ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

ALTAGAS UTILITIES INC. AND
BONNYVILLE GAS COMPANY LIMITED **Decision 2002-027**
GENERAL RATE APPLICATION **Application No. 2000283 (1237650)**
FOR TEST YEARS 2000/2001/2002 **File No. 1402-8**

1 INTRODUCTION

By letter dated September 29, 2000, AltaGas Utilities Inc. (AltaGas) and Bonnyville Gas Company Limited (Bonnyville) (collectively, the Utilities or AUI) filed a 2000/2001/2002 General Rate Application (GRA or the Application) with the Alberta Energy and Utilities Board (the Board). Specifically, the Utilities applied for:

- determination of revenue requirement and rates for AltaGas for the test year 2000;
- determination of revenue requirement and rates for Bonnyville for the test year 2000; and
- determination of revenue requirement and rates for AltaGas (with Bonnyville merged) for the test years 2001/2002.

In the filing, the Utilities also indicated the intent to negotiate the Application with customer representatives with a view to achieving a settlement proposal for presentation to the Board for consideration and approval. By letter dated October 23, 2001, the Utilities indicated that representatives of the Companies and customer groups undertook a Negotiated Settlement Process on October 25, 2000, with a view to reaching agreement on the Phase I portion of the Application, dealing specifically with revenue requirement and rate base. The Utilities indicated that the Phase II portion of the GRA to fix schedules of rates, tolls and charges for the Utilities, would be filed in due course.

In the October 23, 2001 letter, the Utilities indicated that the process to arrive at a negotiated settlement had continued through to September 25, 2001, and that the parties had reached agreement on all issues raised in the Phase I portion of the GRA, with the exception of Rate of Return on Common Equity and Capital Structure. The parties requested that the Board adjudicate these issues. Also, Post-Employment Benefits were not resolved pending the outcome of the same issue filed by the ATCO Group. Both parties agreed to comply with the Board's decision in that case.

On November 14, 2001, the Utilities filed a "Memorandum of Agreement" in support of the Phase I portion of the GRA, setting out details of these unresolved issues and other matters agreed in the Negotiated Settlement Process.

The participants to the Negotiated Settlement were:

- Municipal and Gas Co-op Intervenors
- Consumers' Coalition of Alberta
- Urban Municipalities
- Bonnyville Municipal Intervenors
- Energy Users Association of Alberta

(collectively, the Interveners).

A member of Board staff attended the negotiation meetings

On receipt of the Application on September 29, 2000, the Board published a Notice of Proceeding, advising parties of the GRA filing and the proposed negotiated settlement process. The Notice was published on October 9, 2000 in the Calgary Herald, the Calgary Sun, the Edmonton Journal and Edmonton Sun, and by October 13, 2000 in all other newspapers operating in the service areas of AltaGas and Bonnyville. Notice was also E-Mailed on or before October 13, 2000 to interested parties on the Board's mailing list for the Utilities.

On November 21, 2001, the Board published a Notice of Hearing advising parties of the outcome of the negotiated settlement, and scheduling a public hearing on January 10, 2002. The Notice was published in the Calgary Herald, the Calgary Sun, the Edmonton Journal and Edmonton Sun. Notice was also E-Mailed on November 19, 2001 to interested parties on the Board's AltaGas mailing list.

The public hearing of Phase I of the proceedings was held on January 10, 2002, for the purpose of considering submissions in support of the Application, including the unresolved issues to be adjudicated, and to consider any submissions from parties objecting to the Application.

The Board has concluded its review and examination of the Application and the Memorandum of Agreement. This Decision sets forth the background, particulars of the Application, adjustments made as a result of the Negotiated Settlement, and Board findings with respect to the negotiated settlement and the issues adjudicated at the public hearing.

2 BACKGROUND

The last GRA by AltaGas (then Centra Gas Alberta Inc.) was filed on March 9, 1995 for the test years 1995 and 1996. The Board issued Decision U96116, dated December 16, 1996, approving rates, tolls and charges effective for all consumption on and after January 1, 1997.

The last GRA by Bonnyville was filed on November 4, 1996 for the test years 1997, 1998 and 1999. The Board issued Decision U98059, dated May 20, 1998, approving rates, tolls and charges for Bonnyville, effective for all consumption on and after January 1, 1999.

In the Application, the Utilities indicated the intention to file an application with the Board for approval of a merger of AltaGas Utilities Inc and Bonnyville Gas Company Limited. On March 28, 2001, the Board issued Decision 2001-24, dated March 28, 2001, approving the merger based on an application filed by the Utilities on March 1, 2001. To correspond with the amalgamation, the GRA contained information separately for the two companies for the 2000 test year, and consolidated information for the 2000, 2001 and 2002 test years.

2.1 The Public Hearing

As indicated in Section 1 of this Decision, a public hearing was held in Edmonton on January 10, 2002, for the purpose of considering submissions in support of the Application, including the unresolved issues to be adjudicated, and to consider any submissions from parties objecting to the Application. No submissions were received from parties objecting to the Application, but interveners objected to certain issues: Rate of Return on Common Equity and Capital Structure, and Post-Employment Benefits.

The public hearing was convened before Board members Mr. R. G. Lock, P. Eng. Presiding, Mr. G. J. Miller and Mr. J. Gilmour. Registered interveners and the Utilities were directed to file written argument and reply on January 28, 2002 and February 4, 2002 respectively. The Board considers the record for this proceeding closed on February 4, 2002.

Those who appeared at the hearing and the abbreviations used in this report are listed in the Table filed as Appendix "A" to this Decision.

3 PARTICULARS OF THE APPLICATION

In the Application, the Utilities forecast revenue requirements for the combined entities of $88.4 million for 2000, $98.5 million for 2001 and $102.5 million for 2002. Based on these revenue requirements, the Utilities forecast revenue deficiencies of $1.3 million in 2000, $2.1 million in 2001, and $3.2 million in 2002.

The Utilities indicated that the main factors contributing to the revenue deficiencies were as follows:

	2000	2001	2002
Increased Operating Expense	$1,844,704	$2,033,841	$2,190,378
Increased Depreciation Expense	30,125	834,977	1,115,774
Increased Return	1,035,963	1,061,723	1,256,200
Income and Other Taxes	(686,683)	(150,020)	747,918
Subtotal	$2,224,109	$3,780,521	$5,310,270
Less: Increased gross margin and other income	962,125	1,704,598	2,089893
Revenue Deficiency	$1,261,984	$2,075,922	$3,220,377

The Utilities submitted that, based on these results, the rate of return on mid-year capital (rate base plus unsuccessful exploration and development costs) would be 5.71% (2000) compared to 6.25% requested, 5.17% (2001) compared to 6% requested and 4.75% (2002) compared to 6%

requested. The Utilities indicated that, without requested relief, the rate of return on common equity would be 9.46% (2000), 8.36% (2001) and 6.81% (2002) compared to a requested return of 11.5%. The Utilities submitted that the projected shareholder return was not sufficient to allow the Companies to attract the capital required to continue to provide safe, reliable and cost effective service.

The Utilities proposed that, to avoid a rate increase in 2000, the revenue deficiency in the 2000 test year would be offset by deferred revenues related to changes in income tax deductions and gain on sale of assets.

4 THE NEGOTIATED SETTLEMENT

By letter dated October 23, 2001, the Utilities notified the Board that, as a result of the negotiated settlement process, which concluded on September 25, 2001, the Utilities had agreed with its customers to adjust the Application. Details of the adjustments, supporting documentation, and revised Application schedules, were set out in a Memorandum of Agreement (MOA), ratified by all parties participating in the negotiated settlement, and filed with the Board on November 14, 2001.

In the MOA, the parties indicated that agreement had been reached on all issues raised in the Phase I portion of the GRA, with the exception of:

- **Rate of Return on Common Equity/Capital Structure**
  The parties could not reach resolution on a fair rate of return on common equity or an appropriate capital structure. The parties requested that the Board adjudicate this issue.

- **Post-Employment Benefits**
  In accordance with Section 3461 of the Canadian Institute of Chartered Accountants (CICA) Handbook, the Utilities account for post-employment benefits for financial statement purposes on an accrual basis. The parties have requested that the Board rule on the issue as to whether or not post employment benefits should be accounted for pursuant to Section 3461 of the CICA Handbook. The Utilities indicated that the circumstances with respect to post-employment benefits paralleled those of ATCO Group, and the request acknowledged that ATCO Group filed an application with the Board to deal with this specific issue, which was heard by the Board in late 2001. AUI would accept the outstanding Board Decision on the ATCO Group's application and incorporate Post-Employment Benefits following approved accounting and financial procedures.

As indicated in Section 1 of this Decision, the Board scheduled a public hearing on January 10, 2002, during which, evidence was heard with respect to these issues. Details of the public hearing process are set out in Section 6 of this Decision.

Details of all other issues raised by the negotiating parties and resolved in the negotiated settlement process were documented in the MOA. The resolution of the issues was documented together with the related impact on the Application. The following adjustments to the application were agreed to and reflected in the MOA:

a) Cost of Gas
Gas cost estimates in the Application were adjusted to reflect the gas cost recovery rate (GCRR) approved for the 2001/2002 winter period, and any related GCRR adjustments approved during 2000 and 2001. The Application estimates were also adjusted to include gas management fees and gas storage costs effective November 1, 2001. These costs were considered to be directly associated with the GCRR and Deferred Gas Account functions.

b) Operating Expenses
Forecast Operating Expenses were reduced by $101,500 (2000), $45,700 (2001) and $143,900 (2002).

c) Depreciation and Amortization
Adjustments to forecast plant expenditures resulted in reductions to Depreciation Expense of $43,200 (2000), $227,100 (2001) and $235,000 (2002).

Adjustments to Contributions and Grants resulted in decreases of $292,900 in amortization of contributions in aid of construction in 2000, and $106,000 in 2002 and an increase of $3,300 in 2001.

d) Municipal Taxes
Municipal taxes were adjusted to reflect the change in treatment of property tax for the Bonnyville service area. The parties proposed that, in 2002, property taxes in the Bonnyville service area would be collected through a separate property tax rider, similar to that used in the AltaGas service area. This resulted in a decrease of $38,400 in revenue requirement in 2002.

e) Income Taxes
Adjustments to Income taxes for the test years reflected the effect of all other adjustments to revenue requirement, as set out in the MOA. In addition, adjustments were made to address the following income tax issues:
   a. Updated income tax rates
   b. Capitalized Overheads, and
   c. Corporate Surtax calculation

f) Capital Additions
Forecast 2001 and 2002 capital additions were reduced by $350,000 in each test year, and capitalized costs related to the Town of Hanna were removed from Rate Base.

g) Contributions and Grants
The forecast contributions and grants for the test years were adjusted to reflect formula corrections. In addition, the Utilities agreed to provide more detailed information to

support any future proposal to change the current methodology to determine the standard contribution amount.

h) Working Capital
Gas storage inventory for the 2002 test year was adjusted to reflect updated gas costs. Deferred regulatory costs were adjusted to reflect revised cost estimates and a change in amortization of regulatory costs. Cash Working Capital was adjusted for updates to net lead/lag days related to interest on Long Term Debt, and GST on gas costs. All components of working capital were calculated using methodologies consistent with those used in the most recent Board approved GRA.

i) Cost of Debt
Interest expense for forecast deemed long term debt and forecast new debt for all three test years was reduced to7.42% from 7.60% in the Application. In addition, the interest rate applied to the deemed long-term debt opening balance in 2000 was adjusted from the previously approved rate of 9.25% to the updated new debt rate of 7.42%.

j) Sales Revenue
Sales Revenue was updated to reflect the Utilities' most recently approved gas cost recovery rate. Sales revenue was also adjusted to reflect the 2000/2001 winter gas cost recovery refund and also the inclusion of gas management fees and gas storage costs in the GCRR in 2001 and 2002.

Other revenue was adjusted to reflect an increase in forecast service work revenues in the amount of $18,000 for 2001 and 2002. Interest on Deferred Revenues in the amount of $225,000 was also added to the 2001 test period forecast.

These adjustments to the Application resulted in revenue requirements and revenue deficiencies for the test years as follows:

		($000)	
	2000	2001	2002
Revenue Requirement	93,546	131,657	86,998
Total Revenue at existing rates	92,926	131,141	86,120
Revenue Deficiency	620	516	878

5 BOARD FINDINGS ON THE NEGOTIATED SETTLEMENT

In this Section of the Decision, the Board sets out its findings with respect to the negotiated settlement and the issues agreed by the participants as set out on the MOA. The Board's findings with respect to unresolved issues that were adjudicated by the Board are set out in Section 6 of this Decision.

5.1 Background

As stated in the Board's Negotiated Settlement Guidelines, the Board is committed to the negotiated settlement process in keeping with its objective of achieving greater regulatory efficiency and effectiveness. Negotiated settlements allow applicants and interveners to agree on just and reasonable rates without resorting to the Board's litigated process. Parties should not view this support for the process as a relinquishment by the Board of its responsibility to uphold the public interest. The negotiated settlement must be supported with cogent rationale and must be reviewed by the Board.

The Board hereby acknowledges the Negotiated Settlement Brief as being of great assistance to the Board in reviewing the settlement and preparing its findings.

5.2 Board Views Regarding Circumstances of the Application

The Board will examine the Application in light of Section 45[1] of the *Gas Utilities Act, R.S.A. 2000, Chapter* G-5 (GU Act) and the Board's Negotiated Settlement Guidelines (distributed as an attachment to IL 98-4).

Prior to the introduction of the section that is now Section 45, the Board was required in every case to establish rates on a cost-of-service, return-on-rate-base methodology. The new section in the GU Act allows the Board to approve rates as just and reasonable if they result in cost savings or other benefits to be allocated between customers and the owner of a gas utility or if the rates are otherwise in the public interest. These are factors the Board may consider in determining whether proposed rates in a negotiated settlement are just and reasonable

The mere fact that there is a settlement does not, in and of itself, establish the justness and reasonableness of the applied-for rates. In reviewing the settlement, the Board is guided by the following principles:

- The settlement process must be fair and open to interested parties and sufficient information must be made available to understand the issues being negotiated. All parties should be provided an opportunity to participate and have their interests considered.

- Applicants have the onus of providing sufficient evidence and rationale to support the settlement.

- When presented with a settlement, the Board will not approve it in part if the agreement is contingent on the Board accepting the entire settlement. If the Board rejects the settlement, it will provide reasons outlining the areas causing concern.

- In determining the acceptability of a settlement, the Board will consider whether the agreement is: in the public interest, reasonable and fair to all interested parties, has a well-substantiated rational basis, and complete and adequate to support the application.

[1] Formerly section 36.1 of the *Gas Utilities Act*, R.S.A. 1980, c. G-4

The first issue for the Board to address is whether the settlement process was fair and conducted in accordance with the Negotiated Settlement Guidelines. The Board notes that documentation filed with the MOA included a copy of the Public Notice issued by the Board to initiate the negotiation process, details of all changes to the Application and related rationale, copies of interrogatories exchanged during the process, as well as detailed regulatory schedules supporting the Application setting out the forecasts as originally filed, and as adjusted to reflect the revisions agreed to in the MOA.

In addition, a member of Board staff attended all negotiation meetings, and confirmed that the process was fair and transparent. The Board is satisfied that the materials filed with the MOA, and the attendance of Board staff provide a level of assurance that interested parties were provided with the opportunity to participate, and participants were afforded due process.

The Board is satisfied that the MOA indicates unanimous agreement for the negotiated settlement, and notes that no objections were received or issues raised by any participant in response to the Board's public notice.

The second question for the Board to address is whether the settlement could lead to rates that are not just and reasonable. With this in mind, the Board has analyzed the regulatory information filed in the MOA, focusing specifically on the comparison of the forecast revenue requirement and rate base for the test years with actual financial results for the immediately preceding years. The following table summarizes the items that were reviewed and are on a consolidated basis for AltaGas and Bonnyville.

GRA 2000, 2001, 2002
($000)

	Settlement Agreement			Annual Filings	
	2002	**2001**	**2000**	**1999**	**1998**
Mid-Year Rate Base	142,744	141,190	134,791	128,519	127,167
Percent increase over previous year for mid-year rate base	**1.1**	**4.7**	**4.9**	**1.1**	
Return on Rate Base	8,423	8,416	7,991	7,728	7,755
Natural Gas Supply	57,472	102,952	65,699	39,230	29,362
Operating and Maintenance Expense	13,663	13,605	13,360	12,516	11,771
Percent increase over previous year for operating and maintenance	**0.4**	**1.8**	**6.7**	**6.3**	
Taxes Other than Income	52	86	85	85	86
Net Depreciation Expense	4,952	4,570	4,246	4,480	4,345
Income Taxes	2,436	2,028	2,165	2,090	3,439
Utility Revenue Requirement	86,998	131,657	93,546	66,129	56,758
Less Gas Supply	57,472	102,952	65,699	39,230	29,362
Net Revenue Requirement	**29,526**	**28,705**	**27,847**	**26,899**	**27,396**
Percent increase over previous year for net revenue requirement	**2.9**	**3.1**	**3.5**	**(1.8)**	

From the table above the increases in Rate Base can be noted which will tend to drive some of the other increases such as Return, Operating and Maintenance expenses, which increased in 1999 and 2000, and Depreciation, which increased significantly in 2002 compared to 2001. Overall, the test years do not exhibit increases in Net Revenue Requirement that are out of step with inflation. It is noted there is also an offsetting income tax decrease commencing in 1999 over 1998.

The Board is satisfied that the results of this examination support the conclusion that the forecast revenue requirement and revenue deficiencies for the test years as determined by the parties in the negotiated settlement are reasonable. In addition, the Board is satisfied that no public interest considerations have been identified that extend beyond the immediate concerns of the negotiating parties.

Therefore, the Board approves the settlement as filed and set out in the MOA.

6 ISSUES DEALT WITH AT THE ORAL HEARING

6.1 Capital Structure

In this section the Board will review the capital structure and will accordingly make its determination of the business risk that pertains to AUI.

6.1.1 Position of the Utilities

AUI argued that the requested common equity ratios for 2000, 2001, and 2002 (42.0%, 42.5%, and 43%) are consistent with those approved for AltaGas by the Board for 1995 and 1996 (41.712% and 41.549% respectively in Decision U96019, dated February 16, 1996) net of the preferred equity component, and grants and contribution in aid of construction.

AUI argued that the applied for capital structure was supported by their cost of capital expert Ms. McShane and consistent with the company's business risk profile, small size, and operating leverage. AUI noted that unlike other utilities, it has no preferred shares and counts on customer contributions and government grants to fund much of its rate base. AUI explained that the high contribution level resulted in common equity of less than 27% of gross rate base for the test years, causing greater variability than utilities with a large equity base.

In reply argument, AUI disagreed with the Interveners' position that AUI has a lower business risk based on its higher proportion of residential load versus ATCO Gas South (AGS). AUI submitted that its residential customers are based in a widely dispersed area with greater risk associated, due to the vagaries of and economic dependence on agriculture and one-industry towns.

AUI further stipulated that volatility of earnings arising from weather is a widely recognized utility risk factor, supported by the Dominion Bond Rating Service August 2000 Bonds, Long Term Debt and Preferred Share Rating report. AUI advocated that the report clearly contradicts the Interveners' claim that volatility in earnings arising from weather is neutral over time, and does not constitute a business risk.

AUI noted the Interveners' claim that AUI faces less risk because it has been more successful negotiating with customers than AGS. AUI suggested that it should not be penalized because of management's ability to reach agreement with customers, but that regulatory risk should be evaluated based on the framework in which it operates.

AUI argued that as a small company it lacks diversification of assets causing higher business risk. In addition, its small size limits its access to reasonable cost of capital, which leads to higher financial risks.

AUI noted that the Interveners failed to differentiate the risk factors for AGS and AUI as summarized in Board Decision U96002, dated January 5, 1996, and Decision U96019, which awarded AUI a common equity component of 40% versus Canadian Western Natural Gas' (CWNG, now AGS) 37% in Decision 2000-9, dated March 2, 2000. Additionally, AUI submitted that its common equity ratio of 27% of the gross rate base results in a higher operating leverage.

It noted that AGS's 6.6% preferred share component combined with AGS's common equity results in a total equity component higher than AUI's forecast equity ratios.

6.1.2 Position of the Interveners

The Interveners noted Ms. McShane's evidence that AUI's residential load was 60% versus AGS's residential load of 52%. The Interveners argued that as a result, AUI was exposed to less business risk than AGS. The Interveners also disputed the company's assertion that revenues are weather dependent based on the large heating load. As AUI's revenue requirement was predicated on a normalized forecast, the Interveners asserted that the weather impact would be neutral. The Interveners submitted that the Board-approved 20-year rolling normalization method eliminates weather as an element of business risk. They also noted that Ms. McShane agreed that weather related risk was equal for AGS and AUI.

The Interveners disagreed with Ms. McShane's assessment that longer intervals between rate cases impact regulatory risks for both AUI and AGS. They argued that AUI's management is able to apply for rate increases at any time during a test year, and thereby recover losses for a full year. Therefore, the Interveners argued, if a utility had longer intervals between rate cases it is likely earning more than its allowed rate of return. The Interveners further submitted that AUI's management has reduced regulatory risk by negotiating rate settlement agreements more successfully than AGS.

The Interveners argued that AUI has not suffered any franchise area losses due to rates that are higher than AGS, as municipalities might factor more than cost into franchise agreements, such as service levels, safety, and customer relations.

The Interveners disagreed with Ms. McShane that unbundling would potentially reduce revenue streams and the recovery of costs incurred to facilitate unbundling. The Interveners cited the Board's Unbundling and Methodology Decision 2001-75, dated October 31, 2001, whereby the Board addressed any potential impact, whether positive or negative, on AUI's revenue requirement from stranded costs through the use of deferral accounts. The Interveners disagreed with Ms. McShane's assertions that unbundling would force utilities to remain the default supplier to high cost customers, while also suffering unrecoverable costs such as bad debt. The Interveners surmised that the separation of the retail component from a distribution utility would result in the removal of the gas costs which represent close to 70% of total costs in the test years, transferring bad debts to the retail function resulting in a reduced impact on earnings. In conclusion, the Interveners submitted that unbundling does not increase AUI's business risk, as Board Decision 2001-75 established deferral accounts to deal with stranded costs.

The Interveners further explained that retail competition has only resulted in one retailer entering AUI's market capturing four customers, whereas ATCO Gas has seen 30,000 customers opt for alternative gas supply on the ATCO Gas system. The fact that AUI's customers are dispersed over a wide area clearly reduces the attractiveness of their market to other retailers as compared to ATCO Gas's customers who are concentrated in large urban centers.

The Interveners disagreed with Ms. McShane's opinion that a small utility would suffer cost disadvantages compared to a larger utility, as they argued she is not familiar with economies of scale in the gas distribution business nor was there any evidence supporting AUI's cost disadvantages relative to AGS. They further argued that a small company tends to be less bureaucratic and has greater operational flexibility, which would mitigate its vulnerability to unforeseen occurrences. The Interveners also disputed the possible higher cost of capital espoused by Ms. McShane as a financial risk of AUI, not a business risk.

On financial risk, the Interveners noted that AUI's risk is minimal, as they are a wholly owned subsidiary of a larger corporation. The Interveners argued that the financial leverage and risk of the parent corporation should not be considered when assessing AUI's financial risk as the parent's credit standing is also linked to the electricity industry, irrelevant to the capital structure of AUI.

The Interveners submitted that the total risk of a utility is the sum of the business risk plus financial risk, which results in the capital structure of the utility. The Interveners argued that the financial risk was minimal and, based on AUI's business risk, a maximum of 37% equity component of its capital structure should be allowed. The Interveners concluded that AUI was no riskier and possibly less risky than AGS and advocated an equity component of capital structure no greater than AGS.

In reply argument, Interveners argued that AUI failed to provide evidence that supported the negative impact of contributions on risk and operating leverage, and that it was not given any significant consideration in Board Decision U96002. Furthermore, the Interveners submitted that the risks from grants and contributions in the capital structure are a financial risk, not a business risk. The Interveners noted that despite all AUI's suggestions that business risk and financial risk for AUI is higher than AGS, their expert, Ms. McShane, concluded that its overall risk is the same as that of an average risk utility.

6.1.3 Views of the Board

The Board notes that the evidence on business risk provided by the expert witness, Ms. McShane, on behalf of AUI was compared to that of AGS by the Interveners in argument, and in reply argument by AUI. For the most part, the overall comparison suggests that the elements of risk are quite similar, albeit the two utilities are not the same size. The Board notes that a comparison shows that both have vulnerabilities related to customer make-up. While the risk for AGS is mitigated by a large diversity of customers, it is subject to a greater risk from the fluctuations in the economy. On the other hand, AUI has a larger proportion of residential customers that will provide greater stability in its customer base.

The Board notes that when determining an appropriate capital structure of a utility, the Board must evaluate both financial and business risk. The Board acknowledges that both AUI and the Interveners focused the majority of their analysis on business risk.

The Board notes that the Interveners argued that all elements of financial risk, including leverage, are controlled by AUI's parent and, as a wholly owned subsidiary, AUI faces marginal risk. On the other hand, the Board acknowledges AUI 's submission that its financial risk should be assessed as a stand-alone entity, and as a smaller sized utility it has less access to capital at a reasonable cost. In addition, AUI has a higher operating leverage arising from contributions.

The Board considers that the fact that contributions reduce the gross equity to a value near 27% does result in an element of business risk. The risk stems from the requirement of AUI to be responsible for maintaining the assets, regardless of how they are financed. The Board also acknowledges that contributions are for the purpose of adding new customers that would otherwise increase the rates to remaining customers or be uneconomic based on current rates. In any event, the Board considers that AUI has the ability to propose methods that would mitigate or decrease the impact of the business risk.

The Board concludes that AUI's financial risk is minimal, as the capital structure is dictated by Board rulings and the parent company's option to increase or decrease components of its capital structure within Board approved parameters. The Board further considers that, when evaluated as a stand-alone entity, AUI's capital structure is determined on its individual business risks and not that of its parents, while benefiting from the parent's access to the lower cost of capital. The Board considers that AUI faces only marginal financial risk, and that the capital structure is determined largely by AUI's business risk.

The Board notes that AUI indicated that its revenue was weather dependent and susceptible to higher risk based on its large heating load; while the Interveners countered by suggesting that the impact of weather would be neutral, and that the use of the 20-year rolling average normalization method eliminated weather related risk. The Board recognizes that the large heating load of AUI subjects the company's revenues to the vagaries of weather. The Board notes that Ms. McShane agreed that this weather related risk was equal for ATCO Gas and AUI.[2] The Board believes that AUI has similar weather related risk as does ATCO Gas, and any specific differences stem from their load profiles. The Board acknowledges that AUI's customers are widely scattered throughout their service area, whereas other larger utilities tend to have higher customer concentration. The Board further accepts AUI's argument that despite a higher residential customer base, the utility is subject to higher risk, as these residentials are dependent on the vagaries of the economics of agriculture and one-industry towns. The Board concludes that on balance AUI faces a slightly higher risk than does AGS.

The Board notes that the filed information does not provide enough detail to give an appreciation and understanding of the relationship between degree-days and revenues throughout AUI's service area. Therefore, the Board directs AUI at the next general rate application to provide the average degree-day total, broken down into areas of similar degree-days, and to provide the relationship and formula that will give the Board the detail necessary to understand the impact of weather on revenue and variable margin. This will permit the Board to gain an appreciation of the magnitude of weather related risk.

The Board also considered the position of the parties with respect to certain developments in the regulatory environment. For instance, unbundling of the gas delivery rates was undecided prior to 2001 and therefore presented a degree of risk. However, Board Decision 2001-75 has been issued and has mitigated the uncertainty that may have been previously present. In addition, it was noted that AUI was able to potentially mitigate any bona fide risk of this nature through

[2] Tr. p. 111, lines 8-10

management initiatives. In this instance, the Board is not persuaded to increase either risk premium or deemed equity to compensate for such matters.

The Board further agrees with AUI that regulatory risk is largely based on regulatory framework, and that management's success at reaching negotiated settlements should by no means impact the Board's assessment of regulatory risk. The Board is fully supportive of the negotiated settlement process, and encourages resolution on issues of contention between stakeholders. The Board will not intentionally penalize AUI for the time taken to negotiate a settlement with its customers.

In Decision 2001-96, dated December 12, 2001, the Board set the capital structure for AGS at 37% equity. As noted above, the Board considers that AUI faces a slightly higher risk than does AGS. In AUI's previous GRA the capital structure was set at approximately 41%. The Board is not persuaded that there has been any change in business risk to AUI since 1996 and in fact management is able to propose certain measures to manage many of the risks proposed which in and of itself would reduce the risk faced by AUI. For all of these reasons, the Board concludes that an appropriate deemed equity shall be 41% for all three test years.

6.2 Rate of Return on Common Equity

In this section the Board will evaluate the return on equity and set the rate taking into account the evidence provided for comparable earnings, discounted cash flow (DCF), and equity risk premium. It will also consider the views previously held by the Board in these matters.

6.2.1 Position of the Utilities

AUI argued that a return on equity for the three tests years of 11.5% is supported by Ms. McShane's original evidence, and submitted that her updated return on equity of 11.25% for the 2001 and 2002 test years was a 25 basis point penalty as a result of the delay in the hearing process from its original filing date of September 29, 2000. The company argued that selected snapshots of evidentiary history and continuous updates through to the end of the hearing created risk of distortion and unfairness. AUI submitted that had the hearing been scheduled at the time of the original filing, evidence would have supported a return on equity of 11.5% for all three test years. AUI submitted that a 11.5% return on common equity for all three test years would be fair and reasonable, void of any penalty arising from updated evidence and recognition of its efforts in the cooperative process.

AUI supported Ms. McShane's use of the three tests for return on common equity: equity risk premium, DCF and comparable earnings and submitted that it strongly disagreed with the Interveners recommended return on common equity of 9.5%, 9.4% and 9.0% in 2000, 2001, and 2002 test years respectively.

Equity Risk Premium
AUI submitted that Ms. McShane used three different approaches to the equity risk premium test, which incorporated an adjustment for the relative risk of AUI, a direct estimate of risk premium for a local distribution company (LDC) versus historic risk premiums for regulated utilities, and DCF estimates of cost of equity of LDCs and long-term government bonds. AUI supported Ms. McShane's use of U.S. and Canadian risk premiums in recognition of the

globalized money market, the increased level of Canadian foreign investments, the historic resource oriented bias of the Canadian market, greater diversification of the U.S. market, and differences in the U.S. and Canadian Bond yields. AUI noted that based on historic Canadian and U.S. risk premiums, Ms. McShane estimated the historic market risk premium was 6.5% and 6.0-7.0% after combining future estimates, and 4.25% for AUI after a relative risk adjustment of 0.65 based on co-variability and absolute variability of utility stocks with the TSE 300.
Ms. McShane concluded that the risk premium was 4.5-5.0% plus a risk free rate of 6.0% and financing flexibility of 0.5% totaling a return on equity of 10.75-11.0%.

DCF Test

AUI noted that the DCF test measures a direct estimate of investor requirements for an LDC. The company supported Ms. McShane's use of U.S. data as there was little Canadian data for comparison, and Canadian utilities compete for capital and returns with U.S. companies. AUI submitted that the DCF test 11.4% return on equity supported Ms. McShane's equity risk premium results.

In reply argument, AUI disagreed with the Interveners that the DCF test should be ignored when evaluating return on common equity, as it violated the constant future growth rate assumption of the model, and circularity in growth forecasts. AUI suggested that circularity is mitigated by the fact that growth forecasts are prepared by external analysts, independent of the regulatory process. In addition, AUI submitted that changes in growth forecasts do not alter the assumption of a constant growth rate, but the rate itself.

Comparable Earnings Test

AUI noted that the comparable earnings test compared the level of return utilities must provide versus companies of similar risk to attract capital. The returns for Canadian industrials of similar risk to average risk Canadian LDCs such as AUI were 12.5-12.75% versus the U.S. industrial comparison with an average risk Canadian LDC of 12.5-13.0%.

AUI cited Board Decision E83123, dated September 30, 1983, and Decision U96002, whereby the Board emphasized the need to use a balanced approach incorporating multiple tests to determine a fair return on common equity. AUI also noted that the Board in Decision E83123 recognized that return on rate base is not an exact science, dependent on the judgement of experts, and the use of multiple tests.

The company explained that Ms. McShane supported the use of multiple tests, but recognized that Canadian regulators are becoming more and more reliant on the equity risk premium test, resulting in lower allowed returns as bond (risk-free) rates decline. AUI submitted that over reliance on one test inaccurately reflects the investment marketplace.

AUI submitted that their reliance on a rural customer base exposes them to the agriculture cycle, depression of one-industry towns, and a higher risk of franchise loss based on their widely dispersed customer base. AUI cited Board Decision U96002 that recognized these factors and considered them in determining AUI's return on common equity versus other LDCs. AUI argued that based on their rural customer base, widely dispersed service area, and their exposure to agriculture cycles, a fair rate of return of common equity for all three test years would be 11.5%.

AUI disagreed that the comparable earnings test was invalid because Ms. McShane failed to measure results of the business cycle from trough to trough. There is no rule on exactly how to measure a business cycle, beyond defining it as including periods of expansion, recession, contraction, and peaking. AUI explained that both periods, 1991-1999 and 1991-2000, are consistent with this definition.

Comparable Awards in other Jurisdictions

AUI supported the use of a comparable awards in other jurisdictions method when utilizing both Canadian and U.S. LDCs awarded returns. Allowed returns on equity for Canadian LDCs are 1.5% lower than U.S. LDCs, despite the same relative risk. AUI argued that there is no rational explanation for these results beyond the fact that Canada has become over reliant on the Equity Risk Premium Test.

Equity Risk Premium Test

In reply argument, AUI observed that the risk free rate was 6.0% in 2000 based on 30-year Canada Bonds, with a flat yield curve with 10-year Canada Bonds. AUI noted that Ms. McShane's updated evidence relied on the forecasts of 30-year Canada bonds for 2002. As the yield curve between 10-year and 30-year Canadian Bonds was no longer flat, an adjustment of 30 basis points to the 5.5% 2002 Canada Bonds was required to reflect the current 30-year bond rate. AUI submitted that the 30 basis point spread was consistent with the average spread between January and November 2001. AUI submitted that a reasonable spread should not be based on a spot value, as selected by Interveners from the Edmonton Journal on January 8, 2002, which had indicated an spread of 15-17 basis points as compared to the spread listed on the Bank of Canada website. AUI submitted that the reported spread was in error.

Market Risk Premium

AUI submitted that the use of U.S. data is relevant to the application, contrary to the submission of the Interveners. AUI disagreed with the Interveners' conclusion arising from Board Decision 2000-9, where the Board did not accept the U.S. weighting of data, but stated that U.S. risk premium of 8.0% represented the upper bounds versus the Canadian historic risk premium of 5.5%. AUI noted that when the U.S. data is included, the market risk premium is 6.5%. AUI noted that the Interveners cited the Régie de l'énergie's Decision 99-150 for Gaz Métropolitain for lower risk adjustment, but failed to recognize the 40% weighting given to the U.S. data to estimate the market risk premium of 6.5%.

Financing Flexibility

The company submitted that the Board has consistently allowed approximately 50 basis points for financing flexibility for various utilities, as opposed to the Interveners' suggested 25-30 basis points. AUI argued that it should be compensated for the cost of raising equity.

AUI submitted that the use of expert opinion puts forth knowledge, training, intuition, and independent judgement, which often led to different conclusions. AUI firmly supported the use of expert witnesses, and opposed a mechanistic approach in calculating return on common equity.

The company argued that rate of return should be based on the same fundamental information as the negotiated settlement to avoid updated information creating a different scenario of information than the negotiated process. AUI further suggested that management's successful negotiations with customers should not lead to a punitive finding of reduced regulatory risk, as regulatory risk pertains to the competitive or regulatory framework AUI operates in.

6.2.2 Position of the Interveners

The Interveners noted that Ms. McShane based her recommendations in earlier proceedings on the equity risk premium and comparable earnings test, but in the AGS's 2001/2002 GRA and AUI's current application she also applied the DCF analysis. Ms. McShane also compared awarded rate of returns by U.S. boards and commissions. The Interveners submitted that the Board's conclusions in the 1997/1998 CWNG GRA (Decision 2000-9) discounted the merits of the comparable earnings test as sensitive to various factors, such as business cycles and accounting practices of sample firms. Recent Board Decisions gave primary weight to the equity risk premium test when calculating return on common equity.

The Interveners noted that Ms. McShane stated that the time period of measuring returns must include the entire business cycle, incorporating years of expansion and decline. The Interveners argued that Ms. McShane had analyzed the most recent point-to-point cycle ending in 1999 and beginning in 1991, but changed that period to 1991-2000 in her updated comparable earnings test. The Interveners submitted that Ms. McShane appears uncertain as to the end of the business cycle, and therefore the comparable earnings test should be given no weight in determining the return of common equity.

<u>DCF Test</u>
The Interveners noted that Ms. McShane testified in CWNG's 1998 GRA, concluding that there were some major limitations to the DCF test, as follows:

- Inability to measure investor expectations of dividend growth rates
- Stock prices don't always reflect underlying fundamentals
- Unrealistic investor expectations
- Market value of utility stocks complicate DCF test when significantly above book value
- Circularity of applying the DCF technique, whereby future growth rates are dependent on approved returns

The Interveners submitted that the DCF test should be given no weight in determining AUI's return on common equity, consistent with Board Decision 2001-96, which dealt with AGS's GRA.

<u>Comparable Awards in other Jurisdictions</u>
The Interveners rejected the comparison of awarded returns on equity of U.S. utilities, as it failed to consider the particulars of the utility, the associated allowed capital structure, and the legislation under which the regulatory board operates.

<u>Equity Risk Premium Test</u>
The Interveners argued that the Board should utilize the most current information at the time of the hearing to accurately render a Decision, consistent with Board Decision 2000-9.

The Interveners rejected Ms. McShane's evidence regarding the risk-free rate for 2000 (6.0%), and submitted that the rate should be 5.9% as indicated in cross-examination. Furthermore, the Interveners argued that Ms. McShane's 2002 forecast of 5.8% should be adjusted to a maximum of 5.6% to reflect the December 2001 Consensus Forecast for 10-year government bond yields of 5.2%-5.6%. The consensus forecast does not include a 30 basis point adjustment for the historic spread between 10-year and 30-year Canada's. The Interveners argued the current yield curve is flat and the witness applied 10-year bond yields for the previous two test years. The Interveners noted that the spread between 10-year and 30-year Canada Bonds was between 15-17 basis points at the hearing date. The Interveners submitted that the risk-free rate for determining the risk premium test should not exceed 5.9% in 2000, 5.8% in 2001, and 5.6% in 2002.

Market Risk Premium

The Interveners argued that Ms. McShane's combined Canadian and U.S. market risk premium was weighted based on the maximum Registered Retirement Savings Plan (RRSP) allocation that Canadians are allowed for foreign securities of 30%, but failed to recognize that 'foreign' includes bonds and non-U.S. investments. They also noted that Ms. McShane had no evidence regarding the actual amounts or percentages of Canadian RRSP funds that have been invested in U.S. investment vehicles. Furthermore, the Interveners noted that the Board clearly stated in the Decision for CWNG's 1997/1998 GRA that U.S. data represented the higher bounds for calculating market risk premium and would be given no mechanical weighting. Therefore, the Interveners submitted only Canadian data should be relevant to AUI's return on common equity.

Adjusted Utility Market Risk Premium

The Interveners argued that Ms. McShane's raw beta for Canadian utilities was 0.45, while the most recent data indicated a raw beta of only 0.40. Her adjusted beta is only supported by the Value Line formula, which gives 2/3 weight to the raw beta and 1/3 to the market beta of 1.0. Based on the fact that AUI is not a publicly listed company, there is no accurate method to calculate its beta. The Interveners submitted that Board acceptance of the higher beta of 0.65 proposed by Ms. McShane would result in an increase of return of 1.6%.

The Interveners noted that Ms. McShane determined that AUI faced average business risk, but cited several areas where AUI had greater risk than other utilities:

- weather impact on heating load — the Interveners submitted that normalized forecast neutralizes the impact of weather
- large residential/small commercial base mitigates exposure to business cycle — the Interveners argued that a 70% space heating load for AUI, versus CWNG/AGS space heating load which was only 40%, reduced business cycle risk
- unbundling — the Interveners argued that it is impossible to quantify impact, either negative or positive at this time

The Interveners argued that AUI's business risk is as low or lower than other gas distribution utilities.

The Interveners submitted that the market risk premium should be adjusted by 0.50-0.55 to accurately determine the risk premium for gas distribution utilities, consistent with Decision 99-150 by the Régie de l'énergie, which set a fair return of on equity for Gaz Métropolitain, of 0.55 with a flexibility allowance of 30 basis points. Also Drs. Booth and Berkowitz's estimated beta adjustment was 0.50 in the 1997/1998 CWNG GRA, however, the Board concluded a 0.60 adjustment was appropriate versus Ms. McShane's higher recommended adjusted beta of 0.70.

The Interveners argued that the risk premium adjusted with Ms. McShane's beta would result in an appropriate risk premium for AUI of 3.3% (5.5% X 0.60=3.3%), while the beta used in the Régie de l'énergie decision calculated a risk premium of 3.0%. for the test years. The Interveners noted that the Board concluded a risk premium in the range of 3.25% to 3.5% for the test years was reasonable in AUI's previous GRA.

Financing Flexibility

The Interveners argued that no flotation costs arising from the sale of new equity by AUI's parent in 2002, nor any margin related to the sale of new equity was specified for AUI. None of the factors listed by Ms. McShane would justify a significant add-on for financing flexibility. The Interveners submitted 25-30 basis points could be allowed for financial flexibility.

The Interveners submitted that the maximum allowed rate of return on equity based on Ms. McShane's equity risk premium evidence for the three test years should be as follows:

	2000	2001	2002
		%	
Risk-free rate	5.9	5.8	5.4[1]
Utility risk premium[2]	3.3	3.3	3.3
Financing flexibility	0.3	0.3	0.3
TOTAL:	9.5	9.4	9.0

1. December 2001 Consensus Forecast, UM-AUI.36
2. Compound Average Canadian Market Risk Premium for 1947-1999 times beta 0.60

The results reflected the Interveners' use of Ms. McShane's evidence, the most recent beta of 0.60 employed by the Board in CWNG's 1997/1998 GRA, and the Intervener's financing flexibility allowance.

In reply argument, the Interveners submitted that the Board's use of current information reduces the utility's exposure to risk for unforeseen events. The Interveners argued that the Board has been open to reviews of revenue requirements to applications when situations dictated it.

Equity Risk Premium

The Interveners submitted that AUI does not operate or finance its operations in the U.S., therefore the use of U.S. data to determine market risk premiums is fundamentally flawed. The Interveners noted that the Board rejected U.S. weighting in calculating market risk premiums in Decisions U99099, dated November 25, 1999, 2000-9, and 2001-96. They also agreed that equity risk premiums depend largely on upwardly biased analyst expectations, which resulted in inflated results. Furthermore, a fair return on equity should attempt to be comparable with utilities or industrials of similar risk, but with no guarantee to meet the often unrealistic expectations of investors.

The Interveners cited Decision U96002 that utilized the equity risk premium test and flotation costs to determine return on common equity. The Interveners submitted that the Board must consider the fundamental differences between U.S. and Canadian utilities, instead of relying on the comparative values of the awarded returns.

The Interveners argued that the Board should conclude that the use of expert witnesses and evidence in this AUI application was of little probative value, consistent with Board Decision 2001-96.

6.2.3 Views of the Board

AUI argued that the Board should take into account the timing of the hearing relative to that of the original Application and the protracted negotiations when setting the rate of return. The Interveners argued that the Board should not give any consideration to AUI's argument that the more current financial information put the utility at risk. The Interveners pointed out that such updates had been received by the Board in the past and they could be cause to increase the rate of return as much as to decrease it. In the circumstances of this proceeding, the Board considers it appropriate to consider the updated information.

During the past five years the Board has been presented with evidence from several witnesses that have discussed the merits of at least three measures for determining the Return on Equity. In this proceeding, on behalf of AUI, Ms. McShane provided her views on the Comparable Earnings test, the DCF test and Equity Risk Premium test. She also provided information on comparable awards that compared the returns approved by regulators in U.S. jurisdictions. This latter comparison was meant to illustrate that reliance on only the risk premium test in Canada has resulted in rates being lower in Canada by about 1.5% than in the U.S.

The parties disagreed on the weight that should be given to the Comparable Earnings test. Ms. McShane proposed a weighting of 25% on a range of values 12.5% to 13.25%. The Interveners believed that no weight should be given to this test. In recent decisions the Board has viewed the comparable earnings test as a guide and a check on the reasonableness of the market based tests, but has otherwise given little weight to this test. The Board continues to view the comparable earnings test as being highly sensitive to accounting practices of sample firms, the sample selection, and matters related to restructuring. Therefore, the Board will give little weight to this test other than as a check on the reasonableness of the Equity Risk Premium test.

The parties also disagreed on the weight that should be given to the DCF test. The evidence of Ms. McShane was that the rate fell between 10.8% and 10.9% and should be given a weight of 37.5%. Again, the Interveners argued that no weight should be given to this test. The Board notes the Interveners' reference to Ms. McShane's evidence in the 1997/1998 CWNG GRA, where Ms. McShane concluded that the DCF test was not used as a result of its various limitations, including its inability to measure investor expectations of dividend growth rates, circularity issues, and the concern that stock prices do not match underlying fundamentals. The Board considers that very little weight should be given to the DCF test in this proceeding in the establishment of an ROE. Although the Board considers the DCF test to have theoretical validity, the model suffers from a myriad of limitations, as indicated by Ms. McShane's 1997/1998 CWNG GRA evidence**.** As with the comparable earnings test, the Board will only use the DCF test as a reasonableness check to ensure that ROE is established within reasonable bounds.

The Board believes the most appropriate test to use is the Equity Risk Premium test. The Board has examined the evidence and views of the parties with respect to the risk free rate, the market risk premium and the adjustment for financing flexibility.

The risk free rate proposed by AUI was 6% for all three test years while the Interveners proposed rates of 5.9%, 5.8% and 5.4% for 2000, 2001, and 2002 respectively. The Interveners' rate for 2002 appeared to be based on the consensus for the 10-year bond rate. It is of note, too; that Ms. McShane gave evidence that her updated rates were 6% for 2000, 5.8% for 2001 (based on actual information) and 5.8% based on a forecast for 2002.[3] Ms. McShane's evidence was based on a 10-year bond rate and adjusted to a 30-year bond rate. There was some debate at the hearing surrounding the validity of utilizing 30-year Canada bonds as the risk free rate in calculating the Equity Risk Premium. The Board is concerned that the market may no longer be utilizing 30-year bonds as the standard risk-free instrument, as a scarcity premium exists on 30-year bonds. In the Board's opinion, any adjustment to the 30-year bond rate based on the historical spread between 10-year and 30-year bonds may not accurately reflect the realities of the marketplace and may possibly lead to a risk-free rate above or below underlying fundamentals.

The Board believes that based on the evidence presented in this proceeding it is appropriate to continue with the use of the 30-year bond rate. Therefore, the normal 10/30-year Canada bond yield spread of 30 basis points is reasonable. However, due to the estimated scarcity premium of 30-year Canada Bonds which provides another variable to be determined, and concern that market conditions appear to be changing away from the use of 30-year bonds, the Board is of the view that in future, it will be appropriate to assess current trends and reevaluate the applicability of 30-year Canada Bonds as the risk free rate or if the 10-year rate should become the primary basis. Accordingly, the Board directs AUI, in its next general rate application, to provide a written discussion of the relative merits of the use of 10-year Canada Bonds and 30-year Canada Bonds as the risk free rate.

Consistent with the Board's past practice of giving the greatest weight to the Canadian 30-year bond rate, the Board will accept Ms. McShane's updated studies of the risk free rate of 6%, 5.8% and 5.8%, for 2000, 2001 and 2002 respectively, as being appropriate.

The Interveners argued that the risk premium values, derived by the expert witness, were unsuitable, as they had given weight to U.S. data and that a value of 5.5% would be the result if only the Canadian data was used. The Board believes that Canadian markets already reflect global trends, and U.S. weighting would overemphasize the impact of global capital markets, while undermining the impact of Canadian monetary and fiscal policy. The Board notes that AUI generates its revenue in Canada, and any mechanical weighting of U.S. data is inconsistent with the realities of the market in which AUI operates. The Board continues to see the value of U.S.

[3] Tr. pp. 50-51 and MGCI-AUI.43 p. 4

data as providing an upper limit and therefore will consider the U.S. data in this light when setting the rate of return. The Board notes that the compound and arithmetic averages of Canadian Market Risk Premiums for 1947-1999 are 5.5% and 6% respectively. The Board concludes that this range is reasonable, and the Board will apply it in the equity risk premium test in determining AUI's risk premium.

The Board considers that as AUI is not publicly traded, there is no definitive way to precisely determine AUI ‘s beta. However, the Board does note that the Interveners submitted in argument that the risk premium should be adjusted by 0.50 to 0.55, consistent with betas of other gas distribution utilities, specifically citing the evidence presented by Drs. Booth and Berkowitz in the CWNG 1997/1998 GRA and the Régie de l’énergie’s Decision 99-150 involving Gaz Métropolitain. While Ms. McShane utilized an adjusted beta of 0.65, incorporating the Value Line formula, the Board is not convinced with the appropriateness of its 2/3 raw beta and 1/3 market beta weighting, as it is largely a function of judgement.

The risk premium proposed by AUI and Ms. McShane was between 4.25% and 4.5% for all three test years and was derived using a beta of 0.65. The Interveners argued that this was too high and should be no more than 3.3% (based on a beta of 0.6). The Board has heard the arguments from opposing expert witnesses in past proceedings and notes that Ms. McShane pointed out that the appropriate level is somewhat based on judgement. As such, the Board believes that an adjusted beta of 0.6 should be used against the market risk premium, as it is within the beta range submitted by both the Interveners and the applicant, as well as consistent with recent rulings by the Board. Therefore the Board will apply 0.6 in its determination.

The Board is also aware that the capital raised is through the parent company of AUI, which has a different investment profile than does the parent of AGS and will factor that fact into its determination. The Board notes that based on the compound and arithmetic averages the Canadian Market Risk Premium for 1947-1999 is between 5.5% and 6%. The Board concludes that the range is reasonable and when multiplied by a beta of 0.6, AUI’s risk premium is in a range of 3.3% to 3.6%.

Arguments were also made for the adjustment for financing flexibility. The Board believes that a financial flexibility allowance is required to accommodate flotation costs and a margin for unanticipated capital market conditions. The range proposed by the parties was from 0.3% by the Interveners to 0.5% by AUI. Therefore, the Board accepts that this is a reasonable range and will incorporate this evidence into its determination of the return on equity.

The following table provides a breakdown of the Board’s findings on AUI’s return of common equity, utilizing the equity risk premium test and financial flexibility.

	2000	2001	2002
		%	
Risk-free rate	6.0	5.8	5.8
Utility risk premium	3.4	3.4	3.4
Financing flexibility	0.5	0.5	0.5
TOTAL:	9.9	9.7	9.7

Based on the evidence, and consistent with other recent Board Decisions (see for example 2001-97, 2001-96, and 2001-92, all dated December 12, 2001), the Board considers that a fair rate of return on that portion of the rate base deemed to be financed by common equity should be 9.9% for 2000, and 9.7% for both 2001 and 2002. It is the view of the Board that these rates are reflective of the financial risk of the utility and are consistent with the rates set by the Board for companies of similar financial needs.

6.3 Post Employment Benefits

The issue of post employment benefits was addressed in the MOA wherein both parties agreed to its resolution. In this section the Board will consider any issues that may have arisen subsequent to the MOA.

6.3.1 Position of the Utilities

In the MOA AUI agreed to comply with the outcome of a similar matter before the Board for the ATCO group.

During the hearing AUI stated:

> On December 31st, 2001, the Board issued Decision 2001-105 with respect to the ATCO companies. We concur with the treatment of other post-employment benefits prescribed in that decision.[4]

6.3.2 Position of the Interveners

The Interveners similarly agreed to adhere to the Decision to be rendered in the ATCO proceeding on the same topic. In argument the Interveners recommended that the Board direct AUI to refile, in its Phase II portion of the GRA, the other post employment benefits costs on a cash basis of accounting.

The Interveners noted that AUI also stated [5] that it was looking for Board direction with respect to the issue of whether the regulatory treatment approved for other post-employment benefits should be mirrored for financial statement purposes. At page 3 of Decision 2001-105 respecting the ATCO Group's pension application, the Board stated:

[4] Tr. p. 25
[5] Tr. p. 35

> The Negotiated Settlement stipulates that, for financial reporting purposes, the ATCO Companies may record the liability resulting from the adoption of the CICA Handbook Section 3461. However, with due consideration given to industry practices, the amount may be reflected as a regulatory asset rather than an expense item. This may result in the ATCO Companies establishing an offsetting regulatory receivable (asset) and/or pension liability on the financial statements of each of the ATCO Companies. If so, it will be established solely for purposes of enabling the subject financial statements to comply with Canadian GAAP and not for the purposes of determining the revenue requirements of the ATCO Companies. Further, the ATCO Companies will inform the Board and signatories to the Negotiated Settlement if a regulatory receivable/asset and/or pension liability is recorded on the Financial Statements.

Consistent with the foregoing, it was the submission of the Interveners that AUI may, for financial reporting purposes, record the other post-employment benefits expense on an accrual basis to comply with Section 3461 of the CICA Handbook, assuming the amounts are deemed to be material. However, the Interveners submitted that under no circumstances should the adoption of a different method for financial reporting purposes impact any component of AUI's revenue requirement, and AUI should be so directed.

6.3.3 Views of the Board

The Board notes that Decision 2001-105 respecting the ATCO Group's pension application was issued December 31, 2001. The Decision was the result of a negotiated settlement. The ATCO Group pension decision is applicable to issues to be resolved between AUI and the Interveners in this proceeding. As set out earlier in this decision it was noted that AUI would accept the outstanding Board Decision on the ATCO Group's application and adopt the Board Decision treatment of Post-Employment Benefits from the ATCO Group application.

The Board is satisfied that all parties to this proceeding understand the issues and have agreed to their resolution as outlined in the MOA. Accordingly the Board directs AUI to incorporate the necessary changes for the treatment of Post-Employment Benefits to its revenue requirement, when refiling.

7 BOARD ORDER

In the event of any difference between the wording of the Directions listed below and the wording of the main body of the Decision, the wording of the Direction in the main body of the Decision shall prevail.

Having regard to the evidence and submissions, and having regard to its own knowledge and findings in this Decision, the Board hereby orders as follows:

(1) AltaGas Utilities Inc. shall refile its 2000/2001/2002 GRA incorporating the findings of the Board in this Decision, on or before May 10, 2002 or with its application for Phase II, whichever is the earlier.

(2) AltaGas Utilities Inc., in its refiling, shall include all of the supporting schedules necessary for the Board to make its final determination respecting AltaGas' 2000/2001/2002 revenue requirement. The refiling shall be at a level of detail sufficient to reconcile with the original filing and Memorandum of Agreement, and to demonstrate compliance with the Board's findings.

(3) The Board directs AltaGas Utilities Inc., in its next general rate application, to provide a written discussion of the relative merits of the use of 10-year Canada Bonds and 30-year Canada Bonds as the risk free rate.

(4) The Board directs AltaGas Utilities Inc. at the next general rate application to provide the average degree-day total, broken down into areas of similar degree-days, and to provide the relationship and formula that will give the Board the detail necessary to understand the impact of weather on revenue and variable margin.

(5) The Board directs AltaGas Utilities Inc. to incorporate the necessary changes for the treatment of Post-Employment Benefits to its revenue requirement, when refiling.

Dated in Calgary, Alberta on April 12, 2002

ALBERTA ENERGY AND UTILITIES BOARD.

<original signed by>

R. G. Lock, P. Eng
Presiding Member

<original signed by>

Gordon J. Miller
Member

<original signed by>

J. Gilmour
Acting Member

Appendix "A"

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	**Witnesses**
Alta Gas Utilities Inc. (AltaGas) and Bonnyville Gas Company Limited (Bonnyville) F. V. Martin	 L. Heikkinen A. Mantei K. McShane
Alberta Urban Municipalities Association J. A. Bryan	
Energy Users Association of Alberta H. Unryn	
Municipal Gas Co-op Intervenors and Bonnyville Municipal Intervenors T. D. Marriott	
Consumers' Coalition of Alberta J. A. Wachowich	
Treaty 8 Aboriginal Communities J. Graves	
Alberta Energy and Utilities Board staff J. Hocking, Board Counsel R. Armstrong, P. Eng M. T. McJannet	