Alberta Energy and Utilities Board

DECISION 2001-75

METHODOLOGY FOR MANAGING GAS SUPPLY PORTFOLIOS AND DETERMINING GAS COST RECOVERY RATES (METHODOLOGY) PROCEEDING AND GAS RATE UNBUNDLING (UNBUNDLING) PROCEEDING

PART A: GCRR METHODOLOGY AND GAS RATE UNBUNDLING

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ALBERTA ENERGY AND UTILITIES BOARD
Calgary, Alberta

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	File No. 5680-1 & 5680-2

1 INTRODUCTION

1.1 Scope and Schedule of Proceedings

On February 14, 2001 the Alberta Energy and Utilities Board (the Board) issued a notice to convene a public hearing amongst interested parties and the Alberta natural gas utilities. The proceeding was known as **Methodology For Managing Gas Supply Portfolios And Determining Gas Cost Recovery Rates - Application No. 2001040** (Methodology Proceeding).

The Alberta natural gas utilities involved in the proceedings included AltaGas Utilities Inc. (AltaGas), and ATCO Gas and Pipelines Ltd. operating divisions, ATCO Gas South (AGS, formerly known as Canadian Western Natural Gas Company Limited or CWNG) and ATCO Gas North (AGN, formerly known as Northwestern Utilities Limited or NUL). These operating divisions provide distribution services and regulated natural gas supplies to separate franchise areas in the north and south of the province. Where the two divisions have provided a common position on issues, they are referred to collectively as ATCO Gas.

The Board initiated the proceeding to deal with the positions of the utilities and consumers on the methods that could be used to manage the gas supplies for sales customers, and to determine a Gas Cost Recovery Rate (GCRR) on a going forward basis. Issues to be addressed included, but were not limited to:

- Techniques for management of gas supply portfolios for sale customers, for example, use of AECO C index supplies, storage, long-term contracts, financial hedging, and company owned production.
- Frequency of GCRR adjustments as they might relate to a seasonal, annual, or other period basis.
- Methods to determine the requirement for a GCRR adjustment, for example, formula based guidelines vs. present deferred gas account (DGA) balance guidelines.
- Methods to forecast gas volumes and costs, relative to setting the GCRR.

The Board also considered outstanding matters as they pertained to the 2000 summer period and 2000/2001 winter period DGA balances of AGN and AGS. This review examined the prudence of strategies used by the companies in the use of company owned production and Carbon storage, and any resulting required GCRR adjustments.

The Board received submissions from the organizations or their representatives listed in Appendix 1 of this Decision in accordance with the following schedule:

Register as an Intervener	March 2, 2001
Submissions to Board by Utilities and Interveners	March 16, 2001
Information Requests to Participants on Submissions	March 23, 2001
Information Responses	March 30, 2001
Reply Submissions (if any)	April 6, 2001

A public hearing, originally scheduled to begin April 17, 2001 in Edmonton, was held in Calgary for 9 days commencing on April 30, 2001, before Board members. Dr. B. F. Bietz, Mr. T. McGee, and Mr. B. McManus, Q.C., chairing.

On April 4, 2001, the Board issued a notice to convene an additional public hearing amongst interested parties and the Alberta natural gas utilities. The proceeding was known as **Gas Rate Unbundling - Application No. 2001093** (Unbundling Proceeding).

The Board initiated the proceeding to deal with the positions of the utilities and customers on the proper allocation of costs between the utilities' transportation and gas procurement functions. The purpose of reviewing this allocation was to ensure that independent gas marketing companies were provided a fair opportunity to provide alternative service to gas customers.

The Board had originally provided direction in Decision 2000-16[1] to AGS to begin a collaborative process with its customers, to examine fair cost allocation between the two utility functions. That process was superseded by the Board initiated Unbundling Proceeding. The Unbundling Proceeding expanded on the AGS process to also include AGN and its customers, AltaGas and its customers, and retail gas marketers. The Board took the view that gas rate unbundling issues should be addressed generically for all Alberta gas customers and utilities.

Prior to the oral hearing, the Board convened a Pre-hearing Meeting on April 10, 2001 to explore with parties the scope and scheduling of the Unbundling Proceeding in light of the other gas utility proceedings that were ongoing or scheduled. In particular, the Board wished to receive comments from parties on convening a Technical Meeting prior to the oral hearing to settle on areas of broad agreement, particularly those areas dealt with in the AGS collaborative process. Parties agreed that provision for collaborative discussion regarding unbundling issues would be useful. The Board provided registered parties, prior to the pre-hearing meeting, with a discussion paper that outlined its preliminary views as to the scope and nature of the relevant issues, and the suggested agenda for any Technical Meeting.

The Board provided the following schedule for the proceeding:

Register as an Intervener	April 6, 2001
Pre Hearing Meeting	April 10, 2001
Technical Meeting	April 17, 2001
Submissions to Board by Utilities and Interveners	April 27, 2001

[1] Canadian Western Natural Gas Company Ltd., 1998 GRA Phase II, June 13, 2000

Information Requests to Participants on Submissions	May 4, 2001
Information Responses	May 11, 2001
Reply Submissions (if any)	May 17, 2001

Subsequently, the Technical Meeting was rescheduled to April 19-20, 2001. The meeting resulted in an expansion of the scope of the proceeding to more generically deal with the unbundling of gas utility rates – separating the various functions performed by the utility into separate service options. The meeting also resulted in a proposal for a Memorandum of Understanding (MOU) to be agreed to by all parties. The MOU was to provide a description of principles for unbundling utility rates and functions. A draft MOU was circulated to all parties prior to a settlement meeting held May 25, 2001. At that meeting, parties were unable to reach agreement on the MOU, and it was abandoned.

The public hearing convened on May 23, 2001 and lasted 5 days before Board members Dr. B. F. Bietz, Mr. T. McGee, and Mr. B. McManus, Q.C., chairing.

During the Methodology Proceeding it was decided to combine the argument and reply process for both the Methodology Proceeding and the Unbundling Proceeding. Included as part of the evidence for both proceedings was the record from Applications numbers 2001017, 2001020, 2001030 and 2001070, which were applications regarding the sale of certain AGN company owned production facilities.

By letter of September 7, 2001, the Board requested that parties comment on the effect of the *Natural Gas Price Protection Act*[2] (NGPPA) on their submissions. The Board had noted that, although the Act was in force prior to the date set for receipt of argument, no parties had commented on this piece of legislation. Parties were requested to provide their comments by September 21, 2001.

The Board considers that the closing date for evidence and submissions for these proceedings was September 21, 2001.

1.2 Background

The Alberta retail natural gas market is currently in a state between fully regulated utility operation and competitive retail service. Although competitive gas retailers have been active in Alberta, advertising their presence and providing alternative rate offerings, the retail gas market is dominated by regulated utility service. A principal purpose of both the Methodology and Unbundling proceedings was to examine the effect of the Board approved tariffs on the further development of the competitive retail market. The Methodology Proceeding also dealt extensively with the effect of GCRR rate setting methods on customers continuing on utility gas supply.

The issues of concern in the Methodology Proceeding involved the design of the unit gas charge payable by customers to recover the procurement and management costs for utility gas supplies. The current GCRR is reviewed on a seasonal basis, with rates established for the winter heating

[2] S.A. 2001, c. N-3.5

season (November through March of each year) and the summer heating season (April through October of each year). The GCRR is designed to recover forecast gas costs for the forthcoming season, as well as recoup or repay any differences between previous forecasts and actual gas costs. These rates are flow through rates. The cost incurred by the utility to purchase wholesale gas supplies is ultimately what is paid by the customer taking utility gas supply.

The considerations in establishing a new GCRR methodology included the methods by which the utilities would acquire gas, and the methods by which the rates would be calculated. Alberta gas utilities have, during recent periods, largely acquired gas via daily or monthly indexed market price contracts. This method of gas acquisition passes all variability in the wholesale price of gas to customers, via the GCRR. In the winter of 2000/2001, a severe rise in the wholesale price of natural gas led to an unprecedented increase in the GCRRs for the Alberta gas utilities' customers. The methods used by the utilities were examined to determine if it was appropriate for the utilities to actively undertake gas price management - managing a portfolio of gas price futures contracts, price hedges, gas storage, and company owned production - to attempt to moderate gas price swings being passed on to customers. The methods of calculating the GCRR rates also have an effect on the variability of consumer gas prices. Extending the GCRR period, for example, would reduce the number of gas price changes seen by consumers, but could lead to larger adjustments being required to repay or recoup previous differences between forecast and actual gas costs.

The determination of the GCRR methodology was seen to affect the potential for further development of the retail gas market. Gas marketers argued that long GCRR periods, and particularly the authorization of utility gas price hedging programs, could make utility supplied gas prices very different from actual market prices at any given time. Pronounced differences between utility gas prices and retailer's gas prices, it was argued, could create problems for retail market development.

The Unbundling Proceeding was initiated by the Board to deal directly with issues that arise in the interaction between gas utility tariffs and the competitive gas market. Since the addition of section 26.1(3) to the *Gas Utilities Act*[3] (GUA) in 1990, and the enactment of the *Gas Utilities Core Market Regulation*[4] (Core Market Regulation) in 1995, customers have had the right to contract with unregulated gas supply companies to purchase natural gas. In the instance where a customer elects to take competitive retail gas supply, the gas utility serves only as a "pipes" supplier, a transportation provider for gas.

The Board first dealt with gas rate unbundling issues in the AGS (then Canadian Western Natural Gas Co. Ltd.) 1998 GRA – Phase II[5], in Decision 2000-16. In that proceeding, the issue of rate unbundling arose in regards to the proper allocation of gas acquisition and management costs. In the fully regulated utility environment, variable gas acquisition costs were recovered through the GCRR, but other costs related to company owned production capital, gas

[3] R.S.A. 1980, c. G-4
[4] Alberta Regulation 44/95
[5] The Phase II portion of a general rate application (GRA) deals with the allocation of utility cost between utility functions and customer rate classes.

management, and gas storage were collected through the general gas delivery rate[6]. This suggested that customers taking gas supply from competitive retailers were also paying for a portion of the utility gas supply costs, skewing the economics for customers wishing to take competitive gas supply.

In Decision 2000-16 the Board directed that this issue be reviewed via a collaborative process involving AGS and its customers. At the initiation of the Unbundling Proceeding, the gas cost allocation issue was the focus of the proceeding. However, following consultation with all parties via the Technical Meeting it became clear that this issue was not the only tariff element that was seen to be an impediment to the development of a functioning retail gas market.

In brief, the issues identified included:

- The allocation of costs between the various functions of the utility.
- The ability of retailers to undertake certain of the utility functions on a competitive basis.
- Transition issues arising from the unbundling of utility rates and functions.

1.3 Scope of Part A of this Decision

In its determinations, the Board has decided that it is appropriate to divide its rulings into two parts:

- Part A (this Decision), dealing with rate and policy issues; and
- Part B, dealing with the review and reconciliation of previous GCRRs, to be released in due course as a separate decision.

2 THE ROLE OF THE BOARD IN THE ALBERTA RETAIL GAS MARKET

2.1 Role of the Board Under Existing Legislation

2.1.1 Positions of Parties

AltaGas

It was AltaGas's view that the Board had three essential types of duties under existing legislation:

- the duty to balance the interests of consumers and those obligated to supply them;
- the duty to ensure rates charged by regulated utilities were fair – that the costs of various services were appropriate and that they were allocated to the right consumers; and
- the duty to oversee the ownership, management, and operations of regulated utilities to ensure the public interest was protected.

Until the existing legislation is changed, it was AltaGas's view that the Board had no duty or mandate to create market opportunities for unregulated parties, or to ensure unregulated third parties have a margin (reasonable expectation of profit) on services they provide.

[6] Throughout this Decision, gas delivery rates, transportation rates, or base rates may be used to denote the costs of utility service not associated with the procurement and supply of natural gas itself.

In AltaGas's view the role of the Board was limited by its quasi-judicial nature, and by the framework created by the legislation. The Board was charged with ensuring adherence to a statutory framework designed to protect the public interest where a utility was the sole supplier of an essential service, and the best the Board could do in the process was to help the Government create the necessary legal framework – one that clarified the desired end state model, provided direction on how to get there, and defined the Board's role in the process. AltaGas questioned what legal authority would support the Board's assumption of such a leadership role and doubted whether the statutory framework in place in Alberta would support the Board taking on such a leadership role.

AltaGas argued that it was not the Board's role to implement a new gas supply model in Alberta. Absent clear direction from government – for example, by statute or a clear statement of government policy - an administrative agency such as the Board does not have the power to advance a particular model end state for the supply of natural gas and related services. There was no evidence in this proceeding of a government policy or law that would direct the Board to do this. AltaGas submitted that the Board did not have the power to construct the framework needed for a new gas supply and services model. AltaGas questioned whether section 28(c) of the GUA could be stretched to provide authority for the Board to determine such issues as "what customer information a gas utility is obliged to provide to marketers, and the conditions that the gas utility might impose on marketers with respect to customer enrolment, connection and disconnection".[7]

AltaGas believed the GUA might create problems in pricing unbundled services when considering section 35, which says:

> In considering and acting on any application or matter before the Board and involving the question of rates to be charged for service by any owner of a gas utility, the Board shall not make any ruling or direction to raise rates for that service beyond the amounts that the owner of the gas utility desires to impose.

However, AltaGas submitted that steps could be taken to develop specific proposals for unbundled services and bring them to the Board for approval.

AltaGas noted that the lack of a clear mandate to deal with unregulated suppliers does not affect the Board's capacity to approve and give legal force to proposals such as the AltaGas GCRR Consensus Proposal[8] (the AltaGas Proposal).

ATCO Gas

ATCO Gas considered that the Board has the right to allocate costs to various cost centers to reflect unbundling. ATCO Gas submitted that the Board should provide clear direction to accommodate unbundling.

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[7] ENMAX Argument paragraph 55
[8] GCRR-Ex. 8, GCRR and DGA Methodology – Submission of AltaGas Utilities Inc., Schedule A.

ACC

The ACC expressed its belief that all unbundling changes recommended by the Board should be reflected in appropriate legislation, which would ensure that market participants have certainty with respect to the legality of any unbundled environment.

CCA

The CCA considered that under either existing or amended regulations there is a role for the regulator, and cited its evidence presented in the unbundling proceeding suggesting that regulatory intervention is needed to ensure that unbundling is implemented in a way that levels the playing field, incubates effective competition, and ensures that the interests of consumers are protected. The CCA also agreed that regulatory intervention is needed to ensure that unbundling facilitates competition only to the extent that the competition is in the public interest.

The CCA submitted that "market forces" should not be allowed to replace the role of the Board under existing or future legislation.

The CCA disagreed with the submission of ENMAX, that Alberta Government policy is that gas rate unbundling should be implemented. The CCA considered that the Board should only take direction from the Government through legislation and regulation. The CCA indicated that it did not support repeal of the Core Market Regulation, as this would remove what little protection is afforded to residential customers. The CCA also expressed support for increased bonding requirements to ensure that customers do not lose the benefits of long-term contracts in the event that unbundling moves ahead.

Calgary

Calgary stated that the role of the Board should be to ensure that a regulated rate option (RRO) does not inhibit or impair the development of the retail market. Calgary noted that the Board has broad powers to enact tariff and service rules under its existing mandate. It argued that unbundling the existing delivery rates, transferring certain costs to the GCRR, and establishing stand-alone unbundled service rates is within the Board's current authority. Calgary argued that the entire process could be viewed as a re-pricing exercise, where the collection mechanisms would be different, but the utility would be revenue neutral.

Edmonton

Edmonton stated that the Board's public interest protection role required the Board to encourage competition and customer choice. It submitted that the Board should ensure that customers have access to a reasonable range of competing choices in the marketplace, not just a range of competing choices provided by one or a small number of companies.

ENMAX

ENMAX submitted that the GUA provides the Board with the jurisdiction to accomplish all of the unbundling goals contemplated by ENMAX. It argued that the Board also had the power to regulate the relationship between the gas utilities and retailers, to the extent that utility customers are affected.

Enron

Enron supported the position advanced by ENMAX that the Board has authority under the GUA to implement the changes required to facilitate full unbundling of utility services, except for removal of the incumbent utility from its merchant role obligation.

EPCOR

EPCOR submitted that the Board had a critical role in facilitating a timely transition to a fully competitive market in retail gas sales. EPCOR supported the initiation of a collaborative process to address rate unbundling, market rules, and codes of conduct. EPCOR contended that it was important for the Board to take a proactive role through its decision in these proceedings.

EPCOR noted that retail gas sales to the Core market have been deregulated since 1995, but that there was currently only one competitor to ATCO Gas actively marketing to residential consumers. EPCOR also noted that Decision 2000-16 had provided specific directions to CWNG to initiate a consultative process to address the list of expected outcomes related to unbundling. EPCOR noted that in the year following the Board's decision, only one consultation meeting was held. EPCOR submitted that very little progress had occurred with respect to what appeared to be specific directions from Decision 2000-16.

EPCOR argued that the evidence in this proceeding demonstrated that it was clear that the province continued its strong support of the early transition to a fully functioning competitive market for both natural gas and electricity. EPCOR noted from its Reply Submission, filed in the Methodology Proceeding:

> EPCOR submits that there is considerable merit in considering the fullness of the model, including timetable, developed for deregulation of the retail electricity market in Alberta. The timetable provides for a competitive retail market for all customers by the end of 2005, with only residential consumers eligible for the RRO beyond the end of 2003. EPCOR believes it would be beneficial to fully transition to a competitive market for both forms of energy coincidentally. EPCOR submits that the electric model also clearly delineates the boundaries of regulated and competitive services, and provides guidelines for moving to a fully competitive retail market for natural gas.[9]

EPCOR argued that the 2005 end date for termination of regulated supply of gas should be an outside date, and that the circumstances of the gas market lend themselves to an early transition to a fully competitive market.

EPCOR stated that while a clear Government policy statement would be helpful, it agreed with ATCO Gas and others that the Board could take the necessary action through its decisions in these proceedings to facilitate the transition to a competitive market. It also noted Exhibit 29 of the Unbundling Proceeding, a letter from the Minister of Energy for the Province of Alberta, noting the role of the Board in facilitating retail competition in natural gas.

[9] Methodology Proceeding, EPCOR Reply Submission, Ex. 38, p. 3

EPCOR submitted that the Board has the mandate and direction from the Government to proceed through its decisions to:

- provide a clear delineation between competitive and monopoly services;
- prescribe the timetable for implementation of a fully functioning competitive market for the retail supply of gas;
- establish a clear set of principles to be used in any collaborative process for unbundling;
- establish a firm timetable for the deliberations of any collaborative process with milestones and a requirement for periodic reports back to the Board;
- establish a hearing date to address any consensus reached or the collaborative process and resolve any remaining issues as at the date of the hearing; and
- direct the immediate unbundling of current rates on an interim basis and the adjustment of the utilities' current Phase I and Phase II filings to reflect the board's unbundling directions.

FGA

The FGA expressed concern as to whether unbundling should be done, and if so, by whom. It stated that the Board has responsibility pursuant to the GUA and the *Public Utilities Board Act* [10] (PUBA) as a protector of consumer interests. The Board must consider the impact on consumers if it decides to effect a policy change in this area. It also asked whether the Board, in directing change which might then have a negative impact, might fetter its own discretion with respect to making redress of such events.

The FGA noted that ATCO Gas had conceded that there did not exist a clear policy statement from the Government regarding gas deregulation, but had argued on the basis of the "implicit desires" of the Government. The FGA argued that ATCO Gas's inferences regarding Government policy were irrelevant.

The FGA reiterated its argument that the Board is not a policy board and should not be setting policy for business development. It stated that the Board should await Government direction before allowing any utility to exit or substantially alter existing requirements to provide and maintain the merchant function.

The FGA argued that the letter from the Minister of Energy to the AUMA (Exhibit 29) did not form a statement of government policy.

MI/UM

The MI/UM submitted that the Board's role is to implement "Government policy" within its legislated mandate. The MI/UM expressed doubt as to whether Exhibit 29 would constitute evidence of government policy.

[10] PUBA cite

2.1.2 Views of the Board

The Board considers that section 26.01 of the GUA, and the Core Market Regulation, are sufficient indicators that the policy of the Alberta Government is to provide a reasonable opportunity for the development of natural gas retail competition. Section 26.01 of the GUA gives all Alberta consumers the right to choose their gas suppliers. The Core Market Regulation, enacted under the GUA, establishes rules relating to direct sellers (also known as gas marketers or natural gas retailers). As a result of this legislative framework, there is currently some competition between direct sellers and regulated utilities.

The Board is of the view that the provision of a reasonable opportunity to natural gas retailers to enter into the marketplace is in the public interest, provided that certain procedural safeguards are in place. In this period of transition to a fully competitive market, the Board considers that it should ensure that customers of utilities, and utilities, are treated fairly, while at the same time allowing sufficient flexibility to ensure that gas marketers are able to offer a reasonable and economically viable choice for customers. The Supreme Court of Canada has stated that the Board's jurisdiction to "safeguard the public interest in the nature and quality of the service provided to the community by public utilities" is "of the widest proportions."[11] In the Board's view, the Board's wide jurisdiction to safeguard the public interest includes ensuring that consumers are able to exercise their right to choose their gas suppliers while enjoying the protection afforded by the regulator during a transition period prior to the development of a fully competitive market. More specifically, the Board's power to direct the framework for unbundling as described in section 6 of this Decision is based on the Board's general supervisory power over utilities, as set out in section 22 of the GUA and section 77 of the PUBA, and its power to fix just and reasonable standards, practices, and service to be observed and followed by the owner of a gas utility, as set out in section 28 (c) of the GUA.

2.2 Role of the Board in Competitive Market Enablement

2.2.1 Positions of Parties

AltaGas

AltaGas supported any move toward a competitive market for gas supply that was likely to benefit consumers. The test for any such move in the AltaGas service area would be that it had customer support, and was approved by the Board.

It was AltaGas's submission, that four key realities that should be kept in mind when looking at enabling a competitive environment:

- the assumption of benefits was based more on a "leap of faith" than hard evidence;
- given the current situation in Alberta, once the GCRR was fine-tuned the benefits of competition would likely be marginal at best;
- system supply should continue to be an option until customers decide it is unnecessary; and;
- given the lack of supporting "judicial" evidence the decision to make the leap of faith is one for Government, not a quasi-judicial body like the Board.

[11] *ATCO Ltd. v. Calgary Power Ltd.*, [1982] 2 S.C.R. 557, at 576 (per Estey J.).

AltaGas submitted that the move to a competitive market should be characterized by caution. It argued that there was no room for a leap of faith without a safety net.

In AltaGas's opinion, the only way to develop a system that would benefit consumers would be to take time, work with consumers and marketers, and bring back specific proposals to the Board for approval.

AltaGas stated that four principles should guide the design of the ultimate Alberta model:

- Principle 1 – Real consumer benefit
- Principle 2 – No artificial incentives or barriers
- Principle 3 – Tariffs recover long term incremental costs
- Principle 4 – Utilities will not bear stranded costs

It was AltaGas's view that creating a retail market is a means, not the goal, and that whether or not the consumer will be better off is the question to be answered.

AltaGas expressed concern that some unbundling strategies may increase costs to the consumer through duplication while others may increase costs through complexity. It noted that one of the highest cost items that has been run into in other jurisdictions are information systems.

It was AltaGas's position that unbundling strategies should be developed collaboratively and must reflect the public interest. There should be no artificial incentives or barriers, full cost tariffs for unbundled services, and protection from stranded costs.

AltaGas expressed this view in its submission:

> Unbundling may ultimately result in a fully functioning "textbook" competitive market. In that market there would be numerous buyers and sellers. Ideally no single buyer or seller would significantly influence the price of the service or product being offered. That cannot be achieved if artificial barriers restrict the entry of new participants to the marketplace. Conversely, there should be no artificial incentives, such as barriers to utilities participating in the market, simply to encourage the creation of a textbook marketplace.[12]

ATCO Gas

ATCO Gas considered the goal of unbundling should be to create a framework that would allow the market to work. It stated any changes should reflect the experience that it is contrary to the entire concept of regulation to have a regulated service competing with other competitive supply providers in the same marketplace.

ATCO Gas noted its concerns that certain consumer groups had proposed enhanced utility offerings and the extension of the transition period, while espousing a desire for a competitive market. It supported the development of a competitive market place and noted its proposed

[12] Unbundling; Exhibit.14; p.2

initiatives to further this development, including its proposed sale of producing properties, its proposed sale of retail operations, its proposal to remove the Carbon storage asset from regulated service, and its current market price GCRR strategy.

ATCO Gas expressed concern that further delay in the conversion between regulated and non-regulated service could jeopardize the benefits of both systems. It quoted its witness, Mr. Engler, who said that "... if you try to extend regulated service longer than you should in a deregulated marketplace, you end up probably losing the benefits of regulation and the benefits of competition."[13] It submitted that the transition period should be as short as possible to encourage the entry of new retailers. It also submitted that parties should focus their energies on enablement of the competitive market, rather than the enhancement of the regulated rate.

ATCO Gas stated that it was willing to take the steps necessary to achieve an open, competitive market by January 1, 2002. It submitted that greater flexibility was required in the procurement of gas for the GCRR during a transition period.

ACC

The ACC agreed that a competitive market should be enabled and is desirable, and considered that all gas consumers in Alberta would benefit from a fully deregulated market.

AIPA/EUAA

AIPA/EUAA did not oppose development of a retail market for natural gas, as long as the option for regulated service remains during a set transition period (November 2001-November 2006), and after such a transition period if a competitive market did not exist at that time.

In contrast to the situation in the electricity market, where AIPA/EUAA suggested the benefits are limited to retailers, the over-riding objective has to be real benefits to consumers. Noting the significant investment by ATCO Gas in upgrading information systems and metering functions, apparently driven by the desire to accommodate customer choice, AIPA/EUAA questioned which customers would be responsible for payment of these costs.

AIPA/EUAA made the observation that electricity RRO customers have experienced significant rate increases, and essentially no choice in the retail area, and cautioned the Board against subjecting customers to a mandatory no-choice option and higher prices. With those precautions, AIPA/EUAA would not oppose implementation of customer choice as long as that choice includes the option of regulated supply for a transition period of no less than 5 years.

AIPA/EUAA submitted that the Board should not allow a utility to vacate the merchant function until it can be demonstrated that a majority of customers desire and have selected competitive supply. The test, in AIPA/EUAA's view, for a competitive market should include the assurance of no dominant market share by a single retailer.

[13] Methodology T4: 297

CCA

The CCA noted the variety of positions held on the issue of competitive market enablement, favored most by competitive entrants who see the opportunity for profit. However, the CCA submitted that the absence of unqualified opposition should not be construed as unqualified support for the concept.

The CCA expressed opposition to dysfunctional competition, or unregulated oligopoly or monopoly situations, and submitted that before implementation of further unbundling, market proponents should have to prove the existence of those markets, and a public interest test should be conducted before the Board.

The CCA did not agree that the document tendered by the witness for ENMAX (the Hall Report) [14] should be viewed as representing a cost-benefit analysis on the Georgia model, particularly since the word "cost" is not mentioned in the report. In the CCA's view, the Hall Report was purely a justification of the writer's beliefs about the benefits of competition, a view that the CCA illustrated with observations with respect to the validity of the propositions presented and conclusions reached in the report. The CCA submitted that a major problem with the report, in addition to these limitations, was that the document was untested in that the author was unavailable for cross-examination. The CCA considered that, since the document only presented the benefits, but not the costs, and did so without any field assessment of information, it did little to advance the full understanding of the true lessons from the Georgia experience. The CCA submitted that the report should be given little, if any, evidentiary weight.

Noting that a retail natural gas market currently exists, with EPCOR having already attracted a number of customers, the CCA considered that the requirements of the participants were different**.** Specifically, new entrants desired better terms, the utility wished to shed the obligation of regulated supply, and the customers, represented by the CCA, wished to enhance any potential benefits and reduce costs. Accordingly, the CCA advised a cautionary approach to the development of a retail gas market, which would include examination of the extent to which a retail market would be in the public interest, as the lowest cost delivery system.

The CCA disagreed with the submission of ENMAX, that its unbundling proposal would provide consumers with lower costs. Rather it suggested that further unbundling would raise gas costs, as customers would be charged retail prices, and would be required to absorb stranded costs. The CCA submitted that a contestable market would allow monopoly or oligopoly level profits to accrue to the dominant unregulated provider, and allow little choice for the consumer.

Calgary

Calgary noted that it had supported the development of the retail market for natural gas since the early 1990s, and continued to support this development. Calgary stated that Core gas consumers would benefit from a broader choice of gas supply options, either more suitable to their requirements, or possibly at lower prices than those offered by the utility. Calgary noted the

[14] Consumer Benefits from Deregulation of Retail Natural Gas Markets: Lessons from the Georgia Experience, George R. Hall, March 10, 2000.

evidence of Mr. Engler, that the Alberta retail gas market has been “in a stall mode”. It noted that only one retailer, EPCOR, was active in the residential/small commercial marketplace.

Calgary submitted that the following steps were required to promote the development of the retail gas market in Alberta:

- Utility rates and functions should be properly unbundled.
- The utility should only offer a single, standard service option defined as the RRO.
- While retailers would actively compete against the RRO, the utility would not actively promote the RRO over options offered by retailers.
- The price of the RRO should be adjusted monthly to ensure that the RRO price accurately reflects all utility gas supply costs, minimizing or eliminating the need for exit and entrance fees.

Calgary argued that the RRO should be priced in a manner that accurately reflected the utility’s current cost of gas acquisition, with limited price volatility. Customers would be at risk for all variances in prudently incurred costs by the utility, in Calgary’s proposal. It stated that an equal payment or budget-billing plan, similar to what is currently offered, would continue to be available under the RRO to provide limited bill stability.

Calgary recommended that the need for enabling initiatives, or modifications to existing legislation, would be best left to working groups. It argued that parties must decide on what they wish to accomplish prior to deciding on initiatives or legislative changes. Calgary submitted that, with inputs from the working groups, the Board could find that it has the authority to develop recommendations through tariff applications and related service rules.

Calgary cautioned that care should be taken that artificial programs and procedures are not implemented to enable the market. It argued that the market should be allowed to develop through competitive offerings in a level playing field environment. It stated that the establishment of benchmark prices for fully unbundled services would provide price signals to the competitive market, and form the basis for the emergence of alternative service providers.

Calgary argued that the sale or deregulation of utility rate base assets was not required, nor would that contribute to achieving an unbundled environment. It stated that unbundling is the separation of service into distinct offerings, at defined rates for the service. Calgary argued that the ATCO Gas sale of retail operations would do no more than place 80% of the Alberta customers in the hands of a single supplier. It argued that ATCO Gas should not be given credit for supporting the emergence of a competitive market through actions that did not contribute to the process, and which may in fact diminish the emergence of that market.

Edmonton

Edmonton recommended that a public statement of policy be obtained from the provincial Government. It argued that these steps, together with the implementation of unbundling of at least the gas supply functions, should encourage the entry of additional retailers and provide more options for customers.

Edmonton argued that customers should not be required to leave the RRO until genuinely comparable alternatives are available. It did not support a forced customer allocation process, as used in Georgia.

ENMAX

ENMAX believed that suggestions for a "litmus test" for a healthy, robust competitive market were misplaced, and that ultimately, the number and size of market participants and other traditional measures of market power were not necessarily appropriate, and might actually limit potential customer benefits by depriving retailers of economies of scale and scope. ENMAX believed it was more important to create contestability for the market through the market design, rules, and procedures, because potential competition played a dominant role in constraining prices and promoting competitive behaviour from retail market participants.

ENMAX submitted that a market would be perfectly contestable if three conditions were satisfied.

- First, potential entrants to the market must have access to the same technology, input prices, products and demand information as existing retailers.
- Second, there would be zero sunk costs.
- Third, the time between when a retailer's entry into the market was known by existing firms and when the new firm was able to supply the market was less than the time between when an existing retailer desired to change price and when it could change price.

Under these conditions, ENMAX stated, consumers would achieve maximum benefits.

ENMAX submitted that with a carefully constructed market model, it was possible to create the market conditions necessary to approximate perfect contestability; and that this was particularly true given the proximity of substantial natural gas supplies to the Alberta market, and the well developed, liquid, and competitive wholesale natural gas market.

ENMAX stated that utility rates must be unbundled. It believed that the Board must act to provide the opportunity for competition to develop, and that it was also necessary to develop appropriate market rules as part of the unbundling process.

In ENMAX's submission, the key to robust competition was a substantial commitment of both retailers and customers to the long-term success of the market. ENMAX submitted that the development of a successful competitive market model required the Board to clearly identify its preferences with respect to the end-state of the market, and recommended that the Board adopt its proposed model for utility and market operations.

ENMAX believed that it was necessary for the Board to adopt or identify end-state characteristics for marketers as follows:

- The marketer provides all customer related services.
- The marketer bills customers for commodity and delivery under customer selected billing arrangements.

- The marketer responds to all bill inquiries from consumers.
- Marketers bid to provide supplier of last resort service subject to regulatory solicitation.
- The marketer pays the regulated utility for delivery service, other utility services, and customers' switching.
- The marketer provides regulated utility bill inserts to consumers as required.
- The marketer provides the utility's number for all safety related calls and maintains the capability to automatically transfer calls to the utility.
- The marketer delivers gas commodity to the utility for delivery to consumers based on commodity and capacity requirements of those consumers.

ENMAX acknowledged that the enablement of a competitive market was desirable only if there was a reasonable expectation of benefits to consumers. In a workable competitive market, ENMAX considered there to be two direct benefits produced by competition - lower prices, and more choices. It was ENMAX's opinion that the general conclusions identified in the Hall Report were instructive.

ENMAX noted that while arguably all consumers will be better off in terms of the number of choices, there would be some consumers who, in terms of absolute price, would be worse off in a competitive market. It explained that, under regulation, these consumers would have unfairly benefited from the cross-subsidization inherent in averaged, regulated rates. ENMAX argued that the Board should not be surprised if these consumers oppose the development of a competitive market.

ENMAX stated that lower prices would result from cost savings and efficiency gains in every segment of the business**.** ENMAX noted the results from Georgia that demonstrated that deregulation and retail competition could result in lower prices and a greater range of supply options for the consumer even where there has been wholesale competition, and the margins between upstream gas prices and regulated retail prices have already been squeezed.

Enron

Enron submitted that unbundling enables competition, allows the market to provide services that meet the needs of individual customers, provides cost savings, and also provides the benchmarks required to facilitate competition and market discipline. Enron argued that a retailer's margin could be less than the utility's costs of supply services. Enron further argued that retailers could manage a supply portfolio more efficiently than the utility through the diversity of markets they serve.

Enron argued that a healthy retail natural gas market requires the removal of unnecessary entry barriers and the creation of a level playing field between direct purchase customers, system sales customers, retailers, and utilities and their affiliates.

Enron submitted that this level playing field can be accomplished through the establishment of clear market rules, and the unbundling of all services that can be provided competitively. It proposed:

- Establishing codes of conduct governing the relationships between the utility and any non-regulated affiliates or designates to avoid the potential for cross subsidization and the unfair sharing of competitive information.
- Implementing monthly gas cost recovery rates, which reflect actual market prices to provide clearer market signals and minimize DGA balances, and which would negate any need for exit fees.
- Requiring limited use of hedged products in utility portfolios.
- Using a rate credit rider approach for company owned storage and company owned production, in order to remove the gas cost impacts of these assets and the transfer of other gas supply related costs to the DGA/GCRR.
- Unbundling other types of utility rates and services.
- Disallowing entry and exit fees.
- Repealing the Core Market Regulation, which contains outdated and unnecessary entry barriers.
- Implementing the draft Natural Gas Billing Regulation, which will provide retailers with the ability to bill both gas supply and utility distribution charges.
- Creating reduced notice requirements to switch to retailer supply or return to system supply.

Enron submitted that if the above action was taken, more retailers could be expected to enter the market, thereby increasing competition.

EPCOR

EPCOR stated that it was requesting that the Board take the necessary measures to level the playing field between regulated utilities and competitive gas suppliers by:

- approving the company owned production rider advocated by the NCC (NCC COP Rider)[15] and others for company-owned production;
- implementing EPCOR's proposals for GCRRs/DGA methodology; and
- directing and overseeing the unbundling of ATCO Gas's distribution sales rates, initially and immediately on an interim basis, and ultimately in a timely manner on a final basis.

EPCOR noted that the witness from Enron Canada Corporation, Mr. Keene, had stated that it was important for the Board to implement interim rates immediately in order to send a signal to the marketplace that would encourage participants to be involved in the collaborative process.

EPCOR submitted that the gas utilities should take a proactive role in the development of the retail market for natural gas by:

- supporting and facilitating unbundling at the earliest practical date;
- supporting and facilitating the implementation of the NCC COP Rider; and
- performing the functions of default supplier and supplier of last resort during the transition to a fully functioning competitive market for retail gas.

[15] The NCC COP Rider is discussed in detail in section 5 of this Decision

EPCOR stated that the Board should encourage ATCO Gas through its decisions to be proactive, and to facilitate the expeditious move to a fully functioning competitive market.

FGA

The FGA questioned the need for greater competition in the retail gas market. It noted that if few customers want or choose to exercise choice, it is possible that the market is already competitive, or that customers prefer not to make decisions that they may perceive as not being worth the effort.

The FGA did not oppose inclusion of legitimate gas supply costs in the RRO, however, it did oppose the artificial inclusion of unrelated costs motivated by a desire to increase the apparent attractiveness of alternative retail products. It noted the history of the telecommunications industry and the retail computer hardware industry which provide examples of failed entrants in a competitive market. It noted that, unlike the products of those industries, natural gas is essential to most consumers in Alberta. It stated that those consumers should be assured that they would not be required to incur greater costs or loss of service to enable a philosophical ideal. It stated that this observation should be evident in reference to the state of electrical deregulation in Alberta and the forced moved to “competition” in that market.

The FGA stated that, if the Alberta market is already fully served, at or below a known and recognized index, there may be some concern as to the need for a retail market, and what margin retailers might required to sustain their operations in such a marketplace. The FGA stated that it did not oppose retailers offering competitive products in a marketplace, but did oppose creating unfair advantages for retailers at the expense of existing customers. This would include eliminating services beneficial to existing customers, such as the RRO.

In reply argument, the FGA stated that it assumed that ATCO Gas was prepared to remove the regulated option for customers by January 1, 2002, to create an open, competitive market by that date. The FGA opposed the removal of a regulated choice for customers.

The FGA stated that Hall Report must be approached with caution. It pointed to the report’s finding that, “it is too early to draw many conclusions.” It noted that the report was drafted only six months after the deregulation of the Georgia gas market. It stated that the report appeared to downplay any concerns, and overstated benefits, arising from deregulation in Georgia. In reply argument, the FGA countered ENMAX’s extensive use of the Hall report. It argued that it was not clear that this report was valid for Georgia or Alberta.

MI/UM

The MI argued in favor of unbundling, with the view that it was the only way to determine whether there were any customer benefits, or if another party could provide the same service or function at a lower cost.

The MI/UM submitted that, in the absence of Government policy, the development of a retail market for natural gas requires the Board to provide clear directives and guidelines, without which it would be difficult to identify and implement strategies that would be consistent with such policies and objectives.

The MI/UM stated that a regulated gas utility should neither prevent nor inhibit the development of a retail market, which must be conceived with the creation of customer benefit as being one of the overriding policies and objectives [of regulators]. The MI/UM noted, and agreed, with AltaGas's submission that "given the experience of electric deregulation, the effort to create a competitive marketplace for gas service should proceed with caution."

2.2.2 Views of the Board

The Board acknowledges the concerns of parties that in a transition from a fully regulated utility service to a competitive retail gas service there is potential for significant risk to customers in terms of security of supply, price, and changing circumstances. The Board shares some of those concerns. However, the Board is also of the view that it is not in the interests of consumers to ignore those items that are, on their face, biased against the successful development of the retail gas market.

The Board considers that if retail gas competitors can truly provide service that is of higher value than a continued regulated utility service offering, then the interests of consumers will have been served by providing a reasonable opportunity for retail competition to develop. The goal of the Board in this Decision is to provide that opportunity while safeguarding consumer's interests.

The Board does not believe that it is necessary for the Board to advance a detailed vision of an "end state" for the retail gas market. The Board is also of the view that espousing an end state for gas deregulation would presume knowledge that is not currently available. It is not clear to what extent gas marketers or other competitive entities will be willing or able to undertake the merchant functions of the gas utilities. The Board is of the view that these matters may remain open at this time without harm to customers or to the development of the retail market.

It appears to the Board that certain aspects of utilities' tariff design may be hindering the entrance of participants to the competitive market. For example, some utility gas procurement costs are included in rates paid by direct supply customers. Also, the fact that only one marketer was active in the residential market in Alberta at the time of this proceeding, and that currently there are only two marketers active in the Alberta residential market, lends support to the idea that the tariff design of regulated utilities may have to be revisited to ensure that the development of a competitive market is not hindered.

The Board is of the view that reasonable opportunities should be provided to gas marketers to compete in Alberta, while ensuring that utility customers are protected and utilities are treated fairly. The Board considers that it must balance these interests in order to fulfill its mandate. Ultimately, striking a balance between these objectives will provide consumers with the benefits of competitive gas services, while safeguarding against market problems during the transition away from fully regulated gas service.

3 ONGOING ROLE OF ALBERTA GAS UTILITIES AND REGULATED GAS OFFERINGS

3.1 Overall Utility Responsibilities, and Ongoing Obligation to Provide the Gas Supply and Merchant Function

3.1.1 Positions of Parties

AltaGas

AltaGas stated that consumer's choice should include the choice not to change. Assuming that definition of "merchant function" is the "sale of gas to consumers", it was AltaGas's view that it should continue in the merchant function as long as consumers choose it, or need it, as a supplier. AltaGas went on to say that the law requires the utility to fulfill some merchant functions. AltaGas provided the following to support its contention:

> Section 25 of the GUA prohibits a utility from withholding or refusing service in the face of an Board order. It says:
>
> 25(1) No owner of a gas utility shall …
>
> (c) … withhold or refuse any service that can reasonably be demanded and furnished when ordered by the Board,
>
> Section 28 of the GUA confirms this obligation by providing:
>
> 28 The Board, either on its own initiative or on the application of a person having an interest, may by order in writing, …
>
> > (d) require an owner of a gas utility to establish, construct, maintain and operate, … any reasonable extension of his existing facilities … , and
> > (e) require an owner of a gas utility to supply and deliver gas to the persons, for the purposes, at the rates, prices and charges and on the terms and conditions that the Board directs, fixes or imposes.

It was AltaGas's opinion that these sections legally obligate the utility to fulfill the merchant function, subject to the direction of the Board. AltaGas also stated it was legally obligated to supply gas under its franchise agreements.

In response to a Board information request, AltaGas submitted that consumers should continue to be allowed a "real" choice, which includes the option of purchasing the gas commodity from either the regulated utility or unregulated service providers.

AltaGas stated its position was that unless it is legislated out of the merchant function, consumers should not be precluded from choosing the utility as a supplier; and that the regulatory system is designed to provide a surrogate for competition where there is demand for an essential service, and where the usual supply characteristics of competition do not exist.

AltaGas believed that the consumer views expressed in the proceedings supported the view that the utility should be able to continue supplying gas to consumers until a fully competitive market develops.

It was AltaGas's submission that it is in the best interests of consumers, as consumers have clearly indicated, to allow the utility to continue in the merchant function. By supplying services at regulated rates, the utility can create a benchmark for service offerings from others. It stated that if a competitive marketplace develops in which consumers prefer to take service from someone else, so be it. AltaGas argued that the outcome should be the result of economics, not ideology.

ATCO Gas

ATCO Gas submitted that its responsibility and obligation to provide timely and reliable natural gas service to its customers could be separated into two distinct functions:

- the acquisition of gas supply for sales customers; and
- the delivery of the gas commodity for all customers.

ATCO Gas submitted that the development of a competitive retail market would involve the transfer of the obligation for acquisition of supply from ATCO Gas to competitive retailers over a transition period, at which time ATCO Gas would retain only its delivery obligation (i.e.: operate as a "pipes only" company), and the gas supply function would be undertaken by competitive retailers in an unregulated environment.

ATCO Gas submitted that the transition to a fully competitive market would be smoother if the regulated gas supply product is one that can be easily removed from the marketplace, and did not deter the development of alternative products. It stated that the regulated product should include the costs appropriate to the gas supply function, and reflect the results of the unbundling process, but in all other respects should be a continuation of the current DGA process. It argued that this would leave room for a broader variety of gas service offerings.

ATCO Gas also stated that it was not interested in competing in the retail business, irrespective of the possibility of profits arising from that function. It submitted that there is the potential for the incentive scheme for a local distribution company (LDC) that is required to maintain a regulated rate exists, as long as it is performed by an entity or entities better positioned to assume the risks and to capture the rewards associated with such an undertaking. It also noted that potential buyers of its retail operations could find merit in an incentive system.

AIPA/EUAA

AIPA/EUAA expressed support for a continuation of a regulated gas supply service by the existing utility, as Core customers, who depend on the utility merchant function, need only look to the electricity market to identify concerns with the LDC's outright exit from the merchant function. In AIPA/EUAA's view, exit by ATCO Gas from the merchant function would not be in the best interests of Core customers. With respect to the potential sale of ATCO Gas's retail function, AIPA/EUAA submitted that Board approval should be conditional on an obligation by the purchaser to provide regulated service to Core customers for the duration of the transition period, until it can be demonstrated that a competitive, sustainable retail market exists.

AIPA/EUAA considered that where a utility provides a merchant function with hedging, the costs should be passed through to customers as long as they are prudently incurred. AIPA/EUAA agreed with suggestions for out-sourcing the utility function to third parties, as long as the utility retained responsibility and accountability for the process.

CCA

The CCA submitted that the LDC should manage the supply portfolio, using a full range of risk management tools, including the use of products such as storage. In this way, the LDC would achieve significant savings and less volatile product pricing.

The CCA disagreed with the ENMAX proposal, that the utility should be a pipes company only, particularly if the utility can still be a low-cost provider of other services and products. The CCA also had a number of concerns with the ENMAX proposal that the utility should bill marketers for regulated services provided to the marketer or consumer. Specifically, the CCA submitted that the provision of billing by the marketer might limit the number of entrants to the marketplace, and could deliver a significant cost advantage to EPCOR and ENMAX because they already deliver bills to customers in Alberta. Incremental billing for another service would cost very little and provide an unfair advantage relative to new entrants. The issue of stranded costs and reallocation of those costs to residential customers was also identified by the CCA as a concern with the ENMAX proposal, to the extent that residential customers will undoubtedly be required to pay stranded costs associated with other customers who have left the system.

On the other hand, the CCA supported the proposal of ENMAX for the continued role of the utility in the operation and maintenance of the delivery system, including the enrolment function, the load balancing function, call center function, and system safety.

The CCA noted that ATCO Gas had expressed a desire to exit the merchant function. The CCA submitted that the utility should not be permitted to do so, until it can be demonstrated that the competitive market is the lowest long-term provider of the merchant function. The CCA noted that, under electric industry restructuring, where the utility or a designate is retained as the RRO provider for the years 2001-2006, the RRO model term is subject to extension if the market has not developed to a satisfactory level.

In the CCA’s view, any benefits gained by competitive entrants were likely to represent adverse impacts on the utility customer, to the extent that the new entrants seek to provide a commodity which provides them the opportunity for profit as compared to the existing method which limits provision of the commodity to a flow-through of cost. The CCA agreed with ENMAX that, while standard offer or default service as well as the function of supplier of last resort should be put out for competitive bid, the results of these bids should be compared to the cost at which the utility could provide the same service. For public interest considerations, the CCA submitted that the long-term, lowest-cost provider should always be selected, and that the supplier of last resort should always be the standard or default service provider, to achieve the significant synergies which would result from the combination of these roles.

Calgary

Calgary noted that, ATCO Gas had been providing the merchant function of supplying gas to Core customers for many decades and argued that it should continue to do so for Core market customers wishing to be served by the utility.

Calgary submitted that the gas utilities have an obligation to provide the merchant function at the lowest possible cost, and are rewarded for providing the service through the allowed return on their rate base. Calgary noted that, during the proceeding, parties including the MI, EPCOR, and ATCO Gas had proposed that the utility merchant function, including the current GCRR and DGA mechanisms, could be considered a RRO. It supported the proposal that the utility have an obligation to provide a RRO, and that Core customers would have a right to purchase gas under the RRO. Calgary noted that the gas RRO concept was similar to that developed for electricity, and that using a similar concept for gas could reduce confusion among customers.

Calgary urged the Board to be cognizant of current market conditions including:

- the sudden and sometimes dramatic volatility exhibited by gas prices;
- the desire by consumers that the utility provide protection against price volatility;
- Core customers' right under the GUA to purchase gas supplies on a direct purchase basis; and
- the presence of only one active retail marketer offering Core market customers alternative gas supply options, and the possibility of other retailers entering the marketplace.

In reply argument, Calgary submitted that ATCO Gas South (AGS) could not unilaterally shed its supply obligations. Calgary stated that, at this point, ATCO Gas desires were irrelevant and should have no bearing on the outcome of the Board's decision with respect to the GCRR or Unbundling.

Edmonton

Edmonton supported continuation of the status quo with respect to the merchant function. It stated that its understanding was that the LDC was obligated to remain in the merchant function until a functioning competitive market develops. With respect to the ATCO Gas proposal to sell the "RRO rights" for its customers, Edmonton noted that, depending on the terms and conditions of sale, this sale might not be consistent with the public interest.

ENMAX

ENMAX stated that the regulated gas utilities should ultimately be pipes-only companies. ENMAX believed that in order to achieve that desired end-state set out above, the Board must begin the process of eliminating the regulated gas utilities' merchant function. But, as a practical matter, it might not be possible to immediately relieve the utility entirely from its obligation to sell gas to consumers.

ENMAX recommended that in the end-state of the market the Board should adopt the following desired characteristics for the regulated utility:

- The utility would be a pipes only company.
- The utility would operate and maintain the local delivery system infrastructure.
- The utility would serve as the system operator to protect the reliability of gas deliveries.
- All competitive or potentially competitive services would be unbundled and priced separately.
- Regulated services would be unbundled and priced separately where efficiency requires appropriate price signals.
- The utility bills for the regulated services would be provided to the marketer or the consumer.
- The utility would facilitate customers switching among marketers who would provide commodity and other services to end-use consumers.
- The utility would track customers for billing, energy delivery, and load balancing.
- The utility would perform all reliability and safety related services for the pipes business.
- The utility would have an obligation to connect consumers and to deliver energy on behalf of marketers pursuant to a regulated tariff.
- The utility would provide services to marketers as required to assure safe, reliable, and competitive commodity services to end-use consumers. Such services might include turn-on or turn-off of utility service, Electronic Data Interchange, and other services.
- The utility would receive calls related to system safety (leak calls for example) and for service related inquiries (initiate service, change service, discontinue service, etc.).
- The utility would provide customer service to the marketers.

Enron

Enron submitted that removal of the utility from the merchant role would significantly advance the development of a competitive retail market in Alberta by increasing the economies of scale available to retailers, who would otherwise be competing with utility services. Enron recognized that competitive options for smaller customers were currently limited, and that some customers, notably smaller customers, might desire a regulated default supply option during a transition period. It argued that removal of ATCO Gas and AltaGas from the merchant role could occur in conjunction with the elimination of RRO service in the electricity market on January 1, 2006, or earlier if prevailing competitive circumstances would permit.

Enron noted that some customer groups, such as PICA, supported a similar approach.
Enron was concerned that allowing a utility, or an affiliate or designate, to provide the merchant function indefinitely, without the existence of a strict code of conduct, would provide such entities an unfair advantage, as they may be able to leverage off their existing relationship with the customer to then provide other non-regulated services in competition with retailers.

EPCOR

EPCOR submitted that, during the transition to a fully functioning competitive market, the utility should remain in the merchant function to fulfill the role of default supplier and supplier of last resort. EPCOR recommended that once a fully competitive market had been established, the incumbent utilities' only role should be that of supplier of last resort.

EPCOR noted that ATCO Gas had announced that it was proceeding with its plan to exit the merchant function. It reserved comment on the specifics of any sale of ATCO Gas's retail functions. It stated that it would support the right of the utilities to contract with others to carry out their functions as the default supplier during the transition period. EPCOR also noted that ATCO Gas supported retailers being offered the opportunity to provide natural gas default supply.

FGA

The FGA stated that the utility has a direct and fiduciary responsibility to its customers with respect to the purchase of gas for retail to those customers. The FGA argued that there should be an expectation that the utility would consult and work with its customers to provide the best service possible under any given criteria.

The FGA maintained that the utility should keep a GCRR with some of the existing characteristics, with gas costs index based without markup. The FGA noted that existing regulation does not allow the distributor to exit the merchant function. It argued that if the retail function was sold, and the distributor did exit the function, and the contracted supplier failed; the utility would have an obligation to keep customers whole, and should be required to re-enter the function with the same terms and conditions as were applicable upon its exit. The FGA argued that the above criteria suggested the utility should not be allowed to exit the function at any point.

The FGA rejected the suggestion that the provincial Government had developed a policy on the matter of utilities exiting the merchant function. The FGA submitted that, if the Government were to adopt a policy to allow utilities to exit that function, it should only be undertaken with the highest concern for the well being of utility customers.

The FGA submitted that ATCO Gas could only point to anecdotal evidence, and unsubstantiated discussions with unnamed Government officials, to support its claim that Government policy with respect to customer choice exists. The FGA noted that the Board is a quasi-judicial Board, obligated to follow the rule of law. The FGA submitted that the Board should wait for direction from the Government in the form of legislation before ordering ATCO Gas from the merchant function.

The FGA submitted that the predominant issue should be how customers would be affected if ATCO Gas were not in the merchant function. It stated that it was not relevant whether or not ATCO Gas wished to exit the merchant function. It characterized the current cost of service arrangements as a success story for both the utility and customers.

The FGA stated that a RRO was crucial for the ongoing security and well being of customers. It took the position, however, that the LDC should not be in the business of taking risks for profit, and that the RRO should be a flow-through of monthly indexed prices, without a markup.

MI/UM

The MI/UM stated that market information enabling customers to assess what the seasonal or fixed term price would be for one, two, or more years was not readily available, and that the regulated utility provided a reasonable benchmark for measurement of any merchant function. The MI/UM submitted it was the impacts on consumers that must be weighed to ensure there would be consumer benefits.

The MI/UM also submitted that, although ATCO Gas might want to exit the merchant function, it should not be entitled to do so quickly if it disadvantages customers. The MI/UM agreed with AltaGas that a regulated gas utility should continue in the merchant function, as long as consumers choose it, or need it, as a supplier.

PICA

PICA stated that its philosophical position was that competition was good for consumers, but that the existing level of retail competition was not adequate for the regulated utility to exit the merchant function.

PICA viewed unbundling as the division of utility costs, services, and rates into functional categories. PICA stated that if it was considered there were sufficient competitive alternatives to certain utility services and, therefore, the utility would no longer be required to continue to provide those services as regulated services, then the utility's costs and rates could be adjusted to reflect the removal of those functions or services from regulated rates. On the other hand, if there were concerns that competitive alternatives to regulated services were insufficient, then unbundled utility services might co-exist with competitive services during a transition period, providing choice between utility and competitive market functions or services.

PICA stated that the objective of a transition period should be to allow sufficient competition to develop during this period. The standard for unbundling ought to be the creation of a level playing field and price transparency between utility and competitive services so that customers would end up with genuine choice.

PICA believed that all regulated functions or services presently provided by the utilities were not amenable to choice, however, there were a number of services for which a certain level of competitive alternatives might exist or that would be likely to develop in the future. In PICA's opinion, it was those services that the unbundling process must address.

PICA believed that if the purpose of unbundling was to pave the way for retail choice in certain services currently provided as regulated services, market rules were required to ensure the market functioned efficiently and resulted in a level playing field for all market participants. PICA also stated that rules were required for consumer protection.

3.1.2 Views of the Board

The Board notes that AltaGas has referred to sections 25 and 28 of the GUA in its argument. The Board agrees with AltaGas that based on these sections, the Board has the power to require a utility to fulfill those aspects of the merchant function that the Board deems appropriate.

The Board is of the view that there are two pertinent and opposing factors to consider in determining the appropriate role for the utilities in the current partly competitive market. On the one hand, the utilities provide a safe, reliable, and cost controlled service to consumer for an essential commodity. On the other hand, the continuation of the utilities in the retail merchant role reduces the market available for competitive entrants, thus delaying the development of a fully competitive retail gas market.

The continuation of the role of the utilities in the merchant function is seen by the Board as vital in any transition to a competitive retail gas market, by protecting consumers from transitory conditions in which gas marketers may have significant market control. As noted in the submission of the CCA, “Consumers are particularly skeptical of transitions that raise prices in order to attract competitive entry”[16]. The Board is concerned that a premature removal of the utilities as alternative service providers could have the effect of letting gas prices rise in a less-than-competitive market. The recent experience in the North American competitive energy markets has demonstrated that the need for energy is almost absolute in the short term, and that when prices rise, even to astronomical levels, consumers will still need to make energy purchases. Permitting even a short period of rapidly rising prices arising from market failure can overshadow all promised benefits from the development of a competitive energy market. The Board is of the view that this situation must be diligently guarded against.

However, the Board is also persuaded that, ultimately, robust retail competition in the Alberta gas market will provide for greater economic efficiency for consumers. The Board expects that retail competition for gas will provide consumers with benefits in terms of price, choice as to price stability, billing options, cross-provision of services, and convenience.

The Board notes that there has been until recently only one active non-regulated gas retailer in the Alberta market, and that the one previous market entrant defaulted on its customers. The Board also notes that only one jurisdiction in North America has completely done away with the utility merchant function for a large segment of its customers, that being Georgia.

With these facts in mind, the Board is of the view that there is a continuing need for utilities to provide the regulated gas supply and merchant functions. Accordingly, the Board directs that gas utilities continue to provide regulated gas supply and merchant services to customers. This “safety net” will remain in place for the time being, while steps are taken to create a reasonable opportunity for increased retail gas competition, as described elsewhere in this Decision.

The Board notes the indication by ATCO Gas that it intends to remove itself from the retail gas merchant function by selling its retail operations. As there is no current application for this transaction, and there is no detailed explanation of how this transaction would operate, the Board is of the view that this Decision must be based on the status quo, in which ATCO Gas is an integrated utility. This in no way prevents ATCO Gas from filing an application with the Board in the future for the sale of its retail functions.

3.2 Supplier of Last Resort Function

“Supplier of last resort” is alternatively used to describe either a supplier of gas in the event that a customer has no other supplier (also known as default service), or a supplier of gas in the event that a retail supplier defaults on its customer contracts (also known as back up supply).

[16] CCA Submission, Unbundling, p14

3.2.1 Positions of Parties

AltaGas

AltaGas stated that it will need to be the default supplier and the backup supplier for consumers in its service area for the foreseeable future, and that only legislative change would relieve existing obligations.

To support its position AltaGas offered the following:

- The provisions of the GUA and AltaGas's existing franchise agreements create an obligation to supply that effectively makes AltaGas the supplier of last resort for consumers in its franchise area. This obligation is clearly stated in the Core Market Regulation. Additionally, it is the GUA that creates the right to buy from a direct seller.

- Subject to the regulations, a consumer has the right to obtain a supply of gas from a direct seller for delivery to the consumer by means of the gas distribution system of a distributor, … [GUA s.26.01(3)]

- As a distributor, AltaGas must transport the gas purchased from a direct seller. AltaGas's responsibility does not end there, however. If the direct supply arrangement fails the consumer, section 7(1) of the Core Market Regulation provides:

    - 7(1) A distributor has the obligation under the Act to supply gas to a Core consumer after the consumer ceases to have the right to obtain a gas supply under a direct supply arrangement by reason of the operation of section 6(1).

AltaGas submitted that it was legally required to be the supplier of last resort.

AltaGas also believed the evidence supported the utility as supplier of last resort, where it had the meaning of:

- default supplier – the person who supplies if the consumer doesn't choose a supplier or can't get any other supplier to provide service, or
- backup supplier – the person who ensures supply when the responsible supplier fails.

AltaGas believed that Alberta weather left no room for risk, and that it was the regulated utility that would be the lowest risk source, as it operated the system and would be in the best position to fulfill such a role.

In summary, AltaGas stated that it had a legal obligation to supply gas, default and backup, to consumers in its franchise area. It argued that this was an essential part of the regulatory compact, and that it would continue to honour the compact. It was AltaGas's view that the evidence showed most participants in the process saw an ongoing need for it to fulfill that role. AltaGas intended to do so until a new legal regime created a different responsibility. AltaGas believed that whatever that responsibility was, it should be driven by customer needs, not ideological needs. AltaGas wanted a Board approved process that enabled it to work with its customers to define the scope of that responsibility, and how it could be met.

ATCO Gas

ATCO Gas noted two aspects of this supplier of last resort function. Firstly, requisitioning physical supply in the event of supplier default and, secondly, payment of the requisitioned supply that would be required because a supplier has failed to provide the gas supply.

ATCO Gas noted there should not be concerns with the availability of physical gas supply. It noted that there is more than sufficient local gas capacity to meet even peak day gas demand. It stated that manual intervention would be required in order to curtail service to customers, and that would likely be initiated by the retailer's suppliers when concern about retailer payment default became evident. ATCO Gas argued that retailers should post a performance bond to ensure continuance of supply for a minimum period in the event of retailer default.

ATCO Gas submitted that during transition to a fully deregulated market, the provider of the regulated rate service retains the obligation to supply a customer whose retailer failed. ATCO Gas suggested that, in the event of a failure by a retailer, the supplier of last resort should be authorized to pay for supply at the daily index price subsequent to notice of failure, and access funds from the retailer's performance bond to avoid impact to any regulated rate customers.

AIPA/EUAA

AIPA/EUAA recommended retention of the status quo, and considered that the number of potential alternative providers appears limited, a situation that would suggest an increase in prices otherwise. AIPA/EUAA noted that retention of the utility as the supplier of last resort would achieve consistency with the electric model.

CCA

The CCA strongly supported retention of the utility as the supplier of last resort, in contrast to the views of those who would seek the contracting out of this function without regard for the potential for increased costs or decline in system integrity.

The CCA disagreed with the view of ENMAX that it was potentially costly for the utility to maintain the supplier of last resort function. The CCA argued in response that, since customers will have to pay for the stranded costs of customer migration, as well as paying a third party for assumption of the associated risks, customers are likely no better off with outsourcing.

Calgary

Calgary argued that the utility was required to be the supplier of last resort, given its obligations to provide adequate gas supply service, and Core consumer's right to purchase gas supplies from the utility. It noted that ATCO Gas accepted and acknowledged this obligation.

Calgary argued that there would be a requirement for a supplier of last resort, even in a fully competitive market with several competing suppliers. Gas consumers require supply to be available on demand, 24 hours per day. Calgary stated that the role of the supplier of last resort should be to maintain the supply of gas, and maintain system pressure on short notice, when gas supply has been interrupted for any reason. It also stated that the utility and marketers should be required to backstop their own gas supply.

Calgary argued that in a fully competitive market there could be a call for tenders, on a periodic basis, from qualified companies to serve as the supplier of last resort for those customers relying on non-RRO supplies, based on a supply specification approved by the Board. Fixed and variable costs would be recovered from non-RRO customers. Calgary stated that, given the small number of direct purchase customers at this time, the utility should continue to act as the supplier of last resort for both RRO and non-RRO customers.

In reply argument, Calgary noted that two marketers, ENMAX and Enron, had argued that parties other than the utility should fulfill the role of supplier of last resort. Calgary responded that the utility should continue to serve as the supplier of last resort, at least until a fully competitive retail market emerges. Calgary also submitted that it should not be necessary for the Board to define the detailed terms and conditions of such supplies until such time as a competitive retail market exists.

Edmonton

Edmonton supported the status quo for supplier of last resort. It stated that in its understanding, the LDC continued to be responsible for providing continuity of supply in the event of a retailer failure. Edmonton stated that the adoption of a third party supplier of last resort, as noted in the Georgia example, would appear to be an unnecessary complication in the Alberta market, in the context of a transition to full competition. It did not recommend any change to the present supplier of last resort function.

ENMAX

In ENMAX’s opinion, the standard offer or default service, and supplier of last resort service, serve very different functions, and were the two supply functions required for competitive markets.

ENMAX suggested that the regulated gas utility need not provide standard offer service during the transition to competition. Furthermore, it suggested that the utility need not provide supplier of last resort service, either during or after the transition period. ENMAX stated that out-sourcing standard offer service minimized the risk of stranded cost, assured a market-based, unbundled GCRR, and reflected appropriate cost risks associated with customer migration.

Enron

Enron argued that the supplier of last resort could be differentiated from the merchant role, as the need for it would continue to exist because some retailers could default on their supply service. Enron submitted that this function should continue to remain regulated by the Board. Enron advocated that the Board authorize a supplier of last resort framework that required utilities to obtain competitive bids from established retailers to ensure that this service would be provided at the least cost.

EPCOR

EPCOR submitted that supplier of last resort should continue to be a role of the incumbent utility during the transition period. It argued that in a fully functioning competitive market, incumbent utilities, in their role as "pipes" providers, would be the obvious choice for the supplier of last resort as they operate the gas systems and are in the best position to fulfill this role.

FGA

The FGA noted that the distributor has the responsibility to be supplier of last resort under the Core Market Regulation. It argued that, should a fully competitive market develop, and the distributor be allowed to exit or be denied participation in the merchant function, then all costs associated with providing supplier of last resort services should be shared or distributed amongst all retail service providers.

The FGA stated that a non-regulated retailer should be required to accept a fair portion of customers of failed suppliers as part of an obligation to serve. It also noted that prudential requirements should be established for each retailer in a sufficient amount to cover the cost of purchasing gas for all of the retailer's customers for the period of its 60 peak demand days. It argued that this security should be accessible to the supplier of last resort.

The FGA stated that it was more concerned with the security of customers' gas supply than in achieving the lowest cost for the supplier of last resort service. The FGA noted the Enron submission that $250,000 was a reasonable bond level for retailers. It contrasted this with the $15,000,000 bond for Peachtree Gas in Georgia.

MI/UM

The MI/UM stated that the role of supplier of last resort should remain with the regulated supplier, since there would be a need for this function if there were a default by a retailer for whatever reason. It would be the regulated supplier, as a pipe-owner, that would be in a position to deliver if a customer lost supply. The MI/UM submitted that the supplier of last resort must be compensated in the form of a management fee or a margin similar to a retailer for complete recovery of its costs to perform that function.

The MI/UM would support out-sourcing the supplier of last resort service to a third party as long as the regulated gas utility was held ultimately responsible and accountable for the subcontracted service. Further, the MI/UM submitted ATCO Gas should bear ultimate responsibility for providing the services, including any contractor's acts or omissions, at least until a fully functioning retail market exists. It stated that the ongoing obligation should be similar to that of a wires owner, which has delegated its authority to carry out its functions as wire services provider, pursuant to section 5 of the Roles, Relationships and Responsibilities Regulation under the *Electric Utilities Act*.

3.2.2 Views of the Board

As noted by AltaGas, section 7(1) of the Core Market Regulation requires the utilities to act as default supplier to customers who have lost their right to acquire gas under a direct supply arrangement due to termination of their arrangement with the direct seller. In the Board's view this would include default of the direct seller. The Board will provide its opinion here as to this one aspect of the Regulation, and will provide its views on the operation of the Core Market Regulation generally in section 7.1.1 of this Decision.

The Board finds that the provision of supplier of last resort service can be evaluated solely on its effect on the security of gas supply for consumers. It concurs with AltaGas that “Alberta weather leaves no room for risk.” The Board does not believe that it is necessary, or desirable, to change this aspect of the current regulatory framework established in the GUA and Core Market Regulation to move towards improving competition in the near term. The Board is of the view that when the security of consumer’s gas supply is in question, a cautious approach is best.

The Board notes the proposals of some parties to separate the roles of default supplier and backup supplier. The Board is aware of the different requirements and risk profiles that are associated with these two functions. However, it considers the separation of these roles to be an unnecessary complication at this time. Currently, most customers are on default supply; relatively few have opted to take competitive service. As this changes, the relative risks and the requirements of providing these services will diverge. The Board recognizes that if substantial numbers of retail gas customers opt to leave default service, the separation of the supplier of last resort functions will need to be reconsidered.

The Board notes that several parties have proposed that utilities be permitted to out-source the supplier of last resort service to a third party, provided that the regulated utility would remain ultimately responsible for this service. This concept may be appropriate during a transition period prior to the development of a fully competitive market. However, the Board is of the view that regulated utilities cannot, and should not, avoid the attendant obligations of providing this necessary service at this time. The Board therefore directs that regulated utilities continue to provide both supplier of last resort service and default supply service.

3.3 Co-existence of Regulated/Non-regulated Gas Supply

3.3.1 Positions of Parties

AltaGas

AltaGas stated that the regulated utility should continue to be allowed to co-exist with unregulated suppliers. In its view, regardless of the theoretical objections, this was a sensible solution.

In response to a Board information request, AltaGas stated, “In our opinion consumers should continue to be allowed a “real” choice, which includes the option of purchasing the gas commodity from either the regulated utility or unregulated service providers.”

AltaGas stated that if a system works, it should not be abandoned simply because it is not theoretically appealing.

ATCO Gas

ATCO Gas submitted that the co-existence of regulated and non-regulated gas supply could contribute to confusion and uncertainty in the marketplace, unless the nature and duration of regulated supply was clearly delimited. It also submitted that any changes to the status quo should not have a regulated service directly competing with retailers in the marketplace. ATCO Gas argued that it should only offer one gas supply product that generally meets the needs of most customers, and that any introduction of additional regulated gas supply products would be an impediment to the further development of the deregulated market.

ATCO Gas noted that a clear policy statement regarding the terms and conditions under which the natural gas market will be deregulated had not been issued by the Government. However, it stated that it believed that there was an implicit desire to develop retail competition, and that the Board had the authority to move this forward.

AIPA/EUAA

AIPA/EUAA expressed support for continued co-existence of regulated and non-regulated functions such as sales and transportation service at present, with regulated gas supply service continuing at least through any transition to a fully competitive market.

AIPA/EUAA stated that, contrary to ATCO Gas's submission, it did not believe that one regulated product could be force-fitted for all customers. It submitted that, if the Board were convinced that one supply product must fit all customers, the monthly regulated product would be preferable.

CCA

While the Core Market Regulation set the foundation for competition in the natural gas marketplace, the CCA noted that participation of new players has been limited. The CCA made the observation that, unlike the situation in the electric industry, natural gas LDCs are under no legislated obligation to exit the merchant function. Accordingly, in the CCA's view, it would be premature to suggest that natural gas utilities should no longer offer a GCRR. Recognizing that competitors view the GCRR as a risk-free vehicle for LDCs, and appear skeptical about the continued co-existence of the GCRR with competitive alternatives, the CCA submitted that the provision of regulated and unregulated gas supply already co-exists and that the status quo should continue. The CCA noted that marketers had failed to point out that the GCRR process produces no opportunity for the utility to profit at the expense of the gas consumer. On the other hand, the CCA considered that it was the potential for profit that provided an incentive for marketers to enter the market. While in support of the continued co-existence of regulated and unregulated gas supply, the CCA considered that this would require enhanced customer awareness and continued regulatory attention.

The CCA submitted that if marketers truly believed that customers should have choice, that choice must include retention of the status quo with or without some modification. The CCA considered that customers would be worse off if the GCRR was withdrawn, since it appeared that the proposed competitive market would pass on additional costs to residential customers, over those costs existing with the current methodology.

The CCA disagreed with the ATCO Gas assertion that introduction by the utility of additional gas supply products would impede the development of a deregulated market. The CCA suggested that the fundamental issue should be the effects of the introduction of increased competition, rather than its introduction per se. The CCA considered that, to date, the threat of increased competition has led to the loss of significant amounts from customers, as the utilities have responded to the threat of customer migration by moving the GCRR away from long-term gas contracts.

Calgary

Calgary noted that throughout the GCRR Methodology Proceeding, ATCO Gas and EPCOR advocated that the regulated gas supply should be phased out as soon as a competitive market emerges, or by 2005. Calgary noted that ENMAX, EPCOR, Enron, and ATCO Gas had each argued that the presence of utility regulated gas supplies would impair the development of the retail gas market. Calgary argued that none of these parties had provided any evidence to support their arguments.

Calgary noted from its evidence, that regulated and non-regulated gas supplies have coexisted in Ontario for more than a decade without compromising the growth of the retail markets in that province. It also noted that Mr. Todd, appearing on behalf of the CCA, had pointed to the growth of the Ontario retail market in the presence of the utilities' regulated supplies. Calgary submitted that there was no basis on which the Board could establish a termination date for the RRO. It argued that as long as there were customers demanding to be served under the RRO, the utility should be obligated to offer the RRO.

Edmonton

Edmonton recommended the continuation of the status quo with regards to the coexistence of regulated and non-regulated gas supply. It recommended that the LDC should only provide a regulated supply, based essentially on market price, and that it should continue to be available until a verified competitive market is established that includes at least one offering comparable to the regulated choice. Edmonton noted that ATCO Gas had indicated that the proposed sale of the "RRO" was intended to be to a new market entrant that would be interested mainly in promoting non-regulated alternatives. Edmonton argued that this could effectively oblige customers to select from options that were less economic than even the existing GCRR.

ENMAX

ENMAX submitted that replacing the regulated gas supply provided by the utility with a regulated gas supply provided by the market, under the conditions proposed by ENMAX, would permit both regulated and non-regulated gas supply functions to coexist. ENMAX believed it was important that the regulated gas supply, provided by a party other than the gas utilities, reflect all of the costs of such a service. Those costs included the following:

- commodity purchase, procurement and planning;
- gas supply contract management;
- working capital associated with commodity purchase, payroll, materials and supplies for the merchant function;
- taxes —payroll and other related taxes associated with any of these activities;
- accounting costs associated with the purchase and payment of invoices for commodity;
- administrative and general expenses associated with the above activities;

- general plant costs associated with the above activities; and
- uncollectible accounts expense associated with commodity purchases.

Enron

Enron argued that the co-existence of regulated and non-regulated gas supply would impede retail market development and therefore, after a transition period, the regulated default supply option should be abolished.

EPCOR

EPCOR submitted that there was no role for regulated gas supply following the transition to a fully functioning, competitive gas sales market. It noted that ATCO Gas was of the same view. It stated that during the transition period the regulated rate for default supply should be the monthly index price.

FGA

The FGA noted that the current situation, where regulated and non-regulated gas supply co-exist, has utilities providing a market-based, least cost supply option; and the retailer offering fixed-term products, in a manner which appears to properly serve the market. The FGA argued that if customer benefits and choice were the goals, then the customers' option to access the pure market rate without markup should be maintained.

The FGA noted that ATCO Gas, as the regulated utility, offers a unique service to customers - natural gas at a price that does not include a profit margin. The FGA argued that this service represented the lowest-cost supply of gas for customers on an ongoing basis.

The FGA noted that retailers, and those who supported deregulation, had stated throughout the GCRR Methodology and Unbundling hearings that the benefit to customers of deregulation and a fully developed retail market was not a direct reduction to the price of gas itself. It further noted their statements that the value added through deregulation was from unique and creative "packaging" of other "products" along with the gas, such as fixed priced long-term contracts, or air miles. The FGA argued that to have only "packaged" services offered to customers, and not an RRO, would be a disservice to customers. The FGA stated that retailers would never be able to sell the gas, by itself, as inexpensively as the regulated utilities.

The FGA agreed in part with the witness for ATCO Gas, Mr. Simard, that a regulated utility should not be in the business of trying to beat the market. The FGA stated that an LDC should not be expected to do so. It stated that its preference was for a single RRO, reconciled monthly, based on monthly indexed pricing, and with no profit margin. It proposed that the supply portfolio of the RRO would include only gas purchases, with no storage. It argued that those customers who were not comfortable with paying market prices for gas would be free to seek products from other retailers offering long-term, fixed-price contracts, or another product of their liking.

The FGA stated that the only exception to its approach would be if the utility and customers agreed, in advance through negotiations, to a strategy that proposed to try to beat the market. If so, it stated that there should be no after-the-fact penalties on the utility if the strategy failed to achieve the desired outcome.

The FGA stated that if retailers, with their stable rates and creative packages, were not able to compete with an RRO which was established and advanced through negotiations, then a fully developed retail market was not in the best interests of customers. Accordingly, it should not be pursued by the Board at this time, especially considering that no clear Government policy exists on the matter.

In reply argument, the FGA argued that ATCO Gas had no evidence to support its claim that regulated and non-regulated supplies cannot co-exist. It stated that as long as there are customers requesting a regulated service offering from the utility, the utility had the obligation to provide that offering.

The FGA noted that a continued RRO would provide a benchmark rate for the market, ensuring that competitive offerings were not at a significantly higher price or lower quality. It agreed with AltaGas that the results in the marketplace “should be a result of economics, not ideology.”[17]

The FGA noted that ENMAX and EPCOR had touted the innovation of retailers that would allow them to make their products more attractive, or even cheaper, than the RRO. It submitted that retailers would not be living up to their promises if they were to enter the market without having to compete against a RRO.

MI/UM

The MI/UM did not consider that the co-existence of regulated and non-regulated gas supply would impede retail market development. It submitted that not all customers wanted to avail themselves of direct purchase, and they should be given the choice of staying with their full service provider.

The MI/UM further submitted that the regulated gas supplier should provide a stable and reasonably priced commodity, without mark-up, profit, or loss, for those customers who wish to bear their own price variance risk. It stated that, accordingly, there was no need for any explicit compensation for risk, as the regulated supplier would be compensated for owning and operating the distribution system.

The MI/UM stated that the regulated gas supplier should also provide a RRO or transition rate, at least until a mature or fully competitive market develops. The MI/UM argued that the consumer should not be exposed to higher regulated rates solely to foster competition that may possibly, at some future date, result in lower costs. It argued that if retailers could not beat the surrogate for competition [the regulated rate], consumers should not be forced to move away from the surrogate to incur greater costs.

[17] AltaGas argument, p.8

PICA

PICA stated that for gas supply, there was a well-developed wholesale market in Alberta. However, notwithstanding the Core Market Regulation allowing retail level competition for gas supply to Core market customers commencing since 1995, retail competition for gas supply to small and medium sized Core customers was still limited to one active retailer.

Given this limited alternative for retail gas supply service, it was PICA's view the utility ought to continue to provide regulated gas supply services until a viable market for competitive gas supply services develops. In PICA's view, unbundling of all regulated gas supply related costs was a priority.

3.3.2 Views of the Board

Under the current legislation, the Board makes the determination as to the appropriate regulated tariff offerings of the utilities. The Board considers that it must balance the protection of customers from the potential for ill effects during market transition with the need to provide a reasonable opportunity for the development of the competitive market for retail natural gas.

As noted in section 3.1 of this Decision, the Board is concerned that any transition to a fully competitive retail gas market should not exhibit short-term price spikes or other market disruptions. Under the current legislation, the continuation of the regulated rate offering is the only mechanism available to provide security against market disruptions. The Board notes that Georgia is the only jurisdiction in North America that has gone completely away from regulated service.

On the other hand, the Board notes that there may be insufficient demand in Alberta to attract robust competition to the small retail energy markets. It is possible that the continued presence of a regulated gas offering may impede the development of robust retail competition. The Board notes the evidence that retail gas competition has grown in Ontario, even with the presence of a regulated utility gas rate. However, it is not a given that the Ontario experience would necessarily be reproduced in Alberta.

While the Board wishes to provide a reasonable opportunity for gas marketers to compete in the Alberta market place, it will not do so at the cost of potential significant harm to consumers. The Board considers that regulated gas offerings are an important consumer safeguard. Therefore, the Board will require the utilities to continue to provide regulated gas offerings. The details of these regulated offerings are provided elsewhere in this Decision.

The Board has examined the proposals by parties to establish an end date for the regulated utility offerings. At this time, the Board does not feel that there is sufficient information available to determine the effect that setting such a date would have on either the development of the retail market, or on consumers. The Board notes that the Minister of Energy may amend the *Regulated Rate Option Regulation*[18] for electricity to change the end date for the electric RRO.

[18] Alta Reg. 132/2001

While the Board does appreciate that having certainty as to the termination of regulated offerings would provide assurances for customers as well as an incentive for marketers, it does not believe that it is appropriate for the Board to establish that date at this time. The Board will readdress this question after the benefit of further experience and input from interested parties.

4 GAS PURCHASE HEDGING PROGRAMS, GCRR METHODOLOGY, AND UTILITY RATE PROGRAM ENTRY/EXIT FEES

4.1 Gas Portfolio Structure and Strategy

The gas portfolio is the combination of gas contracts, gas holdings, and financial arrangements used to ensure physical gas supplies and to manage gas costs. Physical gas supplies may be procured through contracts with variable prices (usually based on a market index price) or fixed prices. If contracts are for delivery of gas in the future, they are known as forward contracts. Financial arrangements can also be made to manage gas costs. These arrangements are generally known as price hedges. Price hedges can be used to fix gas costs, or limit gas cost variability.

4.1.1 Positions of Parties

AltaGas

When AltaGas received notice of the Methodology hearing, it met with representatives from its customer groups to look for an approach that would meet the needs of its system and its customers.

The end result of there meeting was a proposal that contemplated a collaborative effort. Under the AltaGas Proposal, each year AltaGas and its customers would:

- review results of the previous year,
- determine customer risk preferences,
- adopt an appropriate risk management plan, and
- develop an acceptable compatible gas management plan.

AltaGas stated that the transcript showed that AltaGas customers generally supported this approach. It stated that it would like the Board to approve the collaborative process that AltaGas has followed, or, alternatively, to allow AltaGas to go ahead and use it. With that approval it would work on a risk management plan.

The company stated that it intended to honor the AltaGas Proposal and its agreement with its customers, and was reluctant to make any comments that may be construed as directly or indirectly contrary to the word or intent of that agreement. AltaGas stated that the agreement included provisions for an annual planning and review mechanism that would collaboratively develop gas management plans, and review them on a regular basis.

AltaGas provided no discussion in their argument regarding contracting practices and parameters, financial hedging, arbitrage, physical hedges, or storage. However in the AltaGas Proposal, it included the following:

Rate 1 Customers

- Portfolio will include both hedged supply and supply purchased at market price.
- Hedged supply (including physical storage) will account for approximately 50% of total winter (November to March) supply requirements.
- Summer (April to October) supply will in all likelihood not include any hedged supply.
- In addition to hedged supply, the Company may also use “costless-collars” and possibly call options to help stabilize annual gas costs.
- The cost of a call option is approximately $0.75 (seventy-five cents) per GJ. Call options are most valuable (expensive) at times of significant market fluctuation. However, the least expensive time to enter into call options has been at times of stable prices and when summer differentials are minimal.

Two Supply Options for Rate 2 and 3 Customers

- An annualized GCRR that is the same rate offered to all Rate 1 customers and is based from the same gas supply portfolio that may utilize a variety of gas purchasing “tools” including, but not limited to hedging, costless collars, term supply, and market priced supply. This option is proposed to be the default option for Rate 2 and 3 customers; or
- A GCRR based on portfolio of monthly indexed supply only. Monthly indexed supply may permit customers to use financial tools available through financial intermediaries to enter into their own hedging agreements, if they choose. The rate could be either seasonal or monthly, but it would be impractical for both to exist simultaneously.

ATCO Gas

ATCO Gas recommended a structured gas portfolio that consists of a mixture of AECO based monthly and daily indices, and daily spot purchases. ATCO Gas recommended continuing with its existing gas acquisition practices.

ATCO Gas noted its concern that utility hedging programs can result in a lopsided risk, where the utility risks having costs disallowed in an ex post review, without receiving an additional risk premium. ATCO Gas considered that a hedging or fixed price strategy could have negative consequences in the marketplace, and on customers who chose to purchase their requirements from the DGA.

AIPA/EUAA

AIPA/EUAA considered that, for seasonal customers, the gas supply options should be a monthly or seasonal GCRR. It suggested that the portfolio for both would be structured with short-term supplies; the monthly GCRR set for the start of the month on a rolling monthly basis, and the seasonal GCRR set on a seasonal basis, with application of the traditional Board approved tolerance parameters for seasonal costs.

AIPA/EUAA considered that, for an annual GCRR, the portfolio should reflect annual supplies with necessary daily purchases to accommodate temperature-induced variations, and application of the approved tolerance parameters for forecast costs during the period. AIPA/EUAA considered that contracting practices should reflect short-term monthly purchases for a monthly GCRR, short-term supplies for a seasonal GCRR, and annual purchases for an annual GCRR, each augmented by daily purchases to satisfy temperature and precipitation swings.

AIPA/EUAA expressed support for the settlement reached by AltaGas with customers on the issues of Methodology. With respect to Unbundling issues, AIPA/EUAA noted that the AltaGas evidence indicated a willingness to discuss these issues in the collaborative process with customers.

In response to the Board's letter of September 7, 2001, AIPA/EUAA stated that it had recommended that consumers with annual consumption should have the option of the utility providing a gas price hedging program. It stated that the necessity for gas price hedging was diminished by the NGPPA, and that it no longer considered an annual gas price hedging program to be a necessary option for utility supply.

CCA

In the CCA's view, Alberta natural gas utilities should strive to construct a portfolio that would mitigate the effects of gas price increases and reduce the volatility of charges to customers. The CCA expressed support for consideration of long-term contracts, financial hedging, use of storage, and other arrangements that would contribute to stabilization of the overall portfolio price. However, the CCA indicated that its support was conditional on reasonable premiums being incurred for use of these tools.

The CCA considered that residential customers did not have the financial resources to face the consequences of the floating gas purchasing strategy currently in use by LDCs, and expressed support for the view that long-term contracts would not increase long-run cost any more than short-term contracts on a risk adjusted basis.

The CCA submitted that one large, properly hedged portfolio provides multi-dimensional hedging for customers, in contrast to the price offerings of competitors based on fixed prices and fixed volumes, which force customers to make uninformed choices regarding future market prices. It argued that under multi-dimensional hedging, the portfolio is constantly being re-hedged, thereby spreading the risk.

The CCA disagreed with ATCO Gas's positions regarding portfolio structure and an appropriate recovery mechanism. Specifically, the CCA considered that complete reliance on monthly and daily indices was excessively risky, and did not protect customers from month-to-month or year-to-year gas price changes. It argued that the budget payment plan and annual recovery rates should not be the sole mechanism to deal with price stability issues.

The CCA advised the Board to use caution in evaluating the submissions of customer representatives. It referred to statements made in this proceeding by the FGA, PICA, and Canfor confirming their ability to hedge outside of the DGA, or to construct portfolios by virtue of ownership or potential ownership of retailers. The CCA expressed concern that, by contrast, residential customers were left with excessive risk, and seek to have a portfolio properly

balanced between short, mid, and long-term supplies. Unbundling, in the CCA's view, would not solve the problems of an excessively risky portfolio.
The CCA supported the submission of Mirant that competitive bids should be used to obtain services and products, but considered that the utility should also compare third party bids to the cost of providing the service in-house.

The CCA noted the consultative process undertaken by AltaGas resulting in a settlement with respect to matters relative to the GCRR process and related issues. The CCA expressed support for the AltaGas Proposal, and noted that, in light of the AltaGas settlement, the Methodology Proceeding hearing tended to focus on specific matters pertaining to ATCO Gas.

In response to PICA's argument, the CCA considered it important that an annualized hedged rate be offered. The CCA submitted that this would allow for greater rate and bill stability, would be closer to an annualized rate of longer-term priced natural gas, and would reduce DGA deficiencies and surpluses. Furthermore, a hedged portfolio with entrance and exit fees would provide accurate and timely price signals of actual portfolio costs. The CCA expressed concern that a move to monthly adjustments would increase rather than decrease the risk to residential customers.

In response to the Board's letter of September 7, 2001, the CCA stated that it did not wish to change its recommendations for utility gas portfolios based on the NGPPA. It argued that the price protection of the NGPPA can be changed at any time, as it is at the discretion of the Minister of Energy. It argued that this protection could be curtailed, for example, by budget considerations. It also argued that Alberta utilities should not be allowed to maintain risky gas portfolios. It stated that the NGPPA was simply a risk transfer mechanism whereby gas price risk would be passed from gas consumers to the provincial government, and then to taxpayers. It argued that as customers are also taxpayers, the NGPPA provides no real price protection mechanism.

Calgary

Calgary argued that, to support an RRO at the lowest possible cost, utilities would require a flexible, diversified, market-based portfolio of gas supply contracts. It stated that such a portfolio would consist of:

- Term contracts
- Seasonal contracts
- Monthly fixed-price contracts
- Monthly index contracts
- Spot contracts
- Company-owned production and storage

Calgary argued that AGS's current portfolio met these requirements, with the exception of the longer-term reserve base contracts and index contracts. Calgary argued that the AGS gas portfolio was over-weighted with the quantity of gas index to daily AECO C NIT prices.

Calgary stated that the responsibility for designing and managing the RRO gas supply portion at the lowest cost on a day-to-day basis is part of the utility's merchant function, for which the utilities are compensated. It argued that the utility must be accountable for managing the portfolio in the least cost manner.

Calgary took issue with AGS's extensive use of daily gas index gas supply contracts. It argued that there was virtually no benefit to including daily index contracts in the AGS portfolio, in that they introduce considerable volatility into the cost of utility gas supplies. Calgary submitted that AGS should be directed to restrict the use of daily indices to the minimum level necessary to hedge against price fluctuations of excess volume sales.

Calgary countered the CCA argument that AGS should include long-term price contracts in its portfolio. Calgary responded that there were significant risks (e.g. credit risks) and costs to such contracts with no offsetting benefits.

Calgary submitted that any longer-term contracts (e.g., greater than one year) should have indexed pricing terms. The prices under such contracts could be fixed through the financial market for varying terms, depending on the utility's approved hedging strategy.

Calgary stated that the Board should approve the AltaGas Proposal. It argued that there was no basis, however, to use the settlement with AltaGas as a model for the appropriate GCRR methodology for AGS.

Edmonton

Edmonton stated that the LDC should provide a gas supply based mainly on short-term (monthly or similar) indexed purchases, with a supporting strategy to moderate price swings through a combination of physical and financial hedges. Edmonton also recommended that there be a customer-consultative approach to setting specific strategies ahead of each gas year.

Edmonton stated that, although it had no direct interest in the AltaGas proposal, it considered as a general principle that retailers and customers throughout Alberta should be subject to generally similar rules and conditions. It argued that exceptions should be based on legitimate customer needs, not on the basis of utility preferences. It argued that, in the interests of ensuring consistency across Alberta, the AltaGas proposal should be developed and implemented to provide equivalent arrangements to the ATCO Gas service areas, to the greatest extent possible.

ENMAX

ENMAX believed that regulated gas utilities should no longer provide gas supply services, except perhaps during a transition period.

ENMAX submitted that:

- the services offered by gas utilities should be clearly identified and separately priced;
- the cost of each of the services offered by gas utilities should be clearly identified;
- those costs must be free from cross-subsidization;

- the price signals with respect to the services offered by gas utilities should be accurate and free from distortion; and
- the level of risk borne by the gas utility must be similar to the level of risk that must be borne by an unregulated competitor.

ENMAX stated that a gas utility should be permitted to structure its gas portfolio in any manner, so long as these principles are met.

Enron

Enron argued that contracting practices should allow for a monthly Alberta market priced GCRR, with the majority of the system sales portfolios based on monthly or daily AECO C indices. Enron submitted that some level of hedging by a utility might be appropriate in limited circumstances, but that the terms of any hedged position, as may be authorized by the Board, should be subject to specific parameters that do not exceed one year.

In response to the Board's letter of September 7, 2001, Enron argued that the NGPPA protection reduced the need for any comprehensive level of utility price hedging of natural gas. It reiterated that utility price hedging could significantly affect the development of the retail gas market.

It submitted that the NGPPA was an appropriate safety valve that could be used in conjunction with some limited level of utility hedging.

EPCOR

EPCOR supported ATCO Gas's current contracting practices and parameters. It noted the ATCO Gas's evidence in the Methodology Proceeding that, since the introduction of a natural gas retail market in 1995, ATCO Gas had been directed or encouraged by the Board to provide a gas supply that was flexible and responsive to price changes in the marketplace, and provided the lowest possible cost consistent with those two objectives.

EPCOR noted that in the Methodology Proceeding, AltaGas put forward a plan for gas supply management and cost recovery that had been developed in the course of meetings with representatives from its customer groups. It noted that, while AltaGas stated that its approach was the best approach for the unique circumstances of its utility, AltaGas had recognized that its approach might not be appropriate for other utilities in Alberta.

EPCOR also noted that, in the Unbundling Proceeding, AltaGas had proposed that it would participate in a generic process to address market rules, which it believed should be the same in respect to all utilities. EPCOR noted that, under cross-examination, AltaGas confirmed that in the future its consultative process would involve its customers, and brokers and marketers that chose to participate. EPCOR supported the AltaGas approach.

FGA

The FGA stated that regardless of any ultimate move to deregulation, gas utilities should offer a single RRO reconciled monthly, based on monthly indexed pricing with no profit margin. The FGA stated that the utility should not engage in physical or financial hedging unless a clear

strategy had been developed in consultation with customers. This consultation should recognize the risk tolerance of customers served.
The FGA noted that if no consensus could be reached amongst customers, the utility should be required to offer the least-cost, at-least-risk product, a pure market rate based index with no portfolio management through use of storage hedging or arbitrage products. It argued that this approach would ensure the most risk adverse customers were properly served, and those with greater tolerance for risk could either accept that product offering or choose an alternative product from the market.

The FGA supported the AltaGas proposed treatment of its gas supply portfolio and the methodology to create and managing its GCRR. The FGA agreed that AltaGas was unique as a utility, and supported the process utilized by AltaGas to reach settlement with its customers.

The FGA took the position that all utilities are unique and that, where possible, all utilities should utilize negotiations with customers rather than litigation to reach agreement on gas rate methodology and unbundling issues.

Mirant Americas Energy Marketing Canada Ltd (Mirant)

Mirant indicated that its participation in this proceeding was for the purpose of conveying the single message that, if the Board directs ATCO Gas to change its gas supply portfolio management, the Board should also require that ATCO Gas use a competitive bid process to procure those services from a party with existing expertise. Mirant submitted that ATCO Gas does not have the commitment, expertise, or appetite to change its current strategy, and that it would not be in the best interests of ratepayers to allow ATCO Gas to hand this function over to an affiliate.

Recognizing that this could be viewed as an issue for the ATCO Group Affiliate Transactions and Code of Conduct proceeding (Affiliates Proceeding), Mirant considered it appropriate to raise the issue in this proceeding on the basis that ATCO Gas would use its affiliate, ATCO Midstream, to provide gas portfolio management services following a direction from the Board. In Mirant's view, a Board decision was required as to whether or not the use of ATCO Midstream for provision of the service was acceptable.

Mirant noted that the Calgary, one of ATCO Gas's largest customers, appeared to find such an arrangement unacceptable, and that there was precedent in other jurisdictions where similar arrangements have been viewed negatively. In Mirant's view, the use of an affiliate by ATCO Gas, without a competitive bid process, would virtually guarantee an after-the-fact prudence review. This could be avoided if the issue was addressed now rather than later in the Affiliate proceeding.

Mirant noted that there was considerable support among the parties in this proceeding for pursuing the objective of achieving the lowest gas cost while reducing price volatility. With the exception of the NCC, there was general agreement with the conclusion that ATCO Gas should be required to adopt an alternative methodology. Mirant noted that ATCO Gas's customers parted company in deciding which alternative strategy was appropriate. In this regard, Mirant referred to the AltaGas Proposal, resulting from a settlement agreement with customers, which called for development of a gas purchase plan by an outside expert. Mirant noted that, while the plan is based on management objectives and guidelines developed by AltaGas in conjunction with customers, the outside expert is currently an affiliate, selected with customer concurrence. Mirant also noted that, in the event that customers determine that use of an affiliate is inappropriate, AltaGas has acknowledged that an outside expert could be sought through a competitive bid process.

In ATCO Gas's case, Mirant noted that there was no consensus on an alternative strategy or the party that should implement it, and no demonstration of willingness on ATCO Gas's part to take responsibility for establishment of the future strategy. Mirant speculated that this could be attributed to ATCO Gas's lack of interest in the portfolio management function, given its commitment to get out of the merchant function. Furthermore, Mirant referred to comments of ATCO Gas's expert witnesses as acknowledgement that the Company has no skills, knowledge, or expertise in this area.

MI/UM

The MI saw no reason to depart from the utilities' contracting practices of obtaining their gas supplies primarily as a blend of AECO C daily and monthly indexed supply, as it understood that most gas bought and sold in the province is purchased on this basis. The MI agreed with Calgary and the other customer groups that ATCO Gas's GCRR portfolio should consist of a mix of short and long term products, plus company-owned production and storage, in order to support a RRO at the least possible cost and with a degree of rate stability. The MI also agreed with Calgary that supply contracts should have indexed prices that would enable fixing prices for all or part of the volumes through financial products.

The MI considered that the utilities should continue to provide the GCRR or a RRO equivalent for at least five years. The MI submitted that the utilities should use physical (storage and fixed price contracts) and financial hedges to manage price risk and to mitigate the impact of gas price volatility on customer rates. The MI disagreed with EPCOR and ENMAX that gas utilities should assume the same risk as retailers, and be allowed to earn a competitive return on the gas commodity services that it provides.

The MI argued that customers would be concerned if they had to pay a premium or incentive on a RRO to encourage a market that may not fully develop for some time, or a market that they may never choose to participate in. It argued further that providing an incentive-based gas cost recovery plan would do nothing more than to increase the cost of gas for those customers who chose to stay on the RRO.

The UM supported the AltaGas Proposal that was filed with the Board on March 16, 2001. The UM submitted that the settlement agreement represented a consensus of what AltaGas and its customers believed was in the best interests of both parties, and should not necessarily be influenced by the determinations with respect to ATCO Gas, where various interest groups have differing opinions.

The UM submitted that the majority of small Rate 1 customers should not be forced to accommodate the minority of larger Rate 1 customers that appeared to favour a seasonal GCRR.

In response to the Board's letter of September 7, 2001, the MI responded that it did not change its position on the need for hedging on the basis of the passage of the NGPPA. It stated that it had advocated hedging since 1997, when gas prices were well below the $5.50/GJ price specified in the *Natural Gas Price Protection Regulation* (NGPPR)[19], and continued to believe that hedging was appropriate to stabilize rates.

PICA

PICA proposed that there should be two types of GCRRs: a flow-through, and a price managed GCRR. It stated that customers choosing to take the price managed GCRR would be liable for any hedging costs incurred on their behalf.

4.1.2 Views of the Board

The key change proposed to the utilities' gas portfolio and purchase strategy is the use of not only long term gas supply contracts, but the proposed use of financial hedging alternatives. In contrast to purchasing physical gas supplies for an agreed price for future delivery, financial hedging products are essentially an insurance policy written against gas price fluctuations. In effect, however, whether via physical purchase contracts or financial contracts, the aim of this form of gas portfolio management is to reduce the volatility of gas costs for consumers. It is important to note that price management should not be expected to lower gas costs. In fact, the opposite can be expected over time. Whether purchasing long-term gas delivery contracts or financial price hedges, the gas utility will have to pay a premium over gas market rates to receive price stability.

The Board is sympathetic to the call for utility gas price hedging programs by several of the consumer groups. Certainly the experience of the rapid rise in gas prices during the winter of 2000/2001 has provided everyone, including the Board, with a new benchmark as to the price volatility inherent in the current gas market. If there were no other risk mitigation measures in place, the Board would consider ordering the gas utilities to enter the market and provide regulated rate customers with a managed gas portfolio.

However, the Board notes that there is already a price protection program that, in effect, provides the benefits of a price cap to Alberta consumers. Under the NGPPA, the Government of Alberta has the power to authorize the payment of rebates to consumers in Alberta when the price of gas rises above an amount specified under the regulations to the NGPPA. This protection is provided at no direct cost to consumers. In effect, Alberta consumers receive the benefits of a provincial "physical hedge" – the Government can protect them from rising gas prices through rebates, because as gas costs rise, the Government receives sufficient additional revenue via gas production royalties to provide consumer relief from high gas prices. Further, the NGPPA rebate program will not cost anything if gas prices are below the threshold established by the Minister of Energy. By contrast, the hedging programs proposed by the parties are paid for directly by consumers, and price hedging can be expected to be at a cost regardless of gas price levels.

[19] AR 157/2001

As noted above, price hedging programs are not free. In the long run, parties providing price hedges wish to profit by providing insurance against price excursions. The market for wholesale gas futures and hedges is mature and liquid, as noted by Calgary. The implication of this market being mature and liquid is that it will adjust rapidly to any expected future price movements. Counter parties to gas price hedges can be expected to maintain a profit margin above the actual price of gas, over most trading periods. It is not reasonable to assume that, on a regular basis, a gas price hedging program will "beat the market", and provide significant savings. Over time, gas price hedging will cost more than daily or monthly index pricing.

When the hedging program is protecting against significant price spikes, it is possible for a hedging program to provide large savings to consumers. That insurance may, in and of itself, be worth the cost of the hedging program in absence of other price protection programs. However, in the current circumstances, where the Government of Alberta has passed legislation to allow for relief in the event of rising gas costs, the value of further gas price hedging becomes less apparent. The potential benefit of reducing persistent above average prices is lowered, and the insurance value of protecting against very high prices is nil.

The Board must also consider the effect that a "managed rate" would have on the development of the competitive retail market. The key element identified by ENMAX, Enron, and EPCOR was the potential competition that such a rate would present to new market entrants, reducing the available market opportunities. While the Board acknowledges that this is a potential effect, it is of the view that this would not be the most significant effect of a hedged price program.

As further discussed in section 4.8 of this Decision, the implementation of gas price hedging programs can create a need for entrance and exit fees to be charged on regulated rate offerings. Without entrance and exit fees, there is a potential for customers to strand hedging costs undertaken on their behalf with remaining utility customers. It is also worthy of note that the calculation of these fees becomes a complex task. Although the Board has the utmost faith that Alberta consumers are as knowledgeable as any with respect to energy markets, the calculation of required exit fees or entrance fees based on a comparison of purchased hedges versus future hedge prices will leave most consumers confused. The Board is concerned that entrance and exit fees, if required to administer a managed rate, could create a serious impediment to customers wishing to choose direct supply.

As noted in section 2.1 of this Decision, the Board considers that its role is not generally to create policy, but to review matters under its purview to ensure that Government policy is implemented consistent with the Board mandate to protect consumers. In this instance, Government policy itself is aimed at protecting the public interest by providing relief to consumers from high gas prices in the form of rebates. The Board is of the view that allowing additional hedging programs, administered by the utilities, would likely act against the overall Government policy of enabling retail market development.

The Board notes the views of parties that responded to the Board's letter of September 7, 2001. In particular, the CCA and MI/UM have reiterated their desires for utility gas price hedging programs, even with the NGPPA price cap set in the regulation (NGPPR) at $5.50/GJ. The Board notes the view of the CCA that the NGPPA price cap is set at the discretion of the Minister of Energy, and there is no guarantee as to the term or stability of that price protection.

The Board notes from a news release from the Energy Minister, dated September 28, 2001, that the availability of the NGPPA rebates is not affected by the recent downturn in Government revenues from the oil and gas sector, but that the rebates are simply not expected to be needed during this winter season due to low gas prices. The Board notes that, as Government revenues increase directly with the price of gas, it can be expected that the Government will be in a position to follow through with its rebate program in the event of a gas price increase. Because of this ability, the Government has established a policy that allows it to provide a major portion of the gas price protection needed by consumers. The Board finds that the NGPPA is an important statement regarding the Government's commitment to Alberta gas consumers.

In the Board's view, consumers' interests are adequately safeguarded by the NGPPA in the current circumstances. In section 3 of this Decision, the Board has directed that the gas utilities are to continue to provide a gas offering based on a pass through of wholesale gas costs. These gas costs, without the added cost of gas price hedging, make for as low a rate as is possible on an ongoing basis. The NGPPR caps the gas price at a level that is not significantly higher than the average market price was over the past several years. Employing the NGPPA price cap as the only price protection mechanism is, in the view of the Board, most likely to be the least-cost gas supply option for consumers.

Thus, the Board looks to the effect on retail market development as a major consideration in deciding whether or not to support utility gas price hedging. The Board's expectation is that regulated gas utility hedging programs may seriously affect retail gas market development, and therefore, the Board finds that such programs are not seen as necessary at this time.

With respect to the structure of the remaining gas portfolio, ATCO Gas has recommended a mix of daily and monthly indexed price products, as well as daily spot purchases for any residual requirements. The Board is of the view that, in the context of the other findings in this Decision, the ATCO Gas proposal will provide accurate market pricing, and sufficient operational flexibility for the utilities to manage their gas acquisition programs. The Board notes that some long term gas supply contracts may continue to be in force at this time. Given that marketers have not objected to a limited amount of gas price hedging in the utility gas portfolios, the Board is of the view that the simplest approach is to include the value of remaining contracts in the utilities gas pricing portfolios. However, new long-term contracts should not be added to the utilities' gas portfolios.

The Board notes the special circumstances regarding AltaGas. AltaGas has made an effort to negotiate a gas price hedging program with its consumers, and has succeeded in reaching an agreement with the general support of all customer representatives. The Board acknowledges the desire of customer groups for additional price stability. As noted earlier in this section, if the NGPPA program was not in place, the Board would consider encouraging utility gas price hedging programs. The Board is sensitive to the potential that, due to the small size and more remote location of the AltaGas service territory, retail market competition may not provide benefits to AltaGas customers. However, the Board is of the view that at this time, retail market development should not be inhibited in the AltaGas service territory. The Board considers that, given the provisions of the NGPPA, AltaGas customers will be sufficiently protected. Accordingly, the Board does not consider the hedging provisions of the AltaGas Proposal to be necessary. In the event that retail market competition does not materialize for AltaGas customers after some reasonable period, the Board may be prepared to revisit the need for a hedged gas rate for AltaGas customers.

4.2 Instruments for Gas Price Hedging

Gas price hedges can be either physical or financial in nature. Physical price hedges include: company owned gas production, gas in storage, and forward gas contracts. Financial price hedges are purely financial contracts established to fix the price of gas, or to reduce the variability of gas prices.

4.2.1 Positions of Parties

ATCO Gas

ATCO Gas submitted that financial hedging/arbitrage arrangements are better left to retailers. It stated that over the long term, these arrangements represent a zero sum game.

ATCO Gas recommended that storage should no longer be used as a physical hedge. It cited its filed evidence that storage was no longer needed for operations, and argued that storage is also a zero sum game. ATCO Gas also submitted that company owned production introduced market distortion, and should not be used to provide service under a RRO.

With regard to the production of base/cushion gas from Carbon storage, AGS indicated in argument that it would be filing an application to remove the Carbon storage asset from regulated utility service. On July 18, 2001, ATCO Gas filed an application with the Board for approval of a process whereby ATCO Gas will be able to transfer its Carbon Storage facilities to ATCO Midstream at fair market value.

AIPA/EUAA

AIPA/EUAA submitted that the process and procedure for financial hedging and arbitrage activities should be determined through the collaborative process, and those activities should be considered to apply to both regulated and non-regulated supply.

AIPA/EUAA submitted that there was no compelling reason for elimination of storage as a physical hedge, as the costs of storage would be a charge against the winter or annual GCRR, and would have no impact on the development of a competitive retail market. In AIPA/EUAA's view, to the extent that company owned production provides a lower cost supply to Core customers, it may represent an unfair advantage to the regulated supply over unregulated supply. Accordingly, AIPA/EUAA considered that the concept of pricing company owned production supplies at market price for the regulated portfolio and applying the difference between market price and cost as a credit to the regulated delivery function might alleviate any retailer concerns.

AIPA/EUAA submitted that, since customers have paid for the initial injections of base or cushion gas in storage facilities, they should be provided with the benefits.

CCA

The CCA noted the change in gas supply strategy, commencing in the early 1990's, where utilities moved away from long-term supply contracts to monthly-based contracts that are price adjusted with reference to various indices. As pointed out in argument before the Board (and previously the Alberta Public Utilities Board) in proceedings since 1994, the CCA continued to hold the view that use of price variable contracts was excessively risky, and that residential customers were unable to bear the risk associated with fluctuations in natural gas prices. The CCA cited the need for Provincial Government assistance to residential customers in the winter of 2000/2001 as an example of the impact of price variable short-term contracting.

The CCA submitted that the use of exit fees would mitigate the financial risks potentially faced by utilities with long-term contracts deemed imprudent by the Board, where customers have left sales service leaving stranded costs.

The CCA disagreed with ATCO Gas's assertion that financial hedging/arbitrage would better left to retailers. It pointed out that, currently, only one retailer offered hedged products to residential customers. The CCA noted that the price offered by that marketer was coupled with complex terms and conditions of service, and appeared to be significantly higher than the price that a utility could offer.

Referring to its participation in ATCO Gas's storage procurement process for the 2001/2002 winter season, the CCA noted that ATCO Gas had entered into some synthetic storage contracts, as they were the lowest cost bids in that process. While expressing concern about the potential credit risk associated with the use of synthetic storage, the CCA indicated support for use of physical hedges to reduce GCRR volatility.

In response to submissions by ATCO Gas regarding physical hedges, the CCA pointed out that storage is the only hedging activity that partially protects customers of AGS against movements in the price of natural gas, and therefore should continue to be part of the gas portfolio. In addition, the CCA considered that the removal of company owned production, which provides price stability to customers, would eliminate benefits that would otherwise accrue to future generations.

Acknowledging that use of storage does little to reduce year-to-year volatility, the CCA expressed support for use of company-owned and third party storage to reduce GCRR volatility.

The CCA submitted that company owned production provides long-term, stable prices for a percentage of the portfolio, and cited the example of the AGN portfolio where company owned production was set at an arbitrary 15% of the gas portfolio, resulting in a difference of approximately $1.00/GJ between the AGN and AGS GCRR in the winter of 2000/2001.

The CCA considered that in the event that storage facilities can no longer be used as a low cost storage provider, it would be appropriate to examine the use of base or cushion gas for the benefit of customers. The CCA did not view the use of base gas as a sale of a physical asset, but rather as the use of assets previously used for storage in the form of company owned production.

Calgary

Calgary noted that there has been a range of financial hedging products available on the market on competitive terms for several years. These products are widely used to manage price volatility. It was also noted that the ATCO Group used hedging products to manage price risks associated with other aspects of its business.

Calgary argued that AGS's approach to managing its gas portfolio resulted in prices that were at or near the volatile end of the spectrum. Calgary noted that AGS had not used financial hedging products. It also noted that prior to the winter 2000/2001, AGS used Carbon storage as a physical hedge, but without a defined objective with respect to the customers' appetite for risk. Calgary argued that this had resulted in a highly volatile GCRR. It interpreted the evidence of the AGS witness, Mr. Simard, to imply that AGS's portfolio approach assumed that AGS Core customers have a high appetite for risk.

Calgary argued that consumer reaction over the winter of 2000/2001 demonstrated that consumers did not believe that AGS understood consumer needs, and expected AGS to provide protection against price volatility. Calgary noted that it and other consumer groups proposed to the Board that utilities should implement risk management plans to reduce the volatility of consumer gas prices. Calgary stated that the objective of these plans should not be to "beat the market", but to reduce price volatility.

Calgary recommended that a goal should be established that the average purchase price over the year should not exceed 110% of the market forecast or forward price for the forthcoming year. It also suggested that the objectives of a hedging program could be established through a collaborative process, and it would be willing to participate in such a process.

Calgary proposed that, once the objective of a hedging program was established, AGS should be required to design a risk management program covering details such as:

- the physical and financial hedging tools that would be used;
- the maximum amount of the total supply portfolio that AGS would hedge at any point in time;
- the maximum amount of the portfolio that it could hedge on a single day;
- the policy with respect to credit risks;
- internal approval processes; and
- accounting and reporting requirements.

Calgary argued that the outcome of the collaborative process and the utility risk management scheme would be a RRO price that would exhibit less price volatility than the current GCRR. It proposed that the assessment of AGS's performance would then be measured on a prospective basis.

Calgary noted that ATCO Gas had argued that it should not engage in physical or financial hedging, that it does not need storage, that company-owned production introduces market distortions, and that it had indicated that it would be filing an application to remove Carbon storage from rate base. Calgary characterized ATCO Gas's arguments as nothing less than astounding.

Calgary argued that many consumers want a market-based gas supply with limited volatility similar to the service available in other jurisdictions. It noted that such an option is not currently available from retailers, and countered ATCO Gas's argument that the retail market could better protect customers from price volatility.

Calgary also noted the arguments of retailers that the utility should not hedge any part of the gas supply portfolio for the RRO. Calgary argued that even a hedged RRO would not compete with the products currently offered by retailers.

Calgary argued that AGS should use both financial and physical hedges and that there was no basis or merit to restricting a utility to physical hedges alone.

Calgary argued that utilities should be expected to use company-owned rate based storage in their pursuit of the least cost gas supply for the RRO that meets the volatility objective. Calgary noted that it had supported the use of company-owned production in AGS's gas supply portfolio. It argued that the utility should manage and operate company-owned production within the context of other alternatives in the least cost manner.

Calgary argued that the utility should constantly monitor and evaluate the most cost-effective use of base or cushion gas as company-owned production. It argued that the company should use an effective gas management strategy to employ this asset in the best interests of ratepayers. In the event that cushion gas was used as production gas, Calgary argued that the proceeds should be credited to distribution rates benefiting all utility customers, not just RRO customers.

Edmonton

Edmonton supported financial hedging of up to 10% of supply on two-year contracts.

Edmonton supported the use of physical hedges, and made the following recommendations:

- Storage -- up to 10% of annual requirements;
- Company-owned production -- up to 25% of annual requirements (ATCO Gas North); and
- Storage (base/cushion gas) -- up to 25% of annual requirements (Edmonton noted that this was not an ATCO Gas North issue).

Enron

Enron noted that there is recognition among interested parties that utility hedging would inhibit retail market growth and submitted that the only potential use of utility hedging would be to reduce annual rate volatility.

Enron did not support utility gas price hedging for the following reasons:

- Hedged utility portfolios would compete with services offered by retailers and impede retail market development by delaying entry of participants into the market.
- The desirability of retail supply would be a function of whether a utility's hedges are above or below market prices, this would create artificial incentives for customers to either leave or return to utility supply.
- Hedging increases the potential for exit and entrance fees, which create entry barriers, would be complex to administer and would confuse customers, further impeding customer choice.
- Hedging can increase the risk of stranded costs in cases where the utility's hedged portfolio price is out of the market and customers move to competitive options.
- Hedged costs may bear no resemblance to current market prices, making it difficult for customers to reasonably compare utility versus retail options.

Enron argued that it was not appropriate for a utility to make price choices for customers through the use of hedging tools, as such choices should be at the customers' discretion. It recognized that some customers, particularly residential and small commercial customers, presently have limited options to manage price volatility and accepted that some limited utility hedging may be reasonable for such customers until the Board is satisfied that a sufficiently competitive retail market exists.

Enron argued that creating a level playing field and removing unnecessary entry barriers would promote retailer entry and development of hedged and other pricing options and services.

Enron did not take a position as to whether or not physical hedges should be included in the supply portfolio. However, Enron argued that the current use and rate treatment of the physical hedges results in a GCRR that is consistently lower than market prices.

Enron further argued that if Carbon storage, salt cavern gas, or company owned production supplies were included in the utility's portfolio, the NCC COP Rider methodology should be applied, wherein the GCRR would reflect these supplies at the current market price of gas, and the benefit of these supplies (market price less cost) would be credited to distribution rates.

Enron suggested that the costs of storage capacity, leased at market-based prices, should be included in the GCRR/DGA.

EPCOR

EPCOR submitted that, in the event that the Board determined that ATCO Gas was to be permitted to engage in price risk management practices, ATCO Gas should be subjected to the same risks as non-regulated suppliers and be allowed a return commensurate with the risks undertaken. EPCOR quoted its witness, Mr. de Palezieux, who testified as follows:

> If we are subject to compete with the utility that is not subject to the same risk, [volume and price risk] then there will not be a level playing field and it will make it difficult for retailers to fully develop this marketplace.[20]

[20] Methodology T8: 855, ll. 8 -- 22

EPCOR also noted that witnesses for ENMAX had provided a similar opinion.

EPCOR stated that the current regulatory treatment of company-owned production in ATCO Gas's rates produced a price for gas that was less than the market price. EPCOR argued that this created a significant barrier to competition in the retail gas sales market, particularly in the AGN service area.

EPCOR noted the statement of Mr. Engler for ATCO Gas, that, "the gas price reflected in the GCRR for ATCO Gas North is significantly less than the market price for gas."[21]

EPCOR supported the NCC proposal to address this problem by requesting the Board to order ATCO Gas to include in the GCRR company-owned production at market price, and to adopt the NCC COP Rider.

FGA

The FGA stated that the use of financial hedging instruments should be limited due to the risk of mismanagement or disallowance. It noted that the use of storage could be desirable as it may provide, at a limited cost, a means of price stabilization. It also noted that the use of fixed or term pricing, or forward purchasing, was another option available to the utility, although it noted that any such option should only be undertaken following customer consultation.

The FGA stated that any collaborative process to design a hedging strategy for ATCO Gas should be done in close collaboration with customers, with detailed agreement on the elements of the strategy. It stated that, if customers reached an agreement with the utility proposing physical hedges, than the use of storage would be appropriate. It agreed with the NCC proposal to increase company-owned production levels and adopt the NCC COP Rider.

The FGA argued against the production of base/cushion gas, since such a strategy would be short-term, and would require an unknown cost to replace the cushion gas produced.

MI/UM

The MI considered that hedging was essential to achieving a degree of rate stability for GCRR customers and that, although hedging could be considered a matter of individual customer choice, it did not appear to be practical for residential customers or financial institutions to embark on such hedging programs. It submitted that it would be patently unfair and unreasonable to preclude utilities from hedging the GCRR because the utilities would then be forced to provide essentially a monthly GCRR that would result in precisely the volatile rates that customers were attempting to avoid. The MI also noted that a pure indexed supply fails to provide any protection from price volatility.

The MI also submitted that the creation of competition should not result in higher rates charged to customers, and objected to any performance based or incentive gas cost recovery plans that would only add costs to the GCRR.

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[21] Disposition of Production and Gathering Facilities Proceeding, T 11, p. 979, ll 12-24

The MI argued that storage is an integral part of an overall hedging strategy to mitigate rate volatility. It argued that storage allowed the utility to capture the summer-winter price differential that has historically existed, while at the same time providing a physical hedge against rate volatility. It also noted that storage allows the utility to enter into long term contracts with higher load factors, improve market liquidity, provide load balancing, and transactional services.

The MI submitted that the storage requirements for the GCRR should be reviewed annually in collaboration with customers and should also reflect the findings of the Board with respect to Carbon Storage following the Affiliates Proceeding decision.

The MI submitted that increasing company owned production, at least for AGN, represents not only reduced costs for gas supply, but would also serve as a physical hedge against rate volatility.

4.2.2 Views of the Board

The Board again notes the concerns of customers that they should be provided with gas price protection as part of regulated gas supply. As noted in section 4.1 of this Decision, the Board is sympathetic to those concerns; however, it finds that the price protection available to customers via the NGPPA will adequately protect the interests of consumers at this time. The Board is concerned that continued or increased utility gas price hedging programs would seriously affect the potential for retail gas market development, and that such development should be provided a reasonable opportunity to succeed. Therefore, the Board is of the view that utility gas price hedging programs, of any nature, are not seen as necessary at this time.

The Board notes the concerns of marketers that including gas price hedges in the regulated gas portfolio may create difficulties in establishing a level playing field between regulated and competitive gas offerings. The Board is of the view that provision of an un-hedged regulated gas rate eliminates these complications, and will create a reasonable opportunity for the further development of the retail gas market.

The Board notes that there are already physical hedge assets owned by the utilities. In the case of ATCO Gas, there are specific company owned gas production assets and gas storage assets that can, by nature, provide gas price hedging. The treatment of company owned production assets has been addressed by the NCC in its proposal that the costs savings of company owned gas production should be passed to all Core consumers via a credit to base rates, while the gas commodity rate should be charged at the market price for gas. This proposal for company owned production is discussed further in section 5.1 of this Decision.

The Board considers that the use of storage facilities as a price hedging mechanism presents some of the same attributes as company owned production. In both cases the facilities can be described as “legacy assets”, assets that have been paid for by all gas consumers in the previously fully regulated market. In both cases, crediting the benefits arising from the facilities directly to the gas commodity rate creates an economic bias towards regulated gas rate offerings, and implies that customers taking competitive gas supply do not receive any of the benefits from these assets. The Board is of the view that both of these results are undesirable.

Therefore, the Board directs that company storage facility costs and benefits related to gas price stabilization or hedging are to be treated in accordance with the NCC COP Rider proposal. The gas withdrawn from storage will be valued at the current GCRR portfolio cost for inclusion in gas commodity rates. The net benefits (or costs) achieved using utility storage assets will be credited to base rates on a per gigajoule basis. Customers, whether they elect to receive gas from the utility or from a marketer, will share in the benefits arising from utility storage.

Based on the evidence before the Board, only the AGS Carbon storage facility meets the criteria of being company owned storage used primarily as a physical hedge mechanism. The Board notes that AGS has filed an application, dated July 18, 2001, to commence a process to remove this facility from utility operation. Until such time as the Carbon facility is removed from regulated service, the Board expects AGS to operate the Carbon storage facility for the benefit of customers, and to allocate the costs and benefits of that facility in the manner described herein to the account of AGS Core customers paying towards the Carbon facility in their rates. With respect to the Salt Cavern storage facility in use for AGN, the Board acknowledges the evidence of parties that this facility is used primarily as a substitute for additional transmission facilities. On an interim basis, the Board is of the view that the Salt Cavern facility does not create the need for a credit rider mechanism. However, the Board will re-examine this conclusion as part of a final rate review.

The Board also notes that, as provided for in Decision 2001-22, Application for Approval of an Arrangement for Acquisition of Storage Services for the 2001/2002 Gas Storage Year for ATCO Gas South, dated March 27, 2001, AGS acquired rights to additional storage for the 2001/2002 gas year. Similarly, in Decision 2001-23, Application for Approval of an Arrangement for Acquisition of Storage Services for the 2001/2002 Gas Storage Year for ATCO Gas North, dated March 27, 2001, AGN has acquired rights to additional storage for the 2001/2002 gas year. These arrangements pertain to the winter of 2001-02, for withdrawals up to March 31, 2002. The Board notes that these arrangements were undertaken prior to the enactment of the NGPPA. The Board directs that arrangements arising from Decisions 2001-22 and 2001-23 should be maintained for the 2001/2002 gas yearly only, with all costs and benefits going to the account of AGS or AGN utility supply Core customers as appropriate.

4.3 GCRR/DGA Programs

The effect of a Gas Cost Recovery Rate/Deferred Gas Account (GCRR/DGA) mechanism is to spread the cost of gas acquisition and management over a forecast period, keeping consumer gas prices stable during that period. The use of a DGA to keep track of differences between actual and forecast gas costs ensures that customers pay no more and no less than actual costs incurred on their behalf. However, the reconciliation between forecast and actual costs occurs over one or more seasons.[22] During periods of rapid gas price increase, as experienced in the winter of 2000/2001, the accumulated balances in the DGA can become large. The current system of GCRRs/DGAs has defined tolerance limits on the size of the DGAs, requiring the utilities to file for gas rate adjustments when the variance between forecast and actual costs becomes too large. These tolerance limits were exceeded during the 2000/2001 winter season.

[22] The current GCRR seasons are: winter (November through March of each year) and summer (April through October of each year).

4.3.1 Positions of Parties

AltaGas

AltaGas explained that the Gas Management Plan in the AltaGas Proposal includes an annualized GCRR for Small General Service customers with the option of a seasonal GCRR for the larger Rate 2 and 3 customers. The Gas Management Plan provides details regarding the DGA process for each GCRR available to its customers.

ATCO Gas

ATCO Gas recommended implementation of a single gas supply service offering that uses a rolling twelve month GCRR with a periodic adjustment every three or four months, not unlike the practice of other utilities in Canada.

ATCO Gas proposed the following DGA procedure:

- GCRR – annual rate with quarterly adjustment
- No seasonal tolerance limits
- Reconciliation period – quarterly
- Reconciliation method – include quarterly account balance with annual forward view forecast of costs when deriving the new annual rate
- Proposal submission and timetable – each quarter provide actual and estimated cost and recovery information for the previous quarter and forecast costs for the next quarter
- Application submission and timetable – applications include proposal information filed every quarter
- Interim reporting – Current balance of DGA forwarded to Board monthly

ATCO Gas submitted that it would develop recommended procedures for these additional services, if the Board directed it to provide additional gas supply services.

ATCO Gas stated that the issue of price volatility should be addressed through the GCRR, and not through the introduction of hedges into the gas supply portfolio. It noted again that hedging is a zero sum game. It considered that the administrative difficulties of allowing over 700,000 customers the option to select varying GCRRs would be confusing to customers at least, and potentially cause a significant amount of increased costs for all customers. It did state, however, that it was prepared to continue with the current seasonal GCRR for irrigation and other non-Rate 1 customers, if so directed.

In reply argument, ATCO Gas argued that a GCRR with less frequent changes had a better likelihood of being able to absorb the market distortions that would arise should the Board direct that it have a significant amount of hedged supply. It argued that hedging programs are likely to require entrance and exit fees.

AIPA/EUAA

AIPA/EUAA argued that an annual GCRR could apply to rate classes with annual consumption to provide some rate stability, and a monthly or seasonal GCRR to rate classes with seasonal consumption.

AIPA/EUAA disagreed with the suggestion of ENMAX for elimination of the DGA through outsourcing, on the basis that outsourcing would only lead to higher gas supply costs for irrigation and farm customers in the short term, in the absence of competitive retail alternatives. In response to the Board's letter of September 7, 2001, AIPA/EUAA stated that, as the NGPPA had capped the gas price, the necessity for an annual GCRR/DGA option was diminished. It argued that gas price volatility below the prescribed price cap could be addressed through utility levelized payment options or budget plans.

CCA

While suggesting that the LDC should strive for a GCRR that required less frequent adjustment, the CCA indicated preference for a yearly GCRR to enhance rate stability. The CCA adopted this position for the 2001/2002 winter season as a means of spreading the price spike from the heating season to the summer period.

The CCA was not supportive of separating the DGA into classes of customers or by rates, on the basis that such a separation will cause the total amount paid by all customers to increase due to the loss of diversity benefits enjoyed when all customers share the same natural gas pool. In particular, the CCA expressed concern with PICA's attempt to have its higher load factor customers removed from the DGA while its low load factor customers remain to reap the benefit of the higher load factors of remaining customers.

The CCA expressed concern that marketers appear to value their own commercial interests more highly than the interests of the residential customer, and questioned whether or not customers would be better served by maintaining the status quo. The CCA speculated whether customers might be better served by modifying the GCRR methodology, or by allowing the GCRR provider greater flexibility to modify its portfolio.

Noting that competitors seek profits and customers seek stable rates, the CCA submitted that the two are not necessarily mutually exclusive and may not both be in the public interest. The CCA therefore submitted that there was no valid reason to move from a flow through cost portfolio to one where customers provide profit to competitors.

Calgary

Calgary submitted that an essential characteristic of the GCRR, or the price of the RRO, is that at any point in time, it should reflect the utility's actual gas supply costs as accurately as possible.

Calgary argued that this approach would have several benefits, including:

- providing consumers with accurate market signals allowing them to regulate their gas consumption;

- reduced inequities between customers whose consumption varies from the average;
- encouraging the development of the retail market by minimizing or eliminating the need for entrance and exit fees; and
- reducing administration costs.

Calgary argued that the more frequently the GCRR is adjusted, the more accurately it would reflect the costs of utility gas supplies, minimizing DGA variances. Calgary recommended that the GCRR be adjusted at the beginning of each month to reflect any cost changes. It argued that this alternative was practical and would accurately recover AGS's gas costs, which are known in large measure at the beginning of each month. It argued that any inaccuracy would be related to gas purchases indexed to daily prices. Calgary recommended that these quantities be reduced. Calgary noted that ATCO Gas, PICA, and the CCA agreed that a GCRR adjusted monthly would reduce or eliminate the need to impose exit or entrance fees.

Calgary submitted that the current seasonal GCRR adjustments have resulted in frequent and large DGA variances, exacerbating price volatility. It argued that this created inaccurate pricing signals, leading to significant confusion among consumers and impairing the development of the retail gas market. Calgary noted the evidence of Mr. Simard, that there would be even more problems with a GCRR adjusted on an annual basis. Calgary indicated that ATCO Gas's preference for an annualized GCRR was based on the assumption that future gas prices would be less volatile. Calgary submitted that ATCO Gas had provided no evidence to support its assumption.

Calgary noted that, under its proposed GCRR method, utilities would not require a proceeding seeking the approval of the Board prior to adjusting the GCRR each month. Its proposal called for utilities to provide interested parties and the Board with a detailed explanation and schedule supporting the requested change. Utilities would then file an application with the Board on or before the end of February each year for review and approval of all gas costs incurred during the previous gas year. Under the Calgary proposal, the utility would be expected to demonstrate that all costs were prudently incurred, and that its hedging program was implemented and conducted within the framework approved by the Board.

Calgary also recommended that each month the utility would prepare a report of its gas supply costs and activities. Interested parties would be expected to raise concerns as they arose.

Calgary noted in reply argument that most parties have expressed support for the Board's current objective of minimizing DGA balances. However, Calgary argued that many of the same parties had proposed GCRRs using adjustment periods that would continue to generate large DGA balances and worsen price volatility.

Calgary argued against the CCA proposal that GCRR levels should be established annually while maintaining existing DGA tolerance levels. It argued that utility gas prices would bear no relationship to gas costs, creating undesirable DGA balances. It stated that the threshold levels would then be breached frequently, resulting in frequent adjustments to the GCRR.

Calgary noted that Edmonton and ATCO Gas had argued on the one hand that there should be no exit or entrance fees for customers switching between retail and utility gas supply service, but on the other hand, had argued for a GCRR mechanism that could create significant DGA balances. Calgary submitted that any GCRR mechanism that did not track utility gas costs closely, and did not adjust the GCRR as often as feasibly possible, would create unnecessary DGA balances, would do nothing to reduce consumer price volatility, and would create the need for entrance/exit fees.

Calgary countered the MI criticism of Calgary's proposed GCRR mechanism. Calgary submitted that price volatility is inherent in today's gas market. It argued that hedging would reduce this volatility, while extending the GCRR adjustment period would not reduce volatility. It argued that, at best, extended adjustment periods would mask price volatility, but could result in excessively large and potentially disruptive GCRR adjustments to respond to changing prices and accumulated DGA balances.

Calgary argued that the proposals by PICA and MI for two RROs or GCRRs would be unnecessarily complex. However, Calgary did not oppose these approaches as long as all consumers could choose between the proposed monthly and seasonal options.

Edmonton

Edmonton recommended annual GCRRs, with quarterly adjustments.

ENMAX

In ENMAX's submission, the continued existence of deferral accounts for gas utilities posed a serious barrier to competitive entry. It stated that any attempt to maintain the GCRR and DGA, as currently structured, increased the risk of stranded costs if the utility experienced a rapid migration of customers from its gas supply service. ENMAX believed that the elimination of the DGA was a necessary condition for creating a level competitive playing field, and for ensuring that standard offer service reflected market prices. ENMAX submitted that a gas supply portfolio dominated by purchases on the spot market, combined with infrequent rate adjustments, had a significant potential to stifle competition.

It was ENMAX's view that, in order to ensure fair cost recovery and the transmission of accurate and undistorted price signals, more frequent rate adjustments were required. It was also ENMAX's view that the most frequently that rate adjustments could reasonably be done was the same frequency as the metering interval, monthly.

ENMAX submitted that regulated gas utilities should no longer provide gas supply services. It argued that if regulated gas utilities are permitted to continue to provide these services, the DGA should be eliminated immediately.

In order to equip consumers with the information they need to make informed decisions regarding competitive options, ENMAX argued it was important that the price signals sent by the existing gas utilities to customers and retailers be accurate and undistorted, until all gas supply services are out-sourced.

ENMAX recognized that some consumers desired rate stability. However, ENMAX suggested that this stability should be provided by the competitive market.

ENMAX believed that appropriate price signals were necessary for the creation of a robust, competitive natural gas market. ENMAX stated that monthly pricing without a DGA provision eliminated the potential for stranded costs associated with unrecovered gas cost balances. It was ENMAX's view that by eliminating the DGA and passing through gas costs on a monthly basis, the Board would encourage competition while minimizing the potential for stranded costs.

ENMAX recommended that the Board order a one-time reconciliation of the over-collected balance in January 2002 as part of the elimination of the DGA. ENMAX believed that elimination of the DGA was an integral part of the outsourcing of the ATCO Gas standard offer. ENMAX stated that the refund should be a lump sum credit to consumers based on their consumption during the months when the over-collection occurred.

Enron

Enron recommended that monthly GCRRs be used in order to minimize DGA balances, send appropriate price signals to customers, negate the expressed requests of some parties for exit fees, and reduce cross subsidization between customer groups. Enron suggested that the existing seasonal GCRR/DGA methodology gave rise to various problems. It argued that GCRRs, by not being reflective of actual monthly gas costs, create uncertainty for customers who are trying to assess supply options, and discourage retailers from entering the market. It added that large deferral balances can arise, necessitating large rate adjustments, and creating the potential for exit fees and carrying charges on the deferral balances, as evidenced in the 2000/2001 winter season.

Enron argued that the deficient design characteristics of the present GCRR methodology were more acute than ever, due to the recent volatility in the natural gas wholesale market. Enron submitted that if ATCO Gas were required to adjust its gas cost rate monthly to reflect current prices and expected gas costs, the following would be accomplished:

- Ongoing deferred gas account balances, and resulting carrying charges, would be minimized.
- Any arguments in support of entrance and exit fees would be addressed.
- Cross subsidization between customers with different load types would be reduced.
- More accurate price signals would be sent to customers, allowing them to more easily assess gas supply options and to respond to price signals by changing consumption patterns.

Enron supported market-based solutions that would provide clearer market signals to customers, would encourage retail market development, and would also lead to increased market based solutions to control volatility, such as the fixed prices currently offered by retailers for multi-year terms.

EPCOR

EPCOR supported the retention of a GCRR/DGA mechanism as part of regulated gas supply during the transition period to a fully competitive market for retail sales. EPCOR stated that more frequent adjustments, or true-ups, would provide the best market signals for customers, would allow for a proper comparison between regulated utility supply and competitive options, and would allow for seamless customer choice without the need for exit fees.

EPCOR supported the design of the GCRR on an annualized basis, but conditioned its support on the premise that the DGA would be trued-up on a frequent and regular basis. EPCOR proposed that the GCRR be designed using a twelve-month forecast for gas cost and sales, and be adjusted for changes to these forecasts on a monthly basis. DGA balances would be cleared on a rolling basis over the next two months forecast of sales with a deficiency or credit rider.

FGA

The FGA noted that Alberta sits on top of natural gas resources. It argued that the DGA approximates competition to such an extent that retailers may not have a profit margin. It stated that in perfect competition, profit is zero in the long run.

The FGA argued that the GCRR should not be eliminated even if a retail market develops. It argued that the RRO should remain part of customer choice.

The FGA stated that retailers should not be counted on to advance the interests of customers. It noted the emphasis that retailers put on the incorrect price signals deriving from the DGA. The FGA argued that the DGA operates within limits and that over time, all ups and downs in the DGA even out.

The FGA noted that in Alberta in recent years, midseason adjustments were required to the GCRR, such that essentially a quarterly GCRR adjustment was utilized. It argued that moving to a monthly GCRR would remove many of the concerns expressed by retailers, and would also effectively eliminate concerns with entrance and exit fees.

The FGA stated that the collaborative process should determine what customers wish to see the utilities offer as a GCRR/DGA model. It noted that AltaGas had undertaken such consultations. The FGA noted that there could be need for AltaGas to engage in further consultations with customers to address the frequency of true-ups or adjusting the forecast through the term of the GCRR. It recommended that, if agreement could not be reached, a pure market indexed GCRR, with monthly reconciliations, should be offered.

The FGA countered the ENMAX statement that the DGA masks accurate price signals. It noted that ENMAX supported retailers offering unrelated goods along with gas, as part of creative packaging used to attract customers. The FGA submitted that this marketing strategy would create a greater masking of accurate price signals than does the DGA. It submitted that ENMAX's comments pertaining to the DGA mechanism should be dismissed.

The FGA also countered the ENMAX statement that the DGA shields the utility from forecast risk. The FGA noted that a deferral account requires that any under-collection must ultimately be recovered in a later period. The FGA stated that this creates risk for the utility as the DGA causes prices to go up and down, causing some customers to leave the utility for other offerings.

MI/UM

The MI/UM submitted that primary consideration should be given to the best interests and wishes of the end users in determining the GCRR methodology, as opposed to potential market entrants. It submitted that customers should be given the choice of selecting either an annual/seasonal GCRR or monthly GCRR.

The MI also submitted that the proposals suggested by Calgary and EPCOR would continue to include rate volatility.

In response to the Board's letter of September 7, 2001, the MI stated that it did not wish to change its recommendation with respect to the GCRR/DGA in light of the NGPPA. It noted that the NGPPA may expire on June 30, 2003, and as such, may not provide protection through the transition period to full competition.

4.3.2 Views of the Board

The Board notes the wide range of views on this topic provided by parties. Some have argued that the most current pricing should be used, in order to provide accurate signals to the market. Some customer groups, most notably the CCA, have argued that the GCRR and DGA mechanisms should be extended from their current seasonal format to an annual format, to further reduce price instability.

The Board notes the most recent review of the GCRR/DGA mechanisms, in Decision 2001-16, dated February 28, 2001, for AGS and AGN. In that Decision, major changes were required to the previous GCRR mechanism in order to deal with the rapid gas price increases during the winter 2000/2001 gas season. An annualized GCRR to spread the increased gas costs across both winter and summer seasons was approved for residential customers. Also, as a consequence of the very large DGA balances, exit fees for the GCRR were established to ensure that customers could not strand their share of gas cost under-recoveries. As it turned out, although the exit fees were provided for in the Decision, there has not been a need to collect those fees due to dropping gas prices and DGA balances.

As noted in section 4.1 of this Decision, the Board is particularly concerned that exit and entrance fees to the regulated rate could create a serious impediment to customers wishing to choose direct supply. It is clear that exit fees would be required in any GCRR that extended for a longer duration than the current seasonal periods. Exit fees are in place now, with a seasonal GCRR scheme. In the view of the Board, the only solution to avoiding exit fees arising from the GCRR/DGA mechanism would be the monthly scheme proposed by several of the parties.

The Board is aware that adopting a monthly GCRR/DGA scheme will mean that rates become more variable month-to-month. However, there is a limit to this variability that results from the implementation of the NGPPA. The Board takes the view that the NGPPA will allay significant concerns with price stability, without direct cost to gas consumers. The Board also notes, as mentioned by AIPA/EUAA, that customers will continue to have access to utility levelized payment plans. Although customers will be ultimately responsible for the cost of the gas they use, at the time that they use it, the levelized payment programs have been a long-standing method for customers to manage volatility in their individual gas bills.

In view of this, the Board has examined proposals from parties with respect to GCRR/DGA mechanisms with a view towards reducing the potential for large DGA balances. The Board agrees with those parties that have proposed monthly GCRR adjustments as a means to minimize DGA balances, thereby removing the need for entry and exit fees for consumers. The Board also considers that a monthly forecast GCRR should provide more timely and accurate price signals; that more closely reflect the actual cost of gas, for the most accurate possible gas rate.

The Board appreciates some of the inherent complexities that might be introduced through a monthly GCRR; however, the Board considers that the benefits outweigh the possible cost and administrative effort. While the final mechanics have yet to be determined, the Board expects that gas utilities will be able to administer and accommodate a monthly GCRR. The Board considers that the existing DGA and gas cost accounting procedures used by the utilities are sophisticated enough to handle a monthly GCRR. For example, the Board would expect gas utilities to continue with their present practice of estimating current month gas costs (purchases, storage, company-owned production, and other related costs) that is adjusted to actual the following month.

To ensure that the Board, gas utilities, and interested parties all have the same understanding with respect to the DGA and GCRR procedures and, specifically, the manner by which forecasts, estimates and the adjustments to actual will be incorporated into the monthly GCRR, the Board directs the gas utilities to file with the Board and interested parties a mock GCRR application that reflects the Board’s findings, on February 1, 2002, for the February GCRR period. The mock GCRR should clearly reflect and illustrate the above-mentioned estimates and adjustments. The gas utilities should use the mock GCRR to raise any concerns they have with respect to the monthly GCRR. Interested parties will have until March 1, 2002 to file concerns they may have with respect to the monthly GCRR.

The Board notes the proposed review and approval mechanism proposed by Calgary, wherein the utilities would no longer file formal GCRR applications with the Board, but would instead file their actual results and rate calculations on a monthly basis, as a filing for acknowledgement. The Board finds that this proposal has merit and directs the utilities to administer the regulated monthly GCRRs in this fashion commencing April 1, 2002. A period of 30 days following the filing of each monthly GCRR will be provided to parties to raise any concerns with the GCRRs, price and volume forecasts, and prior period reconciliations.

Reconciliation of any DGA balances over a three-month rolling period should allow the utilities to make adjustments to the actual gas cost balances. The Board is of the view that this will provide suitably low DGA balances, while allowing for a reasonable period for the costs of actual gas acquisition, storage injections/withdrawals, company-owned production, compressor fuel, excess system sales, exchanges, etc. to be captured by the GCRR mechanism.

The monthly GCRRs will begin as of April 1, 2002, in conjunction with the revised interim rates noted elsewhere in this Decision.

Pursuant to the Board's general supervision powers over all public utilities contained in section 22 of the GUA and section 77 of the PUBA, the Board will also retain the discretion to review the monthly GCRR filings on its own initiative to ensure that the GCRRs continue to be just and reasonable.

The Board has reviewed the proposal by Enron, that the GCRR should be provided by the market. At this time, the Board does not believe that there is necessarily sufficient competition in the market to provide such a service. As noted in section 3.1 of this Decision, the Board will require utilities to maintain a regulated rate offering for gas consumers. This offering will continue on the basis of a cost flow through, providing customers with a low cost regulated alternative to the competitive market.

4.4 DGA Price Review Tolerance Thresholds

DGA price review tolerance thresholds are either percentage or absolute differences between forecast and actual gas cost recoveries that trigger a review of the existing GCRR.

4.4.1 Positions of Parties

AltaGas

The AltaGas Proposal for Rate 1 customers stated:

- The Company will file with the Alberta Energy and Utilities Board for periodic adjustments, if necessary, in order to trend the deferred gas account (DGA) balance to $0 (zero dollars) at the end of the GCRR year.
- Generally, a +/- 3% (plus minus three percent) of total forecast gas costs imbalance at year's end will be the trigger for a rate adjustment application

For rate 2 and 3 customers choosing a seasonal option the proposal stated:

- The Company will file with the Alberta Energy and Utilities Board for periodic adjustments, as necessary, in order to trend the seasonal-specific deferred gas account (DGA) balance to $0 (zero dollars).
- Any accumulated deficiencies or excesses will be charged or refunded to customers at the end of each respective season.

ATCO Gas

ATCO Gas recommended the establishment of tolerance guidelines of ±$10 million, within which there would be no interest adjustment. It suggested that, when the DGA balance is outside of these guidelines, an interest adjustment should be applied reflecting a financing rate of the overall cost of capital incurred by ATCO Gas for under-recoveries in the DGA. The interest rate paid by ATCO Gas should reflect the rates that can be achieved by ATCO Gas in the marketplace for over-recoveries in the DGA.

AIPA/EUAA

AIPA/EUAA considered existing DGA tolerance levels to be appropriate, and disagreed with ATCO Gas's recommendation of a financing rate that reflects a weighted cost of capital, and an interest rate that could reflect short term borrowing costs. AIPA/EUAA's proposed that the rate for carrying costs paid and received should reflect the rate of prime plus 1.5% discussed in the 2000 Electric Pool Price Deferral Account proceeding.

CCA

The CCA argued that price stability was preferable to frequent changes to the GCRR, and noted that adjustments are required less frequently with use of long-term contracts in the gas product portfolio. The CCA was supportive of existing tolerance limits

Calgary

Calgary argued that under its proposal for a monthly GCRR, DGA variances would be minimized, and DGA variances would be cleared each month. It argued that experience with the existing thresholds and a volatile market has demonstrated that they are difficult to administer and are frequently ignored.

Edmonton

Edmonton recommended DGA tolerances be increased to $5 million or 3%.

Enron

Enron noted that if monthly GCRRs and automatic settlement of prior month imbalances were implemented, tolerance levels would not be required.

FGA

The FGA stated that the currently approved GCRR adjustment tolerance levels may have exceeded a reasonable ability to smooth rates based on the dollar limit for past winter rates. It argued that adopting its proposal for a monthly GCRR would trend to a zero balance DGA on a month-to-month basis, which would eliminate the concern with tolerance limits.

MI/UM

The MI supported the current DGA guidelines for percentage adjustments of +/- 3%, but considered that the dollar limits were outdated. The MI submitted that monthly or rolling adjustments to the DGA, as proposed by other parties, could still result in rate volatility.

4.4.2 Views of the Board

DGA variance thresholds are intended to determine if a GCRR adjustment needs to be undertaken between the usual review periods. As the Board has decided in section 4.3.2 of this Decision to proceed with monthly GCRR adjustments, and as monthly adjustments are as frequent as is reasonably possible, the need for DGA variance thresholds is eliminated.

4.5 Volume and Price Forecasting for GCRRs

4.5.1 Positions of Parties

AltaGas

AltaGas stated that it assumed it would continue to employ its current forecasting methods – forecasting prices based on forward strip information, and sales based on the current GRA-approved method using weather normalization.

ATCO Gas

ATCO Gas argued that the forecast of monthly market demand of sales customers should continue to be based on normalized temperatures. It supported Risk Advisory's evidence that by far the most appropriate method for forecasting gas costs is the use of forward market gas prices. It argued that this represented a broad consensus of market participants who are putting their capital at risk. It also noted that this information was available in real time for those ratepayers desiring such price signals.

ATCO Gas noted that AIPA/EUAA had described its forecasting methods as using normalized precipitation values. It stated that it continued to forecast irrigation consumption on the basis of average consumption over the past five years, as the measurement of precipitation had limited usefulness for forecasting.

AIPA/EUAA

For purposes of forecasting gas costs, AIPA/EUAA submitted that forward strip prices should be used, with the subsequent month's strip used for a monthly GCRR, and a six-month strip used for a seasonal GCRR. The selected price would be on a date as close as possible to the end of the month or 6-month period.

CCA

The CCA expressed support for current regulatory practices.

Calgary

Calgary argued that where utility prices and costs can be determined with certainty (e.g., prices fixed through physical or financial hedges), those costs should be used for the gas cost forecast. Calgary noted that AGS's gas supply portfolio is based largely on contracts indexed to monthly AECO C prices. It also noted that these prices are either known with certainty, or can be predicted with accuracy, a few days prior to the commencement of each month. Calgary noted that forward market prices are also available, and are widely accepted in industry.

Calgary recommended that in conjunction with a monthly GCRR, the monthly spot price determined at the end of the week for the near month be used as the price for all daily and monthly gas expected to be purchased in that particular month. Calgary argued that such an approach would virtually eliminate DGA variances. Calgary argued against any proposal that the GCRR be based on the market price for gas to be delivered over the future 12 months. It stated that such an approach would almost certainly create imbalances in the DGA account and that there were no advantages to using the forecast when actual costs were known.

Calgary stated that volume forecasts should continue to be based on historical averages for each month.

Edmonton

Edmonton recommended that the LDC make a forecast, after having the benefit of collaboration with customers.

Enron

Enron stated that customer volumes should be forecast by the utility using current procedures approved by the Board.

Enron supported the methodology described by PICA to administer monthly GCRRs. It proposed that the monthly GCRR could be set just prior to the start of the month, based on the AECO C monthly index, which would then be applied to the utility's forecast volumes and contract prices.

Enron noted that to the extent the utility's supply purchases are primarily based on the AECO C index and the Carbon storage, salt cavern and production supplies are valued at market prices using the NCC COP Rider then ATCO Gas's actual system sales supply costs should be fairly close to the monthly GCRR, and DGA balances should be minimal. It stated that any DGA balances that did result should be cleared in the following month's GCRR.

FGA

The FGA stated that it did not have any difficulty with the existing forecasting methods, which rely on weather normalization of actual sales for prior periods. It noted that the utilities have traditionally consulted with customers on the preparation of forecasts, and that customers are empowered to propose changes, and that they expect the utility to respond in a responsible manner to expressed concerns.

MI/UM

The MI submitted that the current methods of forecasting normalized sales and the use of forward AECO"C" curves, which represent the consensus view of all participants in the market for purposes of the GCRR, were satisfactory.

4.5.2 Views of the Board

The Board notes that there is relative consensus amongst parties that the current methods applied to forecasting sales volumes are adequate for continued use. The Board concurs that the continued use of weather-normalized forecasts is acceptable for determining forward GCRR sales volumes. Therefore, the Board directs the utilities to continue with current practices for forecasting monthly sales volumes.

The Board is of the view that there is merit to the positions put forward by Calgary and Enron, to establish price forecasts, based on monthly market index prices, as close as reasonably possible to the beginning of each month. As determined in section 4.3.2 of this Decision, the Board considers that monthly GCRRs are appropriate. By attempting to use as up-to-date information as possible, the utilities should be able to minimize the variances between forecast and actual gas costs accumulated in the DGAs.

The Board is not certain that the time lines for determining the forecast GCRR gas costs proposed by parties provide sufficient time for the utilities to determine, file, and implement monthly GCRR changes. The Board therefore directs that the utilities prepare and file a proposal, within 30 days of the release of this Decision, for establishing their GCRRs based on monthly market index prices, attempting to most accurately forecast the actual gas cost for each month.

4.6 Continuation of GCRR/DGA

4.6.1 Positions of Parties

AltaGas

AltaGas stated that, subject to the Board's approval, it planned to honour the AltaGas Proposal as agreed to with its customers. The proposal did not address termination of the DGA process.

ATCO Gas

ATCO Gas recommended that the current GCRR/DGA structure should be continued throughout the transition period, with some modification. It stated that it anticipated that the Board would remove any regulated service offering once it was determined that the competitive market had developed sufficiently.

AIPA/EUAA

AIPA/EUAA strongly supported continuation of regulated supply in any transition period, which would require continuation of regulated DGA procedures. In AIPA/EUAA's view, DGA procedures should not be terminated until it has been determined conclusively that a competitive market exists, and demand for regulated supply has diminished significantly.

In response to the submission of ATCO Gas, AIPA/EUAA expressed support for a seasonal or monthly rate for irrigation and an annual rate for farm service. AIPA/EUAA submitted that ATCO Gas's proposal for a single regulated service offering was unduly restrictive. AIPA/EUAA considered that ATCO Gas's suggestion, that there be a transition period of only a few months after the decision from this proceeding, was unrealistic, on the basis that this timetable would allow no time for a collaborative process, nor time for a retail competitive market to unfold.

CCA

In the CCA's view, the LDCs should remain in the merchant function, with continuation of the requirement for a reconciliation process.

Edmonton

Edmonton recommended continuing the DGA for at least two years, to the end of 2003, but not later than the end of 2005.

ENMAX

ENMAX believed very strongly that the DGA must be eliminated as soon as possible. Also, it argued that the standard offer and supplier of last resort rates should include an element to account for the risk of over or under collection.

Enron

Enron submitted that DGA/GCRR procedures that incorporated its recommendations should be used to administer a regulated supply option during the transition period to full retail Core market competition, and should be continued until the merchant role of the utility is eliminated.

FGA

The FGA replied to the ATCO Gas proposal to remove the regulated option after the transition period by arguing that, if a competitive market develops in the presence of an RRO, there would be no point in removing it. It reiterated that an RRO should remain part of customer choice.

MI/UM

The MI/UM submitted that, unless and until small-volume customers demonstrate that they want retail choices by switching to retailers, a GCRR or RRO should continue to be provided by the utilities. The MI/UM also submitted that the large majority, if not all, of the customers, ATCO Gas, and the retailers concede that the GCRR should continue through a five year transition period. It recommended approval of that proposal.

4.6.2 Views of the Board

As noted in section 3.1 of this Decision, the Board has no intention of removing the regulated supply option from customers at this time. It is of the view that a regulated supply option must be available for customers to ensure that the transition to a competitive retail market does not lead to short-term market dislocations. The regulated supply option will continue to operate on a GCRR/DGA model, although on a modified basis. The GCRR term will be shortened to monthly periods, with a view to minimizing DGA balances.

4.7 Determination and Use of Entrance/Exit Fees for Regulated Rate Programs

Exit and entrance fees to a regulated rate are used to ensure that customers either entering or leaving the rate do not burden other customers with extra costs. For example, if the regulated rate turns out to be greater than the market rate at some point in time, there is an incentive for customers to leave the regulated rate. However, if gas price hedging costs have been incurred on behalf of those customers, allowing them to exit the regulated rate without a fee would leave the remaining customers to pay for those hedging costs.

4.7.1 Positions of Parties

AltaGas

AltaGas noted that the AltaGas Proposal developed with customers specifically addresses exit fees for Rate 1 (Residential) customers as follows:

> 3(e) Customers choosing supply alternatives other than those provided by the utility will be required to pay their respective share (on a per Gigajoule basis) of any cumulative deficiencies that may exist in the DGA at the time they switch to alternative supply.[23]

Although the AltaGas Proposal did not specifically address entrance fees, AltaGas's initial view was that individual entrants should be treated as new customers. Special arrangements would be needed, however, if a large number of customers returned because a marketer fails or withdraws.

ATCO Gas

ATCO Gas submitted that it generally did not support the use of exit fees, but considered that exit fees may be appropriate in specific circumstances. It noted that the complexity of entrance and exit fees might lead to higher administrative costs. ATCO Gas also submitted that entrance/exit fees could act as a deterrent to the development of a competitive market.

ATCO Gas considered that the use of entrance/exit fees was subject to the complexity of the DGA mechanism used during the transition, and the frequency of GCRR adjustments approved by the Board. It submitted that entrance/exit fees should only be considered if there were a clear reason to do so.

ATCO Gas submitted that the frequency of GCRR adjustments would have a direct bearing on the requirement for entrance/exit fees.

AIPA/EUAA

Where transition costs arise, AIPA/EUAA considered that there would be a requirement for entrance and exit fees to ensure fairness for remaining and new customers. However, AIPA/EUAA did not see the need for these fees in the case of a monthly GCRR, which would be based on a monthly index with daily supplies, or in the case of a seasonal GCRR unless the utility could substantiate the existence of transition costs.

However, in the case of an annual GCRR, AIPA/EUAA submitted that since customers are subjected to variances in supply volumes and price, the movement of customers to and from the portfolio could shift cost responsibility. Accordingly, to ensure equity and fairness, AIPA/EUAA considered that entrance and exit fees should be used in an annual portfolio, although evaluation would be required to determine those circumstances under which fees would or would not be levied.

[23] [GCRR; Exh.4; Sch.A; P.1]

CCA

The CCA reiterated its previous expressions of support for cost causation accountability and reduction of a customers' ability to gain from departure or return to the company portfolio.

The CCA referred to excerpts from both EPCOR's current contract, and the comments of the PUB/ERCB in the Gas Supply and Transportation Services Enquiry Report, to illustrate EPCOR's exit conditions, in contrast to the position previously stated by the Calgary.

The Calgary

Calgary stated that it agreed with the view expressed by ATCO Gas and others, that entrance or exit fees would impair the development of the retail market. Calgary argued that having a GCRR designed to minimize DGA variances would eliminate the need for entrance or exit fees.

Edmonton

Edmonton recommended that there be no entrance or exit fees.

ENMAX

ENMAX saw no rationale for the existence of entrance or exit fees, stating that such fees tend to inhibit customer choice and create uncertainty for retail market participants.

Enron

Enron was concerned that entrance and exit fees would create entry barriers to customers, and submitted that such fees are not required with the appropriate GCRR structure. It submitted such fees are detrimental to retail market development for these reasons:

- Such fees inhibit retail market growth as some customers may be unwilling to choose a retailer if there is an upfront cost related to doing so, despite the fact that a choice may be favorable in the long term.
- The potential for exit or other fees, which can be adjusted at any time, creates market uncertainty and inhibits market growth as both customers and potential retailers cannot confidently make choices or offer products when the rules and charges can change.

Enron argued that in the event that exit or entrance fees are implemented, such fees must also include credits to customers whose transfer would otherwise result in net benefits to existing sales customers.

FGA

The FGA argued that its proposal for a monthly GCRR and DGA would effectively eliminate the need for any entrance or exit fees.

MI/UM

The MI/UM supported both exit and entrance fees for as long as the gas markets remain volatile, and the utilities cannot react quickly enough to those changes to mitigate the balances in the DGA.

The MI/UM submitted that exit and entrance fees should be implemented if residential customers stand to gain more than $20 or $25 by leaving system gas supply during shortfalls in the DGA or returning to system gas supply when there are surpluses in the DGA.

4.7.2 Views of the Board

The Board notes that many of the customer groups argued that entrance and exit fees may be necessary for the administration of regulated rates. The Board notes that the current ATCO Gas GCRRs provide for exit fees. Also, there is an exit fee associated with the AltaGas Proposal. The Board also notes the evidence of parties that entrance and exit fees to regulated rates can serve as an impediment to further retail market development.

At the Core of this issue is the relative fairness accorded to individual customers. In the opinion of the Board, price hedging programs and/or extended DGAs for volatile energy commodities will inevitably require the imposition of entrance and exit fees to ensure that customers pay their fair share of costs that have accrued, or will accrue. The Board takes as an example the recent Decision 2001-61, where entrance and exit fees were imposed on ATCO Electric RROT customers.

However, the Board takes the view that entrance and exit fees for gas utility service offerings are to be avoided where possible. The complexity of rate design that arises when fairly establishing entrance and exit fees is far greater than is normal for other aspects of utility operations. This exercise must take into account the difference in future prices for the energy commodity between the day rates were established and the time that a customer wishes to enter or exit the regulated rate program. It is the view of the Board that such complexity, in and of itself, creates an unfair imposition on the right of the customer to understand and freely choose his or her gas service alternatives.

In the current situation, the Board finds that the necessity for price hedging programs and extended DGA periods – the price stabilization features that could require entrance and exit fee provisions – is obviated by the passage of the NGPPA. The use of this outside mechanism to protect consumers from gas price increases allows the Board to greatly simplify the overall rate design exercise, and eliminate the need for entrance and exit fee provisions for regulated gas rate offerings.

Therefore, the Board directs that no entrance or exit fee provisions be included in the regulated gas rate offerings provided for in this Decision.

4.8 Alternatives to Entrance/Exit Fees

4.8.1 Positions of Parties

AltaGas

AltaGas observed that some alternatives to entrance/exit fees, such as notice provisions, are part of existing tariffs. For example, notice period requirements for customers switching from utility supply are part of AltaGas's Board approved General Conditions of Service. Also the AltaGas Proposal included some notice requirements for various types of service switching.[24]

AIPA/EUAA

AIPA/EUAA considered that the establishment of a notice period could be an alternative to entrance and exit fees, if the period was sufficiently long to allow for adjustment of the portfolio without incurring additional costs. The notice period could be combined with penalty provisions for insufficient notice

CCA

While expressing a preference for entrance and exit fees, the CCA agreed that any workable alternatives that ensure customer responsibility for costs incurred should be examined, and submitted that entrance or exit fee alternatives must be explored in each circumstance.

Calgary

Calgary reiterated that its preferred solution to entrance and exit fees was to implement a monthly GCRR adjustment to minimize DGA variances. Calgary suggested that a two-month notice period required of customers would provide the utility with advance notice that a problem with customers migrating from the RRO may be emerging. It argued that the utility could be able to restore the RRO through its hedging program by locking in lower prices.

Edmonton

Edmonton recommended that a notice period of two months be established to go on or off system supply.

ENMAX

ENMAX submitted that there was no need for entrance or exit fees, and that there was no need for alternatives to such fees. ENMAX submitted that customers who elect to leave the standard offer or supplier of last resort service and receive service from a retail merchant, should be able to do so at the start of a calendar month, provided that notice was given five working days prior to the first day of that calendar month.

Enron

Enron submitted that the applicable notice period a customer must provide to leave system supply should only reflect the time required by the utility to process customer transfers.

[24] See for example, GCRR Exh.4, Sch.A , P.2, Option 2 (c).

Enron also submitted that a one month notice period would be adequate for such transfers, and could even be reduced further, depending on systems developed by the utility to manage this process.

Enron recommended that processes and systems be reviewed by industry working groups.

EPCOR

EPCOR submitted that entrance or exit fees impacting customers switching between regulated and non-regulated gas supply constituted unnecessary barriers to competition, and would be inconsistent with the public policy initiatives to develop a fully competitive, unregulated retail gas supply. EPCOR noted that, if incumbent utilities were subject to the same risks as non-regulated suppliers and were allowed a return commensurate with the risks undertaken, the result would be the elimination of the need to introduce exit fees.

EPCOR also submitted that its proposal for a modification to the current GCRR/DGA mechanism, with more frequent true-ups of the DGA, when combined with an appropriate notice period for customers switching, would minimize the need for exit fees.

FGA

The FGA stated that, whatever alternative to the existing utility market is eventually approved, the process must be transparent and allow a ready transition from one class of service to another. It stated that moving to a monthly GCRR should effectively reduce the need for reliance upon cost true ups, notice provisions, and entrance and exit fees.

MI/UM

The MI suggested a combination of exit/entrance fees and more timely adjustments to the GCRRs as a means of mitigating potential stranded balances in the DGA.

4.8.2 Views of the Board

As noted in section 4.7.2, the Board is of the opinion that it is preferable to design rates such that entrance and exit fees are not required. The Board believes that this can be accomplished by reducing the DGA period and by discouraging gas price hedging. As noted throughout this Decision, the Board is of the view that the NGPPA provides sufficient price protection for customers.

As there is no need for entrance or exit fees, the Board is of the view that there is no need for alternative mechanisms to accomplish the same end. In keeping with this, the Board is of the view that exit notice provisions should be as short as can be facilitated administratively. The Board directs the utilities to file with the Board a proposed exit notice provision for their regulated gas rates that is as short as can be facilitated administratively, by February 1, 2002.

5 TREATMENT OF GAS ACQUISITION COSTS AND COMPANY OWNED PRODUCTION BENEFITS AND EXPENSES

5.1.1 Positions of Parties

AltaGas

In the view of AltaGas, the only service for which a good case could be made for unbundling was Gas Portfolio Costs. AltaGas stated that the ill fated MOU provided a guiding principle –

> Any costs currently in delivery rates which would be avoided if a utility ceased to supply sales gas to customers should be transferred to the GCRR/DGA.

ATCO Gas

ATCO Gas submitted that it had attempted to unbundle all costs associated with producing properties from its delivery service rates, and that other costs related to portfolio design and acquisition should be moved to the DGA.

AIPA/EUAA

AIPA/EUAA submitted that direct costs related to the commodity could be transferred from the delivery costs to the GCRR in a first phase, and the determination of further unbundling left to a second phase, after recommendations to the Board from a collaborative process.

AIPA/EUAA submitted that, directionally, the method of recovering gas portfolio costs should remain the same as under existing procedures, and forecast portfolio costs should be trued-up to actual costs on a monthly basis.

CCA

Noting that customers are naturally skeptical that unbundling results in no increases in costs, the CCA suggested that, to the degree that costs can be separately identified, the quantum can be assessed and set against the likely benefits for comparative purposes. However, the CCA submitted that before proceeding with unbundling, the benefits must be real and clearly identified.

In the CCA's view, another factor to be considered in the weighing of costs and benefits is the duplication of costs. The CCA expressed concern that since unbundling allows for duplication of gas supply service, there will be a resultant duplication of costs, which may not be in the public interest.

The CCA considered that the proposal for unbundling represents a fundamental change, inconsistent with the regulated monopoly supply of an essential commodity. The CCA submitted that, although there are limitations with a monopoly supply, there are also advantages, the most obvious of which is the capture of economies of scale, where the advantages of wholesale aggregation of supply are passed on to customers.

The concern identified by the CCA is that, while this aggregation is accomplished with no "mark-up" to the commodity price, the unbundling proposals will result in new entrants to the marketplace seeking to perform the same or similar services as the GCRR provider, with the addition of a "mark-up" on price. The CCA submitted that unbundling would therefore result in a substitution or duplication of service and product, with the addition of a profit element that will be passed on to consumers.

The CCA considered that incorporation of unbundled costs into the GCRR would be an ideal topic for a further consultative process.

Calgary

Calgary argued that all direct and indirect capital and operating costs associated with the acquisition, management, and cost recovery of utility gas supply should be recovered through the GCRR. Calgary suggested including in the GCRR:

- gas management expenses that are currently recovered through distribution rates;
- costs associated with company-owned production including capital costs; and
- costs associated with billing gas and uncollectible costs.

In reply argument, Calgary countered the CCA concern over the addition of a "markup" on price. Calgary argued that the price a third party marketer offers for a service must be competitive with utility service.

Edmonton

Edmonton supported the transfer of direct gas purchase costs to the GCRR by the end of 2001, with matching interim unbundled rates. Edmonton supported the use of a consultative process to begin in mid-2001, and to be completed by November 2001. It suggested that this initial phase would deal only with direct costs, and a second phase would deal with indirect costs. It also stated its view that stranded costs could be minimized by phasing in the transition to unbundled rates.

Edmonton noted the evidence provided by EPCOR, Enron, and others that the development of the retail market was hindered by the presence of company-owned production in the AGN GCRR. Edmonton recommended that company-owned production be moved to a rate rider on the Cost of Service as proposed by the North Core so as not to reduce the attractiveness of competitive offerings from retailers.

Edmonton recommended that gas purchase costs be moved to the GCRR by the end of 2001.

ENMAX

ENMAX stated that it was appropriate to include the following costs in the utility's gas cost recovery rate, to the extent commodity costs remain regulated:

- commodity purchase, procurement and planning;
- gas supply contract management;

- working capital associated with commodity purchase, payroll, materials and supplies for the merchant function;
- payroll taxes and other related taxes associated with any of these activities;
- accounting costs associated with the purchase and payment of invoices for commodity;
- administrative and general expenses associated with the above activities;
- general plant costs associated with the above activities; and
- uncollectible accounts expense associated with commodity purchases.

ENMAX stated that all costs —both direct and indirect— associated with gas acquisition or other activities, might appropriately be unbundled. ENMAX believed that the Board could accomplish this by removing all gas commodity and delivery services upstream of the city gate from the utility's distribution rates.

Enron

Enron agreed with the methodology suggested by EPCOR in the Unbundling Proceeding The methodology proposed to include some unbundled retail costs in the GCRR to allow customers to more easily compare the "all in" utility cost of the supply and retail services that can be provided by a retailer. It argued this would allow customers to more easily compare retailer cost versus the utility cost of providing such services.

Enron submitted that the evidence was unequivocal in the proceedings that the GCRR does not include all gas supply related costs, and there was broad consensus that the GCRR should include all costs that would disappear if ATCO Gas discontinued providing a regulated supply option.

Enron, while agreeing in principle with the consensus, suggested a combination of cost transfers and revised rate treatment to deal with the problem of direct purchase customers paying twice for utility facilities they neither use nor benefit from.

EPCOR

EPCOR argued that for all functions associated with the acquisition of gas supply, any cost of service costs that would disappear if the DGA disappeared should be moved to the DGA. EPCOR submitted that all costs associated with the utilities' gas supply portfolio should be moved to the DGA, and recovered through the GCRR, with one exception.

It argued that the appropriate treatment of the production and gathering function would be to value the company-owned production in the DGA at market prices, but provide an offsetting credit rider on the delivery charge. It argued that this would leave both consumers and the utility revenue neutral, while properly reflecting the value of the company owned production in the GCRR.

FGA

The FGA noted that the collaborative process undertaken with CWNG arising from Decision 2000-16 had identified certain non-contentious issues and approximate costs that could be moved from the cost of service to the DGA. It further noted that the Unbundling Technical Meeting addressed those issues and appeared to provide a consensus on making the changes as identified. It noted that the attempt to have all parties endorse a MOU based on a process was not successful. However, it argued that that did not mean the process had failed.

The FGA stated that it had informal discussions with the NCC, ATCO Gas, and retailers on developing a recommendation for revising the GCRR for AGN by moving direct costs related to gas supply from the cost of service to the DGA with an effective date of November 1, 2001. It also stated that the NGCI had participated in similar informal discussions with AltaGas and other interested parties involved in that utility's GRA for 2000, 2001, and 2002. It stated that this group had also expressed a desire to effect the transition of direct costs associated with gas supply to the DGA, with an effective date of November 1, 2001.

The FGA supported transferring direct and noncontentious costs of gas supply to the GCRR. It supported the NCC allocation of production and gathering costs to a credit rider.

MI/UM

The MI/UM considered, with some qualifications, that the following items should be included in the DGA:

- gas purchase costs;
- company owned production royalty costs;
- cost of gas stored;
- imbalance costs;
- contract storage costs;
- transportation costs upstream of the utilities' pipeline systems;
- DGA portfolio management and administration costs;
- production and gathering costs;
- transportation receipt costs;
- DGA gas supply-related bad debts; and
- DGA balance carrying costs.

The MI further considered that the direct costs related to gas management and administration could be included at this time, but any costs related to the overall management of system gas should remain in the cost of service; while specific issues such as indirect cost allocations, and the calculation of bad debts and carrying costs would require further review by a working group, and could be moved to the DGA at a later date.

NCC

In its submission on the Disposition of Production and Gathering Assets, the NCC acknowledged that the current regulatory treatment of the AGN production and gathering assets resulted in the AGN GCRR being significantly below the market price for gas in Alberta. It stated that it was difficult for natural gas retailers to provide a competitive product offering to AGN customers.

The NCC proposed a credit rider to apply to all Core customers of AGN to capture the advantages or disadvantages of company owned production for all customers. The NCC COP

Rider was proposed to be equal to the avoided cost of gas (the market cost for an equivalent volume of gas to company owned production) divided by the total of gas purchases and company owned production. The NCC proposed that this rider be applied to the charges for every Core customer.

The NCC argued that direct sales customers would benefit from this rider by receiving appropriate credit for the costs of production and gathering assets included in base rates. It noted that customers leaving utility supply service would continue to receive the benefits of those assets.

The NCC stated that, as the NCC COP Rider would be calculated on a forecast basis, it would need to be reconciled similarly to the GCRR/DGA procedures. It also argued that the rider should only be eligible to customers paying the production and gathering costs. It stated these would be Rates 1,3,4,5,6,7, University of Alberta, 11, and 15. It also advocated that Rate 13 and 13B customers should be allocated a share of the production and gathering costs, but should also receive the Rider. It argued that Rates 4 and 6 should be closed to new customers, so that large transportation service customers do not return to reap a windfall gain from the rider proposal.

PICA

PICA stated that unbundling of gas supply costs must result in a level playing field between utility supply and competitive supply. PICA submitted that two criteria might be used to assess this principle:

- First, all gas supply related costs normally incurred by a competitive supplier should be included in the Gas Cost Recovery Rate (GCRR).
- Second, all costs that would disappear if the Gas utility were no longer in the retail gas supply business ought to be moved from cost of service and base rates to the GCRR.

PICA noted that there were a number of gas supply related cost categories included in the delivery (base) rates. These comprised gas management and administration costs, gas procurement and contract administration, asset related costs of production and gathering facilities, bad debt and penalty revenue related to gas supply, and working capital related to gas supply. PICA believed that these could be included in the GCRR.

PICA proposed the cost of production and gathering assets could be put into a separate cost centre, and that company owned production could be treated the same or similarly to the NCC's COP credit rider proposal for AGN.

5.1.2 Views of the Board

The issue as to the allocation of costs between the utilities' cost of service charges and GCRR was the original impetus for the Board to review gas rate unbundling. This issue was first addressed in Decision 2000-16 for CWNG. The Board encouraged interested parties to collaboratively resolve the matter. A collaborative process was undertaken between CWNG customers and the utility. A further attempt to arrive at a collaborative decision on this issue was made at the Technical Meeting held before this proceeding. Unfortunately, parties could not agree on specific elements of these proposals.

The Board is of the view that the inclusion of gas management costs in the general cost of service payable by all customers is a serious inequity to those customers taking direct gas service. These customers still receive delivery service by the utility. In the current circumstance, they are subsidizing the gas procurement costs of other customers.

The Board has reviewed the positions of parties on this issue. The Board is of the view that, as an interim measure, the following direct costs should be transferred from utility cost of service to the GCRR through interim rates:

- gas purchase costs;
- imbalance costs net of imbalance revenue;
- transportation costs upstream of the utilities' pipeline systems;
- GCRR portfolio management and administration costs;
- transportation receipt costs;
- GCRR gas supply-related bad debts; and
- DGA balance carrying costs.

Further, AGS and AltaGas are directed to undertake an examination of all other costs, related to the gas acquisition and management function, whether direct or indirect, and provide a report to the Board on these costs within 90 days of the date on which the Board issues their forthcoming approved Phase I revenue requirements. AGN is directed to report to the Board within 30 days of release of this Decision as to how it would propose to undertake a similar examination of gas acquisition and management costs, or provide an acceptable surrogate to such an examination.

The Board has reviewed the proposal by the NCC to allocate the benefits of the legacy company owned production to all customers, based on a distribution credit rider. The Board finds that the NCC COP Rider proposal meets the criterion of fairly allocating the benefits of these assets. Prior to the transition towards a competitive market, all customers shared in the cost of these assets; therefore, the Board agrees that all customers should benefit from their ongoing value.

The Board directs AGN and AGS to apply the NCC COP Rider methodology for the treatment of company owned production costs for inclusion in interim rates.

As noted in section 4.2.2 of this Decision, the Board is of the view that company owned storage assets used for gas price stabilization are of the same nature as company owned production assets, as they are legacy assets originally provided for the benefit of all customers. As noted in section 4.2.2, the Board directs that storage costs and benefits be treated in the same manner as the NCC COP Rider for inclusion in interim rates.

The Board directs AGS and AltaGas to file for interim rates by February 1, 2002, based on the transfer of the direct gas supply costs noted above, as well as the Board's approved treatment for company owned production facilities and storage facilities used for gas price management, using the most recent approved revenue requirement. These interim rates are to come into effect April

1, 2002, coincident with the change to monthly GCRRs. The Board directs AGN to provide a report to the Board, within 30 days of the release of this Decision, as to how it would propose to file for interim rates on a similar basis.

6 UTILITY RATE AND FUNCTION UNBUNDLING

Utility rate unbundling is the separation of the costs of the various functions undertaken by the utility into separate rates. Utility function unbundling is the separation of utility functions into separate service options so that those functions can be undertaken by parties other than the utility.

6.1 Appropriateness of Functional Unbundling

6.1.1 Positions of Parties

AltaGas

AltaGas believed it would be helpful to future discussions if the Board provided a definition of what it meant by “unbundling” in its decision. To assist, AltaGas offered the following definition:

> Unbundling is the process of identifying each service currently provided by a utility that could reasonably be provided by someone else, determining the cost of providing that service, establishing a corresponding tariff for the service, and enabling customers to purchase the service from the utility at that tariff or from an alternate supplier.

ATCO Gas

ATCO Gas submitted that there are two distinct tests that would identify costs that should be unbundled:

- The first test is that only avoidable costs should be moved to the DGA.
- The second test is to not move costs that are incurred to ensure the pipes company system works properly (e.g. metering, transmission, load settlement and customer enrolment.).

It argued that the initial unbundling should address those functions that were non-controversial, and could be addressed quickly.

ACC

The ACC stated that a function should be unbundled if sufficient competition exists for that service. It argued that establishing a minimum number of market participants and minimum level of market penetration would ensure that a competitive market has developed, and that there is competition.

CCA

The CCA referred to its evidence presented in the Unbundling Proceeding, which indicated that the appropriate test for function unbundling should include the key "acid test" as to whether or not there is a reasonable prospect that consumers will be made better off by unbundling.

The CCA took issue with the assertions of EPCOR, ENMAX, and Enron that a cost benefit analysis is unnecessary as a proper test for unbundling. The CCA did not agree with the assertion that all monopoly services properly belong within the scope of regulated utility service, and non-monopoly services should be unbundled. The CCA argued that the suggestion, that the only test that need apply for unbundling is whether or not the function is a natural monopoly, was an over simplification of the issue. The CCA pointed out that all other jurisdictions that have embarked on unbundling have made it apparent that some form of judgement must be applied, rather than basing conclusions on a simple mechanical assessment of monopoly versus non-monopoly service.

Calgary

Calgary set forth its criteria for testing the unbundling of various functions as follows: "if the utility ceases to provide the service, all embedded cost associated with that service will also cease to exist.". It elaborated that by "all embedded cost", it intended all direct and indirect costs associated with, or embedded in, the rates for providing any particular service. As an example, it stated that the criteria for transferring costs from current functions embedded in the delivery rates to the GCRR should be based upon the principle that if ATCO Gas was removed from the gas supply business, the costs would be eliminated and no longer incurred.

Calgary proposed that those functions that could be unbundled should be unbundled at the fundamental cost level included in current rates. It proposed that all direct and indirect costs included in the delivery service charge should be unbundled.

It argued that at this time parties enjoyed a prime opportunity to unbundle the gas market. It noted that final, cost-based rates were implemented on the AGS system in September 2000, based on a fully allocated cost study approved by the Board.

Calgary countered the MI position that indirect costs should not be included in the unbundled charges. It argued that this was not supported by the existing facts and circumstances underpinning the existing rates. It noted that the current AGS rates contained Board approved and identifiable allocations of direct and indirect cost for the primary functions. Calgary argued that failure to recognize direct and indirect costs would lead to two fundamental errors in the process. First, it stated, windfall profits would accrue to AGS if indirect costs were not recognized. Second, it stated, rates for standalone services would be below cost, thus impeding the development of the competitive market. This in turn, according to Calgary, would result in distribution delivery rates in excess of the actual cost of providing service.

Calgary stated that it fully supported the unbundling initiative instituted by the Board and various parties. It supported the implementation of the working group process, and recommended that most issues addressed should be directed to the working groups with Board observation. Calgary also advocated for a trained, neutral facilitator to be utilized in the workshop process.

ENMAX

ENMAX stated it supported the broadest possible unbundling of rates.

Enron

Enron defined unbundling as "the separation of the costs associated with each utility function into distinct, separately priced services."

Enron submitted that conducting a cost/benefit analysis to determine which services to unbundle was not practical, as it was not possible to predict what new and innovative products and services will be offered in an unbundled world, the full extent of the benefits that will be derived by consumers, or what utility costs would be with or without unbundling. Enron argued that the evidence indicated that the introduction of competition, in relation to those services for which competition is practical, provides benefits to all classes of consumers, and has resulted in lower prices and more choices in other jurisdictions that have proceeded with unbundling.

Enron also argued that, without unbundling, retail competition would be impeded and the opportunity for future benefits will be lost.

EPCOR

EPCOR recommended that, on an interim basis, only identifiable direct costs from existing cost of service studies, and which are reflected in current rates, should be unbundled.

On a final basis, EPCOR recommended that unbundled rates be designed in each utility's next GRA or negotiation process. It recommended that these final unbundled rates should include overhead, indirect, and administrative and general costs, to the extent that it can be demonstrated that these costs can be removed from the remaining "pipes" utility.

EPCOR submitted that practicality needed to be observed throughout the unbundling process. It noted for example that it would be of no use to unbundle portions of staff positions when the remaining distribution-only organization would still require the position.

FGA

The FGA noted that there was some confusion with respect to many of the issues within the proceeding. It stated that insufficient detail had been provided to allow confidence in addressing many of the prospective functions that could be subject to the competitive market.

The FGA stated that it was not necessary to make all changes at once, and proposed that gradualism is a desirable rate making principle. It suggested that for issues that are uncertain or contentious, allowing sufficient time for resolution of those issues could provide a better and more substantial product than accepting a leap of faith. It argued that where the consumer has to accept the costs and consequences of someone else's desire to leap, the latter party should have to prove the case to the consumers' satisfaction.

MI/UM

The MI/UM submitted that the Board should provide objectives and principles to assist the working group, through a collaborative process, in achieving consensus with respect to as many issues as possible.

The MI/UM submitted that indirect costs should not be included in the unbundled charges until it can be demonstrated with some certainty that those costs will not simply be reallocated to other regulated functions.

PICA

PICA stated there were three criteria for unbundling services costs:

- all services and associated costs normally incurred by a competitive supplier should be included in the utility's gas retailing rates;
- all costs that would disappear if the gas utility was no longer in the retail gas supply business, ought to be moved from base rates to the utility's gas retailing rates; and
- new functions such as load settlement, and associated costs that result from unbundling, should be allocated fairly between the utility's wholesale and retail functions.

6.1.2 Views of the Board

The Board notes the two distinct concepts of unbundling used by parties to this proceeding:

- rate unbundling, in which the costs of utility service are separated by function; and
- function unbundling, in which the functions of the utility may be provided by competitive entities.

The Board is of the view that rate unbundling presents no undue difficulties; in and of itself rate unbundling is largely an accounting exercise, with some operational considerations included. The question arising for rate unbundling is the basis on which costs should be unbundled. The Board notes the position of Calgary that rate unbundling should be undertaken on the basis of the last approved rates and cost of service studies available for the utilities. However, the Board is concerned that for those utility services that are functionally unbundled, the use of out of date cost information would potentially distort the true economics associated with providing those services.

The Board considers that the information used to determine unbundled utility rates should be as accurate as possible at the outset of this process. The Board notes that AGS will have a Phase I GRA decision available shortly after the release of this Decision. The Board also notes that AltaGas is expected to apply for approval of a Phase I GRA, which is currently being dealt with by negotiations with its customers. AGN continues to operate under a negotiated settlement originally reached in 1998, and in effect until 2003.

The Board directs AGS and AltaGas to file with the Board an unbundling allocation study within 90 days of the date on which the Board issues its forthcoming approved Phase I revenue requirements. These studies are to provide:

- an allocation of costs between base rates and GCRRs based on the directions made in this Decision;
- an allocation of all applicable direct costs, indirect costs, and overheads for each of the following functions:
  - transmission
  - storage services
  - meters
  - billing
  - customer information systems
  - call centres
  - credit and collections
  - customer enrollment
  - load settlement
  - load balancing
  - marketing and customer information
- an examination of the operations and requirements of each function, describing how these may change during a transition to a fully competitive market;
- an assessment of the potential for stranded costs for each function;
- an assessment of the effect of unbundling on indirect costs and overheads by function; and
- proposed rates reflecting the views of the Board in this Decision.

These studies will provide the basis for further proceedings to finalize rates for unbundled services.

The Board directs that AGN is to report to the Board within 30 days of release of this Decision as to how it would propose to undertake a similar unbundling allocation study, or provide an acceptable surrogate to such a study.

In the following section 6.2, the Board will first consider a test for determining how to gauge the advantages of functional unbundling, and then in subsequent sections the Board will use that test to consider whether or not to unbundle individual functions.

6.2 Appropriate Level of Function Unbundling

6.2.1 Positions of Parties

AltaGas

AltaGas did not believe it would be productive at this time to try to establish appropriate levels of function unbundling in a range of general categories. In AltaGas's submission, it would be more productive to get into the details on a company specific basis, and develop proposals through the collaborative process.

AltaGas suggested, however, that the Board may consider establishing a set of questions and a process for answering them. It stated that to apply a public interest test, it would be helpful if system specific work groups could answer following questions:

- What components of a function could be unbundled?
- Which of these components should be unbundled?
- How would the unbundled component be priced?
- How will the unbundling be implemented?

AltaGas believed this approach was more likely to produce workable results than trying to develop unbundling criteria for the listed functions based on the information available from these proceedings.

ATCO Gas

ATCO Gas considered that the electric model should be followed to the greatest extent possible in gas market unbundling. It argued that the functions of transmission, meter reading, load settlement, and customer enrolment were part of the delivery service and should remain services that it provides.

ACC

The ACC submitted that all functions where sufficient competition can be shown to exist should be unbundled.

CCA

The CCA submitted that all of the functions listed should be subject to a cost benefit analysis.

The CCA expressed concern with the issue of transmission bypass, and submitted that the Board should consider the policy implications in a specific hearing, or in the collaborative process following the Board's Decision.

ENMAX

ENMAX advocated complete unbundling for each service where separate pricing permitted competition, provided there were price signals to promote efficient use and eliminate the potential for cross subsidy. ENMAX stated that the cost of competitive services should be identified so that retailers know what price they must beat in order to be competitive.

ENMAX submitted that it was appropriate to divide ancillary and customer services into two broad categories. The first category represented services integral to safe and reliable delivery service. For such services, all costs should remain with the utility and be charged in the delivery service rate where appropriate, or charged separately where economic efficiency dictated separate price signals. The second category represented services that were currently, or might be, competitively provided, if unbundled. For those services, it advocated that all costs should be removed from delivery rates and unbundled. It suggested such costs should include corporate services, administration, and other allocated overhead costs.

Enron

Enron submitted that most utility functions can and should be unbundled and provided to consumers by retailers in the competitive market, with the exception of the operation of the distribution system and related functions needed to maintain system integrity.

EPCOR

EPCOR argued that those functions associated with the provision of retail service could be provided competitively to a large extent. EPCOR suggested that the only test that need apply is whether or not the function is a natural monopoly service. If it is a natural monopoly, EPCOR stated that the function properly belonged within the scope of regulated utility services.

PICA

PICA stated that there are a number of “other” services performed by the regulated utility such as metering, meter reading, load balancing, billing, credit and collections and customer accounting. In PICA’s view the success of retail competition in gas supply might depend on efficiencies gained in those service categories and therefore, the unbundling of relevant metering, billing and customer accounting costs in utility rates was the next priority following unbundling of gas supply related costs. PICA also believed that load settlement services would need to be performed by the utility.

PICA noted that in the Alberta electric industry, the distribution wire service provider is responsible for performing metering, meter reading, wholesale billing, and load settlement functions. The retailer supplying the RRO assumes cost responsibility for retail billing and call centres.

PICA believed that if a similar approach to that of the Alberta electric industry was followed for gas unbundling, wholesale billing costs for transmission and distribution pipeline service, as well as load settlement, would be applicable to all of the utility’s customers and, therefore, considered wholesale costs. However, costs for retail billing and call center services would be unbundled, and would apply only to the utility’s retail service customers.

6.2.2 Views of the Board

The Board notes the evidence of EPCOR that functions associated with the provision of retail service could be largely available on the competitive market. The Board will refer to these as “customer care functions”, comprised of: billing, customer information systems, call centres, and credit and collections. The notion that these services can be provided on a competitive basis has important implications for the role of the Board and utilities.

The Board’s role is to protect consumers from the monopoly powers of utilities, while treating utilities fairly. The Board has traditionally not exercised jurisdiction over activities deemed to be “non-basic”, or those services that are not monopolistic in nature. Prior to the development of a fully competitive market, the Board will have a role in regulating the relationship between utilities and retailers to ensure that the development of a competitive market is not impeded. In

Decision 2000-10, (the Apollo decision),[25] the Board determined that where a competitive market existed for a service, it had the jurisdiction to regulate the relationship between a utility and a retailer only to the extent that the ratepayers of the utility might be affected. As in the Apollo decision, the Board considers that once customer care functions are functionally unbundled, and a fully competitive market exists for those services, the Board will have little or no role in determining if, or at what price, the utility will provide those services on behalf of competitive retailers, except to the extent that ratepayers of the utility may be negatively impacted.

The Board has examined the proposals put forward by parties suggesting a test for the determination of whether or not a utility function should be unbundled. The Board notes the submissions of some parties that such testing is not possible. The Board is of the view that, at best, such testing would be very difficult.

Ideally, the Board would prefer to be presented with a business case or cost benefit study that would assess the economics of maintaining functions within the utility, or unbundling them. However, the Board has not found evidence that such a quantitative test could be reasonably created. Lacking a quantitative test, the Board has opted to look to a qualitative test that will assess the appropriateness of unbundling each function based on:

- the function's expected ability to assist in the development of a competitive retail gas market; and
- the function's potential for creating large stranded costs or other difficulties.

In sections 6.3 to 6.13, the Board will apply the qualitative tests to each specific gas utility function.

6.3 Transmission

The transmission function involves the transport of bulk gas over a distance. Usually, the gas pipelines for transmission operate at 1000 kpa or greater.

6.3.1 Positions of Parties

ATCO Gas

ATCO Gas argued that the Alberta natural gas transmission system does not represent a competitive marketplace. It noted that the marketplace is regulated by different regulators, and that the marketplace is dominated by the TransCanada Pipelines Limited Alberta system (Nova Gas Transmission Ltd., or NGTL). It noted that the NGTL toll structure has been identified as problematic for fostering pipeline market competition in the province.

ATCO Gas noted that Calgary had asked the Board to unbundle transmission and expose AGPL to bypass. It noted that most parties recognized that such action was premature. ATCO Gas submitted that, as there is neither duplication of transmission costs between it and retailers, nor potential for cost savings with the requirement that stranded costs be recovered from customers,

[25] Apollo Gas Inc. Complaint against Northwestern Utilities Limited and ATCO Gas and Pipelines Ltd. operating as ATCO Gas with respect to Termination of Billing Services.

there was no benefit to unbundling transmission. ATCO Gas also submitted that, while there are important market problems with gas transmission in the province, unbundling of transmission would be premature, and should not be approved by the Board.

ATCO Gas noted that Calgary had suggested that disallowances should be assessed against AGPL. It argued that Calgary's submission was unclear on this important issue, however, it was clear that there were problems with the competitive market for gas transmission in Alberta.

In reply argument, ATCO Gas countered the Calgary proposal to unbundle transmission costs. It reiterated the problems it saw with the Alberta gas transmission market. In particular, it noted that NGTL Alberta facilities do not include a delivery charge for intra-Alberta service.
It recommended that the Board may have to convene a generic hearing on this issue, but noted that federally regulated pipelines were also part of the Alberta gas transmission market.

ACC

The ACC considered that transmission should be unbundled along with all other services and that any customer served off the transmission system should only pay the transmission cost or transmission rate, and not pay for any other services, such as distribution related costs. The ACC considered that costs should be unbundled and allocated to the appropriate service, allowing the customer to utilize other pipelines in competition with this pipeline. The ACC pointed out that an appropriate number of competitive pipelines may not exist in all geographic areas of the province, which meant that the issue surrounding pipeline competition may have to addressed on an area-specific basis to ensure that stranded costs for customers left on a particular transmission pipeline are minimized.

The ACC recommended that working groups study and make recommendations on the feasibility and implementation of a level of transmission unbundling that would allow for pipeline competition. The ACC set out specific criteria for consideration by the working groups.

AIPA/EUAA

In AIPA/EUAA's view, the transmission function should remain bundled with the delivery function at the present time, so that transmission bypass was not permitted. AIPA/EUAA submitted that bypass would only serve to increase costs to remaining customers, and should be an issue for consideration in a collaborative process.

CCA

The CCA submitted that, allowing transmission bypass would result in the end of postage stamp rates in Alberta, a situation that would increase rural rates and reduce urban rates. Given that this represented a major policy change, the CCA suggested that the policy change should be considered in a specific hearing on this issue, or in a collaborative process following the Board's decision.

Calgary

Calgary countered the AIPA/EUAA position that the transmission function should remain bundled with the delivery function. It argued that this would deny consumers the advantages of a competitive market place for transmission services. It noted that the industrial and producer customers enjoy the advantages of this competitive market place.

Calgary stated that its position on unbundling the transmission function was designed to enhance of a competitive market place. It noted that currently AGPL provides economic responses to its industrial/producer customers as a result of competitive conditions in the marketplace. Calgary argued that AGS should be afforded the same competitive opportunities that could be achieved through unbundling and elimination of long-term service agreements for exclusive service with its affiliate.

Calgary argued that with an arms length agreement between AGS and AGPL South, the emerging market place for alternative transmission service would have a benchmark price and the opportunity to develop. It argued that attempts to protect affiliate transactions from the potential benefits of the competitive market place should be rejected.

Calgary countered the MI argument, stating that it sought to combine the issues of unbundling and stranded costs. Calgary argued that stranded costs were not a direct result of unbundling. Calgary stated that the MI did not appear to provide realistic analysis as to whether or not there was a threat from stranded costs arising from unbundling. Calgary argued that it was not necessarily true that there would be stranded costs due to unbundling, stating that those costs were an issue to be addressed if and when they occur.

ENMAX

ENMAX stated that to the extent that transmission service provided for the delivery of the gas commodity to the city gate, it was necessary to unbundle such costs and where transmission facilities provided distribution service, it was not necessary to unbundle those cost from delivery service rates. ENMAX believed that failure to unbundle transmission service prevented retailers from aggregating customers and creating savings on the transmission function for their customers.

Enron

Enron stated that transmission could be unbundled on a case-by-case basis, to the extent that stranded costs could be reasonably mitigated, with details regarding how to review such opportunities being determined through a collaborative process

EPCOR

EPCOR stated that the unbundling of transmission was not critical in the development of the functioning retail market in Alberta at this time, and did not recommend that transmission be unbundled on an interim basis.

FGA

The FGA noted that, since most gas acquired for sale to customers in Alberta is based on the AECO C NIT, which includes costs of upstream intra-Alberta transportation on NGTL, upstream transportation is now fully unbundled. It stated that where the distribution utility has transmission plant in place, that plant should constitute the most effective and reliable source of supply.

The FGA argued that where bypass alternatives exist for some end-users, customers who were not able to access service from the bypass alternatives may then be required to subsidize those customers who were able to access the bypass alternative.

MI/UM

The MI/UM considered that although transmission is a candidate for unbundling, it should be subject to determining and addressing the potential stranded costs that may occur. The MI/UM submitted that all existing distribution customers should pay stranded transmission costs, noting, however, that it was clearly a function requiring detailed review by the working groups before unbundling proceeds.

PICA

In general, PICA considered retail transmission service to be a monopoly service and, therefore, unbundling of this function was not required in the foreseeable future.

6.3.2 Views of the Board

The Board notes that the transmission function has a large potential for stranded costs. The issue of transmission bypass is familiar to the Board. The costs involved are almost always substantial. Further, the Board notes the evidence of EPCOR that unbundling the transmission function is not necessary for advancement of the retail gas market at this time. As EPCOR was the only competitive gas supplier in Alberta to the residential market at the time of this proceeding, the Board finds its evidence persuasive in this matter.

As the transmission function fails both of the Board's qualitative tests for function unbundling, the Board directs that transmission costs remain as part of bundled delivery rates.

6.4 Storage Service

Storage of gas can be used both operationally, and as a physical gas price hedge. For AGN, the Salt Cavern storage facility is used primarily as a replacement for additional transmission capacity. For AGS, the Carbon storage facility has been used primarily as a means to purchase and store low cost gas.

6.4.1 Positions of Parties

ATCO Gas

ATCO Gas submitted that storage related costs should be unbundled. It stated that it intended to file a proposal to remove the Carbon storage facility from regulation. It stated that all costs associated with Carbon would be removed from the distribution rates by the end of 2001.

ACC

The ACC considered that storage costs should be separated out from transmission and distribution rates, and allocated based on cost causation.

AIPA/EUAA

AIPA/EUAA considered that, since storage service was currently available as a competitive service in Alberta, the service could be unbundled.

Calgary

Calgary proposed that Carbon storage should be unbundled by service function, under the multiple service functions it provided. Calgary noted that previous Decisions of the Board had determined that the Carbon facility was a rate base asset and should benefit ratepayers. It argued that Carbon should be unbundled with a full revenue credit to ratepayers.

Calgary argued that contract storage should also be unbundled. It stated that contract storage would need to be examined as to its purpose in order to evaluate the various services provided. It argued that the various storage services should be unbundled as stand-alone service offerings, and recognition should be given for the benefits to ratepayers.

Calgary stated that the MI had mischaracterized the Calgary position on storage. Calgary confirmed its recommendation that Carbon storage should be unbundled by service offering. Calgary did not support moving contract storage to the GCRR.

Calgary argued that, in reviewing the ATCO Gas submission on storage, the Board should keep in mind that current AGS rates reflect the net cost of the Carbon facilities, including revenue imputed by the Board in Decisions 2000-9[26] and 2000-16. Calgary argued that the proposal to remove Carbon from regulated service was not part and parcel of unbundling. Calgary stated that the issue of the requirement for the Carbon facilities was far from being resolved. It argued that Carbon costs should be unbundled from delivery rates, and the service provided from the Carbon facility should be priced on a stand-alone basis.

ENMAX

It was ENMAX's view that where storage service provides for the management of the delivery system, those services need not be unbundled. ENMAX believed that all other storage services were competitive, and it was appropriate to unbundle those services.

Enron

Enron was concerned that utility ownership of storage and salt caverns distorted the gas supply costs as compared to market prices. Enron recommended that, to the extent storage is used to provide services such as balancing, an appropriate portion of the storage costs should be allocated to such services.

[26] Canadian Western Natural Gas Company Ltd., 1997 Return on Common Equity and Capital Structure, and 1998 GRA – Phase I, March 2, 2000.

EPCOR

EPCOR recommended that the cost of storage be removed from the delivery charge, placed in the DGA, and recovered through the GCRR. EPCOR suggested that on an interim basis the Board direct storage to be unbundled using its proposed methodology. EPCOR noted, from Exhibit 23 in the Unbundling Proceeding, that the impact of unbundling storage using its methodology would be modest. EPCOR stated that the precise treatment of unbundled storage costs on a final basis could be left to the deliberations of the collaborative process.

FGA

The FGA noted that the costs of storage were intended to provide price stabilization, rather than security of supply. It stated that it would be appropriate to reflect the costs of storage service through the GCRR, since only sales customers require and are intended to benefit from that service. It recommended that the costs for storage service for both ATCO Gas utilities could be included in the GCRR for the forthcoming winter gas supply season.

It noted that there could be some concern with the functioning costs associated with the ATCO Gas North salt cavern storage facility. It noted that this facility provides hydraulic or operational benefits to the transmission system. It also noted that the structuring of AGPL into Gas and Pipelines divisions raised the question as to who should properly be assigned responsibility, and pay for costs, of gas purchased and stored in the caverns to provide peaking operation for the transmission system.

MI/UM

The MI/UM submitted that the cost of company-owned storage should be allocated between the cost of service and the DGA based on the respective value of load balancing and physical hedging, to create a level playing field between sales and direct purchase customers.

PICA

PICA believed storage services could be contracted from the competitive marketplace. PICA stated that, although ATCO Gas's evidence in regard to the use of storage was yet to be tested, it was arguable that company owned storage could be unbundled and treated as a separate cost center.

PICA stated that if Carbon storage owned by AGS was no longer needed for its historical functions of load balancing or mitigating gas supply costs, it should be unbundled and treated as a separate cost center. PICA proposed that storage facility related costs and revenues could be accumulated in this cost center, and the net benefit of operating the storage facility in a commercial manner credited to base distribution rates.

6.4.2 Views of the Board

The Board has addressed the allocation of the costs and benefits of storage related to gas price management in section 4.3 of this Decision. The Board notes that storage of this type would include the Carbon storage facility for AGS and contracted storage. The Board directed that costs and benefits of storage used for that purpose should be allocated to rates on the same basis as that proposed for company owned production by the NCC. The Board is of the view that this will address the economic bias against competitive gas sales arising from the inclusion of storage related gas management costs in base rates.

With regards to other storage facilities, the Board notes that primary use of the Salt Cavern storage facility for AGN is as a replacement for transmission capacity. As noted in section 6.3.2, bundled transmission service is not seen as an impediment to the development of the retail gas market at this time. Further, storage facilities, being large capital assets, have a potential for creating large stranded costs. Accordingly, the unbundling of storage facilities fails both of the Board's qualitative tests. The Board directs that storage expenses not related to gas price management remain as part of the bundled gas delivery rates.

6.5 Meters

The gas metering function is made up of three components: gas meter purchasing and ownership, meter maintenance, and meter reading.

6.5.1 Positions of Parties

ATCO Gas

ATCO Gas submitted that the meters function should not be unbundled from the distribution service as it:

- was necessary to ensure that the distribution system is operating efficiently.
- needed to be performed by an independent party to ensure customers are being treated in the manner that they believe they should be treated, and
- should mirror the electric model as much as possible, wherein the meters function is provided by the "wires" company.

ATCO Gas also submitted that ownership of meters by retailers would inhibit the choice available to consumers, and that it would be inefficient to have multiple providers of this function.

AIPA/EUAA

Noting that efficiency considerations suggested that the metering function benefits from economies of scale, AIPA/EUAA considered that meter service and related services should remain bundled at the present time. Other considerations to be taken into account, in AIPA/EUAA's view, included safety and system imbalances, where improper readings may move cost responsibility from the pipes company to other customers.

Calgary

Calgary noted that there was broad consensus among parties that during the transition period to full unbundling, meters should remain a utility asset. It argued that meter ownership could be resolved during the development of the competitive market.

With respect to meter reading, Calgary noted that all parties, except ATCO Gas, supported the unbundling of meter reading costs. It argued that meter reading was an area where competition should be allowed to develop. It stated that the unbundling of meter reading would provide the opportunity for alternate service providers to enter this area of the market, and provide the opportunity for competitive pricing for this service.

ENMAX

ENMAX believed that either the utility or the customer could own the meter. It argued that meter ownership, as proposed by Enron, created a barrier to entry by the customers' retailer through the cost of meter amortization and removal.

ENMAX argued that the Board must recognize that metering technology was costly, and imposed system safety related risks associated with the installation of a new meter. It recommended that where a retailer required new technology to support innovative products and services, customers should own the meter, selecting from a menu of utility approved products.

Enron

Enron submitted that metering services could be provided by the market today and should be unbundled. Enron argued that retailers could provide metering services for customers. Enron argued that unbundling of metering was necessary to send price signals to the market to facilitate this future market development. In addition, retailers serving larger customers needed specific metering information available from newer, more advanced meters in order to effectively manage a customers' energy use.

EPCOR

EPCOR recommended the unbundling of the meter reading function from the delivery charge. EPCOR did not recommend unbundling of meter ownership and maintenance at this time. However, it noted that ATCO Gas had outsourced meter reading in certain areas, and had conceded that it could be appropriate for an independent party to own, maintain, and read meters.

EPCOR recommended that the costs associated with meter reading be determined on a stand-alone basis, and grouped with the GCRR for display as a "supply" or "retail" charge on customers' bills.

FGA

The FGA stated that ownership of meters was not an appropriate function to be considered for unbundled rates, customer choice, or competitive market consideration. It noted that gas meters are a controlled product, with limited sources of supply, and a comparatively long useful service life.

The FGA noted that the meter reading function was a simple task, with many agencies or utilities now offering that service. The FGA proposed that all meter reading services could be let out under a competitive tender. It stated that such a direction would ensure that no greater duplication of service would exist than is now in place, compared with allowing individual retailers to read their own meters. It stated that this proposal would also provide a significant opportunity to test the utility cost for this service.

MI/UM

The MI/UM submitted that the utility should be responsible for the meter reading function, but that it could be contracted to an independent third party. The MI/UM submitted that meter ownership should stay with the utility, for the immediate future.

PICA

PICA believed, given the state of internet technology and the potential for cost savings, there might be merit in considering meter reading as a retail cost. It was PICA's view that following the proceedings, the Board could make a determination as to whether or not meter reading costs should be unbundled and included as a retail service cost, or remain as a wholesale cost.

6.5.2 Views of the Board

The Board notes that only Enron was of the opinion that meter ownership and maintenance should be functionally unbundled. These functions were noted by most parties as not being candidates for unbundling in the near term. The Board concurs with this assessment. The Board is of the view that the unbundling of the meter ownership and maintenance function would not contribute significantly to the development of the retail gas market. As well, meters are relatively expensive elements of a customer installation, and are intended to last for many years. Unbundling meter ownership could lead to significant stranded costs at the customer level. Accordingly, the Board does not find that unbundling of meter ownership and maintenance passes its two part test for unbundling.

The advantages of newer, more elaborate metering, cited by Enron, could also be achieved by the efforts of the utilities. Enron, and other retailers wishing to have different metering options available, are encouraged to discuss metering options with the utilities. If a satisfactory, cost based arrangement can be reached, the utilities could then file rates for special metering for approval by the Board.

Many of the parties have proposed that the meter reading function should be open for competitive tender. This can be accomplished by utilities subcontracting meter reading by competitive tender. By contrast, if the meter reading function were unbundled, meter reading would be provided by a competitive retailer, rather than by a utility simply subcontracting the service. As noted elsewhere in this Decision, the Board encourages the utilities to find cost savings wherever possible, and would be open to the subcontracting of utility functions on a competitive basis. However, the determination of the prudence of such arrangements is properly the subject of a GRA.

6.6 Billing

Billing refers to the preparation and posting of customer invoices, and the subsequent processing of invoices and payments.

6.6.1 Positions of Parties

ATCO Gas

ATCO Gas noted its initiative to sell its retail operations in Alberta, and argued that this would effectively unbundle the merchant and billing functions from the delivery costs. It considered that billing related to the gas cost function should be unbundled and moved to the DGA.

AIPA/EUAA

AIPA/EUAA considered that although billing, as a retail function, should be unbundled, appropriate separation of billing elements should be clearly identified on retailer bills.

Calgary

Calgary noted that all parties had indicated that billing services should be unbundled. It noted that ATCO Gas proposed to include the cost of billing in the GCRR, and that other parties supported the unbundling of billing as a stand-alone service offering.

Calgary supported the unbundling of billing as a stand-alone service. It argued that alternate service providers could provide billing services that would achieve economies of scale, or be otherwise innovative or cost effective.

ENMAX

ENMAX stated the customer service functions should be unbundled to create opportunities for marketers to reduce costs and provide better services. It believed that the existence of retail electric competition offered opportunities for savings where a retailer provides both utility services to the same customer. This level of competition, ENMAX stated, required that all customer services be fully unbundled.

It was ENMAX's view that the utility would require some level of both customer information and call centre support to operate the delivery system in a safe and reliable manner. For this reason, ENMAX believed some portion of the cost associated with call centre activity, related to system operations and service establishment, must remain with the utility.

Enron

Enron submitted that the operations and customer service functions should be unbundled, as retailers selling natural gas and other products would need to provide all of those services to facilitate their sales. Enron argued that costs should be unbundled in such a manner so that customers who choose to receive service from a retailer do not also pay the utility for services they do not use.

EPCOR

EPCOR stated that the billing, customer information system, call centre, and credit and collections functions are related, and essentially form a single "customer care" function. It submitted that these functions should be subject to a consistent treatment. It noted that with the creation of ATCO Singlepoint and ATCO I-Tek, ATCO Gas had already gone some distance towards isolating those functions.

EPCOR noted that if the use of services were to be unbundled and competitively offered, there would be few, if any, stranded costs. EPCOR recommended that costs for the billing function should be unbundled from the delivery charge, determined on a stand-alone basis, and grouped with the GCRR for display as a “supply” or “retail” charge on customers’ bills.

FGA

The FGA stated that there was a need for significant consultation and examination of alternatives with affected parties to ensure a fair and reasonable solution to the problems confronted in unbundling billing services.

PICA

PICA believed, given the state of internet technology and the potential for cost savings, that there might be merit in considering billing as a retail cost. It was PICA’s view, that following the proceedings, the Board could make a determination on whether billing costs should be unbundled and included as a retail service cost, or remain as a wholesale cost.

6.6.2 Views of the Board

The Board notes that all of the marketers participating in these proceedings were prepared to, and wished to, provide billing services to their customers. The Board takes this as evidence that there could well be a competitive market for billing services.

The Board notes the arguments of parties that it is necessary for marketers to be able to carry out the customer care functions of the utility in order to provide their desired level and economy of service to their customers. The Board finds that it is reasonable for gas retailers to wish to undertake the billing function as part of their Core business. Consequently, the Board is of the view that unbundling of the billing function will aid the development of the retail gas market.

The Board does not have quantitative studies available to it to determine the magnitude of potential stranded costs relating to the billing function. However, it notes that ATCO Gas has already taken the step of separating this function into a competitive affiliate. Therefore, the Board does not expect there to be stranded costs related to billing in the case of ATCO Gas. In the case of AltaGas, the Board notes that most of the hardware costs related to the customer information systems will continue to be required, in order to carry out the utility’s load settlement function. Also, certain of the remaining billing costs are strictly variable (bill costs, envelopes, postage, etc.). Consequently, the Board is of the view that unbundling of the billing function is not likely to create substantial stranded costs or other difficulties.

The Board finds that the billing function passes its two qualitative tests for function unbundling. Unbundling the billing function is expected to aid the development of the retail gas market, but it is not expected to create large stranded costs or other problems. The Board directs the utilities to separate the costs associated with retail billing from the base rate in accordance with the schedule set out in section 6.1.2 of this Decision, and to subsequently levy charges related to those costs only to regulated service customers. The utilities are directed to file a rate for the provision of billing information to retailers at the time of filing their unbundling allocation studies, as directed in section 6.1.2 of this Decision.

As noted at the beginning of this section, once a fully competitive market is established the Board is of the view that an unbundled function that is performed by retailers will not be reviewable by the Board except to the extent that ratepayers of the utility may be negatively affected by the relationship between a utility and a retailer.

As further discussed in section 7.1.2 of this Decision, the Board supports the adoption of a "one bill" model for the Alberta gas market. This approach sees the utility billing gas retailers for the provision of its services with retailers paying the utilities on their customers' behalf. This approach is implicit in the draft Natural Gas Billing Regulation.

6.7 Customer Information System

The customer information system is a data records system for customers' service information, and gas consumption records and history.

6.7.1 Positions of Parties

ATCO Gas

ATCO Gas considered that the customer information system should not be unbundled, because it was necessary to provide service to retailers, and was required to meet the requirements of the delivery service.

AIPA/EUAA

Noting that the retailer must have a system to keep track of customer information for billing purposes, while the utility needs to keep track of information on connections, AIPA/EUAA considered that these services could be unbundled.

Calgary

Calgary noted that, except for ATCO Gas, parties supported the unbundling of the Customer Information Supplier. It noted that ATCO Gas had supported the inclusion of this cost center in the GCRR. Calgary argued that unbundling of this service, on a stand alone basis, would allow the potential competitive market to evaluate it in conjunction with other customer care services.

ENMAX

ENMAX stated the customer service functions should be unbundled to create opportunities for marketers to reduce costs and provide better services. It believed that the existence of retail electric competition offered opportunities for savings where a retailer provides both utility services to the same customer. This level of competition, ENMAX stated, required that all customer services be fully unbundled.

Enron

Enron submitted that the operations and customer service functions should be unbundled, as retailers selling natural gas and other products would need to provide all of those services to facilitate their sales. Enron argued that costs should be unbundled in such a manner so that customers who choose to receive service from a retailer do not also pay the utility for utility services they do not use.

EPCOR

EPCOR stated that the customer information system should be unbundled. EPCOR agreed with the caveat of PICA that any customer information system costs related to load settlement should remain in the distribution tariff.

EPCOR noted that ATCO Gas had essentially unbundled this function through the creation of ATCO Singlepoint and ATCO I-Tek, and that it only remained to unbundled the costs from the delivery charge to complete the unbundling process. EPCOR recommended that the costs associated with the customer information system be determined on a stand-alone basis, and grouped with the GCRR for display as a "supply" or "retail" charge on customers' bills.

6.7.2 Views of the Board

The Board notes the position of ATCO Gas that there will be a continued need for ATCO Gas to have a customer information system function, even if the utility is no longer a natural gas supplier. The Board is of the view that this may in fact be the case, as the utilities will need to maintain customer location records, usage data, and other information to fulfill the load settlement role. The Board anticipates that utility customer information costs are unlikely to decrease substantially due to increased retail competition.

However, the Board would like to test this theory. The Board directs the utilities to provide information on the anticipated effect of increased retail competition on their expected customer information system costs at the time they file the unbundling allocation study directed in section 6.1.2 of this Decision, as part of the Board's direction to examine the customer information system function's operations and requirements.

6.8 Call Centres

Call centres are required by the gas utilities to receive information about problems or emergencies concerning the gas systems, as well as for customer service.

6.8.1 Positions of Parties

ATCO Gas

ATCO Gas considered that the call centre function should not be unbundled, because it was required to meet the requirements of the delivery service.

AIPA/EUAA

AIPA/EUAA considered that call centres should continue to be the responsibility of the utilities.

Calgary

Calgary noted that, except for ATCO Gas, parties supported the unbundling of the call centre function. It noted that ATCO Gas had supported the inclusion of this cost center in the GCRR. Calgary argued that, along with other customer care services, unbundling of the call centre function would allow evaluation of this service by the competitive market place.

ENMAX

ENMAX stated the customer service functions should be unbundled to create opportunities for marketers to reduce costs and provide better services. It believed that the existence of retail electric competition offered opportunities for savings where a retailer provides both utility services to the same customer. This level of competition, ENMAX stated, required that all customer services be fully unbundled.

It was ENMAX's view that the utility would require some level of both customer information and call centre support to operate the delivery system in a safe and reliable manner. For this reason, ENMAX believed some portion of the cost associated with call centre activity, related to system operations and service establishment, must remain with the utility.

Enron

Enron submitted that the operations and customer service functions should be unbundled, as retailers selling natural gas and other products would need to provide all of those services to facilitate their sales. Enron argued that costs should be unbundled in such a manner so that customers who choose to receive service from a retailer do not also pay the utility for utility services they do not use.

EPCOR

EPCOR stated that all parties generally concurred that the call centre function should be unbundled. It noted that ATCO Gas had essentially unbundled this function through the creation of ATCO Single point, and that it only remained to unbundle the cost from the delivery charge to complete the unbundling process. EPCOR recommended that the costs associated with the call centre be determined on a stand-alone basis, and grouped with the GCRR for display as a "supply" or "retail" charge on customers' bills.

FGA

The FGA stated that requiring a competitive process for consolidated call centre services might be preferable to fragmenting a service, which may not now be offered in the most cost-effective manner.

PICA

PICA argued that given the state of internet technology and the potential for cost savings, that there might be merit in considering call centre costs as a retail cost. It was PICA's view, that following the proceedings, the Board could make a determination as to whether call centre costs should be unbundled and included as a retail service cost or remain as a wholesale cost.

6.8.2 Views of the Board

The Board notes that all of the marketers party to these proceedings were prepared to provide call centre services to their customers. The Board takes this as evidence that there will likely be a competitive market for these services.

The Board accepts the arguments of parties that it is necessary for marketers to be able to carry out the customer care functions of the utility, including the call centre function, in order to provide their desired level and economy of service to their customers. Consequently, the Board is of the view that unbundling the call centre function will aid the development of the retail gas market.

The Board does not have quantitative studies available to it to determine the magnitude of potential stranded costs relating to the call centre function. As noted by parties, some level of utility call centre activity will always be required for the safe operation of the utility distribution system. If there is a problem with gas supply, there must be someone available to respond.

The Board notes that ATCO Gas has already taken the step of separating this function into a competitive affiliate. Thus, in the case of ATCO Gas the Board does not expect there to be stranded costs related to call centres. In the case of AltaGas, the Board again notes that a certain level of utility call centre activity will always be required. Consequently, the Board is of the view that unbundling of the billing function is not likely to create substantial stranded costs or other difficulties.

The Board finds that the call centre function passes its two qualitative tests for function unbundling. It is expected to assist in the development of the retail gas market, and it is not expected to create large stranded costs or other problems. The Board directs the utilities to separate the costs associated with retail customer service (including distribution service) from the base rate in accordance with the schedule set out in section 6.1.2 of this Decision, and subsequently levy charges related to those costs only to regulated service customers. The utilities are directed to file a rate for provision of call centre services related to basic distribution service only, for direct connect customers, at the time of filing their unbundling allocation studies as directed in section 6.1.2 of this Decision.

Retailers wishing to use utility call centre services will have to come to a commercial arrangement with the utility. As noted at the beginning of this section, once a fully competitive market is established, the Board is of the view that an unbundled function that is performed by retailers will be reviewable by the Board only to the extent that ratepayers of the utility may be negatively affected by the relationship between a utility and a retailer.

6.9 Credit and Collections

Credit and collections refers to the actions required by the gas supplier to secure payment from customers.

6.9.1 Positions of Parties

ATCO Gas

ATCO Gas considered that the late payment penalty should be allocated between the cost of service portion and the gas cost portion of rates.

AIPA/EUAA

AIPA/EUAA considered that the retailer is in the best position to provide this function, and apportion costs between the retail and delivery functions.

Calgary

Calgary supported the unbundling of the credit and collection function on a stand-alone basis, as it proposed for other customer care services.

ENMAX

ENMAX stated that the customer service functions should be unbundled to create opportunities for marketers to reduce costs and provide better services. It believed that the existence of retail electric competition offered opportunities for savings where a retailer provides both utility services to the same customer. This level of competition, ENMAX stated, required that all customer services be fully unbundled.

Enron

Enron submitted that the operations and customer service functions should be unbundled, as retailers selling natural gas and other products would need to provide all of those services to facilitate their sales. Enron argued that costs should be unbundled in such a manner so that customers who choose to receive service from a retailer do not also pay again to the utility for utility services they do not use.

EPCOR

EPCOR stated that all parties generally concur that the credit and collections function should be unbundled. It noted that ATCO Gas had essentially unbundled this function through the creation of ATCO Singlepoint, and that it only remained to unbundle the cost from the delivery charge to complete the unbundling process. EPCOR recommended that the costs associated with credit and collections be determined on a stand-alone basis, and grouped with the GCRR for display as a “supply” or “retail” charge on customers’ bills.

MI/UM

The MI/UM argued that stand-alone charges should be developed for all of the “customer care” functions. The MI/UM submitted that only the direct costs should be included in the stand-alone charges, until it can be determined with some certainty that the indirect costs will not simply be reallocated to other functions.

PICA

PICA submitted that any costs related to credit and collections could be allocated to the utility's wholesale and retail functions, considering time expended on each. Similarly, costs and revenues related to bad debts, late payment penalties, or working capital could be allocated to the wholesale and retail functions, based on principles of cost causation.

6.9.2 Views of the Board

In keeping with the view of the Board that the retail gas market should be based on a one bill model, each retailer will be responsible for the charges payable to the utilities on behalf of its own clients. The Board is of the view that in this model the credit and collections function for all portions of direct supply customers' bills will naturally fall to the retailer. The utility would retain the credit and collections costs associated with utility supply customers. The Board finds that it is logical that retailers conduct their own credit and collections functions. It also finds that the costs of the utility operation of the credit and collection function should be expected to decrease as the number of customers taking utility service decreases. Therefore, the unbundling of the credit and collections function is not expected to result in any significant stranded costs or other difficulties. The Board is of the view that the credit and collections function passes both of its tests to be unbundled at this time.

To ensure that direct supply customers are not allocated costs related to utility credit and collections, the Board directs the utilities to unbundle credit and collections costs for inclusion in the base rates of utility supply customers only. This is to be filed as part of the unbundling allocation study directed in section 6.1.2 of this Decision.

6.10 Customer Enrolment

The customer enrolment function entails registering new customers in the customer information system.

6.10.1 Positions of Parties

ATCO Gas

ATCO Gas considered that the utility should retain the customer enrolment function, which would ensure that customers are assigned to the proper retailer. It argued that it was important to have a neutral party providing customer enrolment to ensure that customers and retailers are treated fairly. It also noted that most customers stated that it should retain the customer enrolment function.

AIPA/EUAA

AIPA/EUAA submitted that the utility providing the monopoly delivery function was in the best position to provide the customer enrolment function.

Calgary

Calgary argued that the customer enrolment function was a utility function that should be unbundled as a stand-alone service. It argued that the utility was the most neutral party for implementing and administrating this service.

ENMAX

ENMAX believed customer enrolment activities must be unbundled, and that delivery service rates should include the cost of one free switch to or between retailers each year.

Enron

Enron submitted that the utility should provide this function on a non-discriminatory basis for all retailers.

EPCOR

EPCOR recommended that the current enrolment and administrative charges contained in the utilities' tariffs be eliminated. It argued that, to the extent there are ongoing enrolment and administrative costs to the utilities, these cost should be recovered through the delivery charge, not through a stand-alone charge.

FGA

The FGA stated that the utility should not be obliged to bear any enrolment cost for third parties. It argued that those parties may have other commercial prospects for utilization of enrolment or access to retail customers.

MI/UM

The MI/UM considered that revenues related to direct purchase customer enrolment should be treated as a revenue offset, and thus would effectively remain in the cost of service.

6.10.2 Views of the Board

The Board notes that parties generally agree that customer enrolment should remain an exclusive function of the utility. The Board is of the view that this is not a function that needs to be unbundled to advance retail competition in natural gas. Therefore, the Board is of the view that the customer enrolment function should not be unbundled.

The utilities are directed to justify their enrolment charges when filing their unbundling allocation studies, as directed in section 6.1.2 of this Decision.

6.11 Load Settlement

The load settlement function is comprised of the processes and systems required to allocate gas costs between retailers, based on customer metering or load profiles and effecting financial settlement.

6.11.1 Positions of Parties

ATCO Gas

ATCO Gas submitted that load settlement and load balancing should remain with the utility's distribution system, as the utility is a neutral party, and because these functions are integral to the safe and reliable operation of the gas distribution system.

ACC

The ACC submitted that only the appropriate costs that apply to the customer should be allocated to load settlement and balancing. By way of example, the ACC pointed out that some portion of storage and other balancing costs could be allocated to a transmission customer, if these costs support load balancing. On the other hand, where any of these costs support sales operations, they should be allocated to sales customers.

AIPA/EUAA

AIPA/EUAA considered that the load settlement function should remain with the utility.

Calgary

Calgary argued that the load settlement function should be unbundled, but remain as a utility service during the transition period. It noted that future developments may allow this service to be provided by the shipper/marketer community, once higher levels of market saturation are reached.

It noted that each shipper would not require the exact same settlement services; therefore, the establishment of cost and pricing components would be necessary from the beginning. It noted that this would also provide the opportunity for shippers to balance among themselves under any load settlement program.

ENMAX

ENMAX submitted that it was appropriate for the utility to provide services related to load settlement, however, there was some potential that such services could be provided competitively, and therefore the services should be separately priced.

Enron

Enron stated that the load settlement function should continue to be performed by the utility and should be bundled with its distribution service, as it is integral to maintaining system security.

EPCOR

EPCOR submitted that the current rules surrounding load balancing and imbalance settlements are adequate and appropriate. It argued that, to the extent there are balancing costs in the current delivery charges, it was appropriate they remain there.

FGA

The FGA stated that load settlement should reside with the utility. It noted that the utility has an obligation of to ensure that the distribution system is fully operable and able to meet the demands of the customers it serves. The FGA argued that there was no competitive alternative for this service.

MI/UM

The MI/UM submitted that the load settlement function should remain part of the bundled services so long as the utility is providing the GCRR. It argued that this service was required for all customers, sales or direct purchase, because it was integral to tracking receipts, deliveries, and unaccounted for gas, for operational and financial settlement purposes.

6.11.2 Views of the Board

Load settlement costs are incurred by the utility for every customer, whether taking utility or competitive service. Therefore, the unbundling of this function is not seen as being necessary for the further development of the retail gas market. The Board is of the view that load settlement costs should be collected as part of the base transportation rates of the utilities, and should not be unbundled.

6.12 Load Balancing

Load balancing is part of the physical operation of the gas system, whereby gas supplies are adjusted to maintain the correct operating pressure in the gas system.

6.12.1 Positions of Parties

ATCO Gas

ATCO Gas submitted that load settlement and load balancing should remain with the utility's distribution system, as the utility is a neutral party, and because these functions are integral to the safe and reliable operation of the gas distribution system.

It also noted that load balancing costs should be reviewed, as well as the Rate 11 load balancing provisions.

AIPA/EUAA

AIPA/EUAA considered that the utility has the responsibility to ensure that the total system is in balance, and that this function should remain bundled.

Calgary

Calgary argued that load balancing was hand-in-hand with load settlement. Calgary stated that it continued to support retaining load balancing within the utility on a fully unbundled, stand-alone basis. It recommended that in the initial phase, the utility would be the provider of this service.

Calgary argued that this service could not be retained in the distribution delivery charge, as different shippers would require different services. It also noted that market development would lead to shippers offsetting over and under deliveries, reducing the costs of ATCO Gas providing the services. Calgary recommended that these services should be unbundled, and a stand-alone rate developed to assist the competitive market in its development.

ENMAX

ENMAX believed that the utility should provide load balancing, as it was integral to the safe and reliable operation of the delivery system.

Enron

Enron argued that a case can be made for the unbundling of load balancing, as retailers can and do provide these services to customers today, and can provide value to customers by effectively managing the customers' requirements for such services.

EPCOR

EPCOR submitted that load balancing and load settlement are required to operate in tandem, and the functions are not capable of being separated from each other. It argued that the same treatment needed to be accorded to both.

FGA

The FGA noted that unbundling the retail markets may create additional concerns with regard to nominations and balancing for third party suppliers, as transmission suppliers require a trader control of dispatch and balancing within their own systems. It argued that without adequate receipts to meet delivery, the system would fail. The FGA argued that, as the utility is the only party with an obligation to serve and the ability to undertake the dispatch and control functions for the systems they operate, the utilities ought to be allowed to provide the functions necessary to fill their obligations.

MI/UM

The MI/UM submitted, given the difficulties in estimating the load balancing costs, that the portion of storage costs attributable to the value of hedging should be allocated to the DGA and the balance allocated to the cost of service.

PICA

Pica believed that the need for load balancing might arise when there were imbalances caused by differences between nominated and actual supply or demand. To the extent there was an identifiable charge for load balancing from the transmission provider, PICA argued that the charge should be allocated between the utility's retail gas supply function and wholesale function.

6.12.2 Views of the Board

The Board notes that load balancing is required for utility retail and competitive retail customers, as well as wholesale customers. It is clear to the Board that the utilities, as operators of the gas delivery network, are ultimately responsible for load balancing. Based on the evidence of this proceeding, however, it is not clear that load balancing costs can be unbundled and directly assigned in a straightforward manner.

The Board notes that some marketers are willing to undertake load balancing services, and, in doing so, may be able to achieve some economies. However, the Board desires more information as to the potential operational and rate complexities that could arise if this function were unbundled.

The Board considers that a study on the potential for unbundling the utility load balancing function is necessary as part of its further process in this matter, and will provide further direction on this matter subsequent to this Decision. For the time being, load balancing will not be specifically unbundled.

6.13 Marketing and Consumer Information

Utility marketing is usually restricted to encouraging new customers to choose natural gas service. Other utility customer information activities relate to gas safety, energy conservation, and rate information.

6.13.1 Positions of Parties

ATCO Gas

ATCO Gas submitted that it would continue to have a marketing function related to signing up new service lines and encouraging natural gas consumption.

AIPA/EUAA

AIPA/EUAA considered that marketing should be assigned to the retail function.

Calgary

Calgary noted that all responding parties adopted the position that the marketing function should be unbundled. It noted that under the proposed AGPL sale of its merchant function, marketing cost might not be an issue in the future. Calgary submitted that consumer information was a separate and distinct function versus marketing, and that there would continue to be a need for consumer information and education in the unbundled competitive market place. Calgary argued that this would be mostly a transition cost, and would require study by the working groups.

ENMAX

ENMAX stated that in competitive markets, both marketers and the utility have marketing and consumer information obligations, but that the extent of the obligations depended upon the end-state vision adopted by the Board.

Enron

Enron submitted that marketing costs should be allocated to the various unbundled and bundled utility functions.

EPCOR

EPCOR stated that all parties concurred that the marketing function should be unbundled. EPCOR recommended that the costs associated with marketing be determined on a stand-alone basis, and grouped with the GCRR for display as a "supply" or "retail" charge on customers's bills. EPCOR recommended that the marketing costs associated with the customer enrolment function should remain in the delivery charge.

FGA

The FGA stated that all utility data and records should be accessible to all retailers, but remain the responsibility of the utility.

MI/UM

The MI/UM submitted that the allocation of marketing costs is an area that will require detailed review by the working group.

6.13.2 Views of the Board

The Board will deal separately with the issues of marketing costs – costs undertaken to increase consumer demand – and customer information costs. The Board is of the view that there will be an ongoing need for the utilities to provide safety and other general information to all customers. On that basis, the Board does not see a need to unbundle that portion of utility costs from the base delivery rate.

The Board notes that ATCO Gas has also argued that marketing costs related to hooking up new facilities and increasing the use of gas would continue, even in light of it selling its merchant function. The Board does recognize that marketing expenses incurred to increase the volume of gas delivered will benefit all customers by reducing the per customer delivery charges. On that basis, the Board finds that marketing costs should also remain in base delivery charges.

However, the Board does not consider that it would be appropriate for marketing costs to be incurred to attract customers specifically to utility gas supply service. The Board intends that utility supply service should serve as a regulated alternative to the competitive market. Utility supply service is not intended to be of a competitive nature itself.

6.14 Treatment of Indirect Costs

Direct costs for an activity include all salaries and expenses payable to undertake a function. Indirect costs include such costs as administration and overhead costs.

6.14.1 Positions of Parties

ATCO Gas

ATCO Gas submitted that direction is required from the Board regarding the treatment of indirect costs. It also submitted that unavoidable indirect costs should remain part of the distribution rates, and should not be allocated to unbundled functions.

ATCO Gas countered the Calgary argument that all indirect or embedded costs related to a function should be unbundled with that function. It noted that some indirect or G&A costs are not avoidable, and should not be unbundled. It argued that allocating these costs to the DGA would require them to be eventually returned to the cost of service.

ATCO Gas noted that, as a function, G&A costs would not be unbundled, and that it did not expect a significant impact on G&A costs as a result of unbundling. It also argued that costs of employee-benefits and pension costs should be recognized.

ATCO Gas noted the PICA/Canfor argument that "a 25% contribution margin on direct costs is a reasonable allocation of indirect costs to the retail delivery function". It noted that this issue was not addressed during the proceeding, and the issue should be further considered either at the collaborative process, or at a future hearing. ATCO Gas considered that indirect costs, such as pensions and employee benefits, should be included in the direct cost assignment. It noted that this may exceed the 25% margin requested by PICA/Canfor.

ACC

The ACC considered that indirect costs should be allocated to the unbundled service to which they most closely relate.

AIPA/EUAA

AIPA/EUAA submitted that, for the first phase of the collaborative unbundling process, indirect costs should remain with the delivery function, and in the second phase, where 2001/2002 costs should be examined, indirect costs can be tested for appropriate assignment or allocation to the procurement and/or delivery functions.

CCA

The CCA considered that indirect costs should be treated similarly to any stranded costs incurred.

Calgary

Calgary submitted that indirect costs must follow the unbundling process to the end result. Calgary noted that current AGS rates are based upon direct and indirect cost, as approved by the Board in the July 5, 2000 compliance class cost of service study. It argued that failing to track indirect costs would allow the utility to get out of the customer care business while not reducing its overhead cost, thus earning a windfall profit.

In reply argument, Calgary continued to support the recognition of both direct and indirect costs being assigned to each unbundled function. Calgary again argued that failure to recognize direct and indirect costs would lead to windfall profits accruing to AGS and rates for stand-alone services being priced below cost.

ENMAX

ENMAX strongly supported the inclusion of indirect costs in each element of the unbundled rates. ENMAX stated that indirect costs included general plant and related expenses, administrative and general expenses, other overheads (such as supervision), and rate base adjustments including working capital.

Enron

Enron submitted that these costs should be allocated to the various unbundled functions according to their usefulness and contribution to the utility's operation of that function.

FGA

The FGA stated that all costs that could not be avoided or reasonably provided by others through competitive services should be retained within the distribution rates. It stated that it has been recognized that the utility or distributor has certain minimum costs that could not reasonably be avoided.

MI/UM

The MI/UM submitted that with any allocation of indirect costs to the GCRR, overheads and administrative costs would have to be reviewed periodically to ensure that GCRR customers are not bearing more than their fair share of costs, particularly as customers increasingly opt for direct purchase.

PICA

PICA submitted that indirect administration and general costs, as well as any marketing costs applicable to unbundled functions, should track the relevant direct costs.

6.14.2 Views of the Board

The Board has directed the utilities to allocate all costs, direct and indirect, in section 6.1.2 of this Decision. As part of this exercise the utilities have been directed to address the effect of unbundling on indirect and overhead costs.

This information is intended to be the basis for a further proceeding to finalize unbundled utility rates. The Board is of the view that indirect costs cannot be dealt with by a blanket policy, but must be examined in some detail to determine a fair allocation of costs.

6.15 Stranded Costs

Stranded costs are any costs which, due to changing circumstances, will not be paid under an existing rate structure.

6.15.1 Positions of Parties

AltaGas

AltaGas believed the best way to deal with stranded costs was to develop a proposal with the people affected.

AltaGas observed that rate setting is based on forecasting anticipated costs, and then testing those forecasts. It argued that there was no other way to apply the public interest test to rates.

ATCO Gas

ATCO Gas argued that the calculation and treatment of stranded costs should be calculated on a case-by-case basis.

ACC

Noting that stranded costs result from the obsolescence of utility assets, incurred expenses, and contractual obligations as a result of unbundling and reallocation of customers and functions away from the utility, the ACC submitted that identified stranded costs should be recoverable by the utility in full, subject to reasonable mitigation.

AIPA/EUAA

AIPA/EUAA submitted that the transition period should be sufficiently long to minimize the impact of potential stranded costs.

Calgary

Calgary noted that while claims for stranded costs cause anxiety in regulators and consumers, it has not been the experience in North America that stranded costs will necessarily be incurred. It argued that stranded costs are of the same regulatory complexity as any other cost component of the utility's revenue requirement.

Calgary argued that all claims for stranded costs must be subject to mitigation and elimination standards, and evaluated on their own merits at the time of occurrence. It stated that processes and procedures for dealing with stranded costs could be developed in the working groups.

Calgary argued that stranded costs were not a direct result of unbundling. It stated that while stranded costs may occur following the unbundling process, they could not be dealt with in advance of occurrence. Calgary stated that from the earliest days of unbundling, utilities have thrown stranded costs on the table as the ultimate scare tactic. Calgary reiterated that the potential for stranded costs should not be viewed as an impediment to unbundling, and that stranded costs are an issue to be addressed when and if they occur.

Calgary noted that in calculating stranded costs, distinctions should be made between capital and non-capital costs. Calgary stated that although a conceptual process and procedure for addressing stranded costs should be developed in the working group process, it believed that it was premature to finitely determine a calculation method.

ENMAX

ENMAX stated that it was important to ensure that the incumbent utility receives appropriate incentives to minimize stranded and transition costs, and that assuring recovery of these costs removed any basis for the incumbent utility to resist the changes required to institute competition. In ENMAX's view the appropriate transition costs included:

- a gas management system for accepting nominations, system balancing and settlement;
- a customer enrolment system;
- systems for electronic data interchange; and
- retailer customer service systems.

ENMAX believed that these costs could be minimized through a rapid transition to competition, and the associated internal restructuring of the utility to a pipes-only company.

Enron

Enron submitted that stranded costs may arise from the unbundling of some functions, as utility assets and manpower used to provide these functions may no longer be required. Enron argued that there are many options to reduce stranded costs, and only net verifiable stranded costs should be recoverable.

EPCOR

EPCOR submitted that the unbundling of costs in the manner it proposed, the implementation of its DGA proposals, a reasonable transition period, and the ability to deregulate competitive functions should result in no stranded costs to be recovered from utility customers. It stated that it anticipated that, initially, retailers would avail themselves of many of the utilities' stand-alone unbundled functions. It argued that during the transition period, utilities would have adequate time to transform these functions into competitive entities, or to shed the functions if they could not be made competitive.

EPCOR noted that Calgary's witness, Mr. Vander Veen, had testified that stranded costs have turned out to be substantially less than many utilities predicted, and that they should be addressed only once they occur. EPCOR stated that the attention of all participants should be focused on establishing the proper framework for unbundling, developing a fully competitive retail gas sales market, and encouraging utilities to shed all avoidable costs as they move through the unbundling process.

MI/UM

The MI/UM refrained from commenting on the specifics of the calculation of stranded costs, but stated that it was apparent that the identification, quantification, elimination, and mitigation of stranded and transition costs was a matter that should be referred to the working group for detailed review and recommendations to the Board.

PICA

PICA submitted that the unbundling process must examine and deal with the potential for stranded costs, and its impact on various groups of customers and the utility.

6.15.2 Views of the Board

The Board notes the evidence of Calgary that stranded costs can be mitigated in many circumstances. However, the Board finds it reasonable to assume that some stranded costs will arise in the context of moving towards a more competitive retail gas market.

In section 6.1.2 of this Decision, the Board directed the utilities to address the issue of stranded costs in their submissions on unbundling allocations. Without quantitative evidence to determine the relative risk of creating stranded costs through unbundling, the Board has taken the position that functions where that risk is qualitatively large should not be unbundled at this time.

6.16 Treatment of Stranded Costs

6.16.1 Positions of Parties

AltaGas

With regards to stranded costs AltaGas stated that:

> If unbundling results in stranded costs, those costs must become part of the revenue requirement of the utility and recovered through the rates. There is no principle of law or economics that would justify passing these costs on to investors.[27]

AltaGas considered it a fundamental principle of any unbundling exercise that utilities should not be saddled with resulting stranded costs. It noted that the rationale generally given for unbundling was that it would ultimately result in savings to customers. AltaGas questioned that rationale, but argued that given that rationale, the only reasonable allocation of stranded costs was to the ultimate beneficiaries of the exercise – the consumers. It argued that the unbundling process, if undertaken, would need to take a long-term transitional approach that minimized stranded costs, ensured they were fully identified, included them in utility revenue requirement, and ultimately recovered them in rates.

ATCO Gas

ATCO Gas argued that unbundling should proceed in a manner that minimized the potential for stranded costs. It also submitted that the calculation and treatment of stranded costs would need to be reviewed on a case-by-case basis, and that customers would be required to pay for any stranded costs.

ATCO Gas submitted that the Board should focus on unbundling functions that would involve little or no stranded costs. In this regard, it noted that the transmission function had the highest potential for stranded costs.

[27] Unbundling Exh.14; P.2

ACC

The ACC submitted that stranded costs should be distributed to all customers in a manner that ensures fairness.

AIPA/EUAA

AIPA/EUAA considered that, if stranded costs would not arise except for the process of unbundling, there might be a strong argument that such costs be assigned to non-regulated supply customers until such time that the utility has mitigated those costs.

CCA

While expressing cautious support for the submission of the Calgary that stranded costs may be a phantom phenomenon, the CCA considered that it was important to have a plan in place to deal with the possibility of stranded costs.

The CCA stressed that the utility would have a duty to mitigate any costs that could become stranded, and that mitigation would be best achieved with a reasonable time frame for implementation of unbundling.

Calgary

Calgary supported the recovery of all prudently incurred and Board approved stranded costs from customers.

ENMAX

It was ENMAX's view that gas utilities should be permitted to recover all prudently incurred, non-mitigatable stranded and transition costs.

ENMAX's argued that, where stranded costs are expected to be ongoing (beyond the transition period), recovery through delivery service rates was appropriate. It added, where these costs are temporary, recovery through a surcharge to delivery service rates was appropriate. ENMAX stated that the key point was that the costs should not be by-passable and should not create uncertainty for consumers.

Enron

Enron argued that any net verifiable, fully mitigated stranded costs determined by the Board should be allocated to the bundled distribution rate such that all customers, whether they are on system supply or retail supply, would pay for such costs.

FGA

The FGA stated that all costs associated with movement between utility and a competitive market must be fully recovered from those parties creating the costs. It noted that, "The utility has in the past stated that it viewed the costs as small and not worthy of recovery." The FGA noted that it was not the utilities that were required to pay these costs, and that any cost delivered to utility sales customer because of another customer exercising choice was clearly not appropriate.

MI/UM

The MI/UM noted Calgary's statement that once stranded costs have been identified and quantified, a process must be developed and implemented to collect these costs from consumers through an appropriate mechanism. The MI/UM submitted that the process would require detailed review and input from all members of the working group to determine fair and equitable allocation techniques, and appropriate time frames for the short-term transition costs and the longer term stranded costs.

The MI/UM agreed with other parties that the onus is on the utilities to mitigate and eliminate stranded costs to the maximum extent possible before customers are asked to bear any stranded costs.

6.16.2 Views of the Board

The Board is of the view that utilities should be compensated for all unavoidable and fully mitigated stranded costs. The Board takes this view because the scope and pace of change towards a competitive retail market is not fully within the control of utility management. Utilities are always expected to make reasonable efforts to adapt their operations to a changing environment; however, during the transition to the competitive retail gas market, circumstances may change more quickly than a utility can reasonably adapt.

The allocation of stranded costs is an issue that should be decided in light of the particular circumstances creating those costs. However, the Board is of the general view that stranded costs associated with the transition to a competitive retail market should be borne by all customers. Although some customers may not avail themselves of competitive retail service, the Board is of the view that all customers will benefit from an improved opportunity to do so.

The utilities are directed to establish deferral accounts to collect stranded costs arising from the Board's findings in this Decision. These deferral accounts will be considered at the next respective GRAs of the utilities.

6.17 Schedule for Unbundling

6.17.1 Positions of Parties

AltaGas

AltaGas's view was that concrete proposals for unbundling should come from the collaborative process.

ATCO Gas

ATCO Gas argued that it may be advisable to phase in the overall unbundling process. It noted that only addressing non-controversial issues would allow substantial progress to be made on unbundling prior to the end of the year.

ATCO Gas submitted that it was willing to take the steps necessary to achieve the objective of an open, competitive market by January 1, 2002. It suggested that the transition period, during which the RRO would be offered, may be complete no sooner than the end of 2002, with the possibility of getting there within two years. It argued that the North Core agreement should remain in place, and that unbundling for the North Core could be undertaken in 2003, unless parties were willing to agree to an earlier date.

ACC

The ACC considered that a working committee should be established to study and create a report, and recommend to the Board an appropriate level of unbundling for the functions identified, as well as the process by which unbundling for each function should be implemented. The ACC submitted that the working committee should complete its report within one year of the Board's decision after which a hearing should be convened to address the recommendations in the report. The ACC considered that unbundling should be implemented within one year of the Board's decision concerning the second hearing.

AIPA/EUAA

AIPA/EUAA submitted that the collaborative process should establish the process and principles for unbundling, and that a subsequent GRA would provide the implementation details.

CCA

The CCA considered that there was no urgency from the residential customer perspective to speed up the schedule for unbundling, so as to ensure that there is appropriate consideration and testing of all elements of unbundling.

Calgary

Calgary supported an implementation date for unbundling of January 1, 2002. It argued that this could be achieved through Board instruction to the working group as to deliverables based on a defined timetable. It noted that success in meeting that date would be driven by reaching a consensus as to what rates would be unbundled. It noted that unbundling of the current AGS rates should be achievable by that date.

Calgary recognized that the North Core settlement and the AltaGas customer collaborative process would affect the end date for unbundling, and that this could lead to a date of March 1, 2002 being more realistic.

ENMAX

ENMAX supported an aggressive schedule for unbundling. To that end, ENMAX proposed a workshop process designed to develop detailed implementation proposals for the Board's review. It believed that full unbundling was possible by early summer of 2002, if the Board provided strong endorsement of the process and the principles for competition proposed by ENMAX.

ENMAX submitted that a workshop process would only be effective if all parties were required to participate by presenting an affirmative proposal on the issues which significantly interested them. It stated that the Board should provide professional facilitation for each workshop to ensure that objectives were achieved. It submitted that, where possible, the Board should provide guidance to the participants through the principles adopted in the decision resulting from these proceedings.

In ENMAX's view, workshops operated best on the principle that any party raising a problem must also supply a solution within the context of Board mandated guidelines.

ENMAX believed that workshops were required for the following topics:

- System operations
- Cost of service unbundling
- Retail delivery tariff design
- Retailer tariff design
- Electronic data interchange
- Consumer protection
- Billing and customer service
- Barriers to entry

ENMAX stated that it was very important that the Board set out a workshop process that would result in clear recommendations to the Board, and that the Board clearly set out its willingness to consider and make determinations regarding the recommendations that flowed from the workshop process. ENMAX stated that the Board should also set out a clear timetable for the process.

Enron

Enron submitted that customers on direct purchase have been discriminated against and that fairness dictated a prompt resolution to outstanding gas cost reallocation and unbundling issues. Enron agreed with the Board that the gas supply issues were a priority. It submitted that in order for revised rate treatment of gas supply related costs and the unbundling of other functions to proceed, clear Board direction was required regarding the functions to unbundle, the costs to be included, the deadlines and consequences for missed deadlines, and any future hearing processes to resolve outstanding issues.

Enron recommended that the Board provide the following directions in its decision:

- ATCO Gas be required to file proposed interim rate changes within 30 days of the Board decision include:
    - Implementation of rate credit riders for Carbon storage, salt caverns, and company owned production,
    - Transfer of other direct gas supply related costs to the GCRR, including gas supply management, gas procurement, upstream transportation costs, and carrying costs on DGA balances, storage and salt cavern inventories.

- ATCO Gas and AltaGas be required to file proposed interim unbundled rates within 30 days of the Board decision for billing, metering, call centres, and customer information systems, based on direct costs only.

- An unbundling collaborative group, include all interested parties, a Board representative, and a facilitator, be formed to:
    - review the gas supply related rate changes to ensure they comply with the Board's intent,
    - provide comments to the Board on any recommended changes, within 30 days of the initial filing,
    - review the interim unbundled rates,
    - provide comments to the Board within 60 days of the initial filing.
    - determine implementation details for protocols and the details of how and when services shall be provided by retailers,
    - file an unbundling plan designed to fit within GRA processes by September 30, 2001 that would define the process to fully unbundle all services in conjunction with the AGS 2001/2002 GRA and the next rate application covering AGN, with any unresolved issues to be dealt with in a hearing set by the Board in the fall of 2001.

EPCOR

EPCOR supported unbundling at the earliest possible date, and had noted in the Unbundling Proceeding that August 1, 2001 was a reasonable date, given the timing of the proceedings. It noted that early implementation was supported by a number of parties. In particular it noted the support of Enron, ATCO Gas, ENMAX, PICA, and MI/UM.

EPCOR submitted that unbundling the current rates on an interim basis should be undertaken immediately, and that the Board should direct the utilities to file interim unbundled rates at the earliest practical date. On a go-forward basis, EPCOR recommended that the utility should be directed to adjust their current Phase I and Phase II filings to reflect the Board's unbundling directions. It proposed that final rates would arise from the review of these findings.

FGA

The FGA submitted that it would be appropriate to put unbundling aside until such time as all currently filed gas applications for general rate applications, and the ATCO Affiliate Transactions and Pensions proceedings had been concluded. It suggested that this would not pre-empt any collaborative or cooperative processes that the customers and utilities may wish to pursue, but it should allow breathing room to consider a formal process that may proceed if no resolution is reached through the informal process. It argued that the earliest commencement for a formal process should be the end of 2002.

In reply argument, the FGA stated that a company specific collaborative process should proceed for AGN, including the NCC, AGN, and retailers. The goal of this process would be to develop a recommendation for revising the GCRR for AGN by allocating direct costs from the cost of service to the GCRR. It stated that the target date for consensus should be November 1, 2001. It also stated that it believed that a similar process should be undertaken for AltaGas.

MI/UM

The MI/UM submitted that the gas portfolio costs will need to be referred to the working group, with the possibility that the working group could deal with direct gas portfolio management costs as a separate module, in order to move the less contentious costs into the DGA, at least on an interim basis. The MI/UM considered that all other costs to be unbundled required detailed review by the working group to determine if consensus can be achieved on specific services or functions, and failing that, if they should be litigated before the Board.

The MI/UM also considered that the working group should be able to provide recommendations to the Board in approximately six months and, assuming consensus could be achieved on most issues, it could be possible for implementation to be achieved by April or May 2002.

PICA

PICA believed a timeframe might be established for the transition to a fully competitive retail market when regulated unbundled services would no longer be offered by the utility. PICA's suggested timeframe would extend to the end of 2005. PICA proposed that one year prior to that date, a detailed expert study ought to be conducted to determine the extent to which competitive alternatives were available. If the study showed a functioning competitive market had not developed as anticipated, the time frame should be extended as required.

6.17.2 Views of the Board

The Board is of the view that inequities resulting from the inclusion of utility supply related costs in the distribution base rates, and the exclusion of benefits arising from company owned production and storage from the distribution base rates, should be corrected as soon as is reasonably possible. In section 5 of this Decision, the Board directed AGS and AltaGas to file interim rates addressing the direct costs associated with these issues by February 1, 2002, for implementation on April 1, 2002. Also in section 5, the Board directed AGN to provide a proposal as to how to implement interim rates addressing these issues within 30 days of the issuance of this Decision.

The further steps required to establish rates based on the unbundling of rates and functions described in section 6.3.2 of this Decision will take more time to establish. The Board is of the view that it is important that these rate changes are accurate when implemented. On that basis, in section 6.1.2 of this Decision, the Board has directed the utilities to file an unbundling allocation study and proposed rates within 90 days of the issuance of an approved GRA Phase I revenue requirement. This information will serve as a basis for finalizing unbundled distribution rates through further proceedings.

Other matters required for the full implementation of gas rate unbundling and retail market development will be coordinated to be in force at the time of the final gas rate unbundling decision. The Board anticipates that final unbundling decisions may be largely completed by the summer of 2002.

6.18 Discriminatory Treatment of Customer Groups

6.18.1 Positions of Parties

AltaGas

AltaGas believed strongly that in any unbundling scenario there should be a consistent treatment of customers within AltaGas's service area, but given the differences between the ATCO Gas systems and the AltaGas system, there could be a different treatment for ATCO Gas.

ATCO Gas

ATCO Gas argued that the Board should not disturb the North Core Agreement without a proposal from the North Core Committee. ATCO Gas stated that unbundling would not cause harm to sales customers

AIPA/EUAA

AIPA/EUAA submitted that the collaborative process must address the extent to which costs such as information processing costs would not exist without consideration of customer choice requirements, and how such costs should be dealt with.

CCA

The CCA submitted that, since this continued to be a process in the regulatory forum, the Board had the responsibility to ensure that no specific customer group experienced undue discrimination.

Calgary

Calgary argued that the unbundling in and of itself would not cause discrimination among customer classes. It stated that the inclusion of gas supply and gas management costs in the current delivery rate could be construed as discriminatory to consumers, as third party gas marketers also have these costs embedded in their gas supply charges. It argued that the clear allocation of costs to those classes that use or benefit from costs incurred for utility services would reduce the level of discrimination that is built into currently effective delivery rates.

ENMAX

ENMAX submitted that there was no doubt that competition produced benefits for consumers over all. However, it indicated that, competition does not necessarily produce benefits (in terms of lower price) for each consumer. ENMAX stated that there was no realistic expectation that any model of competition would produce savings for every customer.

Enron

Enron submitted that the utilities' current rates, as well as the entry barriers for retailers, both discriminate against and cause harm to direct purchase customers. Enron also submitted that the lack of unbundling also harms customers who wish to have choice of retail services.

FGA

The FGA stated that the Board should be concerned with the prospect of "cherry picking" by retailers. It warned that if retailers concentrate on serving customers in the most densely populated areas of the province, there could be ramifications for the costs and levels of service for the remaining customers.

MI/UM

The MI/UM agreed that current rates and terms and conditions of service, notably with respect to production and gathering costs and gas portfolio management costs, could discriminate against direct purchase customers. The MI/UM submitted that it was not possible to make everyone better off while making no one worse off. It stated that a main problem facing customers was the lack of reliable comparative product and pricing information that would allow them to make informed decisions.

6.18.2 Views of the Board

In this Decision, the Board has purposefully attempted to minimize the likelihood of utility function unbundling creating substantial stranded costs. It has done this by applying a qualitative test of that likelihood when determining which utility functions should be unbundled at this time. In the view of the Board, stranded costs have the greatest potential for creating inequities between those customers that leave utility supply and those that remain on utility regulated supply. The Board is concerned, and notes the argument of the FGA on this matter, that customers outside urban areas might not be reached by marketers. Were there substantial stranded costs, or a substantial reallocation of fixed costs to the utility supply customers, there could be cost ramifications for those customers remaining on utility supply, whether by choice or due to lack of alternatives.

As the transition towards gas retail competition progresses, the Board will monitor the effect of unbundling on customer groups to determine if some customers are being unduly burdened by cost transfers related to retail market development.

7 FURTHER REQUIREMENTS TO DEVELOP A FAIR AND EFFECTIVE COMPETITIVE RETAIL GAS MARKET IN ALBERTA

7.1 Requirements for Board Mandated Tariff Changes

7.1.1 Positions of Parties

AltaGas

In AltaGas's submission, the Board had no mandate to encourage the development of retail competition until the legislature and Government had created the supporting legal framework. AltaGas also stated that the Board, in its capacity as protector of the public interest, would have to decide whether or not the proposed tariffs met the test of being just and reasonable. Whether or not they advanced competition was not a criterion for consideration under current legislation.

ATCO Gas

ATCO Gas submitted that revisions to the tariff could be required to reflect unbundling, and any amendments to, or introduction of, new legislation.

Edmonton

Edmonton did not take any position on market-oriented changes that would restrict the power of retailers to a percentage of the market. It reiterated that the Board should encourage competition and support the availability of options for customers.

CCA

The CCA submitted that mandating tariff changes would be the continuing function of the Board, until workable competition was proven.

The CCA stressed the importance of the need to promote customer awareness of industry changes, recognizing that communication of the necessary information is a significant challenge.

ENMAX

ENMAX explained that a necessary step to develop full unbundling was the creation of a comprehensive unbundled tariff, where a tariff consists of Terms of Service, Rate Schedules and Rules and Regulations. ENMAX submitted that the Board had the jurisdiction to unbundle rates and set new tariffs, as required, under its general rate-making power.

ENMAX argued that the Board had the jurisdiction to regulate the relationship between the utility and marketers by virtue of its express power to fix standards, classifications, regulations, practices, measurements or service which shall be furnished, imposed, observed and followed by the owner of a gas utility.

Enron

Enron submitted that the current utility terms and conditions covering direct purchase were outdated, resulted in entry barriers, and did not adequately reflect the realities of the current marketplace. Enron agreed with other parties that, as part of the collaborative process, the existing utility terms and conditions should be reviewed, and changes made to remove those terms and conditions that constitute barriers to entry for new retailers.

EPCOR

EPCOR stated that there was a need to examine existing practices and terms and conditions of service of the utilities to ensure the modification or removal of provisions that are demonstrated to be redundant, an unnecessary impediment to the development of a fully functioning competitive retail market, or that have been overtaken by market developments. EPCOR stated that the collaborative process could examine the need for these changes provided that the Board, in its decision, gave a clear direction respecting the policy that should underlie such changes.

EPCOR submitted that a prerequisite for the development of a fully functioning competitive market would be a clear framework under which the market would operate. EPCOR suggested that a clear and transparent set of market rules would avoid unrealized expectations for the competitive market on the part of utilities, retailers, investors, regulators, and consumers. EPCOR submitted that the development of appropriate market rules could be left to the collaborative process, provided that the Board gave clear direction respecting the policy that should underlie such market rules and establish the timetable for implementation.

EPCOR noted the evidence of witnesses, Dr. Overcast for ENMAX and Mr. Vander Veen for Calgary, to the effect that there exist models of suitable market rules in other jurisdictions.

FGA

The FGA stated that the Board may not overrule regulations, and has a responsibility to consumers and utilities, not to retailers.

MI/UM

The MI/UM considered that the Board must continue to approve tariffs for the GCRR and the transmission tariffs.

The MI/UM also considered that the Board should approve what is essentially an unbundled wholesale tariff applicable to retailers, with respect to the customer care functions of billing, customer information, call centres, and credit and collections.

PICA

PICA believed the Board had the mandate to establish non-discriminatory tariffs for customer using direct supply and those remaining on utility supply. PICA also believed that delays in establishing non-discriminatory tariffs could potentially be harmful to the development of a competitive retail market.

7.1.2 Views of the Board

As noted in section 2 of this Decision, the Board views its role as that of implementing government policy within its legislated bounds, with a responsibility to protect consumers, while treating utilities fairly. Throughout this Decision, the Board has examined the utility tariffs under its purview in keeping with this view of its role. The Board will continue to act within this role as the retail market develops, and as circumstances change.

The Board is of the view that Government policy is clear with respect to the development of a retail gas market. Many of the details that must accompany any transition to a competitive retail market will fall under the review of the Board, whether specifically directed by legislation or regulation, or due to the Board's overall supervisory powers regarding gas utilities.

The Board is aware that circumstances are apt to change, and may change unpredictably, during the transition to a competitive retail gas market in Alberta. The Board is of the view that even as circumstances change, it must continue to review those items under its control to provide a reasonable chance for retail competition to succeed, while ensuring that customers are protected and utilities are treated fairly.

7.2 Requirements for Legislative Changes

7.2.1 Positions of Parties

AltaGas

AltaGas stated that Alberta's existing legislation provided an inadequate framework for a fully competitive marketplace.

AltaGas recommended the creation of a working group, representing the parties affected by gas services unbundling. That group would be tasked to develop recommendations for Government policy that would establish a clearer framework for the process. In its view, all market participants required a clearer definition of what the Province expected as an "end-result" of the deregulation process. It added that the group would also required a clear framework of legislation and policies to support the achievement of that end result. AltaGas submitted that in that kind of framework, the Board could function effectively in helping establish a process for issue resolution, and also in determining a timeline or setting milestones for implementing the various stages of unbundling as they evolve.

AltaGas believed that if Alberta were to move to a new model for the retailing of natural gas and related services, the leadership would have to come from the Legislature. It stated that the existing statutory framework was based on the traditional regulatory compact between utilities and consumers – the utility had the right to provide service and the consumer had the right to expect safe reliable service at reasonable cost. AltaGas stated that the only way to create the stable structure needed for a functioning fully competitive marketplace was for the legislature to pass suitable supportive legislation. AltaGas felt that the work of the GCRR and Unbundling proceedings could be useful for that purpose.

ATCO Gas

ATCO Gas identified four legislative or regulatory changes required to complete an alignment of the gas and electric markets:

- Set procedures or guidelines for the DGA and GCRR that are consistent with the Electric RRO.
- Address the default supply for natural gas by implementing the same requirements as for the electric default supply.
- Implement the draft Natural Gas Billing Regulation.
- Adopt the electric retailer code of conduct.

ATCO Gas submitted that there would be some change required to the GUA with respect to the utilities obligation to serve. ATCO Gas suggested that a review of the Core Market Regulation may be appropriate

CCA

The CCA considered that the Board and stakeholders must recognize that the gas and electric industries are inherently different, and submitted that there is no need for wholesale change in the legislation governing the natural gas Core market.

The CCA indicated that it did not support repeal of the Core Market Regulation, as this would remove what little protection is afforded to residential customers. The CCA also expressed support for increased bonding requirements to ensure that customers do not lose the benefits of long-term contracts in the event that unbundling moves ahead.

Calgary

Calgary stated that the working group should compile a list of areas of need for legislative review focusing on the Core Market Regulation, Alberta Energy and Utilities Board Act, GUA, and the Public Utilities Board Act. Calgary stated that the Core Market Regulation should be repealed and replaced with regulations that better reflect today's emerging market place.

ENMAX

ENMAX believed the current statutory framework in Alberta, with respect to the distribution and sale of natural gas to Core consumers, was relatively comprehensive. However, ENMAX was of the view some changes would be required to achieve the desired market end-state in the manner it proposed.

ENMAX stated that the present statutory framework appeared to contemplate that gas utilities (as defined in the GUA) would continue to provide gas supply services to Core consumers indefinitely. ENMAX also considered that the *Roles Relationships and Responsibilities Regulation*[28] under the *Electric Utilities Act,* in relation to distribution companies and wire services providers, could be expected to encourage the rapid development of competitive markets.

It was ENMAX's opinion, as the Board had identified in the *Apollo* decision, that the Board had the power to regulate the relationship between a gas utility and a marketer, to the extent that relationship affected the gas utility's ratepayers.[29] ENMAX also noted that, according to paragraph 28(c) of the GUA, the Board had the power to "fix just and reasonable standards, classifications, regulations, practices, measurements or service which shall be furnished, imposed, observed and followed thereafter by the owner of the gas utility." ENMAX submitted that this provided the Board with the jurisdiction to determine how billing and metering services were handled or provided by the gas utility, what customer information a gas utility was obliged to provide to marketers, and the conditions that the gas utility might impose on marketers with respect to customer enrolment, connection, and disconnection.

ENMAX noted that the Core Market Regulation requires marketers to maintain a two-year supply of gas. In ENMAX's view, this requirement had the potential to significantly impair the choice of products marketers might offer to consumers. ENMAX believed that a marketer, obliged to maintain a two year supply of gas, might not be able to offer a product that best suited that the needs of those consumers. It argued that the regulation's requirement for a written contract with a minimum one-year term also created a significant barrier to entry, as it increased customer-acquisition costs unnecessarily, and artificially limited the products that retailers might offer.

[28] Alta Reg. 86/2000
[29] Decision 2000-10, pp. 11-12.

ENMAX recommended that the statutory prudential requirements be modified to give the Board the power to set the level of security required, based upon the principles set out above.

Enron

Enron supported the repeal of the Core Market Regulation, on the grounds that the requirements in that regulation are outdated, impractical, introduce entry barriers, and do not provide any meaningful consumer protection.

Enron argued that if the Core Market Regulation was repealed, the Board would still have the power under section 26.01 and other sections of the GUA to set rules applicable to direct sales, and would also be unencumbered by the Core Market Regulation.

Enron supported prompt passage of the proposed Natural Gas Billing Regulation under the GUA as that would allow retailers to provide a one bill option to customers, which would then allow retailers to better tailor products to suit customer needs.

EPCOR

EPCOR cited the ATCO Gas witness, Mr. Engler, who stated,

> I believe that the Board, here, can take us to the state where the electric market is without any change in legislation. However, to go to the last step where the incumbent pipe company is not allowed to sell gas, then legislation would be required to accomplish that. But I would see that as an, almost, housekeeping issue once the Board has set up the proper framework as we've set out here.[30]

EPCOR noted the further evidence of Mr. Engler that, "...the models are there [for the required changes in gas legislation] for that and they could be adopted relatively quickly."[31]

FGA

The FGA noted that without legislative amendment, the LDC could not exit the merchant function. It also noted that prudential requirements between the market participants and utilities were imperative, as were rules or processes for addressing complaints or failures to provide service, or to meet designated standards of service. It noted that as these matters are presently dealt with in the *Natural Gas Direct Marketing Regulation*, the Board may not have the ability to legally implement inconsistent requirements. The FGA argued that even with appropriate regulations, there was a need for market rules and codes of conduct to be developed and accepted by retailers in order to allow the competitive market a reasonable chance of success.

MI/UM

The MI/UM submitted that a working group should be established to identify, and address in detail, the specific legislative changes which would be required.

[30] Unbundling T: 2, p. 92, 1.23 through p. 93,1.12
[31] Unbundling T: 2, p. 94, 1.22 through p. 95,1.15

The MI/UM stated that they were pro-competition, and believed in the development of a retail market for natural gas in Alberta. They argued, however, that the market should not be allowed to develop in an unstructured manner, and in the absence of appropriate policy guidelines from the Government and/or the Board.

7.2.2 Views of the Board

The Board notes that parties have called for the enactment of the draft *Natural Gas Billing Regulation* (draft NGBR). Generally speaking, the Board also supports the enactment of the draft NGBR. The draft NGBR would regulate the activities of retailers, and the relationship between retailers and utilities, in ways which would protect consumers.

The Board notes that some parties have called for the repeal of the Core Market Regulation and some have argued that the Core Market Regulation should be retained. Both the Core Market Regulation and the draft NGBR contain provisions for the protection of consumers, and there is some overlap between these two regulations. It may be advisable to retain certain elements of the Core Market Regulation that are not reproduced in the draft NGBR, at least for a transition period prior to the development of a fully competitive market. In particular, the Board considers that it is in the public interest to retain section 7(1) of the Core Market Regulation, at least for a transition period. Section 7(1) of the Core Market Regulation provides that utilities must act as default supplier for direct purchase customers.

The Board has noted the evidence and argument of parties that the consumer protection bonding specified in the *Natural Gas Direct Marketing Regulation*[32] (NGDMR) does not provide an adequate guarantee against corporate default. Under the NGDMR, established pursuant to the *Fair Trading Act*[33], retailers must be bonded and licensed, follow a code of conduct, and meet other consumer protection requirements. The Board notes the evidence of parties that current bond levels are $250, 000. Given the evidence adduced in this proceeding regarding experiences in other jurisdictions[34], the Board agrees with parties that in most cases, $250,000 would be an inadequate bond. ENMAX suggested in argument that a flexible approach to retailer bonding may be appropriate. The size of the bond required could vary depending on factors such as the length of term of the contract between the retailer and the customer, and the number of customers the retailer has. The Board considers that the concept of flexible bonding is worth further examination.

7.3 Consumer Protection Changes

7.3.1 Positions of Parties

AltaGas

AltaGas believed that a proper collaborative process would be able to build on the experience of other jurisdictions to create a suitable consumer protection regime for the Alberta marketplace.

[32] AR 186/99
[33] S.A. 1998, c. F-1.05
[34] See e.g. Methodology T. 784, l. 8 to T. 786, l. 14

ATCO Gas

ATCO Gas submitted that there was a requirement for a code of conduct for retailers, which needed to be further reviewed by working groups.

AIPA/EUAA

AIPA/EUAA expressed concern that the ability of retailers to become established in Alberta with minimal bonding requirements exposed customers to potential additional costs, in the event that a retailer abrogated a contract where the contract price is lower than market price in the long term.

CCA

In the CCA's view, in addition to promoting customer awareness, consumer protection would require some form of adjudication, possibly undertaken by the regulator, and encompassing the imposition of penalties or sanctions on any participant. Until the market is sufficiently workable to incorporate some form of self imposed penalties, such as loss of market share, the CCA considered that some form of oversight was important.

Edmonton

Edmonton supported the Board taking a strong consumer protection role in overseeing the development of a competitive market. It recommended that this role include the regulation of marketers' practices, advertising, and marketing.

Enron

Enron noted that consumer protection is provided under the *Fair Trading Act* and under the NGDMR. Enron noted that retailers must be bonded (at a level of $250,000) and licensed, follow a code of conduct, and meet minimum standards. Retailer contracts must provide specific disclosure and meet other requirements.

Enron submitted that if changes to the bond level or consumer protection rules should be reviewed, these issues should be referred to a collaborative process, with the mandate of the participants being to recommend appropriate changes.

EPCOR

EPCOR submitted that adequate protection must be in place to prevent unethical marketing and sales practices, false representations, and inadequate disclosure. EPCOR also stated that market protection rules should not unnecessarily restrict the development of a fully functioning competitive market.

EPCOR supported the initiative of the Department of Energy to repeal the Core Market Regulation and to implement the Billing Regulation, and urged the Board to recommend implementation of this initiative in its decision.

FGA

The FGA stated that, regardless of the market oriented changes that may be considered, the customers' right to least cost and most cost-effective service and to the maintenance of a specific performance standard must be maintained. It stated that customers must not be subject to financial or other penalties due to market failure or breakdown, and should not be expected to pursue redress on their own. It argued that there may be a need for an advocate or monitor that can pursue customer concerns as a situation dictates.

The FGA noted that the need for improved customer protection was clearly made in Dr. Overcast's evidence. It noted that, in Georgia, a $15 million bond was barely adequate to cover stranded costs from the failure of Peachtree Gas. It stated that the current Alberta bonding requirement of $250,000 was woefully inadequate.

MI/UM

The MI/UM suggested that the following, which could be referred to a working group for consideration and recommendation back to the Board, should be developed to specifically address consumer protection:

- a transition with defined review periods to determine progress towards a fully functioning retail market;
- an assured source of supply from a "supplier of last resort";
- exit/entrance fees to compensate the incumbent utility and its customers for stranded and related costs;
- a retailer code of conduct tailored to the gas retail market;
- a billing regulation;
- adequate bonding requirements for retailers; and
- an adequate and readily available source of information to allow customers to make reasoned choices.

PICA

In PICA's opinion, market rules were required for the guidance of market participants. It stated that these might include legislation governing roles and responsibilities of market participants, affiliate code of conduct for gas utilities, and methods of load settlement.

7.3.2 Views of the Board

The Board is of the view that the addition of more stringent bonding requirements on gas retailers would be the most significant additional customer protection measure. These bonding requirements are discussed at length in section 7.1.2 of this Decision and will not be repeated here.

The Board has endeavored, through this Decision, to ensure that consumers are protected from market problems during the transition to the competitive market. The Board wishes to ensure that the move towards utility function unbundling proceeds at a measured pace to avoid stranding utility costs, and to ensure that there is no risk of consumers not having a gas supply.

The Board is of the view that the directions of the Board in this Decision are adequate to protect consumers during the transition to a competitive retail gas market. Because these issues have been addressed, the Board deems it appropriate to also ensure that there is a reasonable opportunity for the competitive retail market to develop. The Board is mindful that consumers should be protected from the harmful aspects of a transition to retail gas competition, but in protecting consumers the Board should not keep consumers from enjoying the benefits that retail competition may bring.

8 FURTHER PROCESS

8.1 Interim Rates

8.1.1 Positions of Parties

AltaGas

In AltaGas's opinion a great deal of collaborative work remained to be done before specific unbundling proposals could be put to the Board. It argued that any discussion of interim unbundled rates would likely slow down the actual unbundling process in AltaGas's case, rather than advance it.

ATCO Gas

ATCO Gas stated that it recommended development of interim unbundled rates by reducing the current delivery rates by an unbundling rider, developed by using extracted costs and forecasts. It further proposed that the final unbundled rates be the rates established in the 2001/2002 GRA. ATCO Gas also stated that AGN has a negotiated agreement in place until the end of 2002 and that any changes to that arrangement prior to January 1, 2003 would need to be negotiated by the NCC.

AIPA/EUAA

AIPA/EUAA considered that the first phase of the collaborative process would identify interim, unbundled rates that would reflect the transfer of direct costs associated with gas management to the GCRR.

AIPA/EUAA suggested that for the first phase of the collaborative process, a filing of a proposed rate reflecting transfer of costs to the procurement function could be accomplished in the timeframe between October 2001 and January 2002. The outcome would be a GCRR forecast for a monthly, seasonal, or annual period, incorporating the transfer of estimated additional procurement costs and a credit rate rider reflecting the transfer of such costs from the delivery function.

CCA

The CCA was not supportive of the adoption of interim rates, on the basis that unbundling of costs had not been addressed in sufficient detail to date, and in the absence of compelling reasons presented by parties.

Calgary

Calgary stated that interim rates would be required for an initial start up of January 1, 2002. It expected that these rates would be in effect for six months or more until a final unbundled rate design was developed out of the AGS 2001/2002 GRA. Calgary argued that to meet the January 1, 2002 timeframe, the current AGS service rates should be those unbundled.

Calgary argued that failure to adopt interim rates would only serve to delay the unbundling process for over a year. It argued that adopting an interim process would allow changes to be implemented as the process unfolds through collaborative working groups, with the Board's guidance and approval. It also noted that events such as the proposed sale of the ATCO Gas merchant function, and the proposed deregulation of Carbon storage, should be addressed in the context of the current GRA. It argued that both of these events had the potential for dramatic impacts on the ultimate rates that would emerge from the current AGS GRA.

Calgary argued that there was no need for interim rates based upon the criteria set forth by ATCO Gas. It noted that there were currently Board approved rates for AGS, in effect, which could be unbundled in the same manner in which they were designed. It argued that there was no need to introduce an artificial set of billing determinants based upon the 2001/2002 forecast. Calgary argued that the current rates could be unbundled based upon the parameters and criteria under which they were developed and approved by the Board. Calgary supported the implementation of unbundled currently effective rates on an interim basis, until final rates are developed in the present AGS GRA.

Calgary supported unbundling the current AGS delivery rates effective September 1, 2000 based on a Board approved class cost of service study. It argued that these rates could be analyzed as to cost structure, the cost embedded in each function, and unbundled in a straightforward manner.

Calgary countered the MI position that the required cost of service information to unbundle rates did not exist. Calgary noted that the existing rates reflected the Board approved rates under the conditions set forth in the 1998 CWNG GRA. It noted that ATCO I-Tek and Singlepoint were not reflected in the current rates. It argued that if unbundling was to start in early 2002, the only Board approved rates available were the current AGS rates.

ENMAX

ENMAX was of the view that there might be no need for interim rates, depending on the timing of the completion and adoption of the workshop process.

ENMAX stated that if new rates were implemented prior to unbundling, but after the market was scheduled to open, the new rates might be a surcharge to rates based on the current cost study and unbundled as part of the market opening.

Enron

Enron submitted that, as approval of final unbundled rates would not be possible for some time, an interim rate approach should be adopted to quickly fix the recognized gas supply cost impacts, and to identify unbundled rates for other functions in order to provide benchmarks that would allow the market to begin objectively evaluating competitive services.

Enron noted that such interim rates would increase interest in the retail natural gas Core market, and would also provide information to marketers to enable them to evaluate the provision of competitive services. The processes for retailers providing competing retail services would be determined by the collaborative group to minimize impacts to all customers.

Enron submitted that if the proposed changes to gas supply related costs and interim unbundled rates were not made, customers who selected direct purchase options and other retail services would continue to subsidize other customers on existing sales rates.

Enron submitted that interim rates could be based on direct costs of functions identified in the underlying cost studies supporting the current rates.

EPCOR

EPCOR submitted that deferring any unbundling until a recommendation from the collaborative process, or until the decision in the utilities' next GRA's, would unnecessarily delay the development of a competitive retail market for gas. It argued that implementation of interim rates would result in benefits of unbundling being realized at the earliest practical date. It noted from the witnesses for Enron and ENMAX, that interim rates would provide a signal to the marketplace that there was an opportunity. It argued that the most cost-effective way to open the market was to have a rapid transition.

EPCOR proposed to extract the currently approved costs for retail functions from the cost of service study underpinning the utilities' current rates. Further, the gas supply costs would be placed in the DGA and form part of the GCRR. It proposed that the retail costs would be determined on a stand-alone basis, and would be grouped with the GCRR for display as a "supply" or "retail" charge on customers' bills. It further proposed that the remaining delivery charge would be adjusted for the extraction of these cost items.

EPCOR noted one exception to its proposed methodology, the treatment of production and gathering assets. These assets would be subject to the treatment put forward by the NCC for this function.

EPCOR argued that, based on the evidence, there appeared to be relevant cost of service studies for all utilities. It also noted the witness for PICA, Mr. Retnanandan, had provided assurance that the North Core Settlement would not pose an impediment to unbundling the rates of AGN.

EPCOR submitted that its proposed methodology of unbundling only currently approved direct costs provided simple, timely, and uncontroversial interim rates. It recommended that all other deliberations be left to the collaborative process. EPCOR stated that the continued bundled nature of ATCO Gas distribution rates constituted a significant barrier to competition that must be addressed at the earliest practical date to ensure the timely development of a fully competitive market for retail gas sales.

FGA

The FGA noted that the NCC and the interveners participating in the AltaGas negotiations for the 2000, 2001, and 2002 GRA had indicated that they were prepared to work with the utilities and retailers to develop unbundled rates for the gas supply function. It noted that this step would see those costs recognized as being directly related to procuring and managing gas supply identified, and transferred from the respective utility cost of service to the appropriate GCRR.

The FGA recommended that the Board approve requests for rate changes based on discussion and/or negotiation among interested parties and retailers.

The FGA stated that there was a real constraint to unbundling rates for AGN, in that the current performance-based rates agreement extended to December 31, 2002. It noted that there was no recent cost of service study that could allow meaningful functionalization of costs or unbundling of services for AGN.

The FGA noted in the case of AGS that the 2001/2002 GRA was still before the Board, and that this was subject to further adjustment through the ATCO Affiliate Transactions and Pensions proceedings.

The FGA stated that it might be prudent for the Board to direct that all future cost of service studies be required to incorporate the elements of unbundling, as referenced during this proceeding.

The FGA did not support development of unbundled rates without first having appropriate legislation and regulation in place, including better consumer protection legislation than existed. It cautioned that even with those prerequisites in place, there were still many questions to be answered with respect to unbundled rates and services. It stated that, under no circumstances should the Board approve interim unbundled rates without significant and substantive customer approval.

MI/UM

The MI/UM submitted that the current cost of service data required to unbundle the customer care functions did not exist at the current time. The MI/UM argued, however, that non-contentious direct gas supply and portfolio management costs could be moved to the DGA. This it submitted was the practical extent to which costs should be moved, and interim rates implemented at this time.

8.1.2 Views of the Board

In section 5 of this Decision, the Board has directed the utilities to file interim rates addressing:

- Allocation to the GCRR of certain direct costs associated with utility gas management.
- Allocation of costs and benefits of company owned production.
- Allocation of costs and benefits of company owned gas storage used for price management.

The Board directed AGS and AltaGas to file interim rates, effective April 1, 2002, addressing the direct costs associated with these issues. AGN has been directed to provide a proposal as to how to implement interim rates addressing these issues within 30 days of the issuance of this Decision. The Board is of the view that these items are of critical importance to the fair allocation of costs between utility and direct supply customers. These costs and benefits are also readily identifiable.

8.2 Further Regulatory Process

8.2.1 Positions of Parties

AltaGas

AltaGas stated there was the need for those affected by changes in the system to work together on developing both the desired end result and the means of getting there.

AltaGas believed that two types of issues would need to be addressed in creating a competitive retail gas marketplace. The first were generic issues that require legislation or Government policy decisions – things like marketplace rules and consumer protection measures. The second were issues that were more system specific and may benefit from approaches that fit the specific system – things like GCRR and DGA unbundling. Given the different nature of the issues, AltaGas suggested two types of parallel collaborative processes – a framework forum and two (AltaGas and ATCO Gas) specific system workgroups.

AltaGas stated that in this approach the framework forum would focus on the framework of legislation and policies required for a competitive marketplace. This would address things like consumer protection and establish market rules. It would benefit from Government participation. The specific system workgroups would focus on developing unbundling proposals for their systems. With this approach there would be a workgroup for the AltaGas system and a workgroup for the ATCO Gas system. Each would develop its own process to achieve objectives set by the Board.

ATCO Gas

ATCO Gas stated that it would file its Phase II application based on the results of the 2001/2002 GRA Phase I decision and any unbundling decisions resulting from this proceeding.

ATCO Gas considered that a consultative process would help speed unbundling along, once the Board has established guidelines for unbundling. It noted that unbundling for AGN would require negotiations between it and the NCC, if any changes were to occur prior to January 1, 2003.

AIPA/EUAA

AIPA/EUAA submitted that the second phase of the collaborative process would examine the remaining issues of the assignment or allocation of costs between delivery, procurement, and retail functions, and would identify stranded costs and mitigation measures.

CCA

The CCA expressed support for creation of a task force to operate under defined parameters and mandate, charged with the objective of presenting a collaborative proposal to be tested in accordance with the test mandated by the Board. The CCA submitted that it was important not to lose sight of the fact that consideration must be given to how the unbundling proposal should be tested, preferably by conducting a cost benefit analysis. The CCA stressed the importance of the Board's expressed concern that there should be "a reasonable expectation that customers will be no worse off".

Contrary to the views of ENMAX and EPCOR, the CCA supported a facilitated process. The CCA disagreed with the ENMAX proposal, to the extent that ENMAX favored acceptance of recommendations based on majority approval and favored striking from the issues list any problem where a solution had not been found.

Calgary

Calgary proposed that following reply arguments a decision could be produced by the Board providing the establishment of a working group with highly defined criteria as to the Board's expectations and guidance on the issues. In reviewing the regulatory calendar, Calgary proposed starting the working group sessions in late October or early November, 2002, with a well-defined plan and a set of operating parameters providing a time line in which current AGS rates could be unbundled. Calgary argued that, given the experience of potential members of the working group in the area of unbundling, meeting the January 1, 2002 date for AGS would not be unrealistic.

ENMAX

ENMAX recommended that the Board hold a hearing on the workshop reports to allow the Board and its staff the opportunity to examine the reports. ENMAX believed that there was a significant advantage to adopting the rules for competition prior to the investment in resources to implement competition. It argued the advantage was that the systems required to implement competition would be less costly to construct and implement with known rules.

ENMAX submitted that the Board had the jurisdiction to order each of the gas utilities under its jurisdiction to unbundle and price separately each of the services identified in ENMAX's submissions

ENMAX believed that it was clear that the provincial Government expected that a deregulated, competitive market would lead to lower prices for Alberta consumers.[35] ENMAX believed that the provincial Government had also stated that it expected that the resolution of matters before the Board, including the unbundling of gas rates, would facilitate retail competition in natural gas, and had clearly indicated that the Government would "take all possible steps to encourage and facilitate real competition in retail gas and electric markets."[36]

In conclusion, ENMAX recommended that the Board:

[35] Letter from Alberta Energy to the AUMA, May 2, 2001, Exhibit 29.
[36] *Ibid.*

- immediately eliminate the DGA;
- direct ATCO Gas to immediately implement monthly GCRR rate adjustments;
- set out the principles for the desired market end-state as specifically as possible;
- establish a structured workshop process as set out in their argument, to start October 1, 2001, and to conclude on a date specified by the Board;
- indicate that a hearing would be held at the conclusion of the workshop process to consider the results of the workshops and make those rulings that were required to achieve the desired unbundled and competitive market end-state by early summer 2002; and
- advise the Department of Energy with respect to proposed changes to legislation required to achieve the desired market end-state.

EPCOR

EPCOR supported having the collaborative process examine:

- the need for changes to the market rules;
- existing regulations, practices, terms and conditions of service, and rate schedules, to remove provisions that can be demonstrated to be redundant, an unnecessary impediment to the development of a fully functioning retail gas market, or that have been overtaken by market developments, and
- ATCO Gas's Phase I and Phase II GRA filings, revised to reflect the Board's directions on unbundling.

Although EPCOR supported a collaborative process, it stated that such a process would not be successful unless the Board provided clear directions respecting the policies that were to be reflected in the deliberations, a timetable with milestones and reporting back to the Board, and a hearing date established to address any consensus reached through the collaborative process and to adjudicate any unresolved issues.

FGA

The FGA supported the use of a collaborative process to identify and address as many issues as possible to expedite the regulatory process. It suggested that the Board could direct that parties structure working groups to address issues of immediate need or relevance, to assist in developing an orderly and rational process. It noted that the Board's current regulatory schedule had little excess capacity to allow such working groups or collaborative processes in the 2001 calendar year.

MI/UM

The MI/UM submitted that the Board should sanction a working group to embark on a further collaborative process to address the unbundling of costs for competitive services and to make recommendations to the Board, where possible, or to identify those issues that could not be resolved and need to be litigated.

To facilitate unbundling, the MI/UM favored the use of workshops that involved discrete topics or functions. The MI/UM proposed that the Board establish guidelines for the working group to address, debate, and make recommendations regarding a number of issues that have been identified in this proceeding.

When addressing unbundling issues, the MI/UM argued that the public interest should place customers' interests first and foremost since unbundling and competition are intended to benefit customers.

The MI/UM generally supported the recommendations of ENMAX set forth in its rebuttal evidence entitled *Process for Implementing Unbundling and Development of Competitive Retail Market.*

The MI/UM reiterated that all recommendations should be submitted to the Board by year-end, with the expectation that implementation could be made by April or May 2002.

8.2.2 Views of the Board

The Board notes that more detailed work is required to resolve the outstanding issues that arise in the context of a distribution tariff for natural gas.

The further steps required to allocate indirect costs to utility functions, and to establish rates based on the unbundling of functions described in section 6.3 of this Decision, will take time to establish. The Board is of the view that it is important that these rate changes are accurate when implemented. On that basis, in section 6.1.2 of this Decision, the Board has directed AGS and AltaGas to file an unbundling allocation study and proposed rates within 90 days of the issuance of an approved revenue requirement. AGN is to report to the Board within 30 days of release of this Decision as to how it would propose to undertake a similar unbundling allocation study, or provide an acceptable surrogate to such a study. This information will serve as a basis for finalizing unbundled distribution rates to be determined following further proceedings on final unbundled rates.

Also, the Board notes that the experience gained in other jurisdictions will be invaluable in evaluating options for market rules and protocols needed for the transition to a fully competitive Alberta retail gas market. The Board is of the view that issues remain that require resolution prior to the full functioning of the Alberta retail gas market. These issues could not be reviewed in sufficient detail during the Unbundling proceeding and are generally of a detailed technical nature. They include:

- detailed market rules;
- electronic data exchange standards;
- operational protocols; and
- retailer bonding requirements.

The Board intends to examine options for review of these issues with parties following the release of this Decision.

9 OTHER ISSUES

9.1 Aboriginal Issues

The Aboriginal Communities (AC) referred to subject areas where federal jurisdiction might apply. By way of illustration, the AC indicated that a municipal council could by agreement grant a right, exclusive or otherwise, to a person to provide utility service in the Municipality for not more than 20 years. The AC pointed out that a Band council might, with a written permit from the Minister, use or exercise rights on a reserve for a period in excess of one year. The AC expressed concern that, while Federal permits emphasize that the underlying rights shall not be assigned or transferred, the Province encourages corporate exchanges as long as “no harm” is demonstrated. The AC noted that the Federal system does not appear to encourage change or encourage debate on how elements of gas bills should be allocated or redistributed between pipe owners, gas procurers or retailers.

The AC pointed out that the First Nation or Band would, as is the custom, look to the Permittee or Franchisee and rely on sanctity of contract, which could include the requirement to supply gas along with the necessary merchant function. In other words, the AC submitted that the First Nations would lean to supporting the status quo.

9.1.1 Views of the Board

The Board notes that the AC have concerns regarding unbundling. In section 3.2 of this Decision, the Board stated the view that the supplier of last resort function should be retained by gas utilities as is provided for currently in the Core Market Regulation. Thus, the AC will have the option of remaining with the utility if that is their preference.

9.2 Franchise Agreements

9.2.1 Positions of Parties

ATCO Gas

ATCO Gas agreed that changes in the regulatory treatment of costs should not impact franchise fees for communities.

MI/UM

The MI/UM submitted that most franchise agreements would need to be reviewed if competitive retailers provide functions that were currently provided in the utilities’ base rates, because the municipalities would not be revenue neutral if a portion of their revenues, otherwise received under the franchise agreements, were transferred to a retailer.

9.2.2 Views of the Board

The Board agrees with MI/UM that under most franchise agreements, municipalities will not be revenue neutral if competitive retailers provide functions that are currently provided in base rates. The Board anticipates that municipalities in these circumstances may wish to negotiate an amendment to existing franchise agreements to provide that franchise fees are levied on the base distribution tariff only. Based on section 45 of the Municipal Government Act, any amended franchise agreements will need Board approval. The Board notes that this is not a new issue, as certain municipalities already levy franchise fees on base distribution tariffs only.

10 SUMMARY OF BOARD FINDINGS AND DIRECTIONS

The following summary of Board findings and directions is provided for the convenience of parties. Should there be any discrepancy between this summary and the body of the Decision, the views of the Board stated in the body of the Decision will prevail.

1. The Board directs that the gas utilities continue to provide regulated gas supply and merchant services to customers. (Section 3.1.2)

2. The Board directs that regulated gas utilities continue to provide both supplier of last resort service and default supply service. (Section 3.2.2)

3. There is no end date for utility gas supply service specified in the Decision. This issue may be re-addressed in the future. (Section 3.3.2)

4. The Board has found that a mix of daily spot market purchases, and daily and monthly index gas contracts is a reasonable utility gas portfolio. Long term gas contracts that are already in place will be continued, but should not be renewed. (Section 4.1.2)

5. The Board is of the view that, at this time, the hedging provisions of the AltaGas Proposal are not necessary for the protection of AltaGas consumers. (Section 4.1.2)

6. The Board directs that the AGS Carbon storage facility costs and benefits are to be treated in accordance with the NCC COP Rider proposal. The treatment of the AGN Salt Cavern storage facility will be reviewed in a further proceeding. The contract storage agreements approved in Decision 2001-22 for AGS and Decision 2001-23 for AGN will be continued until March 31, 2002. (Section 4.2.2)

7. Beginning April 1, 2002, utility GCRRs will be adjusted monthly. Utilities will file rates for acknowledgement each month. A 30 day review period will be provided for parties to raise any concerns with the GCRR. The GCRRs will be based on a three month rolling reconciliation of DGA balances. The Board directs the utilities to file a mock February 2002 GCRR on February 1, 2002, for review by the Board and interested parties. (Section 4.3.2)

8. The Board directs the utilities to continue with current practices for forecasting monthly sales volumes. The utilities are directed to prepare and file a proposal for establishing their GCRRs on monthly market index prices, attempting to most accurately forecast the actual gas cost for each month, within 30 days of the release of this Decision. (Section 4.5.2)

9. The Board directs that no entrance or exit fees provisions are to be included in the regulated gas rate offerings provided for in this Decision. (Section 4.7.2)

10. The Board directs the utilities to file with the Board a proposed exit notice provision for their regulated gas rates that is as short as can be facilitated administratively. This is to be filed by February 1, 2002. (Section 4.8.2)

11. The Board is of the view that, as an interim measure, the following direct costs should be transferred from utility cost of service to the GCRR through interim rates:

- gas purchase costs;
- imbalance costs net of imbalance revenue;
- transportation costs upstream of the utilities' pipeline systems;
- GCRR portfolio management and administration costs;
- transportation receipt costs;
- GCRR gas supply-related bad debts; and
- DGA balance carrying costs.

AGS and AltaGas are directed to undertake an examination of all other costs, related to the gas acquisition and management function, whether direct or indirect, and provide a report to the Board on these costs within 90 days of the date on which the Board issues their forthcoming approved Phase I revenue requirements. AGN is directed to report to the Board within 30 days of release of this Decision as to how it would propose to undertake a similar examination of gas acquisition and management costs, or provide an acceptable surrogate to such an examination.

The Board directs AGN and AGS to apply the NCC COP Rider methodology for the treatment of company owned production costs for inclusion in interim rates. The Board directs that storage costs and benefits be treated in the same manner as the NCC COP Rider for inclusion in interim rates.

The Board directs AGS and AltaGas to file for interim rates by February 1, 2002, based on the transfer of the direct gas supply costs noted above, as well as the Board's approved treatment for company owned production facilities and storage facilities used for gas price management, using the most recent approved revenue requirement. These interim rates are to come into effect April 1, 2002, coincident with the change to monthly GCRRs. The Board directs AGN to provide a report to the Board, within 30 days of the release of this Decision, as to how it would propose to file for interim rates on a similar basis. (Section 5.1.2)

12. The Board directs AGS and AltaGas to file with the Board an unbundling allocation study within 90 days of the date on which the Board issues its forthcoming approved Phase I revenue requirements. These studies are to provide:

- an allocation of costs between base rates and GCRRs based on the directions made in this Decision;
- an allocation of all applicable direct costs, indirect costs, and overheads for each of the following functions:
    - o Transmission

    - Storage services
    - Meters
    - Billing
    - Customer information systems
    - Call centres
    - Credit and collections
    - Customer enrollment
    - Load settlement
    - Load balancing
    - Marketing and customer information
- an examination of the operations and requirements of each function, describing how these may change during a transition to a fully competitive market;
- an assessment of the potential for stranded costs for each function;
- an assessment of the effect of unbundling on indirect costs and overheads by function; and
- proposed rates reflecting the views of the Board in this Decision.

These studies will provide the basis for further proceedings to finalize rates for unbundled services.

The Board directs that AGN is to report to the Board within 30 days of release of this Decision as to how it would propose to undertake a similar unbundling allocation study, or provide an acceptable surrogate to such a study. (Section 6.1.2)

13. The Board directs the utilities to separate the costs associated with retail billing from the base rate in accordance with the schedule set out in section 6.1.2 of this Decision, and to subsequently levy charges related to those costs only to regulated service customers. The utilities are directed to file a rate for the provision of billing information to retailers at the time of filing their unbundling allocation studies, as directed in section 6.1.2 of this Decision. (Section 6.6.2)

14. The Board directs the utilities to separate the costs associated with retail customer service (including distribution service) from the base rate in accordance with the schedule set out in section 6.1.2 of this Decision, and subsequently levy charges related to those costs only to regulated service customers. The utilities are directed to file a rate for provision of call centre services related to basic distribution service only, for direct connect customers, at the time of filing their unbundling allocation studies as directed in section 6.1.2 of this Decision. (Section 6.8.2)

15. The Board directs the utilities to unbundle credit and collections costs for inclusion in the base rates of utility supply customers only. This is to be filed as part of the unbundling allocation study directed in section 6.1.2 of this Decision. (Section 6.9.2)

16. The utilities are directed to justify their enrolment charges when filing their unbundling allocation studies, as directed in section 6.1.2 of this Decision. (Section 6.10.2)

17. The utilities are directed to establish deferral accounts to collect stranded costs arising from the Board's findings in this Decision. These deferral accounts will be considered at the next respective GRAs of the utilities. (Section 6.16.2)

11 ORDER

Therefore the Board orders that the parties implement the directions set out in this Decision within the time frames specified.

Dated in Calgary, Alberta on October 30, 2001.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

B. T. McManus, Q.C.
Presiding Member

(original signed by)

B. F. Bietz, Ph.D.
Member

(original signed by)

T. M. McGee
Member

APPENDIX A - THOSE WHO APPEARED AT THE HEARING

Principals and Representatives
Abbreviations used in Report

METHODOLOGY PROCEEDING

ATCO Gas and Pipelines Ltd. (ATCO Gas)	Mr. L. E. Smith Ms. K. Illsey Mr. T.J. Simard Mr. J. Engler Mr. R. Trovato Mr. M. Hagan Mr. J. Gordon
AltaGas Utilities Inc. (AltaGas)	Mr. F.V. Martin Mr. L. Heikkinen Mr. A. Mantei
Aboriginal Communities	Mr. J. Graves
Alberta Irrigation Projects Association and Energy Users Association of Alberta (AIPA/EUAA)	Mr. J. H. Unryn
City of Calgary (Calgary)	Mr. R. B. Brander Ms. P. Quinton-Campbell Dr. N. Carruthers Mr. H. Johnson Ms. N. Stewart Mr. K. VanderfSchee Mr. P. Milne Mr. H. Vander Veen
City of Edmonton (Edmonton)	Mr. W. Follett
Consumers Coalition of Alberta (CCA)	Mr. J. A. Wachowich Mr. J. Todd Mr. J. Jodoin
ENMAX Energy Corporation (ENMAX)	Mr. L. A. Cusano Mr. D. Wood Mr. K. Willerton Dr. E. Overcast
Enron Canada Corp. (Enron)	Mr. H. Huber
EPCOR Energy Services (Alberta) Inc. (EPCOR)	Mr. H. Williamson Mr. E. De Palezieux
Federation of Alberta Gas Co-ops Ltd. And Gas Alberta Inc, and Municipal Gas and Co-op Intervenors (FGA)	Mr. T. Marriott Mr. M. Heck Mr. D. Campbell Mr. D. Symon

Mirant Americas Energy Marketing Canada Ltd. (Mirant)	Ms. E. Decter Mr. T. Lange
Municipal Intervenors and Urban Municipalities (MI/UM)	Mr. C. McCreary Mr. R. Bruggerman
North Core Committee (NCC)	Mr. J. A. Bryan Mr. R. Liddle Ms. N. Stewart
Public Institutional Consumers Association (PICA)	Ms. N. McKenzie Mr. R. Retnanandan

BOARD PANEL

Mr. B. T. McManus, Q.C	Chairperson
Dr. B. F. Bietz	Member
Mr. T. M. McGee	Member

BOARD STAFF

Ms. J. Hocking	Board Counsel
Mr. A. Domes	Board Counsel
Mr. W. Vienneau, CMA	
Mr. D. R. Weir, C.A.	
Mr. R. Armstrong, P.Eng.	

APPENDIX B - THOSE WHO APPEARED AT THE HEARING

UNBUNDLING PROCEEDING

ATCO Gas and Pipelines Ltd. (ATCO Gas)	Mr. L. E. Smith Ms. K. Illsey Mr. J. Engler Mr. R. Trovato
AltaGas Utilities Inc. (AltaGas)	Mr. F.V. Martin Mr. L. Heikkinen
Aboriginal Communities	Mr. J. Graves
Alberta Cogenerators Council	Mr. R. Secord Mr. R. Jeerakathil
Alberta Irrigation Projects Association and Energy Users Association of Alberta (AIPA/EUAA)	Mr. J. H. Unryn
City of Calgary (Calgary)	Mr. R. B. Brander Ms. P. Quinton-Campbell Mr. H. Johnson Mr. H. Vander Veen
City of Edmonton (Edmonton)	Ms. M. Sherk Mr. W. Follett
Consumers Coalition of Alberta (CCA)	Mr. J. A. Wachowich Mr. J. Todd Mr. J. Jodoin
ENMAX Energy Corporation (ENMAX)	Mr. L. A. Cusano Mr. D. Wood Dr. E. Overcast
Enron Canada Corp. (Enron)	Mr. H. Huber Mr. J. Keene Mr. D. Vetsch
EPCOR Energy Services (Alberta) Inc. (EPCOR)	Mr. H. Williamson Mr. E. De Palezieux Mr. G. Newcombe
Federation of Alberta Gas Co-ops Ltd. And Gas Alberta Inc, and Municipal Gas and Co-op Intervenors (FGA)	Mr. T. Marriott Mr. L. Burgess Mr. M. Heck Mr. D. Campbell Mr. D. Symon
Mirant Americas Energy Marketing Canada Ltd. (Mirant)	Ms. E. Decter Mr. T. Lange
Municipal Intervenors and Urban Municipalities (MI/UM)	Mr. J. A. Bryan Mr. R. Bruggerman
PanCanadian Petroleum Limited	Mr. P. Kahler

Public Institutional Consumers Association and Canadian Forecst Products	Ms. N. McKenzie Mr. R. Liddle Mr. L. Manning
(PICA/Canfor)	Mr. R. Retnanandan
Top Grade Solutions	Mr. W. K. Ferguson

BOARD PANEL

Mr. B. T. McManus, Q.C	Chairperson
Dr. B. F. Bietz	Member
Mr. T. M. McGee	Member

BOARD STAFF

Ms. J. Hocking	Board Counsel
Mr. A. Domes	Board Counsel
Mr. W. Vienneau, CMA	
Mr. D. Gray	