Rates to Proposed Rates

| January | 2005 | | | Proposed | | | |
|---|---|---|---|---|---|---|---|
| Rate | Fixed ($/mo) | Energy ($/GJ) | Demand ($/GJ/mo) | Rate | Fixed ($/mo) | Energy ($/GJ) | Demand ($/GJ/mo) |
| 1/11 | 12.77 | 1.120 | | Low | 19.943 | 0.938 | |
| 3 | 289.99 | 0.302 | 4.19 | High | 19.943 | 0.000 | 8.752 |
| 13 | 330.81 | 0.059 | 6.43 | | | | |
| 13B | 289.99 | 0.302 | 4.19 | | | | |

Similarly, Table 10 compares the rates proposed by ATCO Gas to the rates in place on January 1, 2005[207] at the commencement of the 2005-2007 test period for ATCO Gas South.

Table 10. ATCO Gas South Comparison of January 1, 2005 Rates to Proposed Rates

| January | 2005 | | | Proposed | | | |
|---|---|---|---|---|---|---|---|
| Rate | Fixed ($/mo) | Energy ($/GJ) | Demand ($/GJ/mo) | Rate | Fixed ($/mo) | Energy[208] ($/GJ) | Demand ($/GJ/mo) |
| 1/11 | 13.01 | 1.138 | | Low | 18.296 | 0.917 | |
| 3 | 282.83 | 0.306 | 3.60 | High | 18.296 | 0.118 | 7.468 |
| 13 | 304.64 | 0.166 | 5.89 | | | | |
| 5/18 | 19.87 | 0.943 | | Irrigation | 30.30 | 0.885 | |

Schedule A in Appendix 5 of this Decision shows the proposed rates, billing determinants, revenue on proposed rates and the revenue to cost ratios for ATCO Gas South and North.[209]

For Low Use and Irrigation groups that do not utilize demand meters, ATCO Gas proposed to continue collecting the demand charges through the commodity (Energy) charge.

Many parties referenced that a sound rate design should be guided by the general attributes identified by Professor Bombsight.[210] The Board concurs and notes that the circumstances

[207] Reference Order U2004-443 approving interim rates effective January 1, 2005 for the North and South on a comparative basis unencumbered by riders.
[208] Energy charge includes a Production and Storage component of $0.118/GJ for each of the South Low, High and Irrigation rate classes
[209] Reference Exhibit 018-16 as revised September 15, 2006 by ATCO Gas
[210] *Principles of Public Utility Rates* (2ed), James C. Bonbright, Albert L. Danielsen and David R. Kamerschen Public Utilities Reports, Inc., 1988 at P 383-384

*Revenue-related Attributes:*

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.
2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.
3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to rate-payers and with a sense of historical continuity. (Compare "The best tax is an old tax.")

*Cost-related Attributes:*

4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company;

associated with individual applications must be weighed to appropriately balance all of these criteria.

AUMA/EDM and PICA concurred with the ATCO Gas philosophy that the Board should approve a rate design methodology that closely reflects the cost components that result from the COSS, subject to assessing any concerns that might arise in relation to rate shock for any customer groups. AUMA/EDM considered that any rate shock issues should be further assessed in a compliance filing.

Calgary also supported the recovery of costs based on cost causation, but considered that ATCO Gas should improve the quality of the data utilized in the COSS. Calgary considered that by adopting the Calgary recommendations respecting rate classes, some inequities associated with the ATCO Gas rate design could be mitigated.

In general, the Board considers that results provided by a COSS, if the data and methodology used are found acceptable by the Board, ought to be given considerable weight in establishing the rate design. Overall, the Board considers that while there is an opportunity for a higher level of confidence with the ATCO Gas data in the future through further verifications, the data utilized in the COSS studies provides a reasonable level of confidence for the purposes of the present decision.

**Fixed versus Variable**

Parties did not agree with regard to the level of the proposed fixed charge for the Low Use and Irrigation rates.

ATCO Gas indicated that it believes that the rate components of the rates should closely match how the costs are allocated to the Rate Groups to ensure that customers within the rate group are not cross subsidizing other customers within the same rate group. As an example, ATCO Gas indicated that if a lower fixed charge than required as per the COSS for the Low Rate Group

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(b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. Reflection of all of the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities).
6. Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three dimensions: (1) *horizontal* (i.e., equals treated equally); (2)*vertical* (i.e., unequals treated unequally); and (3) *anonymous* (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).
7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).
8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

*Practical-related Attributes:*

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.
10. Freedom from controversies as to proper interpretation.

See also *Gas Utilities Rate Design Inquiry Report* No. E80100, dated July 31, 1980, p. 53

were implemented, that would reduce cost recovery for the lower spectrum of the Rate Group and increase cost recovery from the upper spectrum of the Rate Group resulting in cross subsidization within the rate group. Further in this regard, ATCO Gas suggested that its ability to earn its approved return would also be impeded if the way costs are being recovered does not properly match the drivers behind how those costs are incurred. ATCO Gas indicated that a fixed cost by its nature should not be impacted by weather, yet by recovering fixed costs in the variable charge, there is a potential for under or over recovering the cost, which it considered would not be appropriate. Accordingly, ATCO Gas suggested that the fixed charge for the Low Use Rate Group should be moved from the current level which recovers 73%[211] of the customer classified costs allocated to the Low Use Rate Group to recovering 100% of such costs. Similarly, it would be appropriate if the fixed charge for the Irrigation Rate Group to be moved from the current level of recovering 40% of the customer classified costs allocated to the Irrigation Rate Group to recovering 100% of such costs.

Calgary considered that until such time as the technology associated with demand metering for small customers might become cost effective, the existing rate structure will need to consist of a fixed monthly customer charge recovering customer classified costs and a variable or commodity charge which includes the recovery of deemed demand related costs.

CCA and AIPA expressed concerns that the level of the fixed charge should not be based upon the level of customer costs as determined from the COSS.

CCA suggested that the fixed charge should be held at its present level. CCA considered that the fixed charge should not recover 100% of the assigned costs if the Low Use class is not split into more homogeneous groups and the minimum system cost methodologies are used.

AIPA recommended that the Board limit the fixed charge to 73% of the allocated customer costs to prevent rate shock in a fashion similar to that adopted in Decision 2000-016.

ABCOM recommended that the fixed charge be eliminated or alternatively be reduced by 10% for First Nations.

The Board considers there are offsetting factors to be weighed. One factor relates to the societal implications in relation to affordability for the lowest use customers. Any consideration in this regard must consider that a rate design that might unduly favour the smallest customers would tend to disfavour the largest customers in that same rate group. Another factor relates to the ability of the utility to earn its approved revenue requirement without being subjected to undue weather related risk that might arise from a rate design that places excessive reliance upon collection of approved revenue requirements through the consumption related variable charge. Other factors to be considered include stability, simplicity and public acceptability.

As illustrated in Tables 9 and 10 above the fixed charge for Low Use customers was approximately $13/month in January 2005 and is proposed to increase to approximately $18 - 19/month in 2007 with the ATCO Gas proposal. Similarly the Irrigation fixed charge is proposed to increase from approximately $20/month to approximately $30/month. The Board notes that there have been a number of rate adjustments and timing influenced riders in 2005 and 2006 that may have had the same impact and been perceived as an increase to the fixed charge for the Low

[211] For ATCO Gas South per Decision 2000-016

Use customers. For example the interim rates in effect, including riders, for Low Use ATCO Gas North and South customers are currently $16.11/month and $16.49/month, respectively. The Irrigation fixed charge under interim rates is currently $19.22/month.

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. The balance of those charges not recovered in the fixed charge would be recovered through the variable charge. The Board notes that the fixed charge for High Use customers is proposed to decrease from its current levels incorporating the COSS results and that no parties expressed any concerns in that regard. The Board considers that no adjustment to the High Use rates would be required to limit the change to the fixed charge.
The Board directs ATCO Gas to limit the Low Use and Irrigation fixed charge to 90% of the level determined in the updated COSS in its refiling.

**Revenue to Cost Ratios**
ATCO Gas proposed revenue to cost ratios of 100% and noted that while the Board has previously relied upon a tolerance window of 95% - 105%, ATCO Gas did not consider that rate shock would be an issue.

AUMA/EDM concurred with ATCO Gas that the cost recovery should be aligned with the COSS unless there were rate shock issues which could be appropriately dealt with in a compliance filing. Other parties generally considered that a tolerance window of 95% to 105% would be reasonable.

Calgary recommended that an adjustment limitation of 90% would be appropriate if there was no split in the Low Use rate group as Calgary had proposed. Calgary considered that even if the revenue to cost ratio were 100% the quality of the data used in the COSS might not be accurate beyond a 90% to 110% threshold. However, Calgary made the distinction that it did not consider that the 95/105% adjustment ought to be used for inter-class adjustments; but only for intra-class adjustments.

The Board considers that utilizing a threshold target range for revenue to cost ratios can provide a mechanism for mitigating rate shock for effected rate groups if the COSS results in significant cost shifts, particularly in circumstances where there may be concerns respecting the reliability of the data or methodologies. The Board considers the revenue to cost ratios can be further assessed in the compliance filing process.

The Board directs ATCO Gas to include interactive sensitivity assessments illustrating utilization of a 95/105% target tolerance, as well as its proposed 100% recovery, in its compliance filing.

The Board would be assisted by an assessment in the compliance filing that includes, as a minimum, comparisons of annual costs for typical customers in each rate class associated with the rates that were approved as of January 1, 2005; current interim rates with and without riders; and the refiled rates proposed in association with the 2005-2007 GRA at varying revenue to cost ratios, and directs ATCO Gas to provide this in its compliance filing.

### 6.1 2005-2007 Rates and Riders

ATCO Gas suggested that in its compliance filing for the decision related to this proceeding, ATCO Gas will use the most current approved revenue requirement forecast available for the determination of the 2007 final rates. ATCO Gas anticipated that this revenue requirement would incorporate the effect of any further compliance filing decisions related to Phase I of the 2005 – 2007 GRA and the Common Matters decision,[212] as well as the 2007 impact of the DFSS from the Retailer Service decision.[213] ATCO Gas indicated it would also incorporate the effect of any Board directives related to the 2007 COSS and rates in the compliance filing process.

ATCO Gas indicated that in several previous decisions (the most recent being Decision 2006-083), the Board had directed ATCO Gas to defer the impact related to the finalization of all outstanding placeholder amounts and address the disposition of such amounts at a future time. ATCO Gas proposed to defer the impact related to any remaining outstanding placeholders for the years 2003 - 2007. ATCO Gas stated it would also develop a rider for the year 2007 to address outstanding deferral accounts at the time of the compliance filing for this decision and to address the effect of not implementing the 2007 rates on January 1.

ATCO Gas noted that Interim Order U2005-133 with respect to the Carbon related assets indicated that "[t]he Riders G, H, and I will continue in effect and the current process to establish their value on a monthly basis would continue until such time as the Board may otherwise determine." ATCO Gas proposes that the finalization of the rate treatment of the Carbon assets commencing with the 2005/2006 storage plan (i.e. April 1, 2005) be addressed through the Riders G, H and I once known. This would allow the finalization of the distribution rates for the years 2005 – 2007 while acknowledging that outstanding jurisdictional matters related to Carbon for those years remain outstanding.

ATCO Gas indicated it believes that the Board had addressed any perceived inequities between rate groups for the years 2005 and 2006 through its directions in Decision 2006-062. In that Decision, ATCO Gas noted that it was directed to adjust the rates commencing August 1, 2006 to the 95%/105% revenue to cost thresholds as well as develop riders to make the same adjustment for the period January 1, 2005 – July 31, 2006. As such, ATCO Gas submitted that no retroactive adjustment to the 2005 and 2006 rates is required and the Board can also declare those rates as final (recognizing the outstanding matters noted above).

AUMA/EDM concurred with ATCO Gas that it continues to believe that rates should not be adjusted retroactively and that the results of this Phase II proceeding should only be applied on a prospective basis from January 1, 2007 forward.

[212] Decision 2006-100 ATCO Utilities 2005-2007 Common Matters
[213] Decision 2006-098 ATCO Gas Retailer Service and GUA Compliance Phase 2 Part B

CCA considered that the 2005 and 2006 rates should be considered final unless it is determined that the rates provided revenues in excess of Board approved amounts. In this regard, ATCO Gas noted that it designs its rates to recover the approved revenue requirement so it would therefore not be possible for ATCO Gas to recover in excess of Board approved amounts on a forecast basis.

Calgary submitted that the 2005, 2006 and 2007 rates should be finalized on the basis of the cost allocation principles that are approved in the Phase II decision. AIPA and PICA expressed similar perspectives.

AIPA indicated that rates for any period during the 2005-2007 test period prior to the implementation of final rates should be adjusted in proportion to the approved 2007 rates. AIPA suggested that any adjustment should be made over a one year period commencing with the implementation of final rates.

PICA suggested that the principles determined in the current proceeding should be used to adjust the cost of service studies and rates for 2005 and 2006 subject to considerations of rate shock.

In Decision 2006-062,[214] the Board indicated the following:

> … traditionally the final year of a GRA test period is considered when examining the alignment between costs and revenues when testing whether any changes to rates may be appropriate in the future. In this regard, the Board considers that it is noteworthy, as emphasized by Calgary, that it would generally be expected and desirable that a utility would be filing its Phase II rate application at an early enough time to facilitate an assessment and Board decision to allow any changes in rates to be implemented within the test period. While ATCO Gas was unable to submit its GRA Phase II application within the 2003-2004 test period for various reasons, the Board does note that ATCO Gas has proposed a process for the balance of this Application proceeding that will endeavour to mitigate those timing issues in its subsequent 2005-2007 GRA Phase II application, in an effort to implement any rate adjustments in the final year of that test period.

The Board continues to view it as appropriate, absent unusual circumstances, that rate adjustments should be made prospectively even when the utility has been operating under interim rates. The Board continues to hold the view as expressed in Decision 2006-062 that any additional rate adjustments ought to be confined to the final year of the 2005-2007 GRA test period. Accordingly, the rates for 2005 and 2006 are hereby made final. Rates for 2007 will be addressed in the decision to the refiling application which would anticipate a rider to true up any revenue requirement deficiency associated with the 2007 months prior to approval of final 2007 rates.

## 6.2 Rate Schedules

The Board notes that the rate schedules will require updating by ATCO Gas in its compliance filing process.

[214] Reference ATCO Gas 2003-2004 GRA Phase II Part 1 Rates as Final, page 5

# 7 OTHER MATTERS

## 7.1 Compliance Filing

ATCO Gas is directed to provide a compliance filing in accordance with the approvals and directions contained in this Decision within seven working days of receiving the decision to be issued by the Board with respect to compliance with Decision 2006-133[215] finalizing (subject to resolution of placeholders) the revenue requirement for the 2005-2007 GRA Phase I.

# 8 ORDER

IT IS HEREBY ORDERED THAT:

(1) ATCO Gas comply with all directions and approvals contained in this Decision.

Dated in Calgary, Alberta on April 26, 2007.

**ALBERTA ENERGY AND UTILITIES BOARD**

*(original signed by)*

B. T. McManus, Q.C.
Presiding Member

*(original signed by)*

J. I. Douglas, FCA
Member

*(original signed by)*

Gordon J. Miller
Member

215 Decision 2006-133, ATCO Gas 2005-2007 General Rate Application – Phase I Second Compliance Filing to Decision 2006-004 Part B issued December 28, 2006

# APPENDIX 1 – HEARING PARTICIPANTS

| Name of Organization (Abbreviation)<br>Counsel or Representative (APPLICANTS) | Witnesses |
|---|---|
| ATCO Gas<br>M. Buchinski | D. Wilson<br>R. Trovato<br>G. Feltham<br>G. Zurek |
| The City of Calgary<br>D. Evanchuck | H. Johnson<br>H. Vander Veen |
| Public Institutional Consumers of Alberta<br>N. McKenzie | R. Retnanandan |
| Alberta Urban Municipalities Association and The City of Edmonton<br>J.A. Bryan, Q.C. | |
| Rate 13 Group<br>I. Webb<br>L. Manning | |
| Alberta Irrigation Projects Association<br>H. Unryn | |
| Consumers Coalition of Alberta<br>J. Wachowich | |
| First Nation Communities<br>J. Graves | |

| | |
|---|---|
| Alberta Energy and Utilities Board<br><br>Board Panel<br>B. T. McManus, Q.C., Presiding Member<br>J. I. Douglas, FCA, Member<br>G. J. Miller, Member<br><br>Board Staff<br>B. McNulty (Board Counsel)<br>R. Armstrong, P.Eng.<br>M. Hagan, P.Eng.<br>B. Shand, P.Eng. | |

## 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.

## APPENDIX 3 – SUMMARY OF 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.

12. The Board considers the proposed method to classify the Production and Gathering function accounts to be reasonable and approves it accordingly. ........................................................ 33
13. The Board considers the proposed method to classify the Storage function accounts to be reasonable and approves it accordingly. ................................................................... 33
14. The Board considers the method to classify the Transmission function costs to be reasonable and approves it accordingly. ........................................................................... 34
15. Given that the Board has determined to accept ATCO Gas' proposed Low Use and High Use classes and given that the evidence in this proceeding shows generally increasing meter costs with increasing consumption levels within these rate groups, the Board approves the Meter Minimum System Method proposed by ATCO Gas for accounts 474 and 478. The Board considers it appropriate that the classification reflect the fact that larger-usage customers require more expensive metering related equipment. Implicit in this approval is the fact that the Board considers it acceptable that meter replacement cost data was used in the Meter Minimum System Method. The Board considers that in relation to estimated replacement costs for distribution mains and services, less judgment is required to estimate meter replacement costs. The Board also notes that meter replacement cost data was also used by ATCO Gas in the previously approved Weighted Customer Meter Approach. ..................... 38
16. Therefore, the Board approves the classification method proposed by ATCO Gas for accounts 673, 678 and 670. .......................................................................................... 39
17. In regard to the remaining accounts under the Distribution Meter function, ATCO Gas submitted that there was no evidence that would indicate that the classification of these accounts was not appropriate. No other party provided comments. The Board considers that ATCO Gas' proposed classification methods are reasonable and on that basis, approves them as filed. ........................................................................................................................ 39
18. The Board considers the proposed classification of Customer Service function costs to be reasonable and notes that no other party commented on the classification of costs under this function. Accordingly, the Board approves the classification of these costs as proposed by ATCO Gas. ........................................................................................................... 40
19. Accordingly the Board approves the Mains Minimum Plant OD Method as proposed by ATCO Gas. ........................................................................................................... 59
20. Given that the Board has determined the Mains Minimum Plant OD Method to be satisfactory and that it has found in this Decision and in Decision 2000-16 that it remains unconvinced that it would be appropriate for ATCO Gas to develop the necessary data to conduct a comprehensive zero intercept study, and that a zero intercept study conducted on existing data has insufficient support to prefer it to the Mains Minimum Plant OD Method, the Board considers this matter as resolved. Accordingly, the Board would not expect to see intervener evidence in the next ATCO Gas Phase II proceeding advocating the zero intercept methodology. The Board would expect to see substantial new evidence as to the benefits of the zero intercept methodology or any other alternative classification approach for mains costs before it would be prepared to reexamine this matter.................................................. 60
21. Accordingly, the Board approves ATCO Gas' proposal to use the Services Minimum Plant OD Method to classify North and South distribution service costs for account 473.............. 69
22. The Board considers the ATCO Gas approach to income credits is reasonable and approves that treatment. ................................................................................................... 71

# APPENDIX 4 – ABBREVIATIONS

| Abbreviation | Name in Full |
|---|---|
| AG | ATCO Gas |
| AP | ATCO Pipelines |
| CFH | Cubic feet per hour |
| COSS | Cost of service study |
| CP | Coincident peak |
| DFSS | Daily forecasting and settlement system |
| DSP | Default supply provider |
| FSU | Firm service utility |
| GasTIS | Gas transportation information system |
| GJ | Gigajoule |
| GRA | General rate application |
| GURDI | Gas utility rate design inquiry |
| NCP | Non-coincident peak |
| NWC | Necessary working capital |
| OD | Outside diameter |
| FSU | Firm service utility |
| TJ | Terajoule |

# APPENDIX 5 – PROPOSED RATES AS REVISED BY ATCO GAS

Schedule A Proposed
North and South Rate

(consists of 2 pages)

**REVISED**

**Schedule A**
**ATCO Gas North**
**Proposed COSS Methodology & New Rate Structure**
**2007 Costs and Revenues ($000)**

| | | | | Distribution Rates | | | Revenue Proposed Rates | | | | | | Revenue |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Billing | | | | | | | | | AGS | to |
| | | | Demand | Fixed | Energy | Demand | Fixed | Energy | Demand | Total | % of | Total | Cost |
| Rate | Customers | Throughput (GJ) | GJ/yr | $/mo | $/GJ | $/GJ/mo | Revenue | Revenue | Revenue | Revenue | Revenue | Costs | Ratio |
| Low | 485,685 | 94,180,000 | | 19.943 | 0.938 | 0.000 | 116,232 | 88,341 | - | 204,573 | 92.1% | 204,573 | 100.0% |
| High | 1,148 | 25,276,000 | 1,974,000 | 19.943 | 0.000 | 8.752 | 275 | - | 17,276 | 17,551 | 7.9% | 17,551 | 100.0% |
| Irrig | - | - | | - | - | - | - | - | - | - | 0.0% | - | 0.0% |
| | 486,833 | 119,456,000 | 1,974,000 | | | | 116,507 | 88,341 | 17,276 | 222,124 | 100.0% | 222,124 | 100.0% |

| | |
|---|---|
| Rate Design Shortfall/(Over Recovery) | (0) |
| Income Credits | 8,585 |
| Deferred Storage - net | - |
| Schedule C Changes | 303 |
| Franchise Fees | 54,059 |
| Total Utility Revenue Requirement | 285,071 |

**REVISED**

**Schedule A**
**ATCO Gas South**
**Proposed COSS Methodology & New Rate Structure**
**2007 Costs and Revenues ($000)**

| Rate | Customers | Throughput (GJ) | Billing Demand GJ/yr | Distribition Rates Fixed $/mo | Distribition Rates Energy $/GJ | Distribition Rates Demand $/GJ/mo | Production & Storage | Revenue Proposed Rates Fixed Revenue | Revenue Proposed Rates Energy Revenue | Revenue Proposed Rates Demand Revenue | Revenue Proposed Rates Total Revenue | Revenue Proposed Rates % of Revenue | AGS Total Costs | Revenue to Cost Ratio |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Low | 485,291 | 84,051,000 | | 18.296 | 0.799 | | 0.118 | 106,547 | 77,075 | - | 183,622 | 90.4% | 183,619 | 100.0% |
| High | 1,079 | 27,918,000 | 2,038,000 | 18.296 | 0.000 | 7.468 | 0.118 | 237 | 3,294 | 15,220 | 18,751 | 9.2% | 18,753 | 100.0% |
| Irrig | 671 | 627,000 | | 30.300 | 0.767 | | 0.118 | 244 | 555 | - | 799 | 0.4% | 799 | 100.0% |
| | 487,041 | 112,596,000 | 2,038,000 | | | | | 107,028 | 80,924 | 15,220 | 203,172 | 100.0% | 203,171 | 100.0% |

| | |
|---|---|
| Rate Design Shortfall/(Over Recovery) | (1) |
| Income Credits | 5,887 |
| Deferred Storage - net | (197) |
| Schedule C Changes | 269 |
| Franchise Fees | 81,405 |
| Total Utility Revenue Requirement | 290,535 |