Decision **2003-072**

ATCO Gas

2003/2004 General Rate Application
Phase I

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Alberta Energy and Utilities Board

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2003/2004 General Rate Application – Phase I
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1 INTRODUCTION

By letter dated August 2, 2002, ATCO Gas (ATCO or the Company), a division of ATCO Gas and Pipelines Ltd., filed Phase I of a 2003/2004 General Rate Application (GRA) with the Alberta Energy and Utilities Board (the Board or EUB). In the Phase I application (the Application), ATCO indicated that the GRA covered the combined ATCO Gas North and South service territories, and requested that the Board approve a single revenue requirement. In previous rate proceedings, the revenue requirement for the North and South service territories were dealt with under separate rate applications for ATCO Gas North (AGN) and ATCO Gas South (AGS) respectively.[1] In the GRA, ATCO forecast that the Company's revenue requirement for the test years would exceed revenue at existing rates[2] by $56.7 million in 2003 and $66.0 million in 2004.

Notice of Hearing for the GRA was mailed to all interested parties on September 6, 2002 and published on September 12, 2002. The Public Notice indicated that the hearing would be split between locations in Edmonton and Calgary and would commence at the Board's offices in Edmonton on March 4, 2003. Parties were advised by mail on February 19, 2003 that the hearing would continue in Edmonton until Friday, March 14, 2003, and reconvene at Govier Hall in Calgary on Monday, March 17, 2003.

By letter dated February 27, 2003, the Board indicated that the commencement date of the hearing had been revised to Monday March 10, 2003, and that the hearing would continue in Edmonton until Friday, March 21, 2003, reconvening in Calgary on Monday, March 24, 2003.

The public hearing was convened in Edmonton on March 10, 2003 before Board members Mr. B. T. McManus Q.C. (Chair), Mr. G. J. Miller, and Mr. J. I. Douglas, FCA. The hearing was completed on March 26, 2003. During the hearing, the Board heard submissions from parties with respect to the need for provision of 2002 actual data by ATCO, and the nature and extent of the information that would be required. By letter dated March 14, 2003, the Board directed ATCO to file an update to all GRA schedules and tables that included a forecast, incorporating 2002 actual data. The Board requested submission of this information, incorporating comparative variance analysis and explanations, by April 22, 2003.

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[1] After restructuring of Canadian Western Natural Gas Company Limited (CWNG) and Northwestern Utilities Limited (NUL) on January 1, 2001, Northwestern Utilities Limited was amalgamated into ATCO Gas and Pipelines Ltd. (AGPL) (formerly CWNG). AGPL now holds all assets for both of the former utilities, and on an ongoing basis, two divisions of AGPL (ATCO Gas and ATCO Pipelines) will continue the operations of the distribution system and the transmission system respectively, with the operating and accounting functions being segregated into AGN and AGS, and ATCO Pipelines North and ATCO Pipelines South, in accordance with Decision U99102, dated November 1, 1999.

[2] As per November 8, 2002 refiling.

In the March 14 letter, the Board confirmed that the hearing would be re-convened on Tuesday, May 20, 2003 to provide parties with the opportunity to examine the test year forecasts in light of the comparison with 2002 actual results. By letter dated April 15, 2003, the Board established the dates for an information request process with respect to the April 22, 2003 submission. ATCO filed its submission with respect to 2002 actual data on April 22, 2003, the hearing re-convened in Govier Hall in Calgary on Tuesday, May 20, 2003 and concluded on Wednesday, May 21, 2003. Parties filed written argument and reply on June 9, 2003 and July 3, 2003, respectively. Accordingly, the Board considers that July 3, 2003 was the close of record for this proceeding.

Those parties who participated in the hearing are attached as Appendix 1.

1.1 Procedural and Other General Matters

By letter dated September 20, 2002, the City of Edmonton (Edmonton) requested that ATCO provide additional schedules supporting the separation of the province-wide test year GRA forecasts between AGN and AGS. ATCO provided the requested information on November 14, 2002.

In the Application, ATCO referred to certain outstanding issues from other proceedings, which, when ultimately resolved, would impact the GRA forecast costs and revenues. ATCO indicated that, pending final disposition, the GRA would not reflect the impact of these issues, which resulted mainly from Board directions in various decisions including Decision 2002-069[3] Asset Transfer, Outsourcing Arrangements, and GRA Issues (the Affiliate Decision) and Decision 2002-072[4] (the ATCO Carbon Transfer Decision).

ATCO also indicated that the Company was still attempting to attract a world-class retailer to purchase its retail function. However, since nothing had been finalized at the time of filing the Application, ATCO indicated that the revenue requirement forecasts reflected the continuing requirement for the retail function.

On December 10, 2002, ATCO announced the proposed sale of the retail function to Direct Energy Marketing Limited (Direct Energy) and indicated, in correspondence dated December 13, 2002, that the impact of the retail sale (the Retail Sale), including identification of costs that would be eliminated from the cost of service, would be addressed in a subsequent separate process. By letter dated January 29, 2003, the Board requested that ATCO provide further clarification with respect to the timing and anticipated process required to reflect the impact of the retail sale and the separate proceedings or studies initiated to deal with the outstanding directions from other Decisions.

By letters dated February 7, 2003 and February 25, 2003, ATCO provided the further clarification requested by the Board with respect to the inter-relationship between the GRA and various other applications that had been filed or would be filed by ATCO in upcoming months. These included the application for the Retail Sale, and certain other applications deemed necessary to comply with directions of the Board in previous regulatory proceedings. In the

[3] Decision 2002-069 – ATCO Group, Affiliate Transactions and Code of Conduct Proceeding, Part A: Asset Transfer, Outsourcing Arrangements and GRA Issues, dated July 26, 2003

[4] Decision 2002-072 – ATCO Gas, A Division of ATCO Gas and Pipelines Ltd., Transfer of Carbon Storage Facilities, dated July 30, 2002

letters, ATCO provided a proposed timetable for the various proceedings, and identified certain components of the forecast revenue requirement as "placeholders", to be replaced with approved amounts in re-filings by ATCO after completion of the separate applications or modules.

On November 27, 2002, ATCO filed a request for approval of interim rates for 2003. ATCO proposed interim increases in the North and South of $18.6 million and $10.2 million respectively, representing 43% of the forecast revenue requirement in each zone. In Decision 2002-115[5] the Board approved an interim increase of $15 million in the North and $10 million in the South effective on consumption on and after January 1, 2003.

1.1.1 Merging of North/South Revenue Requirements

Views of ATCO

ATCO filed the GRA as a combined application of ATCO Gas North and South service territory, and requested the Board to approve one revenue requirement.

ATCO indicated that, in 1998, CWNG and NUL commenced a restructuring that would provide a more focused service to different customer segments through ATCO Gas and ATCO Pipelines. ATCO stated that, as part of the continuing evolution of ATCO Gas, the expiration of the North Core Agreement provided the opportunity to complete the restructuring commenced in 1998, with the bringing together of the separate business units into one for regulatory purposes. ATCO indicated that the Company had undertaken best practice reviews to align the operations of the North and South businesses, and that, from a corporate perspective, decisions were made on the basis of the Company as a whole

ATCO considered that the combination of North and South for regulatory purposes would foster greater understanding for customers and the Board. Therefore, ATCO considered it appropriate that forecasts and revenue requirement covered in Phase I should be reviewed on a province wide basis. ATCO pointed out that the Board would still have the flexibility to investigate the need for allocating costs appropriately to North and South during Phase II of the GRA process.

ATCO considered that the review and setting of one revenue requirement would reduce costs for customers through lower hearing costs and administrative and operational efficiencies. ATCO stated that the setting of one revenue requirement would reduce the complexity associated with the allocation and tracking of costs between the North and the South, and increase the understandability of the revenue requirement for customers and the Board.

ATCO pointed out that the Company needed the freedom to manage its business on a province wide basis, without the added complexity of dealing with North/South distinctions. ATCO indicated that the Company was undertaking several major capital programs, and would need the flexibility to resource and manage those programs on a province wide basis, without worrying about whether the cost of those resources were being tracked to the appropriate North or South account.

ATCO considered that customer rates should also be set on a province-wide basis and indicated that uniform rates for the North and South would be proposed in the Phase II application. ATCO

[5] Decision 2002-115 – ATCO Gas, 2003/2004 General Rate Application, Interim Rate Application, dated December 24, 2002

submitted that the Phase II portion of a GRA was the appropriate place to review the cost allocation methodologies used to assign levels of costs to various customer groups. The established practice for the allocation of costs amongst different customer groups was through the use of cost of service studies, not through the identification and approval of a separate revenue requirement for each community served by the Company. ATCO noted that the allocation methods used in a cost of service study could be as complex as warranted, and that prior to 1982, NUL and CWNG had numerous rate zones through which to address the allocation of costs to different customer groups. The determination of that cost allocation was through the cost of service study, not through the setting of separate revenue requirements. ATCO submitted that it was entirely possible that there were greater differences between the costs of providing distribution service to rural versus urban customers than there were between providing distribution service to the City of Edmonton and the City of Calgary.

ATCO acknowledged that the Board and customers would likely be interested in understanding the consequences of rate differentiation between North and South customers, and committed to providing, at a minimum, a cost of service study addressing this as part of the Phase II application which would follow the approval of a revenue requirement in the Phase I application.

ATCO noted that the concerns of interested parties appeared focused on the potential for the shifting of costs between the North and the South. ATCO considered that cost of service studies could address these concerns in a more transparent manner than the current practices used to account for the North and the South. However, ATCO did not believe that there would be any significant cost shifting, a conclusion based on the preliminary analysis performed in the response to EDM-AG-01, which demonstrated that the cost of providing distribution service to North and South customers was basically the same on a per unit basis, once certain anomalies such as production, storage and transmission services were removed. ATCO pointed out that it must be kept in mind that, while a significant portion of the requested increase in revenue requirement relates to the North, rates in the North are lower than in the South, and there were also a greater number of customers in the North. ATCO submitted that a significant portion of the North increase could be addressed by simply bringing the North rates up to the level of the South rates.

ATCO submitted that both North and South customers would benefit from the combining of operations within the Company, and that the benefit, as discussed in the response to CAL-AG-02-5 and in Exhibit 14-10b, far outweighed the minimal shifting of costs that had already occurred, or that might occur as a result of the merging of the revenue requirements. ATCO also indicated that there was no benefit to a further "transition" period, and that if the Board considered that long-term segregation of the revenue requirements was in the best interests of customers, there would be significant cost increases. ATCO stated that, specifically, the benefits already realized by customers as a result of merging CWNG and NUL would be undone through the attempt to maintain the illusion that the North and the South were two separate, legal and operational entities. ATCO pointed out that, in the event that the Board did not approve one revenue requirement, the revenue requirement forecast would need to be increased, as outlined in Exhibit 14-10b.

Referring to concerns expressed by the City of Calgary (Calgary), ATCO indicated that the differences which existed between the North and the South had been addressed in this GRA. With respect to Calgary's comment regarding the different programs between the North and the South, ATCO indicated that it would have been of assistance if Calgary had provided some examples of those differences. Accordingly, in ATCO's view it was difficult to support Calgary's assertion. Nevertheless, ATCO stated that different areas of the distribution system would require different levels of attention at different times, a condition that was not new, and currently occurred within the North and the South distribution systems. By way of example, ATCO noted that no special rate adjustments were made for the City of Calgary due to the Bare Mains Replacement Program undertaken in that city, and pointed out that the Board had not found it to be in the interest of customers to develop separate revenue requirements for each community within ATCO.

ATCO noted that Calgary did not accept the savings identified in Exhibit 14-10b, but did not identify its specific concerns with those savings. ATCO stated that it was impossible to deal with this unfounded allegation. ATCO agreed with Calgary that this was not the proceeding in which postage stamp rates should be developed for the North and the South, as this was a Phase II matter.

ATCO expressed concern that the Consumers Group (CG) did not signal disagreement with combining the North/South revenue requirement until submission of Argument. In ATCO's view, it would have been fairer if the Company had been provided an opportunity to question these concerns and respond to them prior to Reply Argument. ATCO submitted that, in effect, the CG was using Argument to introduce new evidence, and that the Board should take this into consideration when determining the weight to place on the assertions of the CG with respect to this matter.

In ATCO's opinion, the fact that the revenue requirement for the North had not been tested in a GRA since 1993/1994 was irrelevant to this issue. ATCO pointed out that it had provided a forecast of the revenue requirement for the North, and responded to information requests identifying changes that had occurred impacting North customers. ATCO stated that there was no need for the Board to establish separate revenue requirements to enable the CG to identify the impact of ten years of change on the North revenue requirement. ATCO failed to understand the relevance of that assessment to the test period, indicating that circumstances had changed significantly in the last ten years, making any comparison basically meaningless.

ATCO referred to concerns of the CG that outstanding contentious issues and placeholder amounts needed to be resolved in order to assess a merger of the revenue requirements, and failed to understand the relevance of this to the issue of merging the revenue requirements. ATCO noted that it had the ability to address significant matters specific to either the North or the South on a separate basis if required, through the use of riders.

With respect to the CG's concern regarding differences in the treatment of no-cost capital and income taxes, ATCO noted that the proposed change in tax methodology for the North would address this issue, and indicated that no interested party had indicated an objection to this change. ATCO considered therefore that the Board was able to address this issue in this proceeding, removing a potential impediment to combining the revenue requirements.

ATCO indicated that the impact of the proposed Retail Sale would be identified separately for North and the South, which should address the concerns of the CG in this regard.

ATCO submitted that differences related to the gas cost recovery rate (GCRR), transmission charges, COP and storage, would be dealt with in separate riders. ATCO considered that these matters would be addressed in the Phase II proceeding, and in no way impeded the ability to combine the revenue requirements.

ATCO stated that the most troubling aspect of the CG's position was the fact that they appeared to support a longer transition period to one revenue requirement than the Board required in its direction in Decision U99102.[6] ATCO considered that the CG's comments appeared to ignore the fact that the Board approved the merging of North and the South into one company, and establishment of a transition period in response to interveners concerns. ATCO pointed out that it was only requesting that the transition period be shortened by two years, in order that customers could start to enjoy the benefits of one revenue requirement sooner.

ATCO considered that the CG's concerns with lack of discussion with interveners on combining the revenue requirements appeared to indicate lack of understanding by the CG with respect to the Board directive in Decision U99102. ATCO pointed out that the directive appeared to indicate that the Board recognized that as a result of approving the merging of NUL and CWNG, it was also approving the eventual combining of the revenue requirements. ATCO stated that the Company was not seeking something not previously contemplated, and that the Company's intent to provide benefits to customers sooner rather than later should be applauded, not criticized.

Views of AUMA/EDM

The Alberta Urban Municipalities Association (AUMA) and Edmonton (EDM) submitted that, although ATCO may have concluded that rates should be on a province-wide basis, AUMA/EDM had not determined whether it could support a province-wide postage stamp rate. Accordingly, AUMA/EDM filed EDM-AG-01 on September 20, 2002 requesting that all GRA schedules be separated between North and South. AUMA/EDM noted that, in its limited response provided on October 4, 2002, ATCO concluded that the unit costs for providing distribution service were similar for the North and South service areas. AUMA/EDM also noted that, based on the 2002 actual information and specifically Policy 10.08 (Financial Reporting – North and South Shared Services) filed on April 22, 2003, it appeared that ATCO largely recorded costs at either the Corporate or Business Unit level and then allocated or assigned those costs to North or South. AUMA/EDM submitted that these assumptions, and those included in Policy 10.09 setting out the procedures for development of the North and South Financial Statements, needed to be tested in the context of a full Phase II proceeding.

In requesting the information, AUMA/EDM considered that separate North/South forecasts would be useful for reasons quite apart from establishing two revenue requirements. AUMA/EDM considered that the information would enable the Board to understand the impact of moving to a single province-wide revenue requirement compared to the status quo, provide the best available evidence on the benefits or harm to customer groups by moving to the provincial average, and provide the best available evidence for use during Phase II to help determine whether a single province-wide postage stamp rate was appropriate.

AUMA/EDM noted that Calgary supported the request for a full response on the grounds that the four sets of regulatory books were required "to enable public scrutiny of both cost tracking and

6 Decision U99102 – Canadian Utilities Limited, Northwestern Utilities Limited and Canadian Western Natural Gas Company Limited, Application for Renewal of the Reorganization of NUL and CWNG, dated November 1, 1999

forecasts to ensure that customers were not harmed by the ATCO Gas/CWNG/NUL reorganization." Although ATCO indicated that it would provide detailed analysis in Phase II, AUMA/EDM submitted that it was necessary to determine separate revenue requirements for North and South in order to assist in consideration of Phase II rate design issues and conduct a detailed cost of service analysis with any degree of veracity. AUMA/EDM submitted that the Board should determine separate revenue requirements, allowing a consideration of whether there should be distinct rates for the North and South and ensuring that the impact of the merger could be properly assessed.

AUMA/EDM did not dispute ATCO's claim that there should be benefits from the combining or merging of the operations of the two entities, but questioned ATCO's assertion that, based on a "preliminary analysis", there would be no significant cost shifting and no benefit to a further transition period.

AUMA/EDM submitted that the Board should determine separate revenue requirements for North and South to ensure that the impact of the merger can be properly assessed, and that the Board should continue to require ATCO to maintain separate books of account as directed in Decision U99102 until the impact of merging the operations for ratemaking purposes had been fully tested through a Phase II proceeding.

Views of Calgary

Calgary considered it a concern if the combination of the two revenue requirements interfered with the transparency necessary to examine prudence and fairness on an ongoing basis. Calgary also considered that if the two stand-alone revenue requirements were added together, there would be a transfer in all probability from North to South.

Calgary pointed out that there were a number of matters that had been treated differently in the North and South over the past number of years and submitted that it was better for those matters to be made consistent before the two revenue requirements were combined. Calgary considered that the differences in the revenue requirement increase for the two divisions were significant, and that ATCO was embarking on programs for the North that had already been completed in the South. Calgary submitted that this was not the proceeding in which a postage stamp set of rates should be developed for the North and South.

Calgary expressed the view that use of allocations was always inferior to use of actual data of each division, and that with stand alone rates for North and South, use of individual division data would provide a superior data base as compared to an allocated data base. Calgary considered that the impact of combination would be almost certain cross-subsidization. Calgary stated that, given the magnitude of the increase being sought by ATCO, it was hard to identify the efficiencies claimed by ATCO from combining the two revenue requirements. Specifically, Calgary did not accept the "saving" that ATCO attempted to present in response to the Undertaking at Tr. p. 1446, as no supporting data or substantiation of the numbers was provided.

Calgary considered that merging the revenue requirements of AGN and AGS would result in harm to the customers of AGS, and provided a table summarizing data from the Application to demonstrate that the level of proposed revenue increases being requested were highly disproportionate between the North and the South. Calgary submitted that ATCO had not provided a compelling case for the customers of AGS to share in recovering three to four times more increase requested for the North as compared to the South.

Also, as Calgary's table indicated, simple equalization of rates would require an increase to the North Rate 1 by a percentage in excess of the proposed percentage increase to the South rates. Calgary pointed out that any rate equalization, including the proposed increase, would result in a direct subsidy by the customers in the South to those in the North. Consequently, Calgary submitted that integration of the revenue requirement was inappropriate at this time.

Calgary referred to ATCO's identification of the benefits to customers as a result of combining the revenue requirements of North and South and the view that the benefits far outweighed any perceived benefit related to keeping them separate. Calgary noted that ATCO had indicated that there would be significant cost increases with long-term segregation of the revenue requirements. However, Calgary indicated that its concerns, particularly with respect to transparency, had not been alleviated throughout this proceeding and that ATCO's argument also did not allay those concerns.

Views of the CG

The CG disagreed with ATCO's proposal for combination of the North/South revenue requirements, and recommended that the revenue requirements remain separate pending a re-basing of the revenue requirements for North and South and a separate Phase II proceeding for 2004. The CG submitted that this approach was necessary for a number of reasons.

Firstly, the CG pointed out that the last GRA for AGN covered test years 1993 and 1994, subsequent to which there had been substantial changes in the ATCO organization and there was an urgent need to re-base the North revenue requirement, particularly before proceeding to any combined form of revenue requirement with AGS.

The CG also noted that this was the first time the North and South revenue requirements would be tested at the same time, and considered that once a Board decision was made on separate revenue requirements, a future assessment could reasonably be made as to the appropriateness of a combined revenue requirement for the two divisions.

The CG noted that the North Core Negotiated Settlement Agreement covered the period 1998 – 2002, and that although some examination of major areas was undertaken during negotiations, the settlement was principally a bottom line agreement. The CG considered that the current proceeding would be the first opportunity to examine the effects of this agreement on the forecast North revenue requirements for 2003 and 2004, and examine capital maintenance programs and labour staff complements. The CG expressed the view that it would be premature to eliminate and preclude examination of the separate North revenue requirement prior to Board approval of a reasonable, separate revenue requirement.

The CG submitted that a number of contentious issues remained in connection with the ramifications of the recently released Affiliates Decision Part A, the Carbon Transfer Decision, and the Appeal of the Calgary Stores Block Decision. The CG considered that until the outstanding regulatory issues were resolved, and the impact on the base revenue requirements known, it was difficult to assess a merger of revenue requirements.

The CG expressed concern that ATCO was currently involved in a number of complex proceedings (at various stages of commencement and completion) necessitating numerous placeholders, including consideration of placeholders for the 2004 test year of this GRA. The CG submitted that, until these placeholders were replaced with tested values, it was premature to consider a merged revenue requirement.

The CG referred to significant differences between North and South with respect to the treatment of no-cost capital, negative salvage and the calculation of income taxes, and submitted that a merger should not be considered until the impacts of these types of differences were fully evaluated, with a Board decision rendered.

Referring to the application by ATCO and ATCO Electric for sale of their retail businesses to Direct Energy, the CG considered that merging the revenue requirements at this point would make it more difficult to track costs and ensure that customers were not harmed as a result of the transaction. Consequently, the CG submitted that until the Board dealt with the proposed sale, the two revenue requirements should remain separate.

The CG noted that ATCO Pipelines was proposing separate North and South revenue requirements in its 2003/2004 GRA, but providing combined revenue requirement information on a transitional basis for interveners' benefit. The CG considered this approach appropriate, and suggested adoption of a similar approach for ATCO, pending completion of the re-basing evaluation.

In addition to the fact that ATCO Pipelines was retaining separate books for North and South, the CG noted that the current GCRR was calculated separately for AGS and AGN, which suggested that continuation of separate revenue requirements would be more consistent with the other components of the overall delivery charge (i.e. transmission).

The CG pointed out that company-owned production (COP) facilities and the Carbon Storage reservoir led to significant differences between the North and South, including difference in revenues received. The CG submitted that these differences, combined with differences in revenue from affiliates such as ATCO Pipelines, supported continuation of separate revenue requirements pending further review.

The CG disagreed with ATCO's submission that any North/South differences could be addressed in the context of a Phase II proceeding. The CG considered that there were too many differences and considerations to be addressed on a separate North and South basis to accommodate allocation of costs in a Phase II proceeding at this time. The CG submitted that unless a separate revenue requirement was approved for North and South, there would be no meaningful or effective way to compare rate impacts year over year, or make a comparison of rates under merged versus separate revenue requirements. The CG also submitted that there was no evidence to support ATCO's view that rate classifications were similar for the North and South.

Referring to the cost of service analysis provided by ATCO in response to EDM-AG-01, the CG indicated that the analysis only looked at a "snapshot" of 2003 and 2004, where the differences between North and South rates were minor for distribution wires only. The CG expressed concern that the analysis also ignored any consideration of differentials arising from different growth rates into the future, and failed to take into account any historical differences. By way of example, the CG indicated that capital maintenance might be different because of the differences applied during the negotiated settlement for the North, and there could be differences due to differing transmission costs between the North and South. There might be no justification for provincial allocation for irrigation service as those customers were unique to the AGS. The CG submitted that these factors further supported the recommendation to go slowly and establish a potential transition period for examination of all the facts.

The CG noted that usually a revenue requirement is directly assigned where possible and the remaining costs allocated to rate classes based on billing determinants of demand, energy and customers. The CG considered that, unless the process resulted in costs being functionalized to separate North and South areas, the resulting functionalized costs allocated to rate classes in a Phase II would be different than the allocation arising from a Phase I process for North and South. The CG also indicated that to the extent that producer and industrial revenues are subject to competitive pricing that might not recover allocated costs, any deficiency is recovered from other rate classes, effectively bypassing the North and South distinction.

The CG noted ATCO's suggestion that an additional $100,000 would be required to develop separate depreciation and lead/lag studies in the event that a single revenue requirement were not approved, and that a further $100,000 would be required to prepare and present separate Phase II studies. The CG was not persuaded that these costs would be required, and submitted that even if required, the projected costs might be outweighed by the potential adverse impacts on customers as a result of the merged revenue requirements. In the absence of information to the contrary, the CG urged the Board to err on the side of caution and direct ATCO to maintain separate revenue requirements pending completion of the Phase II proceeding and further examination.

The CG expressed concern with ATCO's failure, before filing the Application, to initiate discussions with North and South Interveners concerning the combining of revenue requirements. The CG noted that the minimal communication that did take place appeared limited and more in the way of noting any explicit objections.

The CG considered it the Applicant's responsibility to establish a credible and defensible case, and that it was not the interveners' responsibility to provide competing evidence on every issue where they disagreed with ATCO. The CG stated that to follow ATCO's implied approach would require a much more protracted and highly inefficient process, so as to allow development of intervener evidence on every issue of concern.

The CG disagreed with ATCO's position that the primary concerns of interveners regarding the separation of revenue requirements was limited to potential cost shifting and cost of service studies. The CG stated that a cost of service study could not "unscramble" the egg. Any meaningful investigation of North and South costs must be done on a separate Phase I revenue requirement basis before any Phase II allocation method can properly be applied. This was particularly true, given that the North revenue requirement had not been fully reviewed for nearly 10 years.

The CG did not believe that ATCO's preliminary analysis and removal of anomalies provided any basis for a fundamental change from separate revenue requirements to a single, combined revenue requirement. The CG considered that, without full disclosure and meaningful analysis, ATCO's conclusions were speculative, without foundation and should be rejected by the Board as a basis for merging the North and South revenue requirements.

The CG submitted that ATCO's view that long-term segregation of the revenue requirements would result in significant cost increases in the future was not supported, without the review of forecasts for future test years. The CG also considered questionable ATCO's view that additional staff would be required for separation, as ATCO had been operating on a separated basis up till now with existing staffing levels.

Therefore, the CG submitted that the Board should direct ATCO to maintain separate revenue requirements for the upcoming test years, and prior to undertaking any merger of revenue requirements in the future, ATCO should be required to undertake a significant level of discussions with stakeholder parties in relation to such a change.

Views of the Board

The Board notes ATCO's comment that all of the concerns expressed by customers with respect to potential cross-subsidization arising from combination of the revenue requirements can be addressed in a Phase II process, and that prior to 1982, the allocation of costs to numerous rate zones and customer groups of NUL and CWNG was accomplished through cost of service studies, not through the setting of separate revenue requirements.

However, the Board considers that there is merit in the submissions of the interveners that there are too many differences and related considerations to be addressed at this time to accommodate allocation of costs in a Phase II unless separate revenue requirements are maintained. The Board shares the concerns of interveners that there would be no way to make a comparison of rates under merged versus separate revenue requirements without evaluating the allocation of costs to rate classes on a combined and separate basis.

The Board notes the agreement of interveners that any meaningful investigation of North and South costs must be done on a separate Phase I revenue requirement basis before any Phase II allocation method can properly be applied, particularly given that the North revenue requirement has not been fully reviewed for nearly 10 years.

The Board notes the CG's claim that a number of contentious issues remain pursuant to the ATCO Affiliates Decision, the ATCO Carbon Transfer Decision, and various other Compliance Decisions; that placeholders need to be replaced with tested values; and that there are significant differences in treatment of no-cost capital, negative salvage, and accounting for COP facilities and the Carbon storage reservoir. The Board notes that the CG and Calgary both consider that the impact of these issues needs to be fully evaluated before any merger is approved, and that this is not the proceeding in which a postage stamp set of rates should be developed for the North and South.

The Board also notes Calgary's submission that the revenue increases proposed in the Application are highly disproportionate between North/South, and that integration of the revenue requirements is inappropriate at this time pending substantive evidence that there is no significant cross-subsidization between North and South.

The Board notes that the consistent theme in submissions of interveners in this proceeding is that the Board should direct ATCO to maintain separate revenue requirements for the test years. The Board notes that specific concerns include the need to determine separate revenue requirements to assist in consideration of Phase II rate design issues, and to allow for a re-basing of the revenue requirements for the North given that the last GRA for AGN covered test years 1993 and 1994.

In addition, while acknowledging the understanding that this Phase I process would proceed without consideration of the impact of the proposed sale of the retail function, the Board recognizes that the proceeding to evaluate the proposed sale is presently underway and that the outcome could have implications that should be considered in making a determination regarding combination of the North/South revenue requirements. The Board acknowledges that, while the outcome of the retail sale proceeding is uncertain at this time, there is the potential that the outcome could have a significant impact on rate design issues, and could create the potential for resolution of many of the concerns raised by interveners with respect to combination of the North/South revenue requirements. The Board considers that this introduces an additional level of uncertainty into the deliberations with respect to establishment of postage stamp or zonal rates, and that it would be important to understand the impact on rate design, and the extent to which contentious Phase I issues might be resolved before initiating a process to establish postage stamp rates in a Phase II.

The Board acknowledges ATCO's position as to the benefits to customers and potential efficiencies that would accrue from merging the North and South revenue requirements, and agrees that this is a worthwhile goal. However, recognizing the significant level of concern expressed by all parties to this proceeding with respect to combination of the revenue requirements, and acknowledging a certain level of apprehension on the Board's part with regard to taking such a major step given the potential impact of the retail sale on revenue requirement and rate design issues, the Board is reluctant to approve ATCO's proposal at this time.

In the Board's view, as the first step towards implementation of a single revenue requirement, there is a need to establish separate revenue requirements for North and South, and develop separate Cost of Service studies to determine the similarities or reasons for significant difference between the rates and rate structure in each region.

Based on the foregoing, the Board directs ATCO, in refiling its GRA to reflect the results of this Decision, to file the revenue requirement separately for North and South. The Board therefore expects that the outcome of this Phase I process will be the setting of separate revenue requirements for North and South, and that separate rates could be set for North and South in the subsequent 2003/2004 Phase II. The Board considers that before a single revenue requirement is implemented, ATCO must be able to demonstrate harmonization in accounting treatment in the North and South by resolving differences in treatment of issues such as no-cost capital, negative salvage, COP facilities and the Carbon reservoir. In addition, the Board considers that ATCO needs to propose a methodology in the rate design process to address any residual cross-subsidization issues between North and South.

In subsequent sections of this Decision, where the Board has made adjustments affecting the revenue requirement on a combined basis, it will be necessary for ATCO to apportion the adjustments appropriately between North and South.

However, despite the direction to determine separate revenue requirements for the North and South, the Board does not see the need for separate rate applications for North and South pending the establishment of a single revenue requirement. Accordingly, pending establishment and approval of a single revenue requirement in this or subsequent proceedings, the Board directs ATCO to file future applications for revisions to North and South rates in a single GRA.

The Board notes Calgary's argument that use of allocations to determine North/South revenue requirement components is always inferior to use of individually recorded data for each region. While accepting that direct recording of data is the ideal, the Board considers that this is not always a realistic goal, and is satisfied that ATCO's allocation methodologies, as supported by evidence in this proceeding, appear to produce allocations on a reasonable basis. Nevertheless, the Board considers that any perceived or identified deficiencies in this regard should not represent a barrier to eventual combination, as specific North/South capital and operating functions can continue to be accounted for separately through continuation of the existing plant accounting methodology.

The Board notes ATCO's response to EDM-AG-01, and the analysis demonstrating that the cost of providing distribution service to North/South customers is basically the same per unit after removing certain anomalies, related to production, storage and transmission services. However, the Board acknowledges the comments of interveners that ATCO's assertion, based on a "preliminary analysis," is questionable. The Board also acknowledges the comments of the CG that the analysis ignored consideration of differentials arising from different growth rates in future, differences due to differing transmission costs in the North and South, and the fact that irrigation service is unique to the South.

Nevertheless, the Board considers that ATCO's "snapshot" analysis provides a good indication that the revenue requirements could ultimately be combined once the anomalies and unique North/South differences referred to by interveners have been harmonized. With respect to intervener concerns regarding differences in growth rates, the Board recognizes that this will always be a feature of the utility business, which should not present a barrier to eventual combination of the revenue requirements.

The Board notes ATCO's comment that if long term segregation of the revenue requirements is deemed to be in the best interests of customers, there would be significant cost increases. The Board considers that it is ATCO's responsibility to determine the additional processes and procedures necessary for preparation of separate revenue requirements, recognizing that customers have expressed the willingness to bear the appropriate related costs.

The Board notes the comments of the CG with respect to the need for further discussions with customer groups prior to combination of revenue requirements. The Board is prepared to accept that a greater level of consultation with customers could result in a more timely resolution of the issue.

1.1.2 Request for Relief from Requirement to Maintain Separate Books of Account

Views of ATCO

ATCO pointed out that, in Decision U99070,[7] the Board directed ATCO to maintain separate accounts for the North and South until 2005. ATCO submitted however, that regulating the two areas separately and duplicating the costs for two separate hearings created higher costs without

[7] Decision U99070 – Canadian Western Natural Gas Company Limited, 1997 Return on Common Equity and Capital Structure; 1998 GRA – Procedural Directions and Partial Phase I Decision, dated July 30, 1999

a corresponding benefit to customers. Therefore, ATCO requested that the Board relieve the Company from the need to comply with the direction in Decision U99070.

ATCO indicated that, while combining the revenue requirements of the North and South might appear to be a significant change, much of the change already occurred when the Board approved the merging of NUL and CWNG. ATCO stated that it was simply requesting that the Board allow the Company to complete the natural evolution of that merger. A further transition period would not make any difference with respect to the concerns expressed, and was not required.

ATCO agreed with Calgary that standalone revenue requirements were superior to allocation methods used in Cost of Service studies, but could not accept that the North and South had true standalone revenue requirements. ATCO stated that due to the merging of CWNG and NUL, and the fact that the North and the South existed in the same legal entity, only those things that could be readily identified and measured could be accounted for separately.

ATCO did not agree that combining the revenue requirements of the North and the South would make comparison of actual data to forecast more difficult, as stated by Calgary. ATCO indicated that comparisons of actual to forecast could be developed on a total basis as easily as for the separate North and South forecasts.

With respect to concerns with compliance with the Board's direction to maintain four sets of books, ATCO considered that Calgary appeared to focus on the amount of time required to provide the 2002 actual data. ATCO indicated that it had maintained the separate accounting for the North and South in the most cost effective manner possible, and did not incur additional costs to modify its financial systems to accommodate accounting for the North and South. ATCO submitted that customers had already benefited from modification of financial systems and maintenance of staff levels, and that the Company had identified additional benefits to customers through the approval of one revenue requirement commencing in 2003, not beyond the test period as suggested by AUMA/EDM.

ATCO considered that it had found the balance between efficiency and complexity appropriate to meet the needs of the Board and customers with respect to accounting for the North and South, given the fact that the Board's directive was short term in nature. ATCO pointed out that the Board approved the allocation methods used for 2001 and 2002 in Decision 2002-069, and has the information required to assess this matter for 2003 and 2004 if one single revenue requirement is not approved. ATCO submitted that there was no need for the Board to "compel" the Company to provide further information regarding its accounting or allocation methodologies for the North and South, as suggested by Calgary.

Views of AUMA/EDM

AUMA/EDM noted that the only potential benefit from adopting one revenue requirement, as quantified by ATCO in Exhibit 14-10(b), related to savings beyond 2003/2004. AUMA/EDM submitted that ATCO should not be relieved from the requirements to maintain separate books of account for the North and South until after the impact on costs and rates had been determined and assessed in a full Phase II proceeding. In AUMA/EDM's view, following such a Phase II, a reasoned decision could be made as to whether or not ATCO should maintain separate books of account. Until that time, AUMA/EDM considered that costs should continue to be tracked as directed by the Board in Decision U99102.

AUMA/EDM considered that potential savings beyond the 2003/2004 test period would still be available after a full Phase II testing of the impact of the merger on rates.

Views of Calgary

Calgary submitted that ATCO should not be relieved of its obligations under Decision U99102, indicating that, as long as there were separate North and South rates, standalone books and records should be maintained. Calgary considered that, in the absence of standalone books and records, the Board would have to rely on the inferior cost allocation methodology under a combined revenue requirement, compared to the superior methodology under standalone revenue requirements and rates.

Calgary considered that use of standalone books and records would also help maintain continuity in the comparison of actual to forecast data. Calgary questioned whether ATCO had in fact been complying with the Board's decision, given the length of time taken to provide 2002 data. Calgary submitted that maintenance of the required "four sets of books" would have provided the source documentation for timely preparation of 2002 financial data for the separate divisions of the Company.

Calgary submitted that the Board should continue to require compliance with its prior decisions and retain its position as set forth in Decision U99102. Calgary considered that the existing North/ South books are the result of both direct assignments and allocations, and until such time as uniform rates could be established on a just and reasonable basis, the continued separation of costs between North and South must be maintained. Calgary submitted that ratepayers in the South should not be exposed to the significantly higher cost increases being proposed for the North.

Calgary considered that, before any relief is granted from the Decision U99102 direction, AGPL, ATCO and ATCO Pipelines should be required to disclose the underlying foundation for all direct and allocated entries into the "four sets of books" and the process should be fully reviewed before the Board. Calgary stated that, if the allocation methodologies were not fully disclosed and reviewed at the end of this GRA process, four years would have passed with no examination of the process and the direction contained in Decision U99102 would expire. Calgary submitted that its position, set out in the responses to Questions 14 through 20 of its evidence, provided the Board with a sufficient foundation to compel AGPL to fully disclose its accounting and allocation methodologies to the Board and Interveners.

Views of the CG

The CG submitted that the Board was clear in its direction to maintain separate books until 2004, noting that ATCO offered to do so as a condition for merger approval. The CG stated that the Board clearly indicated that separate record keeping would allow future scrutiny of the Company's transactions to ensure a balance between customer and Utility interests. The CG considered separate record keeping essential to understanding the potential impacts on the North and South. The CG submitted that ATCO had not justified the staff increases that the Company claimed would be required to continue to maintain separate records, and had not demonstrated any significant efficiencies or cost savings that would result from being relieved from the Board's direction.

The CG did not understand the basis for ATCO's statement that much of the change had already occurred when the Board approved the merging of NUL and CWNG, and disagreed with ATCO's view that the interests of all customers would be best served by the Board relieving ATCO of the direction in Decision U99102. The CG submitted that ATCO had not provided any convincing evidence to justify relief from the requirement to maintain separate books at this time, as such relief would effectively limit future options. Accordingly, the CG submitted that ATCO should be directed to maintain separate books as directed in Decision U99102.

The CG referred to Calgary's concerns regarding those areas where allocations between North and South had occurred, and indicated that absence of records at the entity level was another reason why the request for relief from the requirement to maintain separate books for North and South was premature. The CG submitted that ATCO should be directed to maintain records that would permit identification of material costs specific to each entity, for purposes of recording the actual results for 2003 and 2004.

Views of the Board

The Board acknowledges ATCO's submission that regulating the North and South separately, and duplicating costs for two separate hearings, creates higher costs without a corresponding benefit to customers, and that uniting North and South for regulatory purposes would foster greater understanding for customers and the Board. The Board notes that on this basis, ATCO has requested relief from the need to comply with the requirement in Decision U99102 for maintenance of separate books until 2004.

Similar to the issue of merging revenue requirements, the Board notes the consistent theme in submissions of interveners that the Board should direct ATCO to maintain separate books of account until 2004. The Board notes that specific concerns include the need to maintain separate books until the impact on costs and rates has been determined and assessed in a full Phase II proceeding, and that in the absence of standalone books and records, the Board would have to rely on an inferior cost allocation methodology under a combined revenue requirement, compared to the superior methodology under standalone revenue requirements and rates.

The Board notes that the interveners all disagreed with ATCO's position that the interests of all customers would be best served by relief from the direction in Decision U99102, and also disagreed that ATCO had provided convincing evidence to justify relief at this time, which would effectively limit future options.

The Board considers this issue essentially a component of the issue of merging of the North/South revenue requirements addressed in Section 1.1.1 of this Decision. The Board is of the view that, even in the absence of a proposal to combine the North/South revenue requirements, the appropriateness of ATCO's request for relief would be subject to question. Approval of the reorganization of NUL and CWNG was conditional on the requirement that ATCO maintain separate books until December 31, 2004 to "enable future scrutiny of the Applicants' transactions so as to provide comfort to customers and the Board that such transactions balance the interest of both the customers and the Applicants."

However, the Board recognizes that ATCO's request for relief from the direction in Decision U99102 is a natural extension of the proposal for combination of the North/South revenue requirements, but considers that granting relief would be premature in light of the conclusions in

Section 1.1.1. In this regard, the Board considers that all parties would feel more comfortable with continued maintenance of separate record keeping until the issue of combined versus separate revenue requirements has been resolved. As discussed in Section 1.1.1, given that the issue may not be resolved until the next ATCO GRA, the Board recognizes the need to extend the timeframe for maintenance of separate books of account beyond the end of 2004 as envisaged in Decision U99102.

The Board therefore directs ATCO to continue to maintain separate books of account until the Board is satisfied that the North/South revenue requirements can be combined. Accordingly, the direction in Decision U99102 is amended to require the maintenance of separate books of account if and until the Board approves the combination of the North/South revenue requirements.

1.1.3 GRA Forecasts

Views of ATCO

ATCO identified the forecast revenue shortfall for 2003 and 2004, indicating that the evidence contained in the Application set out the reasons for the shortfalls. ATCO provided historical information for the North and South business units to assist interested parties in their review of the forecast, but reiterated that the review of the test year revenue requirements should be performed on a combined North/South basis. ATCO did not provide a revenue requirement forecast for 2002 due to the fact that the North and South were still regulated separately in that year, but the Company indicated that all significant forecast information with respect to 2002 had been provided for continuity with the test years.

Referring to the examination of 2002 actual data, ATCO indicated that the detailed and comprehensive explanation of the variances between the 2002 forecasts and actual data submitted on April 22, 2003, should serve to show that the Company's forecasting process and methodology were neither arbitrary nor flawed. ATCO stated that after preparation of the 2002 forecasts, subsequent events resulted in differences from the expected outcome, consistent with the nature of forecasting. ATCO stated that it was not possible to develop a forecast that took into consideration every possible contingency, but instead the forecast needed to represent a balancing of both positive and negative unforeseen circumstances, in order to ensure that the utility was able to earn its fair return.

In response to BR-AG-02-7, related to the filing of the April 22, 2003 submission, ATCO expressed concern with respect to the use of information, not available at the time of the development of the GRA forecast, to test the reasonableness of the test year revenue requirement. ATCO did not consider that use of more current information was consistent with the principle of prospectivity, and considered that it created an opportunity to "cherry-pick" the forecast. ATCO pointed out that the Company was not requesting a change to the forecast for certain other issues, not referred to by parties in the context of the April 22, 2003 submission, such as the impact on operating expenses of significantly higher gas prices than forecast, lower sales/customer in the North than forecast, or the potential for higher inflation rates than forecast.

ATCO noted that some of the differences between the 2002 forecast and actuals related to efficiencies that ATCO was able to achieve, and stated that the concept of the sharing of efficiencies between the Company and customers was inherent in the principle of prospectivity. ATCO submitted that continual reduction of opportunities for sharing efficiency gains impacts the incentive for a utility to seek those gains, resulting in a negative consequence for customers. ATCO also noted that focusing too heavily on prior year results could overshadow the fact there were unique or changing circumstances in 2003 and 2004 which impact costs.

Calgary's comment that 2002 actual data should be given the same weight, or even greater weight than other filed data, and in ATCO's view, ignored the fact that the Company had not been afforded the same opportunity to address changes that had occurred with respect to the test years. ATCO expressed concern about the procedural fairness of such an approach, and cautioned the Board against placing undue weight and attention on information that became available after the forecast was prepared.

ATCO did not agree that its concept of prospective ratemaking was inconsistent with the practices of the Board, as stated by Calgary, and cited comments of the Board in Decision 2000-82,[8] indicating that a utility should expect to be able to benefit from efficiency gains achieved during the period between GRAs, and that any transfer of savings to consumers would occur following the subsequent GRA and the setting of new rates.

ATCO submitted that updating the forecast to reflect every changed circumstance up to the approval of the final compliance filing, as advocated by Calgary, would result in the scheme of regulation becoming completely retrospective, and efficiencies for customers would diminish. ATCO did not believe this was consistent with the Board's view of the future of regulation in Alberta.

Regarding the accuracy of the 2002 forecast, ATCO pointed out that the 2002 capital forecast was within $107,000 of actual capital expenditures, and this immaterial difference supported the forecasting methodology used in the development of the capital forecast for 2002–2004.

ATCO noted that approximately $8 million of the change from forecast related to the impact of Decisions 2002-069 and 2002-072, as well as regulatory decisions for ATCO Pipelines (South) with respect to the transmission charge. ATCO indicated that these matters would be addressed in the current Application, and therefore this $8 million deviation had no impact on the validity of the test year forecasts.

ATCO stated that approximately $1 million of the change from forecast related to efficiencies that ATCO was able to find with respect to its information technology (IT) charges, and the remaining deviation from the 2002 O&M forecast was approximately 1.7%. ATCO believed this was a strong indication that the 2002 forecast was accurate, and the forecasting methodology for 2002–2004 was reasonable.

ATCO submitted that the methodology used to develop forecast revenues produced reasonable results, and forecast Rate Revenue and Other Revenue differed from the actuals by only $256,000.

ATCO referred to Calgary's suggestion that the Company should have used the 2002 forecast approved for AGS in development of the 2003/2004 GRA forecast in order to assist evaluation of forecast continuity. ATCO stated that, as indicated in Rebuttal Evidence, it would be

[8] Decision 2000-82 – ATCO Gas and Pipelines Ltd. (CWNG), Request to withdraw the 1999 GRA and assessment of the need for a 2000 GRA, dated December 22, 2000

nonsensical to use a forecast that does not take into account the impact of changing circumstances since the time that forecast was developed. By way of example, ATCO indicated that the 2002 forecast South residential sales/customer was considerably lower than the level approved by the Board in the 2001/2002 GRA. ATCO submitted that, had this forecast been used as a starting point, it would not be properly comparable to the test year forecasts for sales/customer. ATCO did not believe that this would facilitate evaluation of the reasonableness of the forecast being tested.

Views of Calgary

Calgary submitted that the Board should rely on the 2002 actual data and use that data as the starting point for the forecasts in this Application. Calgary considered the 2002 actual data to be the best information available, and did not represent "cherry picking," as stated by ATCO. Calgary noted ATCO's acknowledgement that it updated final forecast information on at least a quarterly basis, and submitted that the Board should not be expected to have inferior information with which to make its decision, compared to that available to ATCO management.

With respect to ATCO's concern that use of 2002 actual data somehow violated the concept of "prospective rate making," Calgary considered ATCO's concern to be inconsistent with virtually all other jurisdictions, and with practices of this Board. In Calgary's view, prospective ratemaking was introduced to provide utilities with a better opportunity to earn their allowed return in a time of increasing inflation, and not to enable a utility to withhold and control information that was relevant to making an informed decision.

Calgary considered the evidence clear that the 2002 forecasts provided in this Application were not indicative of accurate forecasting. Given that ATCO had some months of 2002 actual information when preparing the test year forecasts, Calgary submitted that the accuracy of those forecasts must be questioned.

Calgary disagreed that ATCO "has not been afforded the same opportunity to address changes that have occurred with respect to 2003 and 2004 test years," and submitted that ATCO had the opportunity to do whatever it wanted with the Application, such as modification of the Application to determine certain matters in separate processes, some using entirely new evidence. Calgary considered this inconsistent with ATCO's espoused view of "prospective" ratemaking.

Views of the CG

The CG considered that the best available information should be used to test the forecasts for the test years, and acknowledged that it was inappropriate to selectively use 2002 actual information to update the forecasts prepared by the Company. However, in the CG's view, if actual information provided insights as to the appropriateness of forecasting methods and assumptions used by the utility, those insights should be used to refine the Company's forecasting methods for the test years. The CG also submitted that it was appropriate to use actual opening balances where they were available to determine forecast plant balances or other figures that relied on continuity of numbers from year to year, such as number of year-end customers or employees.

The CG expressed concern with ATCO's vehement opposition to the use of 2002 actual data. The CG stated that it could not be disputed that 2002 actuals provided the most up to date information on the current state of the utility operation, and that not to rely on this information or suggest that the Board attach minimal weight on this evidence was not reasonable. The CG suggested that ATCO's opposition was based on the fact the 2002 actuals explicitly demonstrated the degree of overstatement included in the 2002 forecast and, commensurately, the unsubstantiated increase in the test year forecasts relative to actuals.

The CG stated that it was arguable that ATCO's strong opposition to use of 2002 actuals threw into question the forecast test year process. The CG considered that, certainly, timing was an issue as the 2002 actuals were available much earlier than when ATCO filed this information with the Board and interveners. The CG stated that the constraint on filing actuals earlier in the process was a constraint imposed by ATCO in choosing not to file actuals until the information was provided to shareholders through the Annual Report.

The CG noted ATCO's position that "some of the differences between the 2002 forecast and actuals relates to efficiencies that ATCO Gas was able to achieve." While in support of efficiencies, the CG stated that variances, such as those between 2002 forecast and actual results, related largely to timing of labour additions and vacancies, for instance, and did not constitute actual efficiencies.

Views of AUMA/EDM

AUMA/EDM noted that ATCO was displeased with the use of 2002 actual information, notwithstanding that the Board twice requested full 2002 actual schedules. AUMA/EDM cautioned the Board against placing undue weight and attention on information that became available after the forecast was prepared. AUMA/EDM noted that ATCO attributed some of the differences to efficiencies that were achieved between the 2002 forecast and actual results.

AUMA/EDM submitted that not only has there been a persistent bias towards over-forecasting capital expenditures in test years, but that this bias applied to all aspects of the revenue requirement. AUMA/EDM submitted that it is entirely appropriate to give full weight to the 2002 actual results in order to test the forecasts for 2003 and 2004. AUMA/EDM questioned whether the efficiencies that ATCO was able to achieve in 2002 were truly efficiencies or whether they were simply another example of excessive forecasting. AUMA/EDM submitted that, even if there were efficiencies, they should not be ignored for purposes of the test year forecasts because the utilities should be expected to continually strive for all possible efficiencies.

Views of the Board

While acknowledging that the timing of a GRA filing is under the control and at the discretion of the Applicant, the Board considers that the Applicant needs to bear in mind that parties to the proceeding need to have access to the most up to date actual information for the year prior to the first test period, for the purpose of evaluating the test year forecasts. The Board notes that while the filing of a GRA well in advance of the first test year is a laudable goal, the advantage can be offset by the need to update actual data throughout the hearing process, and in some cases up to the close of the hearing. The Board recognizes that in this proceeding, due to procedural delays, there was a need to adjourn the hearing and establish a separate module to deal with 2002 actual data that was filed during the hearing process.

The Board considers it appropriate to acknowledge the time and effort expended by ATCO in preparation and submission of its filing on April 22, 2003 (Exhibit 14-10), in response to the

Board's request for information with respect to 2002 actual data. The Board found the submission comprehensive and helpful in evaluating ATCO's forecasting process in light of 2002 results.

The Board notes that the main issues to be resolved from assessment of the information in Exhibit 14-10 relate to the extent to which the 2002 actual results supported the accuracy of ATCO's forecasting process, and the extent to which test year forecasts should be adjusted in light of those results.

With respect to ATCO's forecasting process, interveners generally expressed the view that the main question is whether examples of actual expenditure in 2002 below forecast truly represented the efficiencies that ATCO indicated the Company was able to achieve, or were simply examples of excessive forecasting. On the other hand, the Board notes ATCO's position that the 2002 variances show that the forecasting process and methodology is appropriate, and that events subsequent to the preparation of the 2002 forecast resulted in differences from the expected outcome, consistent with the nature of forecasting.

The Board considers that the comprehensive review of Exhibit 14-10, assessment of ATCO's variance explanations and subsequent responses to Information Requests, supports ATCO's position that the Company was able to achieve efficiencies in a number of areas and that many of the variances resulted from the occurrence of subsequent events that could not have been foreseen at the time the 2002 forecast was prepared. However, the Board also acknowledges the CG's comment that, if actual information provides insights as to the appropriateness of forecasting methods and assumptions used by the utility, those insights should be used to refine the Company's forecasting methods for the test years. Overall, the Board considers that examination of Exhibit 14-10 provided evidence that the 2002 forecast was prepared based on a reasonable assessment of known factors at the time, and agrees with ATCO that it is not possible to develop a forecast that takes account of every possible contingency.

With respect to the issue of adjustment of test year forecasts in light of 2002 actual results, the Board agrees with interveners that test year forecasts should reflect the fact that actual 2002 data provides the most up to date information on the operations of the utility, and should be adjusted as necessary to recognize this principle. The Board considers that this principle in no way contravenes the concept of prospectivity, as evidenced in Decision U97065,[9] dated October 31, 1997, Decision E89091,[10] and Decision 2001-96,[11] where the Board concluded that forecasts were found to be deficient, as evidenced by actual information that became available during the course of the proceedings.

While the Board will consider the applicability of this principle in other Sections of this Decision, the Board is aware of the need to balance positive and negative unforeseen circumstances. In this regard, the Board agrees with ATCO that focusing too heavily on prior

[9] Decision U97065 – Alberta Power Limited, Edmonton Power Inc., TransAlta Utilities Corporation, Grid Company of Alberta – 1996 Electric Tariff Applications, dated October 31, 1997

[10] Decision E89091 – TransAlta Utilities Corporation, In the matter of a Filing by TransAlta Utilities Corporation, pursuant to a direction of the Public Utilities Board in Order C88027 dated November 14, 1988, for an Order or Orders fixing new rates, charges or schedules thereof for electric light, power or energy furnished by TransAlta Utilities Corporation to and for the public in Alberta during the years 1988, 1989 and 1990, dated .December 15, 1989

[11] Decision 2001-96, ATCO Gas South, 2001/2002 General Rate Application, Phase I, dated December 12, 2001

year results could potentially overshadow unique circumstances in those years or changing circumstances in the test years.

1.1.4 Other General Matters

1.1.4.1 Sale of Beaverhill Lake and Fort Saskatchewan Production Assets

Views of ATCO

In response to BR-AG-149, ATCO provided the impact of the sale of the Beaverhill Lake and Fort Saskatchewan production assets on the test year forecasts, and was not aware of any issue with respect to the proposed treatment. Also, in the response to CG-AG-127, ATCO identified the adjustment required as a result of the North Core 2002 negotiated settlement. ATCO indicated that these changes would be incorporated into a compliance filing with respect to this Application.

Views of the Board

The Board directs ATCO, in its compliance filing (the Refiling), to reduce forecast expenditures for 2003 and 2004 to fully reflect the sale of the Beaverhill Lake and Fort Saskatchewan properties.

1.1.4.2 Minimum Filing Requirement and Uniform Code of Accounts

Views of ATCO

ATCO referred to Calgary's proposal for use of Minimum Filing Requirements and a standardized Code of Regulatory Accounts, and indicated that it would support the implementation of Minimum Filing Requirements for GRAs if the Board considered that this would improve the regulatory process. However, ATCO pointed out that there must be an understanding of the costs associated with implementing this type of change. ATCO considered that Calgary's proposal indicated a lack of understanding about the potential cost of tracking and reporting information that currently was not available, noting that the more detailed the filing requirements, the greater the likelihood that ATCO would incur additional costs to meet the requirements.

Similarly, ATCO stated that use of a standardized Code of Regulatory Accounts must be reviewed with care, noting that Calgary did not clarify whether it was referring to a code of accounts for all utilities in Alberta, Canada, or North America, or specifically for gas utilities or all utilities. ATCO pointed out that, while the Uniform Classification of Accounts (UCA) currently used by the gas utilities in Alberta was developed in 1963, and likely did not reflect changing circumstances since that time, this did not necessarily mean that a complete overhaul of the code of accounts was required. ATCO submitted that the extent to which changes were made would impact the level of costs associated with such a change.

ATCO indicated that the test year revenue requirement did not incorporate the potential impact of any changes in the UCA, and that imposition of any changes requiring additional costs to be incurred over the test period needed to be taken into account in setting the forecast revenue requirement. ATCO therefore recommended that any consideration by the Board to either of these matters should be done through a consultative process, similar to the process that the National Energy Board (NEB) established with respect to its minimum filing requirements.

ATCO stated that such a process would allow cost issues and the appropriate timing of implementation to be fully addressed.

Views of Calgary

Calgary indicated support for the concept of a working group or collaborative process among all stakeholders to develop both Minimum Filing Requirements and to update the existing 1963 Uniform System of Accounts. Calgary pointed out that it had filed with the Board the Uniform System of Accounts and related accounting instructions for gas and electric utilities utilized by the Ontario Energy Board and the Federal Energy Regulatory Commission as working examples which have served the utility industry for many years.

Calgary submitted that the time is ripe for instituting consistency in the accounting and regulatory reporting of all utilities subject to the Board's oversight. With respect to ATCO's concern regarding the cost of implementing a standardized uniform system of accounts, Calgary considered that the cost could be accumulated in a deferred account and amortized over an appropriate period of time, similar to the process utilized by AGPL for accounting for software development costs.

Calgary submitted that the Board could either impose a uniform system of accounts or create a working group consisting of Board, utility, and intervener representatives with a background in utility accounting to evaluate the Ontario Energy Board and Federal Energy Regulatory Commission systems for best applicability. Calgary submitted that the latter option would provide all parties to the regulatory process with instant knowledge of the accounting systems, and reduce the learning curve requirement.

Calgary also recommended use of a Minimum Filing Requirement process and procedure to enhance the regulatory process. Calgary considered that use of a Minimum Filing Requirement would add consistency to all regulatory filings, as the same schedule would be used for the same item by every utility.

Calgary considered that, as with the implementation of a Uniform System of Accounts, a minimum filing requirements working group could be established to develop the documentation based upon the substantive work of other regulators.

Views of the Board

The Board notes the observations and concerns of Calgary with respect to the need to update the UCA and for development of Minimum Filing Requirements for GRAs. The Board notes ATCO's position that the UCA likely did not reflect changing circumstances since development in 1963, and acknowledges that, as discussed in these proceedings, various aspects of the Company's accounting policies are not completely aligned with the UCA. While the Board considers that the issue of deviation from the classification requirements of the UCA is of low priority, as any deviations appear to be relatively minor, the Board agrees with Calgary that identification and evaluation of deviations from the UCA would be of benefit in GRA deliberations.

Accordingly, the Board directs ATCO to provide, at the next GRA, a summary of any deviations or variations from the UCA.

The Board is supportive of any initiative to enhance the regulatory process, and notes the concerns expressed by interveners during the course of these proceedings with respect to the absence of comprehensive underlying support for information in the Application. The Board notes intervener comments that this created a situation where "challenges to the position of the Applicant are then based on less than the full and complete facts known by the Applicant in support of its case"[12] and that "a GRA is not a game of hide and seek or 20 questions."[13] The Board notes intervener claims that this condition resulted in the need for a more extensive interrogatory process, and notes that the condition was also manifest in situations where test year forecasts reflected a methodology different from that previously approved by the Board.

The Board expects that test year forecasts in rate filings should, at a minimum, be based on previously approved methodologies or policies, and that where the Applicant proposes a change to the approved practices, those changes should be presented in the filing as proposals, indicating the impact relative to the approved policies. The Board notes that the Application was not presented in this manner with respect to all initiatives and changes, which made it difficult for all parties to understand the impact of some of the changes and reconcile them with previous practice.

2 CAPITAL ASSETS

2.1 Capital Expenditure Forecasts

Views of ATCO

ATCO forecast capital expenditures of $143.4 million and $138.9 million in 2003 and 2004 respectively. ATCO pointed out that the forecast level of capital expenditure is higher than recent historical capital expenditure levels, which have ranged between $86.0 million to $89.2 million per year between 1999 and 2001. ATCO indicated that the primary drivers of the capital program are:

- Growth in new customers of approximately 20,000 customers per year.
- Since a significant portion of urban and rural distribution main network is now 30-plus years old, these facilities require replacement due to deterioration in the form of leaks, corrosion, inoperability, obsolescence, and failure to meet current design standards.
- The effect of external forces, including the increasingly dynamic marketplace resulting from deregulation and unbundling, changing customer expectations, and a heightened security consciousness resulting from the events of September 11, 2001.
- A proposed change in the accounting treatment of certain administration costs related to capital, resulting in incremental capital costs of $6.5 million in each of 2003 and 2004.

ATCO submitted that suggestions by various intervener groups that the Company is "ramping up" or "expanding" rate base were incorrect and without merit and presumably based on the level of capital expenditure forecasts in 2003 and 2004 relative to recent years. ATCO indicated

[12] Calgary Evidence, p. 14 of 71
[13] CG Argument, p. 113

that capital projects were undertaken on the basis of the need to serve new customers and maintain infrastructure at the level necessary to provide safe and reliable service.

ATCO stated that, in 2002, a higher than forecast level of customer additions resulted in increased expenditures for Rural Main Extensions and Services, Urban Feeder Mains, Urban Service Lines and Regulator and Meter Setting. ATCO explained the variances from forecast in unit costs for these expenditure categories.

In ATCO's view, there was not a full understanding of the relationship between capital expenditure forecasts and new customer additions. ATCO considered that AUMA/EDM assumed that each additional customer above forecast required a proportionate share of all Distribution Extensions, including gate stations, feeder mains, services, and meters. ATCO indicated that this assumption was incorrect and pointed out that each new customer within a given year required only a service line, regulator, and meter. A customer might not necessarily be connected to an urban distribution main installed in that year, but might be connected to an urban distribution main installed in the previous one to two years. ATCO also noted that the main might be connected to a feeder main served by a gate station, both of which were installed previously or that would be installed in the future. In ATCO's view, it was an oversimplification and incorrect to simply take new customer additions and multiply by an overall unit cost in an attempt to derive a capital expenditure forecast.

While ATCO agreed that the forecasts for the test period were greater than expenditure in recent years, ATCO pointed out that the increase was justified based on need, and did not stick to some preconceived mathematical formula as the CG suggested. ATCO noted also that the CG's argument suggested that total capital expenditures could be determined by taking the product of the customer additions multiplied by some theoretical unit cost. ATCO considered this a dramatic oversimplification, which ignored the Company's evidence. ATCO stated that a thorough analysis of the information provided would clearly support the conclusion that test year forecasts are necessary, prudent, and fully supported by the evidence.

ATCO took issue with the unsubstantiated position of the CG that the Company had failed to provide adequate supporting documentation for capital forecasts, including relevant business cases, and took exception to the allegation that information was being withheld. To refute this claim, ATCO pointed to the substantial information in the Application and responses to several hundred Information Requests in support of the capital forecasts. ATCO submitted that clearly, this met the threshold of providing support for the forecast capital expenditures, and considered that the CG's position regarding business cases also indicated a basic misunderstanding with respect to development of a capital forecast.

ATCO pointed out that the process of developing a capital forecast is, at a particular point in time, to provide an estimate of future expenditures based on the best available information, factoring in the consideration that projects have different probabilities of proceeding. ATCO indicated that clearly, this means that at that particular point in time, some projects have fully developed business cases, some have partially developed business cases, and some projects have just been identified and do not have a formal written business case. ATCO indicated that, in cases where the project justification is straightforward, a formal business case is not developed, nor is one required; but in all cases, only those projects that are fully justified are included in the forecast.

ATCO was also confident that the capital projects would proceed in the timeframe being examined. By way of example, ATCO referred to the Sherwood Park Operating Centre, for which a need had been identified at the time of the filing. ATCO stated that a relatively high level analysis was provided in the filing, and that over the next several months, a business case was developed and submitted in response to BR-AG-31. ATCO submitted that the timing of the business case submission in no way diminished the merits of the Sherwood Park Operating Centre, but demonstrated that at the time of the filing, the project was at an earlier stage of development. ATCO stated that incorporating only those projects with complete business cases would ignore the timing realities of the real world and would exclude projects that were required, but did not have fully documented business cases. ATCO stated that the suggestion to reduce forecasts by 15% on major projects was completely arbitrary, was presented without any evidence whatsoever, and completely ignored the realities of capital projects and related forecasting.

Referring to AUMA/EDM's suggestion that the approval process "…provides for a built in incentive to over-forecast so as not to require any further approvals," ATCO stated that the statement was submitted without supporting evidence. ATCO categorically stated that the expectation of management and directors of the Company is that a capital forecast includes projects based on need and that forecasts are made with the highest degree of accuracy possible, given the information available at the time.

In summary, ATCO indicated that one of the key factors in 2002 was that the increase in customer additions was comprised of a large increase in residential customer additions, partially offset by a reduction in commercial customer additions, both relative to forecast. ATCO indicated that, since the unit cost of serving a residential customer is significantly less than for a commercial customer, the impact of the increase in customer growth on capital expenditures was significantly less than if the increase in customers had been proportionally distributed between residential and commercial customers or predominantly commercial customers. ATCO submitted that AUMA/Edmonton, in its argument, presented a simplistic view that did not have merit once the underlying data was analyzed.

Referring to the CG's comment that contributions were under forecast by reference to the 2001/2002 GRA forecast, ATCO indicated that, as explained in Exhibit 14-10a, the Company proposed a change in the treatment of service line contributions in the 2001/2002 GRA. Since the Board did not approve this change, ATCO indicated that the 2003/2004 GRA forecasts were adjusted and included the previously reduced amounts for customer contributions for service lines. ATCO pointed out therefore, that a comparison with the 2001/2002 GRA forecast was incorrect and understated the actual amount of service line contributions included in the 2003/2004 GRA filing. ATCO pointed out that this accounted for the majority of the difference referenced by the CG. ATCO's position was that the contributions for the test years had been accurately forecast.

ATCO noted that both the CG and AUMA/EDM made comments with respect to Exhibit 13-5, the so-called aid to cross-examination. With respect to the specific information in Exhibit 13-5, the interveners took the position that the information indicated that ATCO over forecasts its capital expenditures. ATCO pointed out that this suggestion had been dealt with through the submission of Exhibit 13-23, which provided a corrected and updated version of Exhibit 13-5, which was further supported by analysis and contextual comments provided by Mr. Bruce in cross-examination. ATCO referred to Mr. Bruce's observation that 1998 data should be excluded from consideration, given the lack of comparability of CWNG and AGS data, and the difficulty in validating the data. ATCO submitted that, with respect to this Exhibit, unique and extraordinary projects for the period of 1999-2002 were identified, primarily in the area of Information Systems. ATCO pointed out that as discussed by Mr. Bruce, removing these extraordinary items resulted in actual expenditures within 3.6% of forecast. ATCO also pointed out that examination of the main category of expenditures, namely Distribution items, indicated that actual expenditures were within 2.8% of forecast.

ATCO stated that the information presented in Exhibit 13-23 clearly demonstrated that the Company had accurately forecast capital expenditures over a period of time, and that there was no credibility to the AUMA/EDM suggestion that capital expenditures might be up to 10% less than forecast in the test years. ATCO stated that AUMA/EDM's opinion had been put forward without evidence or support, and that the evidence demonstrated the Company's historical forecasting accuracy and proved the credibility of the test year capital forecasts.

ATCO pointed out that examination of the data from 1998 is problematic as that data was based on expenditures of CWNG, which was not comparable to AGS even after removal of the Transmission line items. As a result, in ATCO's view, it was more appropriate to examine only the data from 1999-2002. During this period, ATCO demonstrated a high degree of forecast accuracy with actual expenditures being 5.9% (1.5% per year) lower than forecast, and removal of extraordinary items resulted in actual expenditures being 3.6% (0.9% per year) lower than forecast for the period. ATCO indicated that the Distribution category of expenditures typically represented the largest category of expenditures, typically in the range of 75%, and that review of expenditure in the Distribution category indicated that those expenditures were 2.8% (0.7% per year) lower than forecast. ATCO submitted that it was reasonable to conclude that the Company had clearly demonstrated a high degree of accuracy in capital expenditure forecasting.

Views of AUMA/EDM

AUMA/EDM noted that the significant increases in test year forecasts, compared to the average over the years 1999/2001, were driven primarily by Distribution Improvements including the Meter Relocation and Replacement Program (MRRP), service line replacements and the capitalization of an additional $6.5 million of administration costs.

AUMA/EDM noted that final approval of the capital budget by the ATCO Board of Directors occurred in the fall of the year preceding the budget year in question, meaning that the 2002 capital budget was approved in the fall of 2001, the 2003 budget in the fall of 2002, but no specific approval would have been given to the 2004 budget. AUMA/EDM considered it noteworthy that the capital budget approval was final, as stated by ATCO "so long as the spending is within that limit, it does not have to go back to the Board." In AUMA/EDM's view, this presumably meant that further approval by the Board of Directors only applied when the capital budget exceeds the forecast. AUMA/EDM considered that this approval process was asymmetrical and provided for a built in incentive to over-forecast so as not to require any further approvals. AUMA/EDM specifically cited 2002 as a prime example where the capital forecast was $107.7 million compared to actual expenditure of $104.6 million, notwithstanding ATCO's ability to provide service to close to 5,000 additional customers or 25% more than forecast.

AUMA/EDM filed Exhibit 13-5 as an aid to cross-examination to review ATCO's capital forecasting accuracy, and indicated that, as noted in previous proceedings, CWNG and AGS had a long history of over-forecasting capital expenditures in test years. AUMA/EDM considered that this bias translated to an inflated rate base and the return, taxes and depreciation thereon. AUMA/EDM pointed out that as noted in Decision 2000-9,[14] actual capital expenditures for CWNG were 11% less than forecasts filed in the GRAs over the period 1989-1993, and between 1998-2000, forecasts exceeded actual by 10.0%, 7.0% and 8.8% subject to minor adjustments discussed in the context of Exhibit 13-5.

AUMA/EDM indicated that the conclusion to be drawn from Exhibit 13-5, as adjusted for transmission items, was that the total filed costs for the years 1999-2002 were $9 million (4.5%) less than forecast. AUMA/EDM submitted that ATCO's comment that this averaged out at 1.1% per year was confusing to say the least and should be ignored, as on average, the forecast for those years was 4.5% too high. Moreover, AUMA/EDM submitted that the more relevant comparison should include 1998, which was not discredited contrary to ATCO's assertions. AUMA/EDM pointed out that inclusion of 1998 increased the average amount over-forecast to 6.0% over the period 1998-2002. The fact that ATCO was able to serve 25% more new customers in 2002 than forecast for no additional cost, in the opinion of AUMA/ADM, clearly called into question the forecast for that year. AUMA/EDM concluded that, excluding 2002, the average forecast over the period 1998-2001 exceeded actual by $5.2 million or 9.7%, which was consistent with the 11% over forecast by CWNG during 1989-1993 as identified in Decision 2000-9.

AUMA/EDM submitted that there had been a persistent bias towards over-forecasting capital expenditures in test years, which suggested that actual capital expenditures could also be up to 10% less than forecast in 2003 and 2004. AUMA/EDM considered that the Board should consider this persistent bias when determining the allowable rate base additions for 2003 and 2004.

Referring to ATCO's suggestion that AUMA/EDM might not have a full understanding of how customer additions drive capital expenditures and the comment that, while each new customer would require a service line, regulator and meter, customer additions might not drive urban distribution mains, feeder mains or gate stations, AUMA/EDM stated that these unsubstantiated statements still did not explain how ATCO was able to serve an additional 25% new customers at no extra cost. AUMA/EDM noted that, it appeared to be the rule rather than the exception that the installation of distribution mains followed the number of customer additions. AUMA/EDM indicated that response to AUMA/EDM-AG-02-115 appeared to suggest that the number of new customers largely drives distribution mains.

AUMA/EDM noted that, while the actual cost of new Urban Feeder Mains and service lines increased 23% and 15% respectively compared to the 25% increase in customer additions, the cost of meters and meter/regulator installations, which ATCO stated should follow customer additions, surprisingly decreased by 10% and increased by 7% respectively.

AUMA/EDM referred to ATCO's discussion of the extraordinary items that caused the forecasts to be too high, and submitted that there was no rationale for removing these items from the

14 Decision 2000-9 – ATCO Gas and Pipelines Ltd. (CWNG), 1997 Return on Common Equity and Capital Structure; 1998 GRA Phase I, dated March 2, 2000

forecasts. AUMA/EDM pointed out that the majority of these items were deferrals or delays that contributed to the forecasts being too high and which might well recur in the 2003 and 2004 forecasts. AUMA/EDM noted that ATCO attempted to rationalize the deferrals with the statement "projects that are deferred due to changes in growth requirements in a particular year are generally constructed the following year or shortly thereafter." AUMA/EDM considered that ATCO appeared to be missing the point. AUMA/EDM stated that ATCO had a bias towards forecasting rate base additions in advance of when they would realistically be completed and placed into service, which attracts return, taxes and depreciation, and contributes to the persistent over-forecasting as demonstrated in Exhibit 13-5.

Views of the CG

The CG noted that average capital additions were forecast at an average of $141 million per year in the test years, in contrast to average actual additions of $87.6 million during the period 1999-2001 inclusive. The CG expressed concern that this was indicative of a ramping up of rate base, noting that customer growth between 2000 and 2004 was at only 10%. The CG submitted that the level of forecast additions was not justified, particularly in light of customer growth.

In addition to the level of capital forecasts, the CG also expressed concern with the difficulty experienced in assessing the reasonableness of proposed capital projects or the related timing, given the lack of supporting documentation (e.g. internal business cases), or criteria applied as justification. The CG also expressed concern with a significant under forecasting of net customer contributions of approximately $4 million when comparing actual 2002 results for AGS against the forecast. The CG considered that the Board should use these trends to make significant adjustments to the ATCO GRA forecast.

The CG submitted that ATCO has had a history of over forecasting as indicated in Exhibit 13-23, which demonstrated that the Company over forecast capital additions in each of the years 1998, 1999, 2000 and 2001 by percentages ranging from 7% to 13.3%. The CG considered that the Board should rely on the best information available when determining the reasonableness of the requested revenue requirement, and that actual plant balances when known, should be utilized as the base for any further additions.

The CG pointed out that this was the third time that ATCO had failed to provide business cases for major capital additions in a GRA filing, despite repeated directions from the Board. The CG expressed concern that, in this GRA, ATCO provided the required business cases in response to information requests, resulting in inefficiency in the hearing process. The CG considered that the simple process of forecasting capital projects did not satisfy the used and useful criteria per se. The CG submitted that the Company had to demonstrate that the project was prudent and needed, by submission of a detailed report available with the filing of the Application. The CG considered that it would be appropriate for the Board to reduce by 15%, the forecast for any major capital addition for which the business case was not provided in the GRA.

The CG noted that this concern was most noticeable in the case of service centre projects, where little or no internal approval documentation appeared to exist. The CG considered that this concern was further justification for reduction of the forecasts, and submitted that ATCO should be directed to provide, in future GRAs, information concerning its capital approval process that would allow for an examination of the appropriateness of the process.

In the CG's view, simply stating that a capital project was needed to provide safe, reliable or efficient service was inadequate to support a rate base addition. The CG stated that instead, ATCO should be required to provide objective standards for safe and reliable service to customers.

Referring to the Board's Phase I decision for CWNG for the test years 1997 and 1998, dated March 2, 2000, the CG noted that the Board concluded that ATCO must provide sufficient information to facilitate evaluation of the reasonableness of aggregate forecasts, and that should the Board find that the tests of prudence and usefulness were not met, the Board would disallow all, or a portion of, the project from rate base.

The CG also referred to the Board's specific information requirements as set out in that Decision and repeated in Decision 2001-96 with respect to the AGS 2001-2002 GRA, and submitted that ATCO had not complied with these directions and expectations, particularly with respect to reliability and safety criteria for additions of capital projects.

The CG considered that any project not adequately supported by ATCO should not be included in rate base.

Views of the Board

The Board notes intervener submissions with respect to the Company's history of over forecasting, and the specific observations regarding the forecasts for 1998-2002. The Board notes that the data provided by AUMA/EDM, based on historical results for AGS set out in Exhibit 13-5, was subsequently revised by ATCO in Exhibit 13-23. The Board accepts the revised data in Exhibit 13-23, which demonstrates that the actual expenditure for 1999-2002 was 4.5% less than forecast, and that if extraordinary items identified in the forecasts during that period are excluded, this would be reduced to 3.6%. The Board also notes ATCO's observation that in the Distribution category, which accounts for 75% of total expenditure, actual expenditure during the period was 2.8% less than forecast. The Board is prepared to accept ATCO's submission that 1998 should be excluded from the comparison, given the lack of comparability of CWNG and AGS data, and the difficulty experienced by the Company in validating the data for that year.

While acknowledging ATCO's submission that the extraordinary items identified in Exhibit 13-23 consisted of expenditures deferred from the original forecasts, the Board is not convinced that these items should be excluded from the forecasts for comparison purposes, as deferral of forecast expenditure is not uncommon and is a condition that should be considered in evaluating the test year forecasts.

The Board is satisfied that Exhibit 13-23 indicates that actual expenditures from 1999-2002 were between 2.8% and 4.5% below forecast. While the Board accepts AUMA/EDM's position that historical results indicate a tendency to over-forecasting, the Board agrees with ATCO that test year forecasts are unlikely to be overstated by the 10% identified by some interveners. Thus, the Board does not agree with intervener suggestions that historical results justify an overall reduction to capital expenditure forecasts of 10%, and recognizes that a reduction on this basis could duplicate any adjustments made to specific capital expenditure categories in this Section of the Decision. However, the Board will consider the mid-point of the historical range (3.5%) as a benchmark for this application when evaluating forecasts for specific capital expenditure categories.

The Board disagrees with the comments of AUMA/EDM that the Company's budget approval process was asymmetrical and provided for a built-in incentive to over-forecast to avoid the need for further approvals. The Board considers that the evidence does not indicate that the Company's budget approval process has contributed to over-forecasting.

The Board notes the comment of AUMA/EDM that the actual capital expenditure in 2002 was $3 million below forecast, despite providing service to 5,000 additional customers, thereby calling into question the forecast for that year.

The Board also notes ATCO's position that it is incorrect to assume that each additional customer above forecast requires a proportionate share of all Distribution Extensions, including gate stations, feeder mains, services, and meters. The Board acknowledges ATCO's submission that each new customer within a given year requires only a service line, regulator, and meter, and might not necessarily be connected to an urban distribution main installed in that year. The Board accepts that it may be an oversimplification, and not necessarily correct, to apply an overall unit cost to new customer additions in an attempt to derive a capital expenditure forecast.

The Board notes the CG's concern that the business cases for major capital additions, particularly for service centre projects, were filed by ATCO in response to information requests rather than in the Application as directed by the Board in previous GRA decisions. The Board acknowledges the CG's concern and agrees that failure to provide the business cases contributed to some inefficiency in the hearing process. Nevertheless, the Board accepts ATCO's submission that the information provided in the Application and in response to the large volume of information requests with respect to forecast capital expenditures met the threshold of support for forecast capital additions.

Accordingly, on the basis that all relevant support for major capital additions was ultimately placed on the record, the Board does not consider that failure to provide the information at the time of filing the Application is sufficient reason to justify a 15% reduction in capital forecasts as suggested by the CG.

The Board also recognizes that in some instances, due to the timing of the project, a complete justification with the level of detail required by the Board may not have been available when the Application was filed, and that for projects driven solely by safety considerations, an economic justification would not be meaningful.

However, to continue to promote efficiency in the hearing process, the Board again directs ATCO, in future rate applications, to file business cases for all major capital additions in accordance with the directions in Decision 2001-96, so as to include:

- a detailed justification including demand, energy and supply information;
- a breakdown of the project cost;
- the options considered and their economics; and
- a discussion of the need for the project.

The Board notes the CG's concern that net customer contributions for 2002 were $4 million under forecast, and ATCO's comment in response that the difference was entirely due to the fact that the 2002 forecast anticipated a reduction in customer contributions for service lines that the Board subsequently did not approve. The Board acknowledges ATCO's position that the actual contributions for 2002 and forecasts for the test years reflect the higher level of contributions than forecast in 2002, in accordance with the Board's ruling in Decision 2001-96. Accordingly, the Board agrees with ATCO that it is incorrect to evaluate the test year forecasts for customer contributions with reference to the variance in results for 2002.

2.1.1 Development of Reserves

Views of ATCO

ATCO indicated that this category included development drilling, re-completion of wells, well workovers, land acquisition, and seismic activity required to produce company-owned reserves. ATCO stated that forecast capital expenditures of $625,000 for each test year focused on optimizing production levels in the Beaverhill Lake and Fort Saskatchewan fields.

ATCO pointed out that the sale of the Beaverhill Lake and Fort Saskatchewan fields resulted in reduced expenditures for 2002, and that expenditures in the North in 2003 and 2004 were not required. ATCO indicated that this would be reflected in a GRA compliance filing.

Views of AUMA/EDM

AUMA/EDM noted ATCO's confirmation that $615,000 of the capital expenditure forecast for development of company-owned reserves in each of the test years would be eliminated as a result of the sale of those producing properties. AUMA/EDM submitted that ATCO should be directed to reduce the AGN capital expenditures on development of reserves by $615,000 in each of 2003 and 2004 in its refiling.

Views of the Board

The Board directs ATCO, in its Refiling, to reduce forecast expenditures for development of company-owned reserves by $615,000 in 2003 and 2004 to reflect the sale of the Beaverhill Lake and Fort Saskatchewan properties.

2.1.2 Production/Storage Projects

Views of ATCO

ATCO forecast a capital requirement of $2.7 million and $1.8 million for 2003 and 2004 respectively to install pumpjacks, install miscellaneous surface equipment, and overhaul a compressor. Storage projects typically undertaken add capacity, maintain deliverability, meet regulations and codes, and provide a reliable level of service at the Carbon Storage facility. ATCO indicated that, in the test period, forecast capital expenditures were required to ensure COP continued to meet industry specifications for quality, to install secondary containment at storage tanks, to perform storage well workovers, to run casing inspection logs, and to conduct miscellaneous piping and facilities work.

ATCO indicated that the sale of the Beaverhill Lake and Fort Saskatchewan fields resulted in reduced expenditures for 2002, and that expenditures in the North in 2003 and 2004 were not required, which would be reflected in a GRA compliance filing.

Views of AUMA/EDM

AUMA/EDM noted ATCO's confirmation that $582,000 and $452,000 of the capital expenditure forecast on production and storage projects in each of the test years would be eliminated as a result of the sale of the Beaverhill Lake and Fort Saskatchewan producing properties. AUMA/EDM submitted that ATCO should be directed to reduce the ATCO Gas-North capital expenditures on production and storage projects by $582,000 and $452,000 respectively in 2003 and 2004 in its refiling

Views of the Board

The Board directs ATCO, in its Refiling, to reduce forecast expenditures for production and storage projects in 2003 and 2004 to fully reflect the sale of the Beaverhill Lake and Fort Saskatchewan properties.

2.1.3 Distribution Extensions

Views of ATCO

ATCO explained that Distribution Extensions typically included projects undertaken to extend distribution mains to serve new urban and rural customers, install distribution Regulating Meter Stations (Gate Stations), and construct Urban Feeder Mains.

ATCO indicated that forecast expenditures for Urban Main Extensions were completed for each area of the ATCO Gas service territory and were based on the number of lots requiring a main extension and the average cost to serve a lot. ATCO pointed out that, in the test period, expenditures were forecast to be $12.0 million and $11.0 million in 2003 and 2004 respectively.

Main and Service line extensions were described by ATCO as required to serve new customers in rural franchise areas and were based on an analysis for each "type" of new rural customer. ATCO indicated that customer types were: Rural Pool, Urban Pool, and Non-Grantable. ATCO indicated that capital expenditures for this category of expenditure were forecast to be $6.9 million and $6.7 million in 2003 and 2004 respectively.

ATCO stated that the experience in 2002 was somewhat unique in that overall residential lot development increased while commercial lot development decreased relative to forecast. ATCO also pointed out that the amount of main installed per lot decreased in 2002. ATCO submitted that these factors resulted in the Company extending service to a greater number of lots relative to forecast, but at a reduced overall cost in 2002.

With respect to Rural Main Extensions and Services, ATCO noted that in 2002, expenditures of $8.11 million were significantly above the forecast of $6.26 million.

ATCO stated that Urban Feeder Mains were forecast based on budget estimates for each project. In addition, unspecified projects were forecast based on the general level of subdivision development in communities served by the Company. ATCO indicated that forecast expenditures of $5.5 million in 2003 and $5.6 million in 2004 were required to meet the strong growth at the outer edges of major urban centres.

ATCO indicated that similar to Urban Feeder Mains, new Regulating Meter Stations were forecast based on budget estimates for each project. In addition, unspecified projects were forecast based on the general level of subdivision development in communities served by the Company. ATCO stated that these facilities were required to provide a source of supply for new areas. ATCO indicated that forecast expenditures were $1.3 million and $1.2 million in 2003 and 2004 respectively.

ATCO pointed out that in 2002, actual expenditures on Urban Feeder Mains of $6.94 million were significantly above the forecast of $5.85 million. ATCO indicated that evidence had been provided demonstrating that the vast majority of Feeder Mains serve customers in the year in which they are installed.

ATCO submitted that the capital additions forecast for Distribution Extensions for the test period remained appropriate.

ATCO referred to the issues related to subdivision servicing, including external forces such as developer decisions, deep utility servicing, and general economic conditions driving new housing starts. ATCO noted that the CG made the erroneous suggestion that forecast expenditures for Distribution Extensions should be based on the arithmetic average of the total capital expenditures from 1999 to 2002. ATCO indicated that this oversimplified approach would not be an accurate method to forecast capital expenditures, and pointed out that the necessary detailed analysis had been conducted by the Company, and was presented in evidence, including the response to various information requests.

Referring to AUMA/EDM's suggestion that the Company had under forecast contributions for Urban Main Extensions, ATCO stated that, as discussed in the response to AUMA/EDM-AG-10, contributions are rarely received for Urban Main Extensions. ATCO pointed out that, by virtue of the Company's Service Regulations and most municipal franchise agreements, ATCO is required to extend service, at no cost, to every customer served by municipal water and sewer service in a municipal area. ATCO submitted that, because virtually all new customers in a municipal area are served by water and sewer, it is a rare exception to receive a contribution. ATCO pointed out therefore that it had not included a forecast for contributions in this category.

Referring to AUMA/EDM's suggestion that a "minimum reduction of 10% and up to 20% of the forecast 2003 and 2004 urban (feeder) mains is warranted," ATCO considered that this suggestion was presented without evidence and was based on the issue of specified versus unspecified projects. ATCO also pointed out that AUMA/EDM's suggestion totally ignores the evidence submitted by ATCO, particularly given that in 2002, the actual expenditures exceeded forecast by approximately $1.1 million, due mainly to completion of projects that were not forecast. ATCO considered AUMA/EDM's argument to be flawed due to a lack of understanding of subdivision development. ATCO pointed out that Feeder Mains are forecast in consultation with the key stakeholders including developers, engineering consultants, and municipalities to develop a forecast of projects to be completed in the test period. ATCO noted that the realities of subdivision development result in the deferral of some projects that were previously specified. By the same token, some unforeseen projects are developed.

ATCO pointed out that, with respect to Regulating and Metering Stations and Feeder Mains, a deferred project will in most cases be constructed in the following one to two years, and will be incremental to the forecast in the year in which it is built. ATCO considered that removal of deferred projects from the forecast would be inappropriate and would result in an understatement of the overall forecast.

ATCO noted that AUMA/EDM continued to relate the Urban Feeder Mains forecast to customer additions, and stated that this approach was incorrect since a feeder main was required to serve all the new customers in a particular area of development. ATCO pointed out that these customers do not all request service in the same year that the feeder is constructed, as discussed in the response to AUMA/EDM-AG-02-115. Regarding the suggestion of AUMA/EDM that Urban Feeder Mains might be an appropriate subject for a deferral account, ATCO could not recall the submission of any evidence on this issue prior to comments in written argument. ATCO indicated that the response to CG-AG-02-130 provided clear evidence that Feeder Mains are used and useful immediately or shortly after installation, and submitted that the Board should not accept the suggestion for use of a deferral account in this area.

Referring to the comment of AUMA/EDM that "customers pay long before the assets are in service", ATCO submitted that the statement was incorrect, and pointed to the response to CG-AG-02-130, which provided clear evidence that the vast majority of Feeder Mains installed in 2002 were in service and had customers connected in 2002 or 2003. ATCO stated that this refuted AUMA/EDM's claim.

With respect to Urban Main Extensions, ATCO noted that AUMA/EDM suggested a decrease in unit costs for Urban Main Extensions based on a decrease in 2002 actual unit costs compared to forecast. ATCO pointed out that the reasons for the decrease (increased activity and less main per lot) were unique to that year, and the conditions in that year could not be attributed to the expected volume of work and mix of lots forecast for 2003 and 2004. ATCO continued to believe the forecast was accurate for Urban Main Extensions in the test years.

ATCO noted AUMA/EDM's suggestion that the forecast for Regulating Meter Stations should be reduced by between 10% and 15% and that this category of expenditure should be a candidate for a deferral account. ATCO submitted that its position presented with respect to Feeder Mains applied equally to this issue. ATCO indicated that Regulating Meter Stations typically serve new urban areas that were formerly part of the rural distribution system, and that depending on the exact arrival time of customers, the need for a Regulating Meter Station might be deferred or advanced from the planned schedule.

Views of AUMA/EDM

Contributions for Urban Main Extensions

AUMA/EDM noted that although contributions for Distribution Main Extensions averaged $276,000 per year on an actual basis between 1999-2001, ATCO did not provide for any contributions for Urban Main Extensions in 2002, 2003 or 2004. AUMA/EDM noted ATCO's position that contributions for Urban Main Extensions had not been forecast, on the basis that contributions in the past have typically been fairly small. Nevertheless, as AUMA/EDM pointed out, contributions had occurred in the past.

AUMA/EDM submitted therefore that ATCO should be directed to include the historical average contributions for Urban Main Extension contributions over the period 1999-2001 ($75,000 and $200,000 respectively for AGN and AGS), in its Refiling for 2003 and 2004.

Urban Feeder Mains

AUMA/EDM noted that ATCO forecast a 67% increase in Urban Feeder Mains for the years 2002 through 2004 compared to actual expenditures for the prior three years. AUMA/EDM also noted that, in response to BR-AG-10, ATCO indicated that specified projects were defined as projects that could be identified with a very high degree of probability of proceeding in the year identified, and unspecified projects were defined as projects where it was expected with a high degree of probability that development would occur, although the exact project had not been identified.

AUMA/EDM noted that AGS forecast eleven new Urban Feeder Mains in 2001, of which only two proceeded as planned, one was delayed a year and 14 new projects, likely from the unspecified category, were added. AUMA/EDM noted that, in 2002, AGS forecast nine new Urban Feeder Mains, of which three proceeded as planned and eight new projects were added, again likely from the unspecified projects.

AUMA/EDM stated that, despite ATCO's assertions about the probability of proceeding, the cost of 2001 Urban Feeder Mains in the South was 37% less than forecast and the updated forecast for 2002 was 24% less than the 2001/02 forecast. In AUMA/EDM's view, it appeared that ATCO might be including virtually all Urban Feeder Mains identified by developers in the forecast of specified projects, rather than applying some probability to the overall specified projects based on historical experience. AUMA/EDM submitted that the "high degree of probability" principle applied by ATCO was simply not supported by experience.

AUMA/EDM's review of known or specified projects identified in the AGS 2001/02 GRA indicated that AGS proceeded with only $1.7 million out of the $2.9 million identified for 2001. For 2002, ATCO spent only $2 million out of the $2.6 million forecast for known projects. AUMA/EDM considered that those figures did not support the "high degree of probability" principle, raising the question of what factors were applied in determining the forecasts of unspecified Urban Feeder Mains projects. AUMA/EDM submitted that the net result of this persistent over-forecasting was that costs go into rate base and customers pay long before the assets are in service.

AUMA/EDM pointed out that on average, forecasts for 2001/2002 for AGS were close to 20% greater than actual, contributing to the historical over-forecasting. AUMA/EDM submitted that a reduction of between 10% and 20% of the test year forecast expenditures on urban mains was warranted based on the probability that not all known or specified projects would proceed as anticipated, or that the probability of unspecified projects proceeding was not as high as forecast by ATCO.

AUMA/EDM considered that, in future rate applications, ATCO should be directed to clearly identify all known Urban Feeder Mains projects, their cost, the probability of proceeding and the basis for that probability. With respect to unspecified projects, AUMA/EDM considered that ATCO should be directed to identify the projects in total and provide historical substantiation for the percentage expected to proceed. AUMA/EDM stated that, if ATCO had as little control over development of Urban Feeder Mains as it implied, an alternative might be to treat this account as a deferral account.

AUMA/EDM considered that ATCO stated the obvious when indicating that the vast majority of Feeder Mains serve customers in the year in which they are installed. AUMA/EDM, however, questioned whether or not the forecast expenditures for new Feeder Mains were reliable. While ATCO noted that 2002 expenditures of $6.94 million exceeded the forecast of $5.85 million, AUMA/EDM pointed out that the Company failed to note that the 2001 forecast for ATCO Gas South exceeded actual by 37%.

Urban Mains Extensions

AUMA/EDM noted that actual expenditure in 2002 on mains extensions decreased from forecast by $41 per residential lot and by $1,691 per commercial lot, due in both cases to fixed costs being spread over more lots and smaller than normal lot sizes. AUMA/EDM noted that, based on historical Engineering, Supervision and General (ES&G) costs of about 15% and an increase in the number of lots serviced of about 25%, as indicated by ATCO in Exhibit 13-6, ES&G would decline about 3% on average or about $15 per residential lot and $170 per commercial lot. AUMA/EDM speculated that the balance, or $25 (residential) and $1,500 (commercial) would relate to smaller lots.

AUMA/EDM submitted that the average unit cost per residential and commercial lot should be rebased by $25 (residential) and $1,500 (commercial) per lot to reflect the trend to smaller lots for the test years. AUMA/EDM noted that this would result in a reduction to Distribution Extensions for residential customers of $220,000 (2003) and $210,000 (2004) and for commercial customers of $445,000 (2003) and $330,000 (2004)

Regulating Meter Stations

AUMA/EDM noted that ATCO forecast a significant increase in new Regulating Meter Stations in the test years, and that actual expenditure over the period 1999 to 2002, which averaged $744,000 per year, was forecast to increase to $1.3 million (2003) and $1.2 million (2004). AUMA/EDM indicated that, not unlike Urban Feeder Mains, forecast expenditure for AGS exceeded actual by 13% in 2001 and 2002. AUMA noted that AGS forecast seven new meter stations in those years, but only two were constructed while three new stations were added presumably from unspecified projects.[15]

In AUMA/EDM's view, as in the case of Feeder Mains, it appeared that ATCO might well be including all regulating meters identified by developers in the forecast of specified projects, rather than applying some probability to the overall specified projects based on historical experience. AUMA/EDM repeated its assertion that the high degree of probability principle applied by ATCO was simply not supported by experience.

AUMA/EDM noted that in 2001 and 2002, the forecast was 13% greater than actual for AGS, contributing to historical over-forecasting. AUMA/EDM submitted that a reduction of between 10% and 15% of the forecast test year expenditure for Regulating Meter Stations was warranted, based on the probability that not all known or specified projects would proceed as anticipated and that the probability of unspecified projects proceeding was not as high as forecast by ATCO.

AUMA/EDM considered that, in future rate applications, ATCO should be directed to clearly identify all known meter regulating stations, their cost, the probability of proceeding and the

[15] Tr. pp. 468 and 469, 2001/2002 GRA and BR-10 South Attachment, p. 13 of 14

basis for that probability. With respect to unspecified projects, AUMA/EDM considered that ATCO should be directed to identify the projects in total and provide historical substantiation for the percentage expected to proceed. AUMA/EDM stated that, if ATCO had as little control over new meter regulating stations as it implied, an alternative might be to treat this account as a deferral account.

AUMA/EDM stated that expenditures for new Regulating Meter Stations were below forecast in 2002 ($252,000 versus $362,000), but that these stations would be installed in 2003 or 2004. AUMA/EDM stated that the problems associated with forecasting new Regulating Meter Stations were similar to those for new Feeder Mains.

Views of the CG

The CG noted that test year forecasts were well above recent levels of expenditures for Distribution Extensions, with the forecast for 2003 over 40% higher then the average capital additions in this area for actual 1999–2002, and the 2004 forecast close to 35% higher. The CG considered that the forecasts for Distribution Extensions in each test year should be limited to the 1999–2002 average additions of $22.928 million.

With regard to new Regulating Meter Stations, the CG noted that ATCO was able to defer approximately 41% from 2002 into 2003 and 2004. The CG considered that it should also be possible for ATCO to continue deferring 41% of forecast capital additions into the future in the absence of any notable adjustment to the forecasts. Therefore, the CG recommended that the Board reduce ATCO's forecast for new Regulating Meter Stations by at least 41%.

Views of the Board

The Board notes ATCO's response to AUMA/EDM's suggestion that test year forecasts for urban mains extensions should incorporate contributions of approximately $275,000 in line with actual results for 1999-2001. The Board acknowledges ATCO's position that contributions are rarely received for urban mains extensions, on the basis that the Company is required to extend service, at no cost, to every customer served by municipal water and sewer service in a municipal area. The Board is prepared to accept ATCO's submission that contributions have not been forecast for this category, since virtually all new customers in a municipal area are served by water and sewer.

The Board notes AUMA/EDM's observation that ATCO's classification of forecast expenditures for Urban Feeder Mains, based on identified probabilities for specified and unspecified projects, was not supported by historical results, and that the updated 2002 forecast for the South was 24% less than the amount forecast in the 2001/2002 AGS GRA. The Board also acknowledges ATCO's submission, in Exhibit 14-10, that the Company anticipated a reduction in the level of activity compared to that experienced in the 2001/2002 GRA.

Based on review of ATCO's response to CG-AG-02-130, the Board is prepared to accept ATCO's submission that the realities of subdivision development dictate that feeder main projects might be deferred or advanced from the planned schedule. The Board notes that the response to CG-AG-02-130 clearly demonstrates the existence of this condition in 2002, where actual installations exceeded the forecast amounts in both North and South. In this regard, the Board notes that actual expenditure for 2002 exceeded forecast due mainly to completion of projects that were not forecast. The Board also considers that the response to CG-AG-02-130 provides clear evidence that the vast majority of Feeder Mains installed in 2002 were in service and had customers connected in 2002 or 2003, in contrast to AUMA/EDM's claim that "customers pay long before the assets are in service." The Board agrees with ATCO that since Feeder Mains are used and useful immediately or shortly after installation, there is no need to adopt the AUMA/EDM suggestion for use of a deferral account in this area.

While recognizing that the evidence discussed in the previous paragraphs supports ATCO's position with respect to the realities of deferred and unforeseen projects, and explains the circumstances unique to 2002, the Board shares AUMA/EDM's concern that forecast expenditures for Urban Feeder Mains is more than 60% greater than actual expenditures in the previous three years, and that ATCO had failed to explain why actual expenditures in the South in 2001 were 37% below forecast. The Board therefore considers that a reduction in the range proposed by AUMA/EDM is warranted with respect to forecasts in this category of expenditure.

However, the Board agrees with ATCO that AUMA/EDM's recommendation for a 10%-20% reduction in forecasts did not recognize the Company's evidence that while the circumstances in 2002 may have been somewhat unique, actual expenditures in that year were $6.9 million, in line with test year forecasts.

With this in mind, the Board considers that a reduction at the lower end of the AUMA/EDM's proposed range (10%) is warranted. Accordingly, the Board directs ATCO to reduce forecast expenditures for Urban Feeder Mains by $551,000 in 2003, and $556,000 in 2004.

The Board also considers that there is merit in AUMA/EDM's recommendation regarding the identification of future projects. Accordingly, the Board also directs ATCO, in future rate applications, to clearly identify all specified Urban Feeder Mains projects, their cost, the probability of proceeding and the basis for that probability, to identify unspecified projects in total and to provide historical substantiation for the percentage expected to proceed.

With respect to forecasts for Urban Main Extensions, the Board notes AUMA/EDM's recommendation that ATCO rebase average unit cost/residential and commercial lot by $25 (residential) and $1,500 (commercial) to reflect the trend to smaller lots for the test years, based on information provided by the Company with respect to 2002 data in Exhibit 14-10. The Board however, is prepared to accept ATCO's explanation that the decrease in 2002 actual unit costs compared to forecast resulted from circumstances unique to that year, which cannot be attributed to the expected volume of work and mix of lots forecast for the test years.

The Board notes AUMA/EDM's observation that ATCO's classification of forecast expenditures for new Regulating Meter Stations, based on identified probabilities for specified and unspecified projects, is not supported by historical results considering that expenditures for 2001 and 2002 were 13% less than forecast. The Board also notes the argument of the CG that evidence of deferral of 41% of projects from 2002 justifies a reduction of 41% in test year forecasts.

The Board acknowledges ATCO's submission that, as in the case of Urban Feeder Mains, the realities of subdivision development appear to dictate the deferral or advancement of projects from the planned schedule. Nevertheless, the Board notes that forecast expenditures for new Regulating Meter Stations in the test years are 37% greater than actual and forecast amounts for the previous four years. The Board is not persuaded that the significant increase in test year forecasts is justified based on historical results or supported by evidence of probability assessments.

Recognizing that the forecast methodology, and issues identified in the case of new Regulating Meter Stations are similar to those identified with respect to Urban Feeder Mains, the Board considers that a reduction of the same magnitude, or 10%, is warranted to test year forecasts in this category.

Accordingly, the Board directs ATCO to reduce forecast expenditure for new Regulating Meter Stations by $128,000 in 2003 and $119,000 in 2004. For the reasons indicated in the discussion with respect to Urban Feeder Mains, the Board considers that there is no need to adopt the AUMA/EDM suggestion for use of a deferral account in this area.

As with Urban Feeder Mains, the Board considers that there is merit in AUMA/EDM's recommendation that ATCO clearly identify information concerning future projects. The Board therefore also directs ATCO, in future rate applications, to clearly identify all specified Regulating Meter Station projects, their cost, the probability of proceeding and the basis for that probability, to identify unspecified projects in total and to provide historical substantiation for the percentage expected to proceed.

The Board notes the CG's concern that forecast expenditures for Distribution Extensions are between 35%-40% greater than expenditures incurred and forecast between 1999-2002. The Board is not persuaded that the significant increase in test year forecasts is justified based on historical results or supported by evidence of probability assessments for specified and unspecified projects. The Board, however, agrees with ATCO that the CG's proposal for establishing forecasts for Distribution Extensions based on a historical arithmetic average of expenditures is an oversimplified approach to forecasting this category of capital expenditure. Accordingly, the Board believes that a reduction of the magnitude proposed by the CG is unjustified. Rather, the Board considers that the reduction identified earlier in this Section as a benchmark for evaluation of specific forecast categories should apply to this forecast category.

Therefore, in addition to the reduction specifically applied to Urban Feeder Mains and new Regulating Meter Stations in the preceding paragraphs, the Board directs ATCO to reduce forecast expenditure for Urban and Rural Main Extensions and Services by 3.5% in each test year.

The Board also directs ATCO, in future rate applications, to clearly identify all specified urban and rural main projects, their cost, the probability of proceeding and the basis for that probability, to identify unspecified projects in total and to provide historical substantiation for the percentage expected to proceed.

2.1.4 Distribution Improvements

Views of ATCO

ATCO explained that Distribution Improvements provided for the replacement of ageing, leaking and deteriorated pipe and facilities, looping and line relocations, Regulating and Meter Station and Farm Tap Unit upgrading, and cathodic protection improvements. Expenditures in the Urban Main replacements and improvements category were forecast to increase in 2002, through the test period and beyond. Also, the Bare and Unprotected Mains Replacement Program, approved in prior GRAs, was forecast to have reduced expenditures as the project is nearing completion. ATCO noted, however, that normal replacements of the remaining pipe in the system were forecast to increase as the pipe ages and exhibits deterioration. In addition, ATCO forecast expenditures to reflect an increase in the number of isolation valves throughout the distribution system. ATCO pointed out that in total the capital expenditures were forecast to be $7.1 million and $15.1 million respectively in 2003 and 2004 to replace and upgrade urban distribution mains.

ATCO indicated that Urban Main relocations were impacted by infrastructure programs under the control of the federal, provincial and municipal levels of government. ATCO also forecast capital expenditures to relocate mains and service lines that were being encroached upon by mobile homes. ATCO estimated its Capital expenditures for Urban Main Relocations to be $2.5 million and $2.9 million respectively in 2003 and 2004.

Bare and Unprotected Mains replacements were estimated at $5.9 million for 2003 and $1.6 million for 2004.

ATCO submitted that Rural Main replacements and relocations included all capital projects related to the replacement and improvement of mains located in rural areas. This included capital expenditures to replace mains and services constructed of polyvinyl chloride, an early generation of plastic pipe. ATCO forecast capital expenditures of $2.6 million in each test year for this category of projects.

ATCO stated that Regulating and Metering Station Improvements included capital improvements or replacements to existing Farm Tap Units, District Stations, and Gate Stations requiring forecast expenditures of $3.0 million in each test year. ATCO indicated that Cathodic protection expenditures were forecast to be $235,000 and $245,000 in 2003 and 2004 respectively.

With respect to replacement of ageing infrastructure, ATCO stated that a predictive model, ProLeak, was being used to analyze areas based on known characteristics in order to forecast when leaks were likely to occur. A second demerit model was then used to prioritize the monitoring and leak detection activities in suspect areas and then to prioritize replacement, when warranted. Referring to comments of interveners about "the untested, and inappropriate criteria used by ATCO to select mains to be replaced," ATCO pointed out that in Decision 2001-96, the Board was "satisfied that the analytical demerit evaluation program used to justify and prioritize individual projects provides sufficient assurance with respect to prudence of forecast expenditure."

ATCO indicated that justification for the forecast mains replacement projects was presented in the response to BR-AG-4(c), and noted that in 2002, actual expenditures for Urban Main Replacements were $4.19 million compared to a forecast of $4.12 million.

ATCO noted that in 2002, actual expenditures on Bare and Unprotected Mains Replacement were $7.755 million compared to a forecast of $7.760 million. ATCO submitted that the decision to replace deteriorated mains and services was based on economics, and that the Company was proactive in its approach to replacing its infrastructure using analytical tools such as ProLeak and its Demerit program to forecast and prioritize replacement.

With respect to Regulating and Meter Station Improvements, ATCO indicated that historical and forecast information was provided in the response to BR-AG-11, and that forecast expenditures in 2003 and 2004 of $1.645 million and $1.67 million respectively were consistent with the 2002 actual expenditures of $1.808 million. ATCO noted that actual expenditures in 2002 were slightly less than forecast as a result of the deferral of several projects from 2002 into 2003.

ATCO submitted that it was absurd for the CG to suggest that the demerit point system and mains replacement expenditures could not be properly tested because BR-AG-4 was provided only in electronic form. ATCO submitted that a substantial volume of information had been provided, including BR-AG-4, to fully validate the forecast capital expenditures in this area. ATCO considered the claim baseless, as interveners could have used a variety of means to obtain this document in hardcopy, and that the electronic document was entirely legible and easy to follow.

ATCO noted AUMA/EDM's reference to the mains replacement activity forecast as the 'Son of Bare Mains'. ATCO disagreed with this characterization, indicating that the objective of replacing mains is to ensure the safety and reliability of the system. ATCO submitted that this was the major driver of the Mains Replacement Program, and is the driver of all mains replacement projects. ATCO stated that it had presented substantial evidence in the response to BR-AG-4 that the system is aging, and noted that interveners agreed that aging infrastructure must be replaced. ATCO stated that the work was being conducted in a logical, planned fashion, and that the areas identified for replacement had not been arbitrarily selected, but were identified as potential problem areas and then fully analyzed using the Demerit System and/or ProLeak. ATCO indicated that, based on this analysis, these areas had been identified as requiring replacement and subsequently scheduled based on their relative priority.

ATCO noted that AUMA/EDM also took issue with the forecast expenditures for valves and vaults suggesting that ATCO had provided 'precious little information' and was stonewalling. In response to AUMA/EDM-AG-15 and in Exhibit 13-24, ATCO provided detail and the basis for forecasting each project. ATCO failed to see how this constituted stonewalling, and pointed out that capital expenditures in this area are forecast on an individual project basis. ATCO stated that AUMA/EDM had elected to ignore this evidence and instead suggested that these projects should be based on an average cost per valve. ATCO submitted that this suggestion was without merit.

Referring to the CG's recommendation that the Distribution Improvements forecast should be based on the average capital expenditures in this category between 1999 and 2002, ATCO indicated that both the units and unit cost are forecast for each area of the province accounting for unique circumstances in that area. ATCO submitted that the CG's recommendation was, once again, an oversimplification of the process to forecast expenditures and was without merit.

With respect to Regulating and Meter Station Improvements, ATCO noted that AUMA/EDM arbitrarily suggested that forecast capital expenditure in this category be reduced by 10%. ATCO considered this level of reduction arbitrary and presented without evidentiary support and completely without merit. ATCO submitted that substantial evidence had been presented in response to BR-AG-11 describing the historical and forecast costs in this expenditure category.

Views of AUMA/EDM

Urban Mains Replacements

AUMA/EDM referred to Table 2.2.13 of the Application, which set out the costs of urban mains replacement from 1999 to 2004, indicating an increase from a low of $1.23 million (1999) to a high of $15.1 million (2004). AUMA/EDM indicated that the information demonstrated that this was a major program with potentially long lasting implications. ATCO indicated that it was of similar magnitude to the Bare and Unprotected Mains Replacement Program scheduled to draw to a close in 2003 coincident with the commencement of the new program and demerit system. AUMA/EDM noted however, that ATCO provided no business case to describe the program or its magnitude, but did file its Distribution Piping Integrity Analysis in response to BR-AG-4.

AUMA/EDM expressed a number of concerns with the proposed Analysis and its impact in the future. First of all, based on the Analysis and comments of ATCO witnesses, AUMA/EDM considered that ATCO appeared to have targeted mains for replacement based on an arbitrary decision to replace all areas that were not cathodically protected, irrespective of the integrity of the pipeline, similar to the decision in 1990 to replace all bare mains.

AUMA/EDM submitted that ATCO had failed to make a prima facie case for replacement of any of the non-cathodically protected areas in the test years and that these projects should not be included in rate base at this time (i.e. Killarney in 2004 and Alyth Court in 2005 as shown on page 83 of BR-AG-4).

AUMA/EDM considered that a number of bare mains not yet exhibiting a leak history to justify replacement identified in the response to BR-AG-4 should be allowed to proceed in 2003 as these projects had been planned for some time now and the construction season was already underway. However, AUMA/EDM submitted that those bare mains projects scheduled for 2004 should not be allowed into rate base, on the basis that these replacements (i.e. Riverdale Park 2, Black Diamond 2 and Black Diamond 3), although identified for replacement around 1990, did not even meet the criteria under the new ATCO demerit system and should be deferred until such time as they could be justified.

Referring to BR-AG-4, AUMA/EDM noted that ATCO had developed a new methodology or evaluation process to assess the condition of its system, which consisted of a demerit system taking into account system factors (inherent properties of the system) and performance factors (state of the system).

AUMA/EDM noted that the factors were assigned various points used to determine when the system is inspected and when replacements were projected. AUMA/EDM considered that use of these factors to determine the inspection frequency was a useful tool that was to be commended but expressed concern with the point system that led to replacements. Specifically, AUMA/EDM pointed out that if the points exceed 40 in critical areas, 55 in commercial areas or 70 in all other areas, replacement was dictated. However, as noted by AUMA/EDM, it was possible that an older system could still be performing well, but be considered for replacement due to qualitative system factors, on which there appeared to be too much emphasis.

AUMA/EDM referred to ATCO's reference to Decision 2001-96 in which the Board stated, "The Board is satisfied that the analytical demerit evaluation program used to justify and prioritize individual projects provides sufficient assurance with respect to prudence of forecast expenditures." AUMA/EDM stated that a review of the background indicated that the finding in that Decision related to a demerit point system that included no specific details of the Bare Mains demerit system, and that there did not appear to have been any detailed examination of the demerit point system in that proceeding.

AUMA/EDM also noted that neither Decision E88018,[16] which that approved the Bare Mains Replacement Program for NUL, nor Decision C90028,[17] that approved the acceleration of the Bare Mains Replacement Program for CWNG, made any mention of the demerit point systems but, rather only that leaks were increasing in the bare mains. AUMA/EDM stated that ATCO's augmentation of this (Bare Mains) analysis through the use of ProLeak and assessment of the risk associated with underground entries provided little support for the new demerit point system.

In the opinion of AUMA/EDM, leaks were the best indicator of pipe integrity. However, when asked how ATCO had come up with the demerit points for below ground leaks, AUMA/EDM noted that the Company's witness thought that they took the previous (Bare Mains) scale and "adjusted the numbers down slightly." This raised significant concern for AUMA/EDM on the basis that the demerit system for the Bare Mains Replacement Program was not of particular concern given that the decision had already been made to replace the bare mains under that program. AUMA/EDM pointed out that Bare Mains demerits were used simply to identify the priority of the replacements.

Referring to discussion on this issue with Company witnesses, AUMA/EDM noted that apparently the factors did not determine whether or not a pipe had to be replaced but dictated the inspection frequency, after which, at some point, a decision would be made to replace the main. AUMA/EDM however, considered that this appeared inconsistent with the process used to identify the projects listed at page 83 of BR-AG-4, and included as rate base additions. AUMA/EDM noted that each of those projects was either a continuation of the Bare Mains Program or exceeded 71 demerit points, with the exception of the Killarney replacement, which as previously noted, was proceeding simply because it was not cathodically protected rather than for integrity considerations. AUMA/EDM submitted that there did not appear to be any evidence on the record with respect to the separate evaluations referred to by ATCO's witnesses.

AUMA/EDM noted that one of ATCO's justifications for moving meters outside under the MRRP was to eliminate the safety concerns associated with gas leakage in below grade installations. In the view of AUMA/EDM, replacement of leaking mains and services would significantly mitigate this concern, creating the appearance that ATCO was attempting to justify each of these programs absent any action in the other program. AUMA/EDM submitted that the Board should consider that these programs are not mutually exclusive when making its decision on these projects.

Using the Westmount replacement project as an example, AUMA/EDM noted that the revenue requirement (return, taxes and depreciation) on the estimated $822,000 replacement cost are about $120,000 in Year 1. AUMA/EDM noted that, based on eight leaks over a nine-year period

[16] Decision E88018 – Northwestern Utilities Limited (NUL), Application to Determine a Rate Base and Fix a Fair Return Thereon for the Test years 1987 and 1988, dated March 18, 1988

[17] Decision C90028 – Village of Standard and Canadian Western Natural Gas Company Limited (CWNG), Application by the Council of the Village of Standard for Approval to Renew a Natural Gas Supply Contract with, to Confer a Special Franchise on and to Renew a Revenue Tax Agreement with CWNG, dated September 12, 1990

for Westmount,[18] the average annual repair cost would be some $2,700 per year or 1/44 of the replacement cost. In the opinion of AUMA/EDM, this project clearly could not be justified on the basis of economics, and given that the Westmount area service entries are above ground,[19] there could not be any significant safety issues driving this replacement other than general concern for a leak in the main itself. Finally, AUMA/EDM noted that a review of Exhibit 13-57 did not indicate any trend toward a worsening condition of the system in terms of leaks over the period 1993-2001.

AUMA/EDM considered that the same conclusions could be drawn with respect to the Allendale and Coronet replacements, neither of which had below grade service entries and that repairs would be much more economical than replacement. Further, AUMA/EDM noted that with respect to Coronet, apparently there might have been a leak problem in the early 1990's that had largely been remedied. However, without further evidence, AUMA/EDM was unable to conclude that a serious leakage problem still existed on a system that was built in 1971. AUMA/EDM did not consider that ATCO had made a compelling case for replacement of either of these mains and that the replacements should be deferred until ATCO could justify them.

Valve and Vault Replacements

AUMA/EDM provided a table setting out the number of replacement valves, total and average cost for the period 2000-2004, which showed an increase in the average from an actual cost of $19,000 in 2000 to a forecast cost of $42,000 in 2004.

AUMA/EDM noted that not only had the number of valves increased significantly, but also the average cost on a forecast basis had more than doubled over the actual costs in 2000 and 2001. Without the further evidence which ATCO was requested to provide, AUMA/EDM submitted that a more reasonable forecast for valve and vault replacements for each of the years 2002, 2003 and 2004 would be $22,000 per valve times the number of valves forecast by ATCO, or $330,000, $484,000 and $418,000 respectively.

Regulating and Meter Station Improvements

Referring to discussions with ATCO witnesses, AUMA/EDM noted that, while the inference was that the specific Regulating and Meter stations and units had been costed out in preparing the 2003 and 2004 budgets, approximately 40% of station improvements as of March 2003 had not yet been specifically identified.[20] AUMA/EDM submitted that in view of the large forecast increases, lower than forecast expenditures in 2002 and the large remaining unspecified improvements, a 10% reduction to 2003 and 2004 regulating and metering station improvements would be in order.

Views of the CG

The CG noted that test year forecasts for Distribution Improvements were well above the recent level of expenditures, with the forecast for 2003 over 30% higher then the average capital additions in this area for actual 1999–2002 of $16.287 million, and the 2004 forecast average over 55% higher. The CG considered that the forecasts for Distribution Improvements should be limited to the 1999–2002 average additions of $16.287 million in each test year.

[18] Exhibit 13-57
[19] BR-AG-4, p. 51
[20] Exhibit 13-35

The CG considered that ATCO did not adequately justify the mains replacement program, and that use of an untested demerit point system should not be used as regulatory criteria for pipe replacement. The CG pointed out that the demerit system was not presented in the GRA filing, but was provided in an attachment to an information response in only the electronic version. The CG indicated that accordingly, it was not possible to fully test the demerit point system or the mains replacement program. The CG considered that ATCO should be directed to file the demerit point system along with evidence to demonstrate that it is appropriate to use the demerit point system as regulatory criteria.

The CG submitted that the appropriateness of the use of the ProLeak and Demerit systems must be evaluated with respect to meeting regulatory standards for rate base additions. The CG did not consider that the simple use of a predictive model or demerit system was adequate to demonstrate need of for a capital project. The CG considered that appropriate safety standards, reliability criteria and economic assessment must also be used. The CG submitted that the Company must present to the Board objective standards that, when used in conjunction with the predictive models or a demerit system, would form the basis of regulatory standards for Distribution Improvements.

Views of the Board

The Board has examined the Distribution Piping Integrity Analysis (the Analysis) filed by ATCO as an Attachment in response to BR-AG-4, and considers that the Analysis is comprehensive and incorporates a substantial volume of evidence in support of the test year forecasts for Urban Mains Replacement.

The Board notes ATCO's evidence that a predictive model, ProLeak, is being used to analyze areas based on known characteristics to forecast the likelihood of leaks. This analysis identifies potential problem areas, which are then analyzed using a demerit system to determine replacement priority. The Board notes that a major issue for interveners is whether or not this demerit system, which is untested, should be approved for pipe replacement. The Board finds it difficult to find fault with ATCO's submission that the areas identified for replacement are not arbitrarily selected, as suggested by AUMA/EDM.

Furthermore, in Decision 2001-96, the Board was satisfied that forecasts under the Bare Mains Replacement Program were determined on a project-by-project basis, and that the analytical demerit evaluation program used to prioritize individual projects provided sufficient assurance with respect to prudence of forecast expenditure. While the Board sees no reason to take issue with that methodology in this proceeding, the Board acknowledges intervener concerns that, since the Analysis was not filed with the Application, the ability to fully test the demerit system and the mains replacement program was adversely impacted.

Accordingly, the Board is concerned that the specific projects identified for disallowance by AUMA/EDM may be based on selective criteria rather than on a comprehensive evaluation of the Analysis, and therefore does not accept AUMA/EDM's recommendations for removal of specific projects from the test year forecasts.

In the Board's view, it is difficult to take issue with ATCO's position that the Analysis identifies potential problem areas, which are analyzed using the Demerit System and/or ProLeak. The

Board considers that the evidence presented indicates that projects are being identified in a logical fashion, and replacements are not arbitrarily selected.

The Board agrees with ATCO that ProLeak is a useful tool to flag potential problem areas that should be monitored. In this regard the Board notes that the Analysis indicates that the results of the ProLeak leak predictions would be used to select the frequency of flame-ionization inspections. Using the Analysis in this manner, it seems logical to monitor more closely in the future those areas that according to the ProLeak predictions, are not actually experiencing the predicted level of leaks. The Board notes that, in addition to selecting inspection frequency, the information is also used extensively to schedule replacements. The Board is concerned that the ProLeak analysis appears to put too much emphasis on predictive leaks and could therefore identify projects for replacement before a leak history substantiates the need. Accordingly, the Board is concerned that the test year forecasts could prematurely include costs for projects targeted for replacement where the leak history does not support replacement. However, the Board agrees with AUMA/EDM that leak history is an important factor and should be given more weight.

The Board also acknowledges the AUMA/EDM's observation that expenditure in the Urban Mains Replacement category had increased from a low of $1.23 million (1999) to a high of $15.1 million (2004), and that this is a major program with long lasting implications. The Board recognizes that this is a new program, and is supportive of the direction that ATCO proposes to take with respect to mains replacement, particularly where safety is an issue. However, the Board acknowledges the observation of AUMA/EDM that ATCO had provided no business case to describe the program or its magnitude, and therefore, has some concern with the absence of substantive evidence to support the proposed approach. Accordingly, the Board considers that, while a forecast of $7 million in 2003 is a significant increase from historical experience, that level of expenditure might not be unreasonable given the goals of the program. However, the Board is concerned that the proposal to increase the level of expenditure to over $15 million in 2004 appears overly aggressive. In the Board's view, the level of expenditure on this program should be held at a level of approximately $7 million in each test year, and the time schedule for the program extended as necessary beyond the targeted completion date.

The Board therefore, directs ATCO to reduce the 2004 test year forecast for Urban Mains Replacements to $7.092 million.

Notwithstanding the reduction to the requested amount for the 2004 forecast, the Board considers that the reduced amount will provide sufficient funds for the replacement of the deteriorated mains where the replacement decision is based on actual experience. As a general principle, regardless of any adjustments to the requested amounts for replacement programs, the onus remains with ATCO to provide the appropriate levels of safety and reliability in its provision of economical service. The Board is cognizant of the fact that this is an area that could impact public safety, and is prepared to revisit the issue at a later date if circumstances change, or if a significant increase in the magnitude of safety concerns warrants re-evaluation.

However, recognizing the absence of a detailed business case, and the timing of the filing of the Analysis, the Board considers that parties have not had the opportunity to fully discuss the proposed program and related cost implications. Accordingly, the Board is prepared to entertain further discussion on the scope and goals of the program at the next GRA.

Accordingly, the Board directs ATCO, at the time of filing the next GRA, to file a comprehensive business case for the mains replacement program together with the Analysis to facilitate a comprehensive review and discussion during the proceedings. The Board expects that the information filed will incorporate details on the relationship between pipe vintage and leak history in determining the projects targets for replacement.

With respect to the forecasts for Valve and Vault Replacements, the Board notes the information provided by AUMA/EDM compiled from data contained in the responses to AUMA/EDM-AG-15 (d) and BR-AG-11. Specifically, the information supports the position that not only has the number of valves increased significantly, but the average cost forecast between 2002 and 2004 has more than doubled compared to 2000 and 2001 actual costs. The Board notes AUMA/EDM's submission that ATCO has not provided evidence to support an increase of this magnitude, and also notes AUMA/EDM's recommendation that a reasonable forecast for the test years would be $22,000 per valve times the number of valves forecast, or $484,000 (2003) and $418,000 (2004). However, given that these expenditures are included with Urban Mains Replacement expenditures, and recognizing the reductions already made to Urban Mains Replacement forecasts, the Board is satisfied that no additional reduction to this category of expenditure is required.

With respect to Regulating and Meter Station Improvements, the Board shares the concern of AUMA/EDM that, while forecasts between 2002-2004 are approximately 73% higher than actual expenditure in the previous three years, 40% of station improvements had not been identified at March 2003. Given the significant increase in test year forecasts and the high percentage of unspecified projects, the Board considers that AUMA/EDM has made a reasonable case for a reduction of 10% in the test year forecasts.

Accordingly, the Board directs ATCO to reduce the forecasts for Regulating and Meter Station Improvements by $301,000 (2003) and $297,000 (2004).

The Board notes the CG's recommendation that test year forecasts for Distribution Improvements should be reduced to the 1999-2002 average level of $16.3 million. The Board also notes ATCO's response that the CG proposal for establishing forecasts for Distribution Improvements based on a historical arithmetic average of expenditures was an oversimplified approach to forecasting this category of capital expenditures.

The Board notes the CG's concern that forecast expenditure for Distribution Improvements is between 30%-55% greater than expenditures incurred and forecast between 1999-2002. However, the Board agrees with ATCO that the CG proposal for a significant reduction may be an oversimplification and that a reduction at the level proposed is unwarranted.

Moreover, the Board considers that, in contrast to the increases proposed with respect to expenditures for the Urban Mains Replacement program, the forecasts for the remainder of the expenditure categories classified under Distribution Improvements are reasonable in light of historical results, and accepts the forecasts as filed for those categories.

2.1.5 Distribution Services

Views of ATCO

ATCO indicated that Distribution Services provided for the installation of new primary and header services for urban customers. Capital expenditures were forecast to be $15.3 million and $15.7 million in 2003 and 2004 respectively.

ATCO explained that, in general, expenditures for service line alterations and replacements were based on historic levels of expenditures. However, these costs were forecast to increase through the test period as a result of replacing service lines that had deteriorated or required alteration or replacement as a result of the Metering Improvement project (discussed in section 2.2 of this Decision). ATCO indicated that expenditures were forecast at $16.8 million and $17.5 million in 2003 and 2004, respectively.

ATCO pointed out that each business unit of the Company develops forecasts for new Urban Service Lines by forecasting the units and unit cost for both residential and commercial installations. ATCO indicated that a significant amount of information with respect to this category was provided in the responses to BR-AG-19 and CG-AG-02-131, and in Exhibit 13-36. ATCO noted that in 2002, service lines were extended to a greater number of residential customers than forecast, partially offset by a reduced number of extensions to commercial customers. ATCO noted that the net result was that actual expenditures were $17.753 million compared to a forecast of $15.499 million.

Referring to the CG's recommendation that the Distribution Services forecast should be based on the average capital expenditures in this category between 1999 and 2002, ATCO indicated that Urban Service Lines are forecast on the basis of residential and commercial units and the respective unit cost for each type of installation. ATCO also indicated that both the units and unit cost are forecast for each area of the province accounting for unique circumstances in that area. ATCO submitted that the CG's recommendation was, once again, an oversimplification of the process to forecast expenditures and was without merit.

Referring to AUMA/EDM's suggestion that the "details have been obfuscated to the point where no specific adjustments can be recommended," ATCO referred to the responses to AUMA/EDM-AG-19 and Exhibit 13-36 which, contrary to the assertion provided very clear and understandable detailed justification regarding the forecast for capital expenditures for New Urban Service Lines.

Regarding AUMA/EDM's suggestion that the Board direct the Company to pursue joint trenching in other communities, ATCO stated that the Company is conducting trial projects in other communities and pursuing joint trenching where there is mutual benefit to all parties.

Views of AUMA/EDM

New Urban Service Lines

AUMA/EDM noted that unit costs for residential service lines were forecast to increase by 15%, 23% and 27% over 2001 actual costs. AUMA/EDM also noted, from discussion with ATCO witnesses that unit costs in the South were significantly lower than in the North largely due to the joint trenching program in Calgary combined with different construction conditions. Although no specific cost savings were attributed to joint trenching, AUMA/EDM considered that ATCO should be directed to pursue the opportunity for similar reductions in service line costs, and for that matter, Distribution Extensions, in municipalities other than Calgary, and report back on the status or progress achieved, at the next GRA.

AUMA/EDM noted that ATCO had been unable to explain why the unit costs of residential service lines in the North were increasing so rapidly, other than to note that the business units were forecasting increased unit costs, but undertook to provide to provide the unit costs per service line by business unit. AUMA/EDM noted that unfortunately, Exhibit 13-36 only provided the unit costs by business unit for the three forecast years but not the historical unit costs. AUMA/EDM noted from discussion with ATCO's witnesses that costs in the Red Deer district had been in the order of $800 per service in the past and that the Exhibit showed unit costs per residential service line in the Red Deer district of $1,081, $1,121 and $1,156, respectively for 2002, 2003 and 2004. AUMA/EDM submitted that the residential unit costs in the Red Deer district should be adjusted to $800, $816 and $832 per service line over the three years to reflect escalation at 2% per year, translating to reductions of $164,000, $190,000 and $207,000 in each of the three years. AUMA/EDM stated that no specific adjustments could be recommended to address concerns over significantly increasing costs in other business units since details were not available.

AUMA/EDM noted that, while ATCO asserted that a significant amount of information with respect to new Urban Service Lines had been provided in responses to information requests, ATCO did not explain the 15%, 23% and 27% increases in unit costs for residential service lines for AGN as compared to 2001.

Views of the CG

The CG noted that test year forecasts for Distribution Services were well above recent levels of expenditures, with the 2003 forecast close to 90% higher then the average capital additions in this area for actual 1999-2002, and the 2004 forecast 95% higher. The CG considered that the forecasts for Distribution Services should be limited to the 1999-2002 average additions of $17.058 million for each test year.

Views of the Board

The Board notes the observations of AUMA/EDM that unit costs for new urban residential service lines in the South are significantly lower than in the North due at least partly to the existence of joint trenching programs in Calgary. The Board acknowledges ATCO's submission that trial joint trenching projects are already being conducted in other communities, and agrees with AUMA/EDM that ATCO should report on the results of these trial projects. Accordingly, the Board directs ATCO, in the next GRA, to report on the results of these trial projects, and the action taken as a result of the trials.

The Board notes the concern of AUMA/EDM with the absence of an explanation for the significant increase in test year forecasts for residential service lines compared to 2001. The Board acknowledges that, in stating its position, AUMA/EDM cites the example of unit costs for residential service lines in Red Deer. The Board has examined the evidence presented by AUMA to support its position that forecast unit costs for residential service lines in Red Deer are about 40% higher than in the previous three years, and higher than unit costs for other areas in the North.

The Board agrees with AUMA/EDM's recommendation that forecast unit costs for service lines in Red Deer should be reduced to the historical average of $800 per unit adjusted to reflect inflation. The Board therefore, directs ATCO to reduce test year forecasts for residential service lines in red Deer by $190,000 (2003) and $207,000 (2004).

The Board notes the CG's recommendation that test year forecasts for Distribution Services should be reduced to the 1999-2002 average level of $17.058 million. The Board also notes ATCO's response that the CG proposal for establishing forecasts for Distribution Services based on a historical arithmetic average of expenditures was an oversimplified approach to forecasting this category of capital expenditures.

The Board notes the CG's concern that forecast expenditure for Distribution Services is between 90%–95% greater than expenditures incurred and forecast between 1999-2002, and recognizes that the significance of the increase is due mainly to the implementation of the MRRP. As this project is dealt with separately in Section 2.2 of this Decision, the issue of the increase referred to by the CG, which relates to the forecast for Service Line Replacements and Improvements category will not be addressed in this Section of the Decision.

2.1.6 Land and Structures

Views of ATCO

ATCO explained that the Land and Structures category provided for new leased and owned facilities to meet growth requirements and also provided for improvements and alterations to owned and leased facilities in order to enhance safety, working conditions and security. ATCO had included forecast expenditures to enhance security at a number of its key facilities.

ATCO indicated that it had identified additional space requirements and was forecasting the construction of an Operating Centre in Sherwood Park. In addition, ATCO stated that the existing Red Deer Operating Centre was no longer adequate and the Company was forecasting the construction of a new Operating Centre in Red Deer.

ATCO submitted that the forecast expenditures for Land and Structures were $10.0 million and $7.1 million in 2003 and 2004, respectively.

ATCO considered that the interveners had presented unsubstantiated opinion with respect to the proposed Operations Centres in Red Deer and Sherwood Park, as well as the Infrastructure Protection Program.

Red Deer Operating Centre

Views of ATCO

ATCO stated that the business case for the Red Deer Operating Centre was presented in the response to BR-AG-30, which pointed out that the existing facility was at capacity and is located in an area of Red Deer that was being redeveloped and no longer suitable for a utility operation. ATCO noted that the Greater Downtown Action Plan of the City of Red Deer had identified this area for transformation from commercial/industrial uses. ATCO stated that the estimated capital cost for such a facility was $5.5 million. ATCO stated that, in 2003 it would seek to secure a site to develop the new operating centre with a target of occupying the new facility in 2004.

ATCO disagreed with the suggestion of AUMA/EDM and the CG that the monthly meter reading program and MRRP were the primary drivers for additional space in Red Deer. ATCO pointed out that the business case clearly shows that the Company must move from the current site, regardless of space requirements for these programs, as it is in a location that will be unsuitable for utility operations in the near future due to plans of the City of Red Deer for redevelopment. ATCO stated that the evidence also clearly shows that owning is a more cost-effective option than leasing for such a facility in the long term.

In response to comments of AUMA/EDM and the CG, ATCO indicated that the project schedule shows the land purchase being finalized by October 2003, which fits into the time frame envisaged in the forecast. ATCO expressed confidence that the schedule set out in the application could be met, and that the new facility should be ready for occupancy by the end of 2004.

With respect to AUMA/EDM's concern with use of the high end of the estimate range for replacement cost supplied by a third party real estate firm, ATCO stated that use of the high end of the range was justifiable given the effects of inflation between the date of the estimate in May 2002 and scheduling of construction in 2004. ATCO took the conservative and prudent approach by using the high range of the estimate. ATCO submitted that the Board should disregard the CG's comments questioning the validity of the estimates supplied by the Company, on the basis that the CG provided no evidence of what it would consider to be a reasonable cost estimate. ATCO considered the submission of an estimate by a third party, was far more substantial than the speculation of the interveners.

ATCO submitted that the drivers for replacement of the facility are that the buildings and land are inadequate to meet current requirements and growth, and that the present location is unsuitable due to redevelopment, in contrast to the CG's argument that justification is based on forecasts of increased labour. ATCO pointed out that the CG had submitted no evidence concerning productivity gains to substantiate its speculation about reduced clerical levels at the operating centre. ATCO noted that the CG's speculation that the storesman position is not full-time is incorrect, and unsupported.

Noting the concerns of the CG and AUMA/EDM that the test years forecasts do not include a revenue estimate for disposition of existing operating centre, ATCO indicated that the Company would seek EUB approval of the sale of the existing Red Deer Operating Centre, but because the disposition was not expected to take place until at least 2005, the matter of the disposition is unrelated to the 2003/2004 GRA. ATCO indicated that furthermore, as stated in response to BR-AG-30(e), the existing Red Deer Operating Centre would be used for most of 2004.

Contrary to intervener concerns about lack of supporting documentation for the Operating Centres, ATCO considered that the information provided in the Application, and in Information Responses (including Business Cases) met the requirements set out by the Board in Decision 2000-9. ATCO indicated that, as described by Company witnesses during the hearing, projects of this magnitude receive scrutiny from progressively higher levels of management at each stage of the budget approval process as they move forward and are approved.

Views of the CG

Referring to ATCO's indication that third party consultants were being used for their expertise in local market information relating to local building and land costs, lease costs and availability of current facilities, the CG noted that a third party, commercial real estate consultant provided a cost estimate of $5.5 million for the requisite land and building.

The CG also referred to an extract of a letter dated May 15, 2003, from a real estate consultant filed in response to an undertaking, outlining replacement costs for the office and shop buildings in the Red Deer area. The CG noted that the cost estimate of $130 per square foot was higher than the $100 per square foot estimate for the proposed Sherwood Park operating centre, which ATCO indicated was due to local market conditions.

The CG noted that ATCO forecast site acquisition for the new facility in 2003, occupancy by the end of 2004 and closure of the existing facility in 2005. The CG also noted that ATCO had not forecast any sale proceeds related to the existing facility in the test years, indicating that an estimate of the potential market value of the existing facility in 2005 was not available at this time.

The CG expressed concern with ATCO's acceleration of the need for the Red Deer Operating Centre, particularly in light of the lack of available land for the project, an excessive forecast of staffing needs and the costs related to the facility. The CG also expressed concern that ATCO had not recognized any available mitigation of costs and need in its forecast for the facility.

First, in relation to the timing of the project, the CG noted that no sites appeared to be currently available to meet the ATCO timetable for occupancy. The CG submitted therefore, that rate base additions associated with the Red Deer operations centre should be removed.

Second, in terms of mitigation, the CG noted the indication by ATCO that an evaluation must still be done as to whether the Company could start with a smaller, expandable facility in the design stage. The CG submitted that ATCO should undertake such an analysis prior to requesting any addition to its rate base on the basis that starting with a smaller facility would minimize revenue requirement effects over the test years.

Third, with respect to the increase in forecast labour for the facility, the CG considered that there was the potential for mitigation of costs, including reductions due to a decrease in personnel complement if the current contractor was no longer available or the bid price excessive, or the requirement for additional meter readers was no longer necessary if monthly meter reading was deemed unnecessary.

The CG also expressed concern with ATCO's cost estimate for the proposed facility, given the absence of internal Company studies on need for or costing of the facility, and the fact that external consultants used to provide cost estimates on availability of existing commercial space were not made available for cross-examination. Consequently, the CG questioned the validity of such unsupported evidence and suggested that it should not be given any weight by the Board. In the event however, that the Board decided to consider the evidence, the CG pointed out that ATCO used the worst case, or most expensive forecast, provided by the external consultant as the basis for its forecast. Accordingly, the CG submitted that, if any evidence was accepted on this matter, consideration should only be given to the more conservative, or lower, forecast.

The CG was also concerned about the lack of any forecast revenues from the forecast disposition of the existing facility, and considered it inappropriate to forecast the need for a rate base addition without forecasting the proceeds of disposition of the property being replaced. The CG submitted that any proceeds in excess of net book value should accrue to the benefit of customers, and that forecasting proceeds from the sale of the existing facility would minimize the rate impact of the proposed facility. The CG considered that an interim estimate of the value of the existing facility could be accomplished using ATCO's estimate of land value and depreciated building value. The CG considered that this amount could then be trued up following actual disposition of the property in question.

Finally, the CG expressed concern with the lack of detailed information and support for such a significant capital expenditure, particularly in light of the Board's specific direction to ATCO's predecessor company, to file detailed justification of the project for all major capital additions, including a cost breakdown and need for the project. The CG submitted that based on the absence of such documentation, there was no evidence to indicate that management of ATCO properly discharged its duty to properly review and screen capital projects. The CG stated that filing of such documentation served to satisfy the prudence test, and was a reasonable expectation in this application.

In conclusion, the CG did not believe it likely that the Red Deer operations centre would be built within the current test period and should be removed from the forecast, and that the costs related to the project and additional personnel used to justify the expanded facility, were over forecast.

Views of AUMA/EDM

AUMA/EDM expressed a number of concerns with the proposed new Red Deer Operating Centre. First of all, it appeared to AUMA/EDM that the Meter Replacement and Relocation Program and the concurrent move to monthly meter reading were the primary drivers for additional operating space. AUMA/EDM submitted that absent approval of these two programs, for which interveners had expressed significant concern, other options such as short term leasing of additional space should be investigated prior to construction of a new operating centre.

Secondly, AUMA/EDM noted from discussions with ATCO's witnesses that available industrial land was scarce within the City of Red Deer and might be contingent on annexation of further land. AUMA/EDM understood that there was no serviced industrial land available within the City of Red Deer in 2002, it would be one to two years before any sites might become available, and ATCO would require one year from purchase of land to occupancy. Accordingly, AUMA/EDM considered that ATCO Gas might have to pursue the short-term lease options in any event.

The third concern of AUMA/EDM was with respect to the cost estimate, should this project proceed. AUMA/EDM noted that the $5.5 million estimate was based on replacement cost information provided by a third party real estate firm, and as confirmed by ATCO's witness, ATCO used the high end of the range provided because the estimate was in 2002 dollars and construction was scheduled for 2004. AUMA/EDM considered it inappropriate to simply use the high end of the range of $130 per square foot. In contrast, AUMA/EDM noted that ATCO also received a third party estimate for the Sherwood Park Operating Centre about the same time, that indicated $100 per square foot. Furthermore, AUMA/EDM noted that the estimate provided in Exhibit 13-7 priced the entire building at $95 to $130 per square foot whereas the Sherwood Park estimate, used $50 per square foot for the light industrial portion of that facility. AUMA/EDM submitted that all of the foregoing suggested that the lower end of the range or about $3.6 million would be a much more reasonable estimate for the Red Deer Operating Centre, if it is considered necessary and can be completed before the end of 2004.

The fourth concern of AUMA/EDM related to ATCO's proposal to add the new facility to rate base in 2004 but not sell the existing facility until 2005. AUMA/EDM considered that this would result in both facilities being in net plant-in-service at year-end 2004. AUMA/EDM submitted that ATCO should not be allowed to earn return and related taxes on both facilities, as clearly, only one of the facilities can be considered used and useful as of year-end. AUMA/EDM stated that, since the evidence suggested that the new facility was either not required or could not reasonably be completed before the end of 2004, the $5.5 million capital addition should be excluded from 2004 year-end plant-in-service.

Views of the Board

The Board notes the submissions of the CG and AUMA/EDM with respect to the accelerated need for the Red Deer Operating Centre and the concern with ATCO's ability to have the Centre constructed and in service prior to the end of 2004.

While acknowledging ATCO's position that the land purchase will be finalized by October 2003, which fits into the timeframe envisaged in the timetable, the Board notes the observations of the interveners that evidence filed by ATCO and comments of Company witnesses indicate slippage in the timetable for the project. In particular, the Board notes the comments of Company witnesses at Tr. p. 486-487, that the timing of the annexation of a suitable site is uncertain, and the response to BR-AG-30(p) which refers to a Real Estate Report dated August 19, 2002, indicating that suitable sites might not be available until "1 or 2 years" from that date.

Accordingly, given the lack of progress in site acquisition at the time of the hearing, the Board agrees with intervener concerns that the evidence suggests considerable uncertainty that the occupancy date as indicated in Business Case can be met. The Board therefore considers it doubtful that the facility will be completed and occupied by the end of 2004. The Board also notes intervener concerns that ATCO failed to include a forecast of disposition proceeds for the property being replaced, and agrees with AUMA/EDM's concern that this would result in both facilities being in net plant-in-service at year-end 2004. The Board considers that clearly, only one of the facilities can be considered used and useful as of that year-end.

For these reasons, while accepting ATCO's position with respect to the need for the Red Deer facility, the Board directs ATCO to remove the cost of the facility from the 2004 test year forecast. The Board recognizes that costs of land acquisition and construction of the facility will be reflected as Construction Work in Progress (CWIP) as incurred and attract the appropriate Allowance for Funds Used in Construction (AFUDC).

The Board notes that the CG and AUMA/EDM take issue with use of the high end of the price range provided by a third party real estate firm for construction of the Red Deer Centre. The Board has examined the estimate filed by ATCO in Exhibit 13-7, and notes that unit costs quoted for the building ranges from a low of $95 per square foot to the high of $130 per square foot used in ATCO's forecast.

The Board also notes AUMA/EDM's observation that, while the entire building was priced within that range in the estimate, a similar estimate provided at the same time for the proposed Sherwood Park Operating Centre quoted a unit cost of $100 per square foot for the office portion of the facility and $50 per square foot for the light industrial portion.

Recognizing ATCO's submission that use of the high end of the range was justified to allow for the effect of inflation between the estimate date and occupancy in 2004, the Board notes that there is no evidence on the record to indicate that conditions in Red Deer and Sherwood Park are sufficiently dissimilar to justify the difference in unit costs. The Board therefore considers that there is some merit in the CG and AUMA/EDM concern with ATCO's use of the high end of the forecast price range for the Red Deer Centre.

The Board notes the CG's concern with the lack of sufficient information to support the forecast for the service centre project, particularly in light of previous Board directions for filing of business cases for major projects. The Board recognizes that the business case for the Red Deer Centre was filed by ATCO in response to information requests rather than in the Application as directed by the Board in previous GRA decisions. The Board acknowledges the CG's concern and agrees that failure to provide the business case in the Application may have contributed to some inefficiency in the hearing process.

The Board notes ATCO's comments in response to intervener suggestions for consideration of the leasing option as opposed to owning the facility, given their submission that a primary driver for the new facility is the MRRP and move to monthly meter reading, programs which the interveners submit should be scaled back from requested levels. While the Board notes that the business case for the project envisages an increase in the number of meter readers, the Board is prepared to accept ATCO's position that the business case for the project demonstrates a need for a new facility of the size proposed by ATCO, regardless of space requirements for these programs, and that owning would be a more cost effective option than leasing in the long term.

Sherwood Park Operating Centre

Views of ATCO

ATCO indicated that the land for the Sherwood Park Operating Centre has been purchased, an architectural firm retained to complete the design, and occupancy was planned for late 2003. ATCO stated that the business case for the Centre was provided in the response to BR-AG-31, which pointed out that existing facilities in the Edmonton area are at capacity and had been so for some time. ATCO considered that the facility would provide a base of operations for employees serving Sherwood Park, the surrounding rural area, as well as South East Edmonton.

ATCO indicated a requirement for a 50,000 square foot facility located on approximately eight acres of land. ATCO estimated the capital cost to build a suitable facility in the Sherwood Park area at $6 million, with construction expected to commence in 2003, with occupancy desired for late 2003.

ATCO disagreed with the suggestion of AUMA/EDM and the CG that the monthly meter reading program and MRRP were the primary drivers for additional space in Sherwood Park. ATCO pointed out that, as shown in the Application, the Business Case (BR-AG-31 9(a) Attachment), and comments of Company witnesses, the main driver for the Sherwood Park Operating Centre is customer growth. ATCO also submitted nevertheless, that a strong case had been presented for the necessity of both MRRP and monthly meter reading and that space allocation for the personnel and equipment in the Sherwood Park Operating Centre was required. ATCO also stated that the CG's suggestion that software expenditures should produce productivity improvements, was unsupported opinion rather than evidence, and should be completely ignored.

Referring to the concerns of AUMA/EDM and the CG about abandonment of the East Side operating Base (ESOB) facility owned by ATCO Pipelines, ATCO pointed out that ATCO Pipelines was allocated the ESOB facility in 1999 when the assets of CWNG and NUL were divided between Gas and Pipelines, as ATCO Pipelines had a greater need for the building. ATCO indicated that the lease of space at the ATCO Pipelines ESOB facility was a temporary solution to a growing space shortage problem within the Company. ATCO submitted that the fact that ATCO Pipelines indicated to the Company that it requires more space in a building which it owns in no way entitles ATCO to some form of compensation.

Contrary to intervener concerns about schedule slippage in land acquisition and delay in occupancy past the end of 2003, ATCO stated that the land had been purchased, an architect retained, and that the design was proceeding.

ATCO noted the CG's position that the evidence put forward by the Company with respect to the need for the new facility was unsubstantiated, and that the Board should use the lower forecasts as a basis for approving the project since the Company had used the most expensive forecasts to develop its estimates. ATCO submitted that ample evidence had been presented in the Application, in Information Responses, and in cross-examination to justify the need for the Sherwood Park Operating Centre. ATCO submitted that the decision should not be based on unsupported opinions such as that submitted by the CG. ATCO indicated that projects of this magnitude are subjected to extensive scrutiny from progressively higher levels of management at each stage of the budget approval process as they move forward. ATCO stated that use of the higher end of the estimates was the more prudent and conservative approach given that the project estimate was finalized in 2002 but construction would not start until over a year later. ATCO submitted that the higher cost estimate therefore took into consideration the impact of inflation.

In response to intervener concerns with respect to exploration of other options such as starting with a smaller, expandable facility, ATCO stated that the best point in time to ultimately finalize the size of the facility is as close as possible to the start of construction, when the pertinent and most recent information is available. ATCO submitted that this would suggest a final design being completed at a later point in the project, rather than an earlier point, as suggested by the

CG. ATCO determined the size of this facility based on the needs, both short term and long term and based the cost of construction on information from third party consultants.

Views of AUMA/EDM

AUMA/EDM expressed a number of concerns with the proposed Sherwood Park Operating Centre. First, it appeared to AUMA/EDM that the MRRP and monthly meter-reading program might be directly and indirectly influencing the need for the Sherwood Park facility at this time. AUMA/EDM stated that if the MRRP and the monthly meter-reading program did not proceed, the need for the new Operating Centre was diminished. Further, AUMA/EDM noted that ATCO is being forced to move out of the ESOB facility due to, "ATCO Pipeline's increased needs," which raises the question as to why ATCO is moving rather than ATCO Pipelines.

Secondly, AUMA/EDM considered it doubtful that ATCO could complete the new operating centre before year-end 2003, noting that the business case indicated that ATCO needed to purchase land by March 1, 2003 and approve the final design by May 1, 2003 in order to occupy the new centre by December 1, 2003. However, AUMA/EDM noted that as of March 12, 2003, ATCO had only made an offer to purchase, and that by May 20, the land had been acquired but the design was still underway.

As AUMA/EDM viewed the information, the land acquisition and the design phases appeared to be one to two months behind schedule, and estimates for construction of the new Red Deer facility indicated 11 months from purchase of land and seven months from final design to occupancy. Based on this information, AUMA/EDM considered it unlikely that the Sherwood Park Operating Centre would be completed by year-end 2003, and should not be included into rate base until 2004.

AUMA/EDM noted that ATCO indicated that, "Starting with a smaller, expandable facility will be considered during the design phase of the building."[21] AUMA/EDM considered that this suggested that the $6 million estimate represented the maximum price. AUMA/EDM stated that if MRRP and monthly meter reading did not proceed, it would not be unreasonable to reduce the light industrial portion of the facility by 10,000 square feet @ $50 and the office portion by 5,000 square feet @ $100 for a total reduction of $1 million.

Views of the CG

The CG noted that, at present, ATCO's capital region operating staff was located in three facilities, namely the North Yard Service Centre, ESOB and St. Albert Office. Referring to ATCO's submission that relocating staff from the existing Edmonton facilities would be more efficient and free up needed space in Edmonton, the CG noted that ATCO forecast the need for a new, 50,000 square foot facility located on eight acres of land, which ATCO assumed would be built on a new site yet to be purchased. The CG noted that, while ATCO expected construction to begin in 2003 with occupancy late 2003, the Company had not completed the purchase of land at the time of the filing, and that during the hearing in May, the design for the building had not been completed.

Referring to the response to CG-AG-29, the CG noted that the estimate provided by third party consultants for purchase of land and construction of the new facility was $6 million.

[21] CG-AG-31(h)

In relation to timing, the CG considered that the timetable appeared to be slipping as the design had yet to be completed, let alone approved, problems that apparently flowed from a delayed land purchase, further complicated by delays in receiving the appropriate municipal zoning and building approvals. The CG considered it unlikely that construction of the Sherwood Park facility would be completed by the end of 2003 for occupancy, and that the asset should not be included in rate base for the 2003 test year.

With respect to staffing, the CG submitted that ATCO had over forecast its needs for the test period and its building space requirements, in light of the potential that the requirement for additional meter readers was no longer necessary if monthly meter reading was deemed unnecessary. In addition, the CG did not see the need to add incremental clerical staff to support field operations and engineering staff, and considered that, as for the Red Deer Centre, the large expenditures on software projected by ATCO should produce some productivity improvements resulting in reductions to clerical staffing levels, rather than increases.

The CG also expressed concern with ATCO's cost estimate for the proposed facility, given the absence of internal Company studies on need for or costing of the facility, and the fact that external consultants used to provide cost estimates on availability of existing commercial space were not made available for cross-examination. Consequently, the CG questioned the validity of such unsupported evidence and suggested that it should not be given any weight by the Board. In the event however, that the Board decided to consider the evidence, the CG pointed out that ATCO used the worst case, or most expensive forecast, provided by the external consultant as the basis for its forecast. Accordingly, the CG submitted that, if any evidence was accepted on this matter, consideration should only be given to the more conservative, or lower, forecast.

The CG was concerned that ATCO had not considered other options including evaluation as to whether the Company could start with a smaller, expandable facility in the design stage. The CG submitted that such an evaluation should take place at an earlier point in the project as it might have a direct bearing on the eventual size and location of the facility. The CG considered it important and appropriate to undertake such an evaluation, as starting with a smaller facility would likely minimize revenue requirement effects over the test years and beyond.

The CG was also concerned about the lack of any forecast revenues from the forecast disposition of the existing facility, and considered it inappropriate to forecast the need for a rate base addition without forecasting the proceeds of disposition of the property being replaced. The CG submitted that abandonment of facilities by ATCO to the benefit of ATCO Pipelines should be done at fair market value. The CG indicated that it appeared that customers were losing the benefit of facilities, which were largely depreciated and purchased years ago at significantly less cost than new construction. The CG stated that, as a result, customers were harmed by the loss of benefit and the unnecessary increase in costs without any offsetting proceeds from disposition. The CG considered that forecasting proceeds from the sale or transfer of benefits of existing facilities would help minimize the rate impact of the proposed facility. The CG considered an interim estimate of the value of the existing facilities whose benefits are being lost by ATCO customers could be done by the Board using ATCO's estimate of land value and a depreciated building value applied in relation to the estimated percentage of current use by ATCO for those facilities.

As in the case of the Red Deer Centre, the CG expressed concern with the lack of detailed information and support for such a significant capital expenditure, particularly in light of the Board's specific direction to ATCO's predecessor company, to file detailed justification of the project for all major capital additions, including a cost breakdown and need for the project. The CG submitted that based on the absence of such documentation, there was no evidence to indicate that Company management properly discharged its duty to properly review and screen capital projects.

Based on the foregoing, the CG submitted that the Sherwood Park operations centre was not needed, would not likely be built before the end of the 2003 test year and, in any event, was based on overstated forecasts of costs and without adequate consideration of alternative approaches to address any possible future need issues.

Views of Calgary

Calgary noted that although ATCO included the Sherwood Park Operating Centre in its forecast rate base addition for 2003, the land had not been acquired nor the architect selected as of March 10, 2003. Calgary considered that, under those circumstances, there was no credibility to the inclusion of the Sherwood Park Operating Centre in the test year forecasts. Calgary indicated that ATCO had provided no evidence that this Centre would proceed within the test years.

Calgary referred to separate comments of ATCO's witnesses made at Tr. p. 67 and at Tr. p. 2981. Calgary concluded that the comments at page 67 indicated clearly that, at that point in the proceeding ATCO had neither purchased the land for the Sherwood Park facility, nor implemented architectural design work

Calgary stated that ATCO had provided conflicting evidence that the Centre would proceed within the test years, and submitted that, under these conflicting positions, credibility of the forecast for inclusion of the Sherwood Park Operating Centre for 2003 or perhaps 2004 was questionable.

Calgary submitted that ATCO added further contradiction or possibly new evidence by stating in Argument that a delay in beginning the architectural and engineering work for this operating centre resulted in deferral of $300,000 in capital expenditures from 2002 to 2003.

Views of the Board

The Board notes the concern of the CG, AUMA/EDM and Calgary with ATCO's ability to have the Sherwood Park Operating Centre constructed and in service prior to the end of 2003.

The Board notes the observations of the interveners that evidence filed by ATCO and comments of Company witnesses indicate slippage in the timetable for the project. While acknowledging ATCO's response that the land had been purchased, and that the design was proceeding, the Board agrees with AUMA/EDM's observation that, since the land was purchased in late May 2003, almost three months behind the scheduled date, there has to be some question about the ability to complete the project in the scheduled timeframe. Specifically, the Board notes that the schedule envisages 11 months from purchase of land to completion of construction and seven months from final design to occupancy.

For these reasons, while accepting ATCO's position with respect to the need for the Sherwood Park facility, the Board directs ATCO to move the forecast expenditure for the Sherwood Park Operating Centre from the 2003 test year to the 2004 test year. The Board recognizes that costs incurred in 2003 with respect to the facility will be reflected as CWIP and attract the appropriate AFUDC.

The Board notes that AUMA/EDM and CG express concern with the forecast cost of the new Sherwood Park facility, given their submission that a primary driver for the new facility is the MRRP and move to monthly meter reading, programs which should be scaled back from requested levels.

The Board has examined AUMA/EDM's calculation for a reduction of $1 million in the forecast cost to recognize the potential that the MRRP and monthly meter reading programs will not proceed as proposed by ATCO. While it is clear from the business case for the project that the new facility would accommodate four additional meter readers as a result of these programs, the Board is prepared to accept ATCO's position that the business case for the project demonstrates the need for a new facility of the size envisaged in the business plan, regardless of space requirements for these programs. Accordingly, the Board does not accept AUMA/EDM's recommendation for a reduction in the forecast cost, noting that there is no evidence to support the suggested reduction in square footage of the facility, which forms the basis of the AUMA/EDM proposal.

With respect to the CG's proposal that ATCO should start with a smaller, more expandable facility in the design stage, the Board accepts ATCO's position that the size of the facility was determined based on needs, both short term and long term.

The Board notes the comments of the CG that large expenditures on software projected by ATCO under major capital projects should produce productivity improvements resulting in reductions to clerical staffing levels, rather than increases, as envisaged in the business case for the new facility. However, the Board agrees with ATCO that the position is unsubstantiated.

The Board notes the CG's concern with the lack of sufficient information to support the forecast for the service centre project, particularly in light of previous Board directions for filing of business cases for major projects. The Board recognizes that the business case for the Sherwood Park Centre was filed by ATCO in response to information requests rather than in the Application as directed by the Board in previous GRA decisions. The Board acknowledges the CG's concern and agrees that failure to provide the business case in the Application contributed to some inefficiency in the hearing process, which will be considered by the Board in the evaluation of cost claims. Nevertheless, the Board accepts ATCO's submission that the information provided in the Application and in response to information requests met the threshold of support for the project.

With respect to intervener concerns that ATCO failed to include a forecast of disposition proceeds for the property being replaced, the Board notes that, according to the business plan for the facility, ATCO will be moving staff out of existing facilities that are currently at capacity. The Board also notes the concern of AUMA/EDM that ATCO is being forced to move out of the ESOB facility due to "ATCO Pipeline's increased needs." However, the Board acknowledges ATCO's submission that lease of space at the ATCO Pipelines ESOB facility was a temporary solution to a growing space shortage at a particular point in time.

The Board recognizes that moving out of the ESOB facility should result in a reduction to the amount of rent payable by the Company to ATCO Pipelines. In this regard, the Board directs ATCO, in its Refiling, to identify how the reduction to rent payable to ATCO Pipelines has been reflected in the revenue requirement.

Infrastructure Protection

Views of ATCO

ATCO stated that the Infrastructure Protection Program was an acceleration of upgrades to the system to better withstand an external attack against Company facilities, and that work planned under this program was more fully described in the response to CG-AG-12.

In response to the CG's suggestion that that there is no evidence of benefits to customers as a result of the infrastructure protection expenditures, ATCO indicated that security concerns had been heightened by the September 11, 2001 incidents. ATCO submitted that if the additional infrastructure protection initiatives were not being undertaken, customers would in all likelihood experience higher costs related to insurance and/or the reserve for injuries and damages. ATCO stated that the benefit to customers therefore was in minimizing those costs as much as possible through the planned expenditures.

In response to intervener concerns about the number of portable gate stations required, ATCO indicated that a variety of configurations and wide range of flows are served off the Company's existing gate stations, and that a single portable gate station could not be sized to meet the large range of flows. ATCO submitted that two portable units of different sizes would be able to meet the widest possible range of flows.

ATCO submitted that the CG was mischaracterizing the explosion at Temple Gate Station as being the justification for infrastructure protection projects. ATCO submitted that the discussion of the Temple Gate Station explosion in the response to AUMA/EDM-AG-29 was presented for the purpose of demonstrating that catastrophic events do occur. ATCO pointed out that the explosion and fire at Temple Gate Station were the result of gas leaking into the station and exploding when ignited, and not caused by a security issue. ATCO indicated that steps were subsequently taken to prevent a similar leak from happening again at other facilities.

ATCO disagreed with the CG's suggestion that a 'head in the sand' approach is warranted, and submitted that the more prudent approach is to examine all the risks of catastrophic events and be properly prepared to prevent them. ATCO felt strongly that the message given by the Federal, Provincial, and Regional security and emergency response organizations regarding preventative measures was critical. ATCO considered that the program undertaken is prudent and essential to elimination or at the very least, reduction of the potential for intentional and serious damage to facilities and the negative impact to customers.

Contrary to the CG's assertion that infrastructure protection projects in 2002 were delayed to the current test years, ATCO pointed out that $541,000 was actually spent on these projects in 2002.

With respect to the CG's suggestion for a 15% reduction to proposed infrastructure protection additions, and a reduction of one (portable) gate station, ATCO noted that the CG's position was that most of the proposed expenditures are related to minor break-ins, vandalism and theft and that costs outweigh the benefits to customers. ATCO also noted the CG's assertion that there was no evidence that any benefits to customers had been reflected as reductions elsewhere in the Application. ATCO pointed out that the Access Control and Surveillance and Early Detection elements of the Infrastructure Protection Project represented a continuation of security enhancements at key facilities that had been ongoing prior to September 11, 2001. ATCO also pointed out that the response to CG-AG-12 (c) showed that break-ins, vandalism and theft could be very expensive, and that the installation of appropriate equipment reduces such incidents to virtually zero. ATCO submitted that the CG offered no evidence for its assertion that costs outweighed benefits.

Views of AUMA/EDM

Referring to the forecast addition of two portable gate stations at a cost of $300,000 each in 2003 and 2004, AUMA/EDM noted that the last major loss of a gate station occurred at the Temple Regulating (Gate) Station in May 1980. AUMA/EDM considered that, while ATCO was to be commended for introducing the concept of a portable gate station for emergency situations, the probability of two emergencies happening coincidently under peak conditions must be extremely low. AUMA/EDM submitted that the 2004 portable gate station should not be approved.

Views of the CG

The CG referred to discussion during the hearing with respect to how certain infrastructure expenditures would enhance customer protection from terrorist type activities. In the CG's view, ATCO had over forecast its requirements for Infrastructure Protection, and cited the example of an incident that occurred at the Temple Regulating Gate Station in 1980, some 23 years previously. The CG considered that if it was necessary to change security measures because of this incident, such changes should have occurred many years ago. While the CG considered it appropriate to install isolation valves in high-risk areas, these projects should have been undertaken in 2002 and not delayed to the current test years, if they were attributable to September 11, 2001 concerns.

The CG did not consider that ATCO had adequately proven the need for two portable gate stations, and that the forecast of capital additions should be reduced to reflect the addition of one gate station only. The CG also noted that a significant portion of expenditures for Infrastructure Protection appeared to be for general security improvements more related to relatively minor break-ins, vandalism and thefts. In the CG's view the cost of these expenditures out weighed the benefits to customers. For the foregoing reasons, the CG submitted that infrastructure protection additions should be subject to the general reduction of 15% previously discussed, in addition to the removal of the cost of one gate station.

Views of the Board

The Board notes intervener concerns about the need for two portable gate stations on the basis that the probability of two emergencies happening coincidentally under peak conditions is remote. However, the Board is prepared to accept ATCO's position that a variety of configurations and wide range of flows are served off the Company's existing gate stations, and that a single portable gate station could not be sized to meet the large range of flows.

Accordingly, the Board does not accept intervener recommendations for removal of the cost of a gate station from the 2004 forecast.

The Board notes the CG's submission that, since the Temple Gate Station explosion happened in 1980, any resulting security measures should have been undertaken some considerable time ago, rather than being delayed until the test years, and that other infrastructure projects initiated in response to September 11, 2001 concerns should have been undertaken in 2002. Recognizing the need to ensure that safety concerns are appropriately addressed, the Board supports ATCO's proposals for Infrastructure Protection expenditures.

The Board acknowledges ATCO's explanation that the CG mischaracterized the explosion at Temple Gate Station as being the justification for Infrastructure Protection Projects, as the discussion of the explosion in the response to AUMA/EDM-AG-29 was merely presented for the purpose of demonstrating that catastrophic events do occur, and that $541,000 was in fact spent on infrastructure projects in 2002.

The Board notes the CG's recommendation for a 15% reduction in Infrastructure Protection forecasts for the reasons outlined above, and on the basis that a significant portion of expenditures appear to be for general security improvements more related to relatively minor break-ins, vandalism and thefts, the costs of which out weighed the benefits to customers.

The Board also acknowledges ATCO's submission that break-ins, vandalism and thefts could be very expensive, and that the CG had offered no support for the position that costs outweighed benefits to customers. Having assessed the respective positions, the Board considers that there is no substantive evidence for a 15% decrease in Infrastructure Protection forecasts. Accordingly, the Board approves the expenditures for Infrastructure Protection as forecast for the test years.

2.1.7 Moveable Equipment

Views of ATCO

ATCO indicated that Moveable Equipment forecasts provided for the acquisition of additional and replacement transportation equipment, tools and work equipment, heavy work equipment, garage stores and shop equipment, office furniture and equipment, instrument and meter shop equipment, and Natural Gas Vehicle refueling equipment.

ATCO stated that its forecast expenditures for Moveable Equipment were $8.9 million and $6.9 million in 2003 and 2004 respectively. ATCO indicated that a major category of expenditures was the purchase of 102 vehicles in 2003 and 81 vehicles in 2004, the majority of which were required to replace existing vehicles. ATCO pointed out that vehicle purchases were forecast at $4.2 million and $3.3 million in 2003 and 2004 respectively.

ATCO noted that actual expenditures in 2002 were consistent with the forecast and was confident that the forecasts for 2003 and 2004 were appropriate.

ATCO noted that all interveners essentially stated that the Board should reduce forecast expenditures for vehicle purchases on the basis that their purchase was required for Monthly Meter Reading and MRRP. ATCO pointed out that no forecast expenditures had been included for new vehicle purchases for MRRP. ATCO submitted that in any event, both initiatives were required and that the Company had started these initiatives and put in place all the required staff, contractors, materials and equipment to complete this work.

ATCO pointed out that the CG's suggestion that capital expenditures for transportation equipment should be based on the average from 1999-2001, clearly ignored the response to BR-AG-141, which outlined the fact that expenditures in 1998-2001 were reduced as the Company proactively reviewed its replacement criteria and was able to extend the life of vehicles which resulted in reduced expenditures during those years. ATCO submitted however, that those vehicles where life was extended were now at the point where they needed to be replaced. ATCO stated that a return to the 1999-2001 average, as suggested by the CG, ignored this evidence. ATCO pointed out that that vehicles are being purchased based on current requirements, current usage and performance, current warranty coverage, and vehicle technology. ATCO considered that purchases based on past history, as suggested by AUMA/EDM would ignore all this information and was not an appropriate mechanism to forecast expenditures in this category. ATCO noted that the CG's witnesses acknowledged that any part of the MRRP program already underway would be used and useful, would promote safety and improve efficiency, and that any of the related costs should be included in rate base. ATCO also noted that those witnesses recommended that half the program be conducted, which undermined any suggestion that the full costs of MRRP be excluded from rate base and revenue requirement.

Views of AUMA/EDM

Referring to the forecast purchase of 40 new half-ton trucks for meter readers in 2002, AUMA/EDM stated that, consistent with the recommendation of AUMA/EDM/CG (reflected in Section 4.2.4 of this Decision), since the increased costs of monthly meter reading could not be justified, it followed that the 40 trucks to be purchased for the meter readers would not be required. AUMA/EDM submitted that ATCO should be directed to remove the cost of these vehicles from capital additions in its GRA refiling.

Views of Calgary

Calgary noted that, while most of the transportation equipment additions related to replacement of vehicles, a significant component related to the increase in meter readers. Calgary submitted that monthly meter reading was not required at this time, with the result that the transportation equipment related to the increase in meter readers was not required.

Views of the CG

The CG noted that the test year forecasts for Moveable Equipment represented a significant increase of expenditures from 1999-2002, with the 2003 forecast close to 70% higher than the average capital additions in this area for actual 1999-2002, and the 2004 forecast 31% percent higher. The CG considered that the significant increase in new employees for meter reading and meter improvement projects had a significant influence on this account, and that if the Board accepted the arguments on the need for the MRRP, the Moveable Equipment forecast should be reduced significantly. The CG considered that, in any event, the forecasts for Moveable Equipment should be limited to the 1999-2001 average additions of $3.015 million for each test year.

Views of the Board

In response to BR-AG-20 and BR-AG-141, ATCO explained that the Company started extending the life of vehicles in 1999 from 5 years to 10 years, with the result that the Company was able to defer replacement scheduled around that time, and has reached the point where the vehicles now have to be replaced. The Board acknowledges that ATCO's policy for replacement of vehicles has resulted in an increase in test year forecasts compared to previous years' actual results, and that determination of forecasts based on historical results, as suggested by interveners, is not an appropriate mechanism to forecast expenditures in this category.

Accordingly, the Board does not accept intervener suggestions that test year forecasts for transportation equipment should be reduced to the 1999-2001 average cost of $3.015 million. The Board also notes ATCO's submission that none of the vehicles included in the test year forecasts relate to the MRRP or monthly meter reading project. However, the Board acknowledges the AUMA/EDM's reference to the purchase of 40 new half-ton trucks for meter readers included in the 2002 forecast, as identified by ATCO in response to CAL-AG-52 (tt). The Board notes that the response indicates that 111 vehicle purchases were included in the 2002 forecast, compared to an average of 43 between 1999 and 2001. On the basis of the concerns expressed in Section 4.2.3 of this Decision with respect to ATCO's proposal for increased meter reading frequency, and the resultant impact on the number of new vehicles required, the Board considers that the rate base should be reduced to reflect a realistic requirement for vehicles.

Accordingly, the Board directs ATCO, in its Refiling, to reduce the test year forecasts to reflect the fact that fewer vehicles than forecast should be required, on the basis that a number of the vehicles purchased in 2002 should now be surplus to requirements for the meter reading program, given the findings in Section 4.2.3 of this Decision.

2.1.8 Information Systems

Views of ATCO

ATCO stated that capital expenditures for the development of new software and replacement of existing software was forecast in the amount of $6.5 million and $2.5 million in 2003 and 2004 respectively.

ATCO stated that customer information system (CIS) enhancements were required to upgrade the functionality of the ATCO Gas billing system. ATCO submitted that it was critical that this IT infrastructure be kept current to meet industry standards and protect the Company's computing assets and customer information. ATCO indicated that the proposed infrastructure updates would improve Internet security, provide a single and personalized entry point to information, business processes and Applications, and support ongoing business process improvement by linking supporting information systems in a rapid, flexible and standardized way by utilizing middleware software.

ATCO provided business cases for all of the forecast software development projects with the exception of the Work Management System, (previously approved in the AGS 2001/2002 GRA), and CIS Enhancements, (on the basis that the Company does not generally prepare business cases for enhancement expenditures, which are not extensive in nature). ATCO noted that Calgary expressed the view that the costs of the IT projects seemed high, based on the contribution of those costs to the IT benchmark ratios in the Gartner report. ATCO considered that the expression of such an observation was not in and of itself evidence that the Board should take into consideration.

Regarding Calgary's recommendation for information to be included in future IT capital project business cases, ATCO submitted that the business cases filed in this proceeding identified the impact on operating costs where it was possible to do so. By way of example, ATCO indicated that the business case for the Distribution Gas Information System (DGIS) provided a breakdown of the tangible benefits of the project, the incremental operating costs associated with the project, and the payback period. ATCO pointed out that other projects, such as the One Bill Model and IT Infrastructure were undertaken to address either changing market requirements or improve/upgrade the IT operating environment. ATCO pointed out that much of Company technology is old and no longer meets operating requirements, and that in those instances, the driver for replacement cannot be quantified on the basis of reductions in costs, but rather on the requirement to be able to continue to operate effectively.

CIS Enhancements

Views of ATCO

With respect to CIS enhancements, ATCO indicated that identifying the types of enhancements that might be required to meet changing market and customer requirements could not be done readily. By way of example, ATCO indicated that factors such as the introduction of the rebate program in 2001, the move to a monthly GCRR and the introduction of the storage and production riders in 2002 could not have been foreseen. ATCO identified that the new template for franchise agreements would likely result in enhancements to CIS in the forecast period, and indicated that the forecasts also included development costs for the One Bill Model project, for which a business case was provided in the response to AUMA/EDM-AG-23(a).

ATCO noted that Calgary recommended a reduction to the forecast for CIS enhancement capital expenditures to $250,000 for each test year, but provided no support as to why that amount should be viewed as reasonable. ATCO also noted that AUMA/EDM submitted that CIS enhancements of only $600,000 per year should be approved.

ATCO pointed out that in 2001, $555,000 was invested relating to enhancements to ATCO CIS, and that since development of the CIS system was completed in that year, enhancement expenditures in that year would not reflect a full year's requirement. ATCO noted that in 2002, $2.2 million was invested relating to CIS enhancements, and that as discussed in response to BR-AG-21 and CAL-AG-02-28, the majority of these investments related to things that could not have been readily foreseen as a result of changing customer, regulatory and operating requirements.

ATCO submitted that the fact that the Company cannot specify at this time the changing requirements that will impact the CIS system in the test years, does not obviate the fact that enhancements will be required. ATCO stated that, based on the historical level of expenditures, the complexity and capabilities of the CIS system and the importance of the system in ensuring accurate billing for customers, the forecast expenditures of $1 million in each of test year is reasonable. ATCO considered it interesting that while AUMA/EDM pointedly ignored 2002 actual expenditures related to the CIS system, they recommended that the Work Management project should take into consideration the 2002 actual results. ATCO pointed out that this was exactly the type of cherry-picking that becomes a concern when dealing with information that was not available at the time the forecast was developed.

ATCO noted that Calgary also did not file any evidence to support a reduction to the CIS enhancement expenditures other than to indicate a potential impact related to the Retail Sale. ATCO stated that the determination of whether the level of CIS enhancement expenditures are impacted by the Retail Sale is a matter that should be addressed as part of the Unbundling

Application, which also addresses the impact of the sale on the ATCO revenue requirement forecast. ATCO submitted therefore that adjustments to the forecast of CIS enhancements as provided in the GRA should not be made for this reason.

Views of AUMA/EDM

AUMA/EDM noted that ATCO forecast $1 million for CIS enhancements in each test year, based on the need to keep the Application current with changes in business requirements and incorporate newly identified customer requirements. AUMA/EDM also noted ATCO's position that business cases are not generally prepared for system enhancements unless they are extensive in nature. Referring to a table setting out the historical and forecast CIS enhancements provided in CAL-AG-68, AUMA/EDM noted that the only CIS expenditure experience appeared to be the expenditure of $556,000 in 2001.

Absent the requested details from ATCO in support of the $1 million forecast, AUMA/EDM submitted that CIS enhancements of only $600,000 per year in each of 2002, 2003 and 2004 could be justified based on the limited information provided by ATCO.

AUMA/EDM noted that although ATCO identified some potential CIS enhancements in the test years, it still had not demonstrated that those enhancements will exceed the cost of enhancements related to the rebate program, the move to monthly GCRR and various other modifications that occurred in 2001. AUMA/EDM submitted that ATCO had not demonstrated that CIS enhancements in the test years are likely to exceed the $556,000 incurred in 2001.

Views of Calgary

Calgary considered the list of IT capital projects acceptable except for the CIS Enhancements project, noting that ATCO did not provide any "newly identified customer requirements" for the enhancements of $1 million in each test year. Calgary indicated that, given that ATCO would apply to the Board for sale of its retail business, these expenditures would probably be much less than forecast, and perhaps not needed.

Calgary recommended that the Board reduce the forecast CIS Enhancement capital expenditures to $250,000 for each test year, and require ATCO to specify the impact on I-Tek volumes in future IT capital project business cases, in the same manner as contracted for mainframe and other related IT services. Calgary considered that the business cases should specify the accounts in which business benefits would accrue and provide an estimate of Return on Investment. Calgary also expected the value of all IT capital projects to be reduced following completion of the ATCO I-Tek benchmarking study undertaken by the Company, on the basis that cost likely exceeded fair market value.

In response to comments by ATCO, Calgary indicated that issues such as rate unbundling and GCRR changes had been under discussion since 1999, and that ATCO should have been able to foresee these potential programs. Calgary submitted that the failure of the system to provide for them is perhaps another indication of the shortfalls of the build versus buy approach to the CIS.

Views of the Board

The Board notes the observation of AUMA/EDM that the only expenditure incurred on CIS enhancements was the expenditure of $556,000 in 2001. The Board also notes ATCO's response to CAL-AG-02-28 indicating that $2.2 million was spent in 2002 on items that could not have been readily foreseen as a result of changing customer, regulatory and operating requirements.

The Board also acknowledges the concern of Calgary that ATCO has not provided any newly identified customer requirements to support test year enhancements, and the observation of AUMA/EDM that there is no evidence to demonstrate that enhancements in the test years will exceed the amount of $556,000 incurred in 2001.

However, recognizing the uncertainty with respect to future enhancements pending the outcome of various benchmarking modules, proposals for enhancements to the load settlement system and the potential impact of the proposed retail sale, the Board is reluctant to accept the proposals of interveners for a reduction to the test year CIS forecasts. Accordingly, the Board accepts ATCO's forecasts for CIS expenditures. However, the Board also recognizes the potential for subsequent requests by ATCO for further revision to the level of CIS expenditures arising from these separate processes, with particular reference to the load settlement enhancements, and expects ATCO, in filing such requests, to identify the reasons and extent to which, any additional costs proposed in those filings would be incremental to the test year forecasts.

The Board notes Calgary's concern that future IT capital project business cases need to specify the impact on I-Tek volumes and other related benefits, and ATCO's response that business cases filed in this proceeding identified the impact on operating costs where it was possible to do so. The Board encourages ATCO to continue to provide this type of information in business cases where applicable. However, the Board acknowledges ATCO's submission that much of Company technology is old and no longer meets operating requirements, and in those instances, the driver for replacement cannot be quantified on the basis of reductions in costs, but rather on the requirement to be able to continue to operate effectively.

Work Management System

Views of ATCO

With respect to the Work Management System, ATCO indicated that the project continued to remain on budget and would meet the intended completion dates for both Phase 1 and Phase 2, despite the need to overcome a change in circumstances that could not be anticipated. ATCO noted that this project was extensively reviewed and approved at the 2001/2002 AGS GRA. The project had been split into two phases with Phase 1 forecast to cost $5.3 million and Phase 2 forecast to cost $2.3 million for a total $7.6 million. Test year expenditures were forecast at $3.1 million in 2003 and $1.1 million in 2004.

ATCO noted the CG's suggestion that customers are paying twice for portions of Work Management and that due to overly aggressive scheduling and uncertainty over timing of expenditures, the forecast of expenditures should be shifted two years. ATCO submitted that the Work Management project would meet the intended year-end completion dates and that the forecast expenditures remained accurate, despite the requirement to negotiate with a second vendor. ATCO pointed out that the CG did not provide any evidence as to how the recommended shift of two years was derived. With respect to the argument that customers were paying twice, ATCO suggested that this represented cherry picking projects that did not proceed as forecast, while ignoring the fact that some projects were completed that had not been forecast. Referring to AUMA/EDM's submission that additions to unamortized software projects should be adjusted based on the 2002 actual expenditures, ATCO suggested that this represented cherry picking one piece of information and making inappropriate use of 2002 Actual information.

Views of AUMA/EDM

Referring to the response to CAL-AG-68, AUMA/EDM noted that forecast capital additions for the Work Management System were $5.3 million for Phase I (including $3.3 million in 2002), and $2.25 million for Phase II for a total project cost of $7.5 million. However, noting that actual expenditure in 2002 was only $1.2 million, AUMA/EDM submitted that the additions to unamortized software projects should be adjusted accordingly.

Views of the CG

The CG noted that ATCO had completed the Request for Proposal process for the Work Management System, and vendors had been requested to submit bids for a turnkey system. The CG also noted that vendors were unable to meet the criteria for a turnkey package, the project was delayed and ATCO was required to alter the bid request to address only the Phase One portion (i.e. Dispatch Software) of the system.

The CG was concerned that customers would be paying a certain portion of the ownership costs for the work management system twice, and indicated that although the system costs were approved for inclusion in the AGS rate base for 2002, some interveners were concerned that the system would not be completed by the end of 2002, specifically because AGS was unable to provide the expected month of completion.

The CG reiterated the concern that ATCO appeared overly aggressive in terms of scheduling for capital additions, noting that there did not appear to be much, if any slack built into schedules for contingencies. The CG submitted that the result was an over forecast of capital additions with benefits to the shareholder and excessive rates for customers.

In view of the continuing uncertainty over timing of expenditures, the CG recommended that the timing of forecast expenditures shown at page 2.4-18 of the Application, be shifted by two years so that the 2002 forecast expenditures would be included with capital additions for 2004.

Views of the Board

The Board notes the concern of AUMA/EDM that the actual expenditure on the Work Management System in 2002 was $2.1 million lower than forecast, and that additions to unamortized software projects should be adjusted accordingly. The Board also notes the concerns of the CG with respect to the impact of delays in the project, and the recommendation that 2002 forecast expenditures should be moved back for inclusion with 2004 forecasts.

However, the Board acknowledges ATCO's explanation that the initial stages of this project were delayed due to the need to renegotiate a contract with a second vendor, and that forecast expenditures remained accurate despite this. The Board considers that this unique situation should not be viewed as a basis for reduction or adjustment to test year forecasts for this project.

Accordingly, the Board approves the expenditures for the Work Management System as forecast for the test years.

Distribution Gas Information System (DGIS)

Views of ATCO

ATCO stated that the business case for the DGIS was provided in the response to BR-AG-33.

ATCO stated that it was incorrect of the CG to suggest that because of an absence of details on the status of DGIS, the project should not be added to rate base. ATCO indicated that a detailed business case had been provided in response to BR-AG-33, and that during cross-examination, the Company's witness indicated "So what this refers to is the project is going to be completed in 2003."

ATCO noted that the CG suggested that DGIS was in fact a cost more appropriately included in ATCO Pipelines' Revenue Requirement because the application was required as a result of natural gas exchange. ATCO pointed out that natural gas exchange refers to the contractual side of the receipt and delivery business, and that because of the sheer size of the system, there are many supply points across the province, each potentially with its own unique composition of gas. ATCO indicated that this includes both supply points from the ATCO Pipelines and TransCanada systems, and that because of the large number of producers on both systems, commingling of gas streams only results in more uniform energy values in localized segments of the pipeline system. ATCO stated that the energy value of any gas stream, commingled or not, can vary with time, and that the Company is required to calculate representative energy values for gas that is delivered off of its system. ATCO pointed out that to accomplish this, all segments of the distribution system with unique gas composition need to be sampled, and that since DGIS is required to manage this process, the costs should be included in rate base in 2003.

Views of the CG

The CG noted that using the $425,000 forecast capital cost and incorporating one-time and ongoing costs and savings of implementing DGIS, ATCO estimated a payback period of 2.4 years. However, the CG considered that, notwithstanding the forecast date for completion, there was a significant question as to whether or not the project would be tested or implemented in the 2003 test year. The CG noted that, although forecast expenditures for DGIS were $278,000 in 2002 and $147,000 in 2003, no expenditures were made in 2002.

Referring to discussion with ATCO's witnesses, the CG submitted that an understanding of the testing phase and the project's expected completion date should be basic information available, and the inability to provide the information requested called into question whether the project would be completed on schedule. The CG submitted that the Utility should be able to demonstrate knowledge of the progress on the project and likelihood of completion based on current information. Consequently, in the absence of details on the status of the project with respect to testing and commencement of operations, the CG submitted that the project should not be added to rate base in 2003.

The CG also expressed concern that this expenditure resulted from pipeline operations and use of natural gas exchange between NOVA Gas Transmission Ltd. (NGTL) sourced gas and ATCO Pipeline system gas, and noted that sales customers already pay for relatively expensive NGTL sourced natural gas. The CG pointed out that as a consequence of the Exchange system between NGTL and ATCO Pipelines, sales customers paid a higher price for NGTL sourced natural gas, but failed to receive the benefits. The CG indicated that these same customers were now being asked to bear the expenses of the DGIS system to track gas of differing specifications and energy values, and submitted that the costs of the project, if and when allowed by the Board, should be charged to ATCO Pipelines.

Views of the Board

The Board notes that a comprehensive business case was filed by ATCO in response to BR-AG-33, which set out costs and timelines for the DGIS project, and that comments of Company witnesses in cross-examination confirmed the 2003 completion date for the project as set out in the business case. Based on the information provided in evidence, the Board does not consider that there is substantive justification for removal of the forecast DGIS costs from rate base.

The Board notes the CG concern that DGIS should be included in ATCO Pipelines' revenue requirement as the expenditure relates to use of gas exchanged between NGTL and ATCO Pipelines. However, the Board considers it difficult to dispute the Company's position that the DGIS forecast costs are appropriately included in the ATCO revenue requirement on the basis that the system is required to manage gas delivered off its system from various sources including supply points on the ATCO Pipelines and TransCanada systems.

2.2 Meter Relocation and Replacement Project

2.2.1 Economic/Business Rationale

Views of ATCO

ATCO explained that the purpose of this forecast capital project (MRRP) was to facilitate monthly meter reading and to achieve increased metering accuracy. ATCO submitted that outside meter sets, coupled with manual reads was preferred because it also addressed a number of other issues beyond the requirement to obtain more accurate and timely meter readings. ATCO stated that these included eliminating standard meters, reduction in system risks, cathodic protection improvements, improved meter reading effectiveness, improved employee safety, improved access and the ability to facilitate workforce rejuvenation. ATCO stated that these benefits would be realized, whether or not meters were read monthly.

ATCO indicated that alternatives to moving inside meters to the outside, which had been considered, included:

- Increase Callbacks – ATCO considered that this alternative did not provide the benefits of relocating the meter outside.
- Automated Meter Reading (AMR) – ATCO considered that AMR did not provide the other incremental benefits achieved by moving inside meters to the outside.
- Status Quo – ATCO indicated that the alternative to not make changes to the accuracy of metering and frequency of meter readings was not considered an alternative as it did not achieve an improvement in billing accuracy.

ATCO stated that it had initiated a pilot project in 2002 to evaluate the process of moving inside meters to the outside. The results of this pilot were to be used to ensure all factors had been identified and processes established to accomplish the work identified.

ATCO provided a forecast estimate for the MRRP broken down into three cost components for which forecast expenditures in 2002 and the 2003/2004 test period were as follows:

Table 1. MRRP Forecast Expenditures

	($000)		
	2002	2003	2004
Moving the Meter	488	11,406	11,861
Service Alterations	762	13,959	14,518
Meter Replacement	57	1,925	1,790
TOTAL	1,307	27,290	28,169

With respect to timing, ATCO indicated that inside sets should be moved outside as soon as possible. ATCO considered that completing the program over a time period of one or two years was logistically unmanageable, and that a five-year program provided the optimum use of resources and would allow the project to be properly managed.

ATCO indicated that the Business Case provided in response to BR-AG-24(c), included the explanation that “Although there are other methods to achieve each of these benefits individually, the MRRP is the only method by which all of these benefits will be achieved. Sending out crews to do the required work for each individual issue would not be an efficient use of resources.” ATCO noted that the Business Case also explained why it was more cost effective to approach this work as a project rather than move meters in conjunction with some other activity, such as meter recalls, that required visiting the customers’ premises on an individual basis.

ATCO took issue with the comment of interveners that “the primary business driver put forward by ATCO in its application is the need for monthly meter reading”, indicating that in fact, there were a number of drivers for MRRP, as set out in the Application and Rebuttal Evidence.

ATCO indicated that its Rebuttal Evidence showed that the Company was behind other Canadian utilities in eliminating standard meters and underground entries, and that to bring the ATCO system up to current industry standard and address the other benefits identified, an accelerated program was justified over simply moving meters as opportunities arose.

ATCO stated that AUMA/EDM’s suggestion that the saving from elimination of curb valve maintenance for residential services had been overstated was incorrect. ATCO pointed out that problems with curb valves generally occur at the time they are operated, and that once the meter has been moved outside with a valve on the riser, there will no longer be a need to inspect or operate curb valves and those costs will be avoided. ATCO indicated that the savings associated with abandoning the curb valves were correctly factored in gradually over a number of years as the meters were moved outside.

ATCO indicated that AUMA/EDM was correct in stating that the error resulting from use of standard meters goes into lost and unaccounted for (LUF). ATCO indicated however, that this meant that individual customers were not being billed accurately and that billing errors were being paid for by all customers.

ATCO stated that AUMA/EDM’s claim that the Company was moving more rapidly than the industry norm was inconsistent with ATCO’s evidence demonstrating that the Company was well behind other Canadian utilities in the replacement of standard meters and providing accurate measurement based on industry standard. ATCO also noted that the CG's witnesses agreed that the work being done under MRRP was used and useful and would enhance efficiency in meter reading and should therefore be included in rate base.

ATCO noted that Calgary attempted to link the MRRP almost exclusively to monthly meter reading and ignored the other benefits and synergy provided by the project in achieving a number of benefits through one initiative.

Views of AUMA/EDM/CG

AUMA/EDM/CG noted that ATCO Gas stated that, "the purpose of this forecast capital project is to facilitate monthly meter reading and to achieve increased meter reading accuracy." and identified five points as business justification for undertaking monthly meter reading. In the view of AUMA/EDM/CG, there was no real business requirement to implement monthly meter reading, and elimination of the primary business need identified by ATCO cast serious doubt as to the need and viability of the MRRP.

AUMA/EDM/CG submitted that the annual operating cost savings of $2.52 million identified by ATCO in the business case, were overstated. AUMA/EDM/CG considered that:

- elimination of curb valve maintenance costs only holds true if all curb valves are removed from the system; and
- if there is no requirement for monthly meter reading, there is no basis for inclusion of the total forecast reduction in meter reading costs in an analysis of project economics.

AUMA/EDM/CG pointed out that the business case also indicated an annual reduction in LUF Gas of 639,000 gigajoule (GJ), attributable to the replacement of standard meters with temperature-compensated meters. AUMA/EDM/CG indicated that, since LUF Gas was contained within the Deferred Gas Account and the costs borne by sales customers, to the extent that this replacement resulted in a reduction in LUF Gas, the total costs borne by sales customers would not change. AUMA/EDM/CG submitted that gas purchase volumes and costs for sales customers would remain the same as under a situation with no MRRP, and to the extent that replacing standard meters with temperature-compensated meters resulted in different meter readings for those customers subject to the MRRP, there would simply be a re-allocation of gas supply costs among sales customers.

AUMA/EDM/CG did not consider a comparison to ATCO's fellow utilities constituted an acceptable or appropriate justification for a major capital expenditure, especially when the situations were not directly comparable. Although ATCO implied that other utilities had conducted programs to replace standard meters, eliminate underground entries and move meters outside, AUMA/EDM/CG considered that the Company had not provided any direct evidence of such programs, and that if such programs were conducted on a stand alone basis, as opposed to forming part of the utilities' normal activities, that should be on record somewhere, including the drivers for each program.

AUMA/EDM/CG also considered that, given the proposed sale to Direct Energy currently before the Board, it remained an open question whether any increased metering requirements would be desirable or required.

2.2.2 Technical Justification for Project

Views of ATCO

ATCO noted that, in their discussion of safety, AUMA/EDM/CG only addressed the possibility of leaks migrating into the home, whereas in the Business Case provided in response to BR-AG-24(c), ATCO described some of the catastrophic incidents, including explosions and fatalities that have occurred at homes with underground entries. ATCO pointed out that five out of the six incidents identified were the result of some activity disturbing the service line outside the house causing leakage inside. ATCO stated that elimination of underground entries and of pressure gas in homes would greatly reduce the risk of these types of catastrophic incidents occurring.

ATCO noted that AUMA/EDM/CG questioned the value of the pilot in determining the availability of contractors and skilled labour necessary to complete the MRRP. ATCO indicated that the analysis of the pilot allowed the determination of the type of contractors and skilled labour that would be required and provided a good understanding of the complexity of the work. ATCO pointed out that as a result, the work description in the contract was sufficiently detailed that the Company was able to go out to a wider contractor base than had traditionally been used and therefore enlarge the pool of available resources. ATCO indicated that this would prepare the Company for the projected retirement of 45% of employees over the next 10 years.

With respect to AUMA/EDM/CG's continued suggestion that the MRRP be downsized to half of the 2003 and 2004 level, in part due to shortage of workers, ATCO stated that the fact remained that the Company had actively canvassed a much broader market and secured the appropriate effort, which had been mobilized.

ATCO noted the AUMA/EDM/CG's argument that "…most safety issues would be better addressed by the end retailer." ATCO submitted that gas escaping into the customer's home was a very serious situation with the potential for property damage and/or injuries and fatalities, and that a prudent utility must take steps to ensure that this situation does not occur which was part of the rationale for MRRP.

ATCO further submitted that safety should not become a rate case game, and that the arguments of interveners revealed attitudes and recommend approaches, which no prudent utility should adopt. ATCO submitted that no responsible regulator should support them either.

ATCO stated that a general point on MRRP was that none of the interveners disagreed with the un-contradicted evidence of Mr. Prefontaine that the MRRP, already being implemented in 2003, would result in facilities which were used and useful, would make the system safer and more efficient in terms of meter reading and access to equipment.

Views of AUMA/EDM/CG

While the MRRP was to take place in a relatively rapid timeframe, AUMA/EDM/CG noted that the utility industry, particularly as it relates to physical facilities, was not noted for rapid change. AUMA/EDM/CG considered this particularly true of physical facilities, where the residential meter, which had been around for over 100 years in roughly its current form, had changed little operationally in that time. AUMA/EDM/CG noted that the delivery system consists of buried pipes and the primary measure of underground system deterioration was leak frequency, degradation of the system was primarily linear and failure modes were well known allowing for a systematic approach to inspection and maintenance.

AUMA/EDM/CG stated that, operationally, utilities had done an excellent job of maintaining and extending the life of the system, residential meters were staying in the field from 15 to 25 years between recalls, and mains and service line lives, as evidenced by depreciation rates, were stable in spite of inferior materials relative to today's standards. In this environment, AUMA/EDM/CG questioned the rationale and purpose behind proposing anything of the scope and pace of the MRRP.

AUMA/EDM/CG indicated that the MRRP, as proposed, went well beyond the bounds of normal system replacement even as defined by the ATCO inspection/replacement decision matrix. AUMA/EDM/CG submitted therefore, that it was incumbent on ATCO to prove the necessity of the program on a balanced and well-substantiated basis. Based on a review of evidence presented to date and an understanding of the issues raised, AUMA/EDM/CG continued to submit that the case had not been made.

AUMA/EDM/CG submitted that ATCO had not provided any evidence clearly defining a measurement error in residential, inside, non-temperature compensated meters. AUMA/EDM/CG noted that Measurement Canada continued to allow the use of non-temperature compensated meters inside residences.

With respect to safety, AUMA/EDM/CG noted that ATCO's primary focus had been underground entries and related higher risk for serious incidents. Specifically, the Company stated that there is an increased opportunity for uncontrolled gas to be inside the residence, a level of risk that ATCO considered unacceptable. While AUMA/EDM/CG's expert witness agreed that underground entries were more vulnerable to leaking gas if it migrated toward the house, none of the evidence filed by ATCO demonstrated a change in the level of risk in recent years. AUMA/EDM/CG stated that, on the contrary, evidence indicated that overall leak frequencies were stable or declining, and that less than 50% of the meter sets being relocated involved underground entries (90,000 out of 195,900 as per pilot program report).

AUMA/EDM/CG submitted that the number of catastrophic incidents over time appeared relatively small and that the mains replacement program had been carried out with the meter replacement program in the past. AUMA/EDM/CG considered that the risk to customers appeared to have been well managed, and that there was no indication that the risk related to safety issues was any greater than in the past. Consequently, AUMA/EDM/CG considered that there did not appear to be any reasonable justification for accelerated replacement, particularly when considering the cost of the program. While acknowledging that safety to servicemen was always important, AUMA/EDM/CG did not consider this sufficient justification for incurring the expense of an accelerated program.

Referring to ATCO's comments indicating that the MRRP was comparable to the Bare Mains Replacement Program, AUMA/EDM/CG indicated that evidence in the Application showed, for AGS, Bare Mains Program expenditures from 1999 to 2004 and ranging from $7.760 million to

$1.605 million. AUMA/EDM/CG considered that the facts were clear that a smaller program was carried out over a longer time frame and that the risk was acceptable to ATCO in that case.

If the MRRP was "much the same as bare mains was" as stated by ATCO, AUMA/EDM/CG considered that the MRRP should be carried out more conservatively, over a longer period than that proposed by ATCO.

Referring to workforce rejuvenation, another benefit, attributed by ATCO to the MRRP, AUMA/EDM/CG noted that media reports continue to express concern about shortages in skilled trades in Alberta and consequential delays and cost overruns. AUMA/EDM/CG submitted that a workload escalating gradually and staying at a certain level over many years had a better chance of training and retaining qualified workers, than in a situation where there was a sharp spike in activity.

AUMA/EDM/CG considered it difficult to fathom how a pilot program moving 929 meters could specifically test the availability of contractors and skilled labour required to move from 21,000 to 51,000 meters. AUMA/EDM/CG expressed concern with the ability to complete a large scale project in Alberta without the commensurate problems being encountered by other large construction projects in the Province.

2.2.3 Cost and Safety Issues

Views of ATCO

ATCO indicated that the MRRP was included in Meters, Regulators and Installations category of forecast expenditures. ATCO noted that interveners ignored the evidence that clearly shows the "industry standard" was a temperature compensated meter located outside the home.

Referring to Calgary's comment that where safety was an issue the projects should proceed without interruption, ATCO stated that Calgary's definition of when safety becomes an issue clearly demonstrated Calgary's total lack of understanding of the operation of a natural gas utility and the potential for catastrophic results in the event of a natural gas leak. ATCO considered Calgary's appraisal to be irresponsible and unacceptable.

ATCO referred to speculation by Calgary that Consumers Gas had a lower percentage of inside meters since they might have added proportionally more new customers since 1974. ATCO indicated that Calgary did not provide any hard data to support this assumption and appeared unaware of the ATCO growth rate since 1974, which had ranged from a low of 6,665 new customers in 1984 to a high of 32,305 in 1976. ATCO indicated that it had added approximately 61% of the current residential and commercial customer base since 1973, and that given the total number of customers each company had and the information provided by Calgary, it was meaningful to compare the percentages of inside meters between the two companies.

ATCO considered the comparison of the Net Present Value (NPV) of the MRRP program to completion of the program over 16 years as discussed by AUMA/EDM/CG completely inappropriate. ATCO noted that AUMA/EDM/CG's only evidence with respect to this calculation was based on a statement made by Mr. Newcombe,[22] who admitted that the statement was not supported by evidence. ATCO also noted that the comparison did not appear to look at

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the NPV of MRRP over its entire life but appeared to focus solely only on the NPV after 16 years, which was an inappropriate comparison. ATCO stated that the NPV calculation ignored what customers actually pay in tolls due to depreciation rates, which extends recovery of these costs well into the future, substantially reducing an NPV calculation on investment rather than tolls.

ATCO stated that, as indicated in response to BR-AG-24(c), the Company would incur a higher level of costs that customers would have to pay for at some point in time, if it did the program on a piecemeal basis, as suggested by AUMA/EDM/CG. ATCO pointed out that in the Business Case, the time required to complete meter moves as part of the MRRP was compared to the one at a time approach proposed by AUMA/EDM/CG. ATCO pointed out that the labour costs would be in the order of 67% greater than MRRP and that there would also be extra expenses for activities that do not occur on every move, such as concrete and carpentry, since there would be increased mobilization and travel costs. ATCO indicated that labour and extra expenses make up the majority of the costs to move a meter so that overall costs would be at least 50% higher than the proposed MRRP costs.

ATCO noted that AUMA/EDM/CG questioned the need for temperature compensated meters but was unable to provide any tangible data to support the case. ATCO indicated that clearly the industry standard was the use of temperature compensated meters and the Company was well behind the rest of the Canadian natural gas utilities in providing this measurement standard. ATCO stated that the inaccuracy in measurement from use of standard meters was reflected in the billing to the customer and ultimately impacts the LUF account. ATCO stated that while there were different solutions that would provide monthly meter readings, all these solutions would be more cost effective when used with outside meter sets.

ATCO submitted that it was clearly attempting to bring the utility up to industry standards with respect to safety (customer and employee) and efficiency in the most cost-effective way possible, and considered the somewhat glib statements of interveners about safety deeply disturbing.

Views of AUMA/EDM/CG

Referring to the response to CG-AG-26 (d), AUMA/EDM/CG noted that the rate impact of the MRRP would be significant, peaking at $34.88 per customer in 2006, and decreasing somewhat thereafter to $25.98 per customer in 2012. Based on ATCO's business case and other references in evidence, AUMA/EDM/CG noted that the MRRP had a NPV of $192 million using a 10% discount rate. AUMA/EDM/CG noted that if integrated into ATCO's normal meter sampling and replacement program, the MRRP would take approximately 16 years to complete, which would require capital costs of nearly $400 million, or 150% of the forecast MRRP costs of $265 million, to result in the same NPV.

AUMA/EDM/CG submitted that it was reasonable to assume that ATCO could design and manage a normal meter replacement program so the total capital cost would be less than $400 million. AUMA/EDM/CG considered that, in any event, the adoption of a normal meter replacement program would result in a smaller annual revenue requirement impact for customers, accruing from the slower expenditure of capital and ongoing effects of depreciation.

AUMA/EDM/CG considered that the accuracy of consumption billing data was to a large extent a non-issue, given that ATCO acknowledged it had no problem with the accuracy of its standard meters or bills. With regard to non-temperature-compensated (standard) meters on inside sets, AUMA/EDM/CG stated that ATCO had failed to substantiate a metering accuracy problem. While agreeing that temperature compensated meters were industry standard, AUMA/EDM/CG considered that current ATCO policy would see all of the current standard meters replaced when due for recall over the next 16-17 years at no additional incremental cost to the customer. Therefore, AUMA/EDM/CG submitted that the need for the MRRP to take place on an accelerated basis did not appear to be the best, or most cost effective approach.

AUMA/EDM/CG considered that ATCO's past practice for meter replacement appeared reasonable and did not raise any lesser or greater safety issues than at present. AUMA/EDM/CG submitted that there was no evidence presented to substantiate not continuing with the current practice, which appeared both reasonable and cost effective.

AUMA/EDM/CG submitted that it was not clear that the MRRP was the lowest cost or most reasonable approach available to ATCO for meter replacement, and indicated that replacement of services in conjunction with mains replacement offered the same opportunities for volume efficiencies. Further, AUMA/EDM/CG considered that the longer the program was spread out, the greater would be the numbers of homes demolished or renovated, thereby reducing the total properties and meters affected. AUMA/EDM/CG stated that it was also not clear that inside meter sets with outside risers ever needed to be replaced except in the normal course of system replacement.

AUMA/EDM/CG indicated full support for the original recommendation of Pref. Engineering for the program to continue as a pilot, but on a larger scale (i.e. no more than half of that proposed for 2003 and 2004). AUMA/EDM/CG submitted that the rationale should be to allow ATCO the flexibility to address high-risk situations, obtain further data and experience and evaluate all the information with a view to providing the most efficient resolution of the problems.

Views of Calgary

Calgary did not object to the movement of meters and related costs where safety was an issue, and considered that where this was an issue, these projects should proceed without interruption. Calgary, however, objected to the accelerated program of meter relocations proposed by ATCO where safety was not an issue.

Calgary stated that ATCO had provided no empirical evidence that there were safety problems, and had failed to demonstrate that the accelerated meter move program was required for reasons of safety.

Calgary indicated that ATCO had not provided any cost/benefit analysis in support of this program to demonstrate that the benefits to ratepayers outweighed the costs, and that the obvious net result was a large addition to rate base without a commensurate benefit to ratepayers.

In response to ATCO's claim that other utilities had a higher proportion of their meters outside, Calgary noted that companies such as Consumers Gas had added proportionately more new customers since 1974 than ATCO. Calgary recommended that the Board approve a controlled program of moving indoor meters outdoors based upon scheduled retirements or recalibration of indoor meters, absent demonstrable moves for safety reasons. Calgary considered that such a program would achieve ATCO's goals and reduce the cost burden on ratepayers.

Calgary stated that any proposal to spend $55 million to improve meter reading efficiency, meter accessibility and billing accuracy to meet the needs of an emerging competitive market should be driven by customer demand for the project and marketers appearing before the Board explaining why they require the MRRP. Calgary pointed out that there had been no customer complaints about indoor meters or excessive complaints about billing accuracy or meter reading intervals.

Views of the Board

The Board notes ATCO's position that, in implementing the MRRP, the Company is attempting to bring the utility up to industry standards with respect to safety. However, the Board considers it difficult to take issue with AUMA/EDM/CG's observation that ATCO's existing practice for meter replacement is effective and has not revealed any significant issues or evidence of increasing concerns with respect to safety.

The Board notes the submission of AUMA/EDM/CG that the primary measure of underground system deterioration is leak frequency, and accepts that historical evidence suggests that failure modes are well known, and that ATCO has effectively maintained the life of the system and residential meters with a systematic approach to inspection and maintenance. The Board is not persuaded that ATCO has presented a compelling case to support an accelerated program of meter replacement in light of the historical maintenance record.

The Board also notes Calgary's submission that the Company had provided no substantive evidence of safety problems. While acknowledging ATCO's reference to the potential for catastrophic results in the event of a natural gas leak, the Board notes that the potential is of long standing, and is likely to relate as much or more to faults in underground pipes than in indoor meters.

The Board notes ATCO's position that inaccuracies in measurement from standard meters is reflected in the billing to the customer, and that a major driver for the program is the need to increase metering accuracy, which would be achieved more cost effectively with outside meter sets, in terms of replacing standard meters with temperature compensated meters.

In contrast, the Board also notes the observations of both AUMA/EDM/CG and Calgary that ATCO had failed to substantiate a metering accuracy problem with standard meters on inside sets, and that there have been no excessive complaints from customers about billing accuracy or meter reading intervals.

The Board accepts ATCO's position that the need for monthly meter reading is not a primary business driver for the MRRP, noting that this was a change from ATCO's position as stated in the Application.

The Board considers that the issue is clearly whether or not there is justification for replacement of standard meters in the accelerated time frame proposed by ATCO. The Board agrees with interveners that ATCO has not made a compelling case for fully accelerating replacement of indoor meters on safety grounds, or on the basis of inaccuracies in meter readings.

The Board notes the observation of AUMA/EDM/CG that current ATCO policy would see all of the current standard meters replaced when due for recall over the next 16-17 years at no additional incremental cost to the customer, as opposed to the MRRP, which AUMA/EDM/CG calculates would cost significantly more on a NPV basis over that same time frame. The Board also notes the AUMA/EDM/CG submission that a program spread out over a longer period provides greater opportunities for volume efficiencies, and potential for reduction in the total number of properties and meters affected as the numbers of homes demolished or renovated increases.

While acknowledging ATCO's position that conducting the program on a "one at a time basis" as suggested by AUMA/EDM/CG would result in an increase of 50% in overall costs as compared to the MRRP, the Board notes the comment of the intervener's witness[23] that those costs could be reduced by establishment of a program that would replace about 8,500 meters per year or a quarter or a third of the number of meters proposed under the five-year program.

In view of the foregoing, the Board agrees with interveners that the case has not been made for replacement of standard meters over a period of five years as proposed under the MRRP. However, the Board is not persuaded that continuation of the status quo is necessarily the preferred option, and considers that there is justification for enhancement to the meter replacement program, particularly where safety is an issue. The Board considers that ATCO should establish a program that will result in replacement of meters over a longer period than the proposed five years, and that replacement should be based on priorities identified, particularly in terms of safety, such as addressing the issue of underground entries, cathodic protection improvements, and improving employee safety. The Board considers that the program should focus on replacement of underground entries and that standard meters on aboveground entries need not be changed until they are recalled. By way of an example, the Board considers that the Program could be broken down and prioritized as follows:

1) for underground entries with or without standard meters – replace/relocate on 10-year program, moving those that need to be recalled first;
2) aboveground entries with standard meters – Standard meter replaced when recall required, consider AMR;
3) aboveground entries with compensated meters – no urgency, negligible safety issues, consider AMR.

Accordingly, the Board directs ATCO to re-evaluate the MRRP and incorporate in its Refiling, a revised proposal for replacement of meters with underground entries over a 10-year timeframe, and replacement/relocation of meters with aboveground entries on a schedule coincident with the recall program. The proposal should identify criteria for replacement and relocation in terms of safety or other considerations. In the Refiling, the Board also directs ATCO to identify the adjustments required to test year capital expenditure forecasts, forecast staffing and labour costs and operating and maintenance (O&M) costs as a result of extending the timeframe from five years as envisaged in the MRRP.

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2.2.4 Impact of Competitive Market On Need for the MRRP

Views of ATCO

ATCO submitted that the majority of drivers for this project were independent of whether or not the natural gas market was a deregulated competitive market. ATCO took issue with AUMA/EDM/CG's claim that one of the three main justifications for the MRRP was "future or speculative retail market requirements", indicating that operational and safety benefits resulting from the completion of the project would be important to ATCO and its customers regardless of the retail environment.

ATCO considered that customers were entitled to accurate billing, and that the Company was behind the rest of the Canadian gas industry in eliminating the measurement errors associated with standard meters. ATCO submitted that the retail market did not drive this improvement to measurement accuracy.

Referring to AUMA/EDM/CG's reference that "ATCO Gas asserts the MRRP is required to facilitate the competitive market," ATCO submitted that this was an incorrect statement, and indicated that the correct statement was that the majority of drivers for the project are independent of whether or not the natural gas market was a deregulated competitive market, and that completion of the project would be important to ATCO and its customers regardless of the retail environment.

Views of AUMA/EDM/CG

AUMA/EDM/CG submitted that there was no evidence to support ATCO's position that MRRP was required to facilitate the competitive market, and that ATCO's own evidence, suggested that there was considerable uncertainty surrounding the requirements of the competitive market. AUMA/EDM/CG considered that the only conclusion to be drawn was that the competitive market was in its infancy, was in a state of evolution and no party to this proceeding, including ATCO, was able, at this point, to foresee with accuracy the future meter reading requirements of the competitive market.

AUMA/EDM/CG stated that furthermore, current competitive retail offerings were limited to fixed price term arrangements, under which, there was no benefit to increased meter readings. Consequently, AUMA/EDM/CG submitted that there was no current justification related to the competitive market in support of the MRRP.

AUMA/EDM/CG submitted that other alternatives to the MRRP exist, and that perhaps ATCO could consult with customers and land on an appropriate, and less expensive mechanism, than the accelerated MRRP.

Given the significant cost of the MRRP, and looking at it from the broadest perspective, AUMA/EDM/CG maintained that the program was not in the best interest of customers.

AUMA/EDM/CG submitted that prudence suggests waiting for the need to be established before justifying the expenditure, and that the goals of the MRRP could be accomplished over a longer time frame, at more reasonable cost, on the same basis that ATCO had been replacing its standard meters in the past.

Views of Calgary

Calgary submitted that this project was neither required nor being sought by the competitive market, noting that not one marketer appeared in the proceeding to set forth a case for monthly meter reading. Calgary considered that lack of input from the competitive market on this issue showed a lack of interest and/or need by the competitive marketplace for monthly meter reading.

Views of the Board

The Board notes that ATCO's position, that the majority of drivers for the MRRP are independent of whether or not there is a competitive, deregulated natural gas market, is consistent with the positions of the interveners on this issue. The Board also agrees.

2.3 Other Capital Asset Issues

2.3.1 Capitalization of Administration Expense

Views of ATCO

ATCO indicated that the Company had historically capitalized fringe benefits for employees working on capital projects. These capitalized charges amounted to approximately $3 million out of total administrative charges of over $50 million.

ATCO submitted that it had reviewed its practices with respect to the capitalization of administrative charges, and viewed that it would be more appropriate to capitalize a more representative portion of the total administrative charges as overhead. Many of these costs related to what could be called "the cost of doing business." In other words, they were costs generally incurred by all companies to some extent, regardless of the type of business they conducted. ATCO pointed out that, when the Company hired a contractor to complete a capital project, that contractor's rates recovered his direct costs to perform the service and also a proportion of his "cost of doing business." In order for ATCO to make informed decisions about whether to use a contractor for a project or to perform the work in-house, cost comparisons must be on an apples-to-apples basis. As these types of costs support all functions performed by ATCO, including its capital programs, ATCO considered it appropriate to charge a portion of these costs to capital. ATCO submitted that this would also ensure intergenerational equity with respect to the recovery of costs associated with the capital investment of the Company.

ATCO provided details of the costs to be capitalized of $6.5 million in each test year. ATCO submitted that the types of administrative costs that should properly be capitalized in addition to fringe benefits, related to head office costs, legal and audit fees, corporate membership fees, bank charges, and labour and supply expenses related to administrative staff.

ATCO agreed with Calgary that the change in capitalization policy did not reduce operating costs but merely postponed them, and that the rationalization for capitalizing the costs was not new. ATCO submitted that the proposal to commence capitalization of additional administrative charges was based on the fact that these costs support the capital programs of the Company as much as the operating programs. ATCO stated that, on that basis, capitalization has the result that customers who benefit from the capital programs being responsible for their full cost, which was an issue of intergenerational equity, that came to light as a result of the review which was undertaken through the ATCO Affiliate proceeding to charge costs to affiliates on a fully allocated cost basis. However, ATCO stated that as Calgary indicated, if the Board did not agree that these services provided benefits to customers in the future and should therefore not be capitalized, operating expenses must be increased in the test year revenue requirement.

ATCO noted that the CG indicated that it was not appropriate to capitalize these costs because it was contrary to the Canadian Institute of Chartered Accountants (CICA) Handbook, and the fact that there was not a direct relationship to the capital activities of the Company. ATCO also noted that the main concern of AUMA/EDM appeared to be the lack of a direct relationship between these costs and the capital activities.

ATCO disagreed with these statements, noting that the CG themselves indicated that the difference between the types of ES&G costs currently capitalized and the capitalization of the additional administrative costs was one of degree. ATCO indicated that while the relationship between these costs and the capital projects of the Company might not be as direct in nature as other charges capitalized, the capital programs could not properly function without these administrative support charges. ATCO disagreed with the CG's position that any in-house capital work performed was not a critical part of utility business, and it was therefore not appropriate to charge these types of costs to capital, in the same manner as capitalization of contractor charges. ATCO pointed out that approximately 30% of the labour force was devoted to the capital programs, which indicated a much greater involvement than simply a "side-line" activity as suggested by the CG.

Views of AUMA/EDM

AUMA/EDM noted that ATCO proposed to capitalize 30% of head office costs, legal and audit fees, corporate membership fees, bank charges and labour and supply expense related to administrative staff, which constituted a change from the current Capitalization Policy 20.01 filed in the AGS 2001/2002 GRA. AUMA/EDM noted that the costs capitalized under that policy included costs that could be directly linked to the acquisition, construction, development or betterment of a capital asset. AUMA/EDM pointed out that the existing policy appeared to follow the section of the UCA that included the statement that the assignment of overhead costs to particular jobs or units shall be on the basis of actual and reasonable costs and that no charge shall be made to primary account plant accounts for the pay of employees whose services in connection with construction are merely incidental, except as provided for in the cost of overhead charged for construction.

AUMA/EDM noted Calgary's position that to the extent that a portion of administrative expenses were directly related to capital improvements and additions, capitalizing a portion of administrative costs directly related to capital functions would be conceptually appropriate but expressed concern that ATCO had not provided any direct evidence.

Referring to the NPV analysis prepared by ATCO's witness, AUMA/EDM provided rationale supporting its conclusion that customers would be relatively indifferent between capitalizing versus expensing over the long-term. AUMA/EDM submitted that the issue was whether the proposed change in policy properly reflected the administrative costs related to capital assets or if it was just another rate base building attempt.

AUMA/EDM considered the application of the 30% allocation factor to be arbitrary on the basis that these administrative charges included rent and operating costs, legal and audit fees, corporate memberships and bank charges that bore no relationship to the labor ratio.

AUMA/EDM concluded that there was no means of determining what portion of the $6.5 million was "actual or reasonable" or "merely incidental" to the assets as prescribed in the UCA.

AUMA/EDM submitted that, since ATCO had not made a convincing case to capitalize the full $6.5 million of administrative costs, or some defined portion thereof commencing in 2003, this change in policy should not be approved at this time.

AUMA/EDM noted that ATCO admitted that the relationship between these costs and the capital projects might not be as direct as other charges capitalized. AUMA/EDM considered that the $6.5 million proposed goes beyond "actual or reasonable" and might be "merely incidental" as prescribed in the Uniform Classification of Accounts (*Alberta Regulation 546/63* [AR 546/63]) and should not be approved at this time.

Views of Calgary

Calgary submitted that the principal issue with respect to capital additions was the change in capitalization policies, which had resulted in a significant increase in the costs capitalized. Calgary expressed concern that instead of reducing operating costs, ATCO was merely postponing them by capitalizing them. In Calgary's view, the rationale for capitalizing the costs was not new, and was as applicable to 2001 and 2002 as it was to 2003. Calgary considered that ATCO had failed to justify the requested change in capitalization policies.

Views of the CG

The CG noted that under ATCO's existing policy, the Company capitalized ES&G expenses attributable to capital projects, and now proposed to capitalize certain administrative overheads in addition to the ES&G presently capitalized.

The CG noted that Section 3061 of the CICA Handbook stated, with respect to capitalized overhead that the cost of an item of property, plant and equipment includes direct construction or development costs (such as materials and labour), and overhead costs directly attributable to the construction or development activity.

The CG submitted that capitalization of additional administrative costs as proposed by ATCO was inappropriate. The CG considered that the types of costs included under ES&G were properly capitalized as being more directly related to capital projects, while on the other hand, the relationship of the additional administrative costs, identified for inclusion under the proposed policy, to capital projects was questionable. The CG considered that, while there was a strong relationship between ES&G and capitalized labour, ATCO had provided no evidence to demonstrate such a relationship between the level of additional administrative costs to be capitalized and in-house capital labour.

The CG noted that one of the reasons ATCO provided for the proposed change was that a contractor's rates recovered his direct costs to perform the service and also a proportion of his 'cost of doing business', and that for the Company to make informed decisions about whether to use a contractor for a project or perform the work in-house, cost comparisons needed to be on an apples-to-apples basis. The CG submitted that, as contractors were in the business of providing construction services, it was appropriate for them to reflect full cost recovery, including their internal overhead costs related to the operation of a contracting business. However, the CG submitted that ATCO was not in the construction business, and any in-house work was ancillary to the core business of gas distribution services and not a critical part of the Utility's business.

The CG noted that the proposed policy assumed a one-to-one relationship between capitalized labour and additional administrative costs, and submitted that such a relationship did not exist. The CG further submitted that the proposed policy was contrary to CICA Guidelines requiring that only overheads directly attributable to a project be capitalized. For all of these reasons, the CG submitted that ATCO's proposed change in policy should be rejected.

The CG submitted that it was appropriate to charge affiliates the fully allocated cost of providing services, including administrative overhead, as ATCO is considered a stand alone utility for regulatory purposes. The CG stated that charging any amount less than fully allocated costs would place the affiliate at a competitive advantage in relation to its competitors. The CG submitted however, that charging administrative overhead to capital expenditures was inappropriate as the administrative overheads related primarily to the business of providing gas distribution service and only incidentally to capital construction projects.

Views of the Board

The Board acknowledges ATCO's position that, based on a review of practices with respect to capitalization of administrative charges, the Company considered it appropriate to capitalize a representative portion of total administrative charges as overhead. The Board also notes ATCO's submission that many of these costs related to what could be called "the cost of doing business," or effectively, costs generally incurred by all companies to some extent, regardless of the type of business they conduct. The Board notes ATCO's statement that, to be able to make informed decisions about whether to use a contractor for a project or perform the work in-house, cost comparisons must be on an apples-to-apples basis and that this is accomplished by capitalizing a portion of the administrative expense.

The Board notes that ATCO determined the amount to be capitalized based on the ratio of capital labour to total labour, calculated at 30%, which resulted in capitalization of $6.5 million in Administrative Expense in each test year. The Board acknowledges ATCO's submission that, in addition to fringe benefits, which had been capitalized historically, the types of administrative costs that should properly be capitalized include an appropriate portion of head office costs, legal and audit fees, corporate membership fees, bank charges, and labour and supply expenses related to administrative staff.

The Board notes AUMA/EDM's position that, while the existing policy appeared to follow the UCA, the proposal constituted a change from the current Capitalization Policy 20.01 filed in the AGS 2001/02 GRA. The Board also notes the CG submission that the capitalization of additional administrative costs as proposed was inappropriate noting that the proposal was contrary to provisions of the CICA Handbook requiring that only overheads directly attributable to a project be capitalized. The Board acknowledges the CG argument that ATCO had provided no evidence to demonstrate such a relationship between the level of additional administrative costs to be capitalized and in-house capital labour.

The Board also notes Calgary's concern that instead of reducing operating costs, ATCO was merely postponing them by capitalizing them, and that ATCO had failed to justify the requested change in capitalization policies.

The Board agrees with intervener submissions that ATCO has not adequately demonstrated that the additional overhead included in test year capital forecasts was directly attributable to a particular construction or development activity. The Board is also concerned that the 30% ratio was based on a "snapshot" calculation, with no evidence of consideration of historical trends, and that ATCO was not definitive about how the ratio would be affected by fluctuations in capital programs on an ongoing basis.

The Board therefore, does not accept ATCO's proposal for capitalization of administrative expense, and directs ATCO to adjust capital and O&M test year forecasts to reflect the re-instatement of the $6.5 million to Administration and General Expense. Further directions of the Board with respect to this issue are included in Section 4.2.9 of this Decision.

2.3.2 Meter Refurbishments

Views of ATCO

ATCO stated that in the 2001/2002 AGS GRA, the Board approved the proposal to capitalize the cost to repair meters and return them to service, on the basis of the rationale that refurbishments significantly extended the life of a meter and offset the requirement to purchase replacements.

ATCO indicated that meter refurbishments comprised two cost categories, the cost to repair the meter and the cost to return the meter to service. ATCO stated that the process of recalling a meter requires a single trip to the customer's premises where the existing meter was removed for testing and repair and on the same trip, a previously repaired meter was returned to service. ATCO noted that in the forecast of costs for the 2001/2002 GRA, the Company incorrectly included only the costs of the repair in its capital forecasts. In the 2003/2004 GRA forecast, however, ATCO corrected this error and included the costs of both repair and recall, resulting in an increase in costs to be capitalized.

ATCO noted that the 2003 test year forecast included the amount of $2.817 million of Meter Refurbishment costs, comprised of $1.673 million of repair costs and $1.114 million to return the meter to service plus $286,000 of removal costs. ATCO indicated that the 2004 forecast included $2.902 million of Meter Refurbishment costs, comprised of $1.724 million of repair costs and $1.178 million to return the meter to service, plus an additional $295,000 of removal costs. ATCO pointed out that, in the event that the Board does not approve the continued capitalization of some or all of these costs, the operations and maintenance forecast must be increased.

ATCO noted that the CG did not object to the principle of capitalizing costs associated with meter recall and meter refurbishment designed to extend life, but did indicate that the opening plant balances where these amounts had been capitalized should be reduced to reflect the fact that these amounts should not have been capitalized without explicit Board approval. ATCO noted that the Board approved the capitalization of the costs to repair meters and return them to service in Decision 2001-96 for the South, and that ATCO acknowledged the error in its forecast with respect to identifying the specific costs associated with these functions. ATCO also indicated that based on the 2001 return of 8.4% for the South, compared to the allowed return of 9.75%, it was obvious that there were other components of the forecast that ATCO did not get right, which went the other way.

ATCO also noted that the CG indicates that the Board should consider whether it was appropriate to commence the capitalization of meter recalls and refurbishments in the North in the year 2002. ATCO expressed significant disappointment with respect to this suggestion, referring to the response to BR-AG-63, which indicated that the appropriateness of this change in policy could be reviewed in the 2003/2004 GRA. ATCO submitted that the CG had the opportunity to do so through the submission of information requests, the filing of evidence and through cross-examination. ATCO noted that, while not one of these avenues was used, the CG in Argument was asking the Board to make a decision on a matter which up to this point had not been at issue, and on which the CG had limited knowledge. ATCO expressed concern that, once again, the CG was using Argument as an opportunity to introduce new evidence, and submitted that the Board must recognize the unfairness of this conduct and the flawed analysis upon which the Board was urged to base its decision.

ATCO noted that the CG also indicated though that the Board should direct the Company to file revisions to its code of accounts and related descriptions to reflect this change. ATCO indicated that it relies on the Uniform Code of Accounts as approved in AR 546/63, rather than any Company specific Code of Accounts.

Views of Calgary

Referring to the evidence of its expert witness, Mr. Kennedy and to the requirements of AR 546/63, Calgary submitted that the costs of the meter recalls should not be capitalized. Calgary indicated that, as pointed out in the discussion on Depreciation, ATCO's approach was neither consistent with the Regulation nor appropriate depreciation accounting.

Views of the CG

The CG noted ATCO's position that meter recall and refurbishment costs extended the life of meters and were therefore appropriately capitalized. The CG considered ATCO's explanation to be reasonable and therefore did not object to the principle of capitalizing costs associated with meter recall and meter refurbishment designed to extend life.

The CG was concerned that capitalization of these costs appeared contrary to the UCA for Gas utilities, which generally prescribe O&M treatment for this type of expenditure. The CG referred to discussion with ATCO's witness who explained that, while O&M treatment under Account 673 applied to refurbishment related expenditures that would help achieve the original expected life, he believed that refurbishment-related expenditures designed to extend the life of meters should be capitalized. The CG submitted that ATCO should be directed to refine its code of accounts so that there is clear distinction between the types of refurbishment expenditures that are life extension related and those that are maintenance related, and to file revisions to the code of accounts to reflect this recommendation, as part of its GRA refiling.

With respect to the North, the CG noted that there were clauses in the North Core Agreement applicable to this issue, and considered that the Board could make reference to the Agreement in its deliberations. The CG considered that any change in accounting policy must still be approved by the Board prior to implementation for AGN, and that customers would be harmed if the accounting change were approved for 2002 or if the increased capitalized amount was allowed to form the basis of 2003 account balances.

The CG considered it inappropriate to change accounting policies related to capitalization without explicit Board approval, and submitted that opening plant balances where these capitalized O&M amounts have been reflected should be reduced to reflect the recommendation that these amounts should not have been capitalized for 2001 and 2002.

Views of the Board

The Board notes that ATCO has taken the position that the Company was given Board approval to capitalize meter refurbishments and meter recalls in the AGS 2001-2002 GRA, and that as a consequence of that approval ATCO commenced capitalizing these activities in the North in 2002. The Board also notes ATCO's statement that the cost of meter recall had not been included in the AGS 2001-2002 GRA application, although that had been the Company's intent. However, the Board approved the capitalization of meter refurbishing in Decision 2001-96 on the understanding that it only included rebuilding the meter once it was in the shop. The Board cannot identify any reference in that GRA to the inclusion of meter recall in the capitalization proposal.

The Board disagrees with ATCO that any portion of the recall activity, i.e. transporting the meter to the customer's premise, exchanging the meter, returning the meter to the meter shop, testing the meter or painting the meter (recall), should be included in the amounts to be capitalized. In this respect, the Board notes that the UCA specifies that accounts 673 and 878 (the latter being now included in the 600 series accounts) are set aside for collection of O&M expense, and that activities expressly included are:

- Changing or exchanging meters and house regulators because of complaints or removal for inspection.
- Inspecting and testing meters on customer's premises or in shops in connection with repairs.
- Cleaning, repairing, and painting meters, and accessories and equipment.
- Rebuilding and overhauling meters without changing their rated capacities.
- Replacing diaphragms, springs and other defective or worn parts.

Notwithstanding the above description, and Calgary's comment that the capitalization is not in accordance with the UCA, the Board approved the refurbishment of meters in Decision 2001-96, consistent with the notion that the related activities would extend the life of the meter.

Based on the foregoing, the Board directs ATCO to eliminate from test year capital estimates all expenses related to the meter recall activity and to add these costs to the O&M estimates. The Board notes that the specific meter recall costs as identified in the response to BR-AG-63 are $1.43 million (2003) and $1.47 million (2004).

The Board agrees with the CG that there is a need to ensure that the Company specific code of accounts correctly reflects the policies and practices being used in connection with expenditures for meter refurbishment. The Board therefore, directs ATCO to refine its internal Code of Accounts to clearly distinguish between the types of expenditure related to meter refurbishment that relate to extension of the life of meters, and those related to maintenance.

With respect to the North, the Board notes ATCO's response to BR-AG-63, indicating that there was consensus during the 2002 negotiations that any clauses relating to this matter in the North Core Agreement would not prohibit ATCO from capitalizing these costs in 2002, and that the appropriateness of the policy change could be reviewed in the 2003/2004 GRA. The Board notes the comments of the CG with respect to the requirement for Board approval of the capitalization of meter refurbishments in the North, and agrees with ATCO that this issue should have been raised in evidence to facilitate discussion during the hearing. However, given the evidence of consensus for the change in the North Core negotiations, the Board accepts ATCO's proposal for capitalization of refurbishment costs in the North on a basis consistent with the approval for the South.

The Board notes the concern of the CG that where changes to capitalization policy have been put into effect prior to the test years without specific Board approval, opening plant balances for the test years should be adjusted to remove the effect of those changes. The Board agrees with the CG and accordingly, directs ATCO to revise 2003 opening plant balances to remove the costs of meter recalls capitalized prior to the test years.

The Board notes ATCO's comment that, in the 2001/2002 AGS GRA, the Company included only the costs of meter repair in capital forecasts, but subsequently adjusted the accounting records to incorporate the costs of meter recall. Given the Board's view that capitalization of meter recall is inappropriate, the Board agrees with ATCO that any costs excluded from test year capital forecasts should be added to O&M forecasts.

2.3.3 2002 Property, Plant and Equipment Closing Balances

Views of AUMA/EDM

AUMA/EDM considered that the best available information with respect to plant balances should be used to determine the rate base. AUMA/EDM indicated that as evidenced by a number of decisions (E89091, U97065 and 2001-96), actual closing balances from the year prior to the test year(s) had been used so as not to distort the opening balances for the test year when actual results were available. AUMA/EDM noted that interveners in those proceedings argued that this did not constitute a departure from prospective ratemaking. AUMA/EDM submitted that the ATCO 2002 actual closing balances of property, plant and equipment (PP&E) and accumulated depreciation should be used as the basis for determining 2003 and 2004 net plant-in-service.

Views of the CG

The CG expressed concern with the potential, as with projects forecast in 2001/02, for deferral beyond the test years. By way of example, the CG pointed out that the 2002 year-end net plant balance for AGS was forecast at $428 million compared to an actual balance of $419 million. The CG also referred to a significant under forecasting of net customer contributions of approximately $4 million. The CG submitted that the Board should consider these trends to make significant adjustments to the GRA forecasts.

Views of the Board

The Board agrees with the observations of AUMA/EDM and the CG that actual 2002 closing balances of PP&E should be used as the basis for determination of test year net plant-in-service, consistent with the findings in Decision 2001-96. The Board notes that actual closing balances for net plant and service were $3.746 million less than forecast in the North ($400.644 million minus $396.898 million), and $394,000 higher than forecast in the South ($418.743 million minus $419.137 million). As indicated in Decision 2001-96, the Board considers that use of forecast data distorts opening balances for the test period when actual results are available.

Accordingly, the Board directs ATCO to reduce the 2003 test year opening balance of net PP&E by $3.352 million ($3.746 million minus $394,000) to recognize actual balances at the end of 2002.

2.3.4 Summary of Board Adjustments and Approved Capital Additions

The following table sets out the Board adjustments made to the capital additions forecast by ATCO for the test years and described in this Section of the Decision. As indicated in the table, the Board will approve capital additions of $127.635 million (2003) and $121.613 million (2004), subject to Note 1 on the table.

Table 2. Summary of Board Adjustments and Approved Capital Additions

	(Millions)	
	2003	2004
Forecasts as applied for	$143.397	$138.870
Less: Reductions in forecasts for		
Urban Feeder Mains	$0.551	$0.556
New Regulating Meter Stations	$0.128	$0.119
Urban/Rural Main Extensions and Services	$0.662	$0.617
Regulating & Meter Station Improvements	$0.301	$0.297
Urban Main Replacement		$7.991
Residential Service Lines	$0.190	$0.207
Red Deer Operating Centre		$5.500
Sherwood Park Operating Centre	$6.000	($6.000)
Meter Refurbishments	$1.430	$1.470
Capitalization of O&M Expense	$6.500	$6.500
Total Reductions	$15.762	$17.257
Approved Capital Additions (Note 1)	$127.635	$121.613

Note 1: Approved Capital Additions do not reflect the impact of adjustments made by the Board to the MRRP Program. The reduction will need to be determined by ATCO after evaluation of the Board findings.

2.4 Necessary Working Capital

Views of ATCO

In the Application, the necessary working capital (NWC) requirement was forecast at[24] $125,349,000 (2003) and $121,090,000 (2004).

2.4.1 Lead/Lag Study and NWC Forecasts

Views of ATCO

ATCO indicated that only one lead/lag study was performed for the division as a whole, consistent with the request to be regulated as one utility. While acknowledging that there might be some minor differences in the timing of revenues and expenses between the North and the

[24] As per November 14, 2002 refiling.

South, ATCO did not view that they warranted the additional expense associated with performing separate studies for each of the North and South.

In the Application, the NWC forecasts were based on the results of a lead-lag study, which used the years 2000 and 2001 for the determination of the lag days. The majority of the revenue components were based on 2001 data, as the Company was able to use the new CIS system for collection of data. ATCO Pipelines (May to December, 2001) and ATCO Affiliate calculations were also based on 2001 data, as that year was more representative of the working capital relationship between ATCO Gas, ATCO Pipelines and the ATCO Affiliates. The remainder of the revenues and costs were analyzed based on 2000 data.

ATCO did not believe that applying the 2001 actual amounts against lags developed using 2000 information resulted in any significant impact on NWC or revenue requirement. ATCO however, submitted that, in the event that the Board did not approve a single revenue requirement, and viewed that separate lead/lag studies would be required in the future, the 2004 forecast revenue requirement should be increased by $20,000.

ATCO expressed some uncertainty with respect to the lag days referred to by Calgary with reference to the exclusion of short-term interest income from the determination of lag days. ATCO assumed that Calgary was indicating that short-term interest income should be excluded from the determination of NWC unless the income was included as a reduction to the overall revenue requirement. ATCO pointed out that the income was included as a reduction to the overall revenue requirement, and that the inclusion of short term interest income resulted in a reduction to working capital, as indicated on Schedule 2.7-A. ATCO failed to understand the concerns of Calgary with respect to this matter.

ATCO referred to a number of changes made to the calculation of cash and financing expenses for NWC in order to better reflect the Company's working capital requirements.

ATCO stated that, in the AGS 2001/2002 GRA, the Board directed AGS to recalculate the NWC balance using a zero lag for transactions with ATCO Pipelines and an expense lag for other affiliate payments no more or less than the lag for other O&M expenses.

However, ATCO pointed out that although ATCO Gas and ATCO Pipelines are divisions of the same company, they behave as if they are separate, legal entities, operating under a Master Services Agreement governing the provision of services between Gas and Pipelines. ATCO indicated that those services were charged on a fully allocated cost basis, the same as for other affiliates, and that the divisions had separate management and staff. ATCO indicated that their financial records were kept separate and distinct, and that commencing in 2003, Gas and Pipelines would be regulated completely separately. ATCO noted that one of the purposes of this segregation was to recognize the fact that each division served different customers, and that it would not be any more appropriate for ATCO Gas to exclude the transactions with ATCO Pipelines in its NWC requirement than it would be to exclude transactions with other affiliates, or charge services provided to ATCO Pipelines on a different basis from other affiliates. ATCO submitted that in order to ensure that the proper revenues and costs are reflected in the appropriate revenue requirement, the NWC must include the impact of transactions between ATCO Gas and ATCO Pipelines. ATCO considered that this would ensure that cross-subsidization between the customers of ATCO Gas and ATCO Pipelines did not occur. Furthermore, ATCO noted that Decision 2001-96 only addressed the lag associated with payments to ATCO Pipelines, ignoring the fact that ATCO Gas also receives revenue from ATCO Pipelines. ATCO submitted that there must be consistency in treatment between the revenue and expense lags related to ATCO Pipelines, a fact that appeared to have been overlooked in Decision 2001-96, which only addressed the expense lag.

ATCO therefore, included the lag days for ATCO Pipelines transactions as part of the Affiliate Payments component of O&M Expense Lag.

ATCO noted that in Decision 2001-96 the Board determined that the expense lag to be used for other affiliate payments was to be 34.16 days, the same as other operating expenses. ATCO pointed out that the comparable lag for other operating expenses, based on the current lead/lag study is 31.81 days, and the lag for other affiliate payments was 29.26 days (including ATCO Pipelines). ATCO pointed out that the impact on the NWC and revenue requirement of the difference between these two lags would be minimal, and considered that the more appropriate calculation of NWC was to include the proper lag for affiliate transactions. ATCO stated that the Company also receives revenues from other affiliates, and there was a revenue lag associated with other affiliate transactions. ATCO submitted that there must be consistency in treatment between the revenue and expense lags related to other affiliates, a fact that appeared to have been overlooked in Decision 2001-96, which only addressed the expense lag.

With respect to incorporating a lag for short term financing into the working capital, ATCO pointed out that the calculation of the lag was provided in response to CAL-AG-56(c). ATCO noted that no issues were raised with respect to this matter in evidence or cross-examination.

ATCO indicated that changes in the calculation of NWC adopted for the North were summarized in the response to AUMA/EDM-AG-2. ATCO pointed out that all the changes were based on changes approved for the South in previous Board decisions, and reflected the fact that the North NWC calculation had not been updated since the inception of the North Core Agreement.

With reference to the CG suggestion that Goods and Services Tax (GST) associated with capital expenditures should be excluded from working capital, ATCO noted that depreciation, interest, preferred shares and common equity all form part of the working capital calculation, and are all related to the capital expenditures. ATCO stated that the purpose of the GST working capital calculation was to address the timing differences between the receipt of GST on the revenue requirement of ATCO Gas and the date that GST was paid on expenditures. ATCO submitted that it would be inappropriate to leave the capital related revenue requirement portion of the GST calculation, but remove the capital expenditure portion. ATCO also noted that the CG did not submit this position in evidence, and did not ask any questions during cross-examination related to this matter. ATCO expressed concern that the first opportunity to address this apparent concern was in reply argument, and submitted that this was unfair and that the Board should take this into consideration when considering the comments of the CG on this matter.

Regarding the use of average monthly balances for gas storage NWC as suggested by Calgary and the CG, ATCO noted that no parties filed evidence on this matter, and no requests were submitted for a comparison of the NWC on this basis to the current method. Furthermore, ATCO noted that there was no discussion as to whether a 13-month average would be more appropriate than a 12-month average. ATCO submitted therefore that the issue was not properly canvassed, and that there was insufficient evidence on the record on which to base this recommendation. ATCO pointed out that there were also other items included in NWC that rely on the mid-year convention, such as deferred hearing costs and materials and supplies inventory, and that it would be inappropriate to focus only on gas storage NWC to determine whether or not a monthly average would be more appropriate.

ATCO noted that AUMA/EDM indicated that the Company was charging costs to the deferred hearing account that had not been approved, and in some instances had not been paid. ATCO addressed the first matter in Section 4.2.6 of this Decision. Regarding the second matter, ATCO stated that costs that had not been paid are not charged to the hearing account. ATCO noted AUMA/EDM's suggestion that, as the ATCO Affiliate proceeding and Carbon Storage Transfer cost orders had not yet been issued, the Board should remove those amounts from the deferred hearing account balances for NWC purposes. ATCO submitted that, once again, AUMA/EDM had selectively chosen the information they had become aware of since the filing of the Application that the Board should consider, and the information that should be ignored.

While ATCO had not received a cost order with respect to those proceedings, ATCO did pay out amounts in 2002 related to other proceedings that either were not forecast, or were higher than forecast, as discussed in Exhibit 14-10a. ATCO considered that it would be inappropriate for the Board to focus only on the two proceedings identified by AUMA/EDM while ignoring other payments made from the hearing account. ATCO stated that, furthermore, if the Board viewed that an adjustment to the opening balance for deferred hearing costs was appropriate, ATCO needed to be afforded the opportunity to adjust its forecast of hearing cost payments in the test years as a result of information that the Company was now aware of, such as the Generic Cost of Capital proceeding. ATCO submitted that the net effect of all of these changes on the NWC and the revenue requirement forecast would likely be negligible.

ATCO pointed out that inclusion of the deferred pension account in working capital was agreed to in the Pension Negotiated Settlement. ATCO stated that it continued to recognize pension and post employment expense on a cash basis in the current GRA, consistent with the treatment agreed to in the Pension Settlement, and that no parties had taken issue with this. ATCO submitted therefore that it was inappropriate for the CG to suggest (for the first time in this proceeding) that the working capital treatment of the deferred pension receivable balance be changed.

Views of Calgary

Calgary submitted that the lead lag study and in particular, the amounts related to ATCO Pipelines and other affiliates, should reflect Decision 2001-96 and that ATCO should be directed to comply with that Decision in its compliance filing. Calgary considered that the short-term interest income should be excluded from the determination of the lag days, unless the income was included as a reduction to the overall revenue requirement.

Calgary noted that there were inconsistencies in the calculation of certain of the working capital components. By way of example, Calgary indicated that for the Payment and Equalization Plan, ATCO used an average of the monthly balances whereas for items such as gas storage a mid year balance was used. Calgary recommended that both be calculated on the basis of monthly averages.

Views of the CG

The CG referred to ATCO's statement that, if a single revenue requirement was not approved and separate lead/lag studies were deemed necessary in the future, the 2004 forecast revenue requirement should be increased by $20,000.

The CG submitted that separate lead lag studies were not required as there were generally uniform policies and practices with regard to timing of cash inflows and outflows for AGN and AGS. Accordingly, the CG considered the need for two separate lead lag studies should not be cited as a reason for prematurely merging the AGN and AGS revenue requirements.

The CG referred to the inclusion of $1.5 million (2003) and $1.4 million (2004) as the GST components of NWC, noting that ATCO included GST related to capital expenditures in the calculation. The CG submitted that NWC should reflect GST associated with components of revenue requirement only, noting that the NWC calculation does not normally recognize any items related to capital expenditures, including any lag on payment of vendor invoices. The CG considered it inappropriate therefore to recognize the GST associated with capital expenditures in NWC without recognizing the lag associated with payment of supplier invoices for capital items. Consequently, the CG submitted that GST associated with capital expenditures should properly be excluded from the GST working capital calculation.

The CG noted that ATCO calculated the natural gas inventory component of working capital using the mid-year convention, whereas on the other hand, used the 13-month average to calculate the payment equalization or budget plan component of working capital. The CG noted ATCO's comment that with respect to the budget plan, a pattern could be seen of an increasing balance over an extended period of time, whereas with respect to the storage, there tended to be up-and-down fluctuations at fairly close intervals.

The CG agreed that the response to CG-AG-42 did show a pattern for natural gas inventory balances. Specifically, the CG noted that the inventory value tends to peak towards the beginning of the gas storage year, in November, and troughs in March. The CG submitted that the inventory balances changed quite significantly from month to month, based on which the average investment in gas inventory was better represented by the average of 13 monthly balances, as opposed to the average of the year end balances. Therefore, the CG recommended that the Company be directed to change its method of calculating the gas inventory component of NWC from a mid year method to a method based on the average of 13 months. The CG calculated that as a result, the gas inventory amount included in NWC would change as follows:

Table 3. Comparison of Gas Inventory for NWC

	2003	2004
Per ATCO Gas Proposed (Mid Year Method)	$66.1 million	$69.6 million
Per CG Recommendation (13 Month Average)	$51.2 million	$50.9 million

The CG also expressed concern with the balance of the Deferred Pension account, noting that, rather than decreasing, the balance appears to be set at $16,000,000. The CG indicated that the issue was the fact ATCO was receiving an effective weighted cost of capital return on the account balance, while the estimated return in the pension plan was only 7%. The CG also noted that the account balance was not being amortized against reduced contribution requirements for the defined pension plan because of the surplus, and submitted that it was reasonable for the balance of the Pension Deferral to receive the return estimated for the defined benefit pension plan.

Views of AUMA/EDM

AUMA/EDM referred to the of details of hearing costs paid or payable from 2000 through 2004 provided in response to CG-AG-85(a), used to determine the Deferred Hearing Costs balance included in the NWC forecast.

AUMA/EDM noted that the costs of the ATCO Affiliates and Carbon Transfer proceedings relating to 2001 and 2002 totaling approximately $3.6 million, represented amounts paid to ATCO's external consultants and counsel and forecast of remaining intervener costs.

AUMA/EDM expressed concern that costs had been charged to this account, which had not been approved and, in some instances, not yet paid by ATCO. AUMA/EDM indicated that it was clear from the Board's cost orders that, as a matter of practice, no amounts were to be charged to a Hearing Cost Reserve account unless and until the individual cost claims had been reviewed and deemed reasonably incurred. AUMA/EDM submitted that the 2003 NWC opening balance should be reduced by $3.6 million and appropriate adjustments made to the 2003 closing balance as well as the opening and closing balances for 2004 in ATCO's refiling. AUMA/EDM calculated that this would result in a reduction in the 2003 revenue requirement of approximately $200,000.

Views of the Board

The Board notes Calgary's concern that short-term interest income should be excluded from the determination of lag days, unless the income is included as a reduction to revenue requirement. The Board agrees with ATCO's submission that short-term interest income is included as a reduction to overall revenue requirement, and that on this basis it is correctly included in the determination of lag days.

With respect to the CG's submission that GST associated with capital expenditures should be excluded from the NWC calculation, the Board acknowledges ATCO's position that other capital-related items, such as depreciation, interest, preferred shares and common equity all form part of the determination of NWC. The Board agrees with ATCO that it is appropriate to reflect the impact of all items of a capital nature in the determination of NWC.

The Board notes the comments of the CG that, even if the Board does not approve a single revenue requirement, separate lead/lag studies need not necessarily be done, since Company policies are generally uniform with respect to timing of cash inflows and outflows. The Board agrees with the CG and considers the combined lead/lag study appropriate for application to the separate revenue requirements of North and South.

In Decision 2001-96, the Board directed ATCO to incorporate a zero expense lag for transactions with ATCO Pipelines and a lag for other affiliate payments equal to the lag for other O&M Expenses on the basis that there was no reason why the lag for affiliate payments should be any less than the lag relating to payments for arms length transactions.

The Board notes that, in the Application, ATCO has calculated a lag for transactions with affiliates independently from the lag for other O&M transactions, and has included the lag for

ATCO Pipelines in the determination of the affiliate lag. With respect to transactions with ATCO Pipelines, the Board notes ATCO's position that, although ATCO Pipelines and ATCO are divisions of the same company, they behave like separate legal entities, and operate under agreements governing services in the same manner as other affiliates.

The Board however, acknowledges Calgary's submission that the lead lag study and in particular, the amounts related to ATCO Pipelines, should reflect the Board's findings in Decision 2001-96. The Board is not persuaded that the rationale supporting ATCO's treatment of ATCO Pipelines is sufficiently different from that presented in the AGS 2001/2002 GRA, with respect to any changes in cash flow, and agrees with Calgary that ATCO should be directed to comply with Decision 2001-96 in its Refiling.

Accordingly, the Board directs ATCO, in its Refiling, to revise the calculation of lag days for transactions with ATCO Pipelines to reflect the findings in Decision 2001-96. The Board however, accepts ATCO's submission that the lead/lag study should reflect the fact that the Company also receives revenues from ATCO Pipelines.

With respect to transactions with other Affiliates, the Board accepts ATCO's position that there is a need to determine the lag independently from the lag calculated for other O&M transactions, particularly given that transactions with other Affiliates encompass both revenue and expense transactions in contrast to transactions with arms length entities.

However, while accepting ATCO's proposals for dealing with this issue, the Board is concerned that ATCO chose to reflect the revised methodology in the Application, rather than presenting the NWC study on the basis of the approved methodology, and requesting Board consideration of the proposed revision.

The Board notes the concern of the CG and Calgary with ATCO's use of a mid-year balance rather than a 13-month average for calculation of the natural gas inventory component of NWC.

While the Board acknowledges ATCO's submission that this issue was not properly canvassed during the hearing and that there are other items included in NWC that rely on a mid-year convention, the Board considers that the volatility in natural gas storage balances is particularly significant.

The Board has examined the information filed in response to CG-AG-42, which shows clearly that inventory balances tend to peak significantly towards the beginning of the storage year in November and trough in March. On this basis, the Board considers that calculation of natural gas inventory balances on the basis of a monthly average for NWC purposes may be more appropriate than the use of a mid year methodology, and consistent with the methodology used for the PEP program. However, the Board recognizes that the natural gas inventory balance has been determined on the basis of the mid-year methodology for some time, and acknowledges ATCO's concern that the issue was not sufficiently canvassed during the proceedings to warrant a change in methodology at this time.

Accordingly, while accepting the natural gas inventory balances included in the NWC balance for the test years, the Board directs ATCO at the next GRA, to recalculate the NWC balances of natural gas stored, materials and supplies and the PEP program on a consistent basis. The Board expects that ATCO will propose that consistency will be achieved by adoption of a monthly average methodology, or indicate why this should not be done.

The Board notes AUMA/EDM's observation that ATCO should not include the projected costs of the ATCO Affiliates and ATCO Carbon Transfer proceedings in the Deferred Hearing Account on the basis that these costs had not been approved by the Board, and except for costs for ATCO's external consultants, had not been paid. Specifically, AUMA/EDM suggested the reduction of the deferred account balance to recognize exclusion of $3.6 million relating to 2001 and 2002 with respect to these proceedings.

While accepting ATCO's submission that it is not reasonable to focus attention on the impact of particular proceedings without consideration of payments made or likely to be made with respect to other proceedings, the Board agrees with the AUMA/EDM that a significant component of the deferred hearing balance included in the test year forecasts, represents estimated costs for which cost claims have not yet been dealt with by the Board. The Board recognizes that this condition is somewhat unique given the large number of proceedings for which cost claims have been generated in the last few years. The Board also recognizes however, that this issue was not subject to a significant degree of discussion during the proceedings.

Accordingly, while accepting the deferred hearing account balances included in NWC for the test years, the Board directs ATCO to re-evaluate the methodology for the deferred hearing cost component of NWC and provide, at the next GRA, detailed explanation and support for the methodology proposed, including the rationale for inclusion of all major items comprising the deferred hearing account balances.

3 COST OF CAPITAL

3.1 Appropriate Return on Equity

Views of ATCO

ATCO noted that the most recent Decision related to rate of return on equity (ROE) for AGS was Decision 2001-96, which determined that the fair rate of return on common equity for AGS for the 2001/2002 period was 9.75% based upon a forecast long Canada Rate of 6.0% and an equity risk premium of 3.75%.

ATCO noted that the equity risk premium of 375 basis points determined in Decision 2001-96 was based upon the Board's review of the evidence tabled in the 2001/2002 proceeding. Based on its review, the Board concluded that there was no evidence supporting a higher risk premium than that previously awarded in Decision 2000-9. ATCO noted that Decision 2000-9 determined the fair rate of return for the years 1997 and 1998 based upon an equity risk premium of 3.75%.

However, ATCO submitted that there had been significant changes in financial markets since the equity risk premium was determined for 1997/98, which indicated that an increase in the equity risk premium was warranted.

ATCO submitted that the rate of return component of the Application posed special challenges in this GRA as a result of the Board's comments in Decisions 2002-096[25] and 2002-097.[26] Those decisions and the related Cost Orders UCO 2002-69[27] and 2002-70[28] expressed serious reservations about the traditional manner of approaching this issue.

ATCO attempted to avoid incurring the significant costs associated with the presentation of expert testimony regarding rate of return issues, and given the Board's clearly expressed concerns, chose not to approach this important subject in the traditional way. Rather, ATCO sought to build upon those components of the Board's most recent decision with an adjustment that would reflect observable and verifiable changes in the market's perception of the difference between the risk of utilities' securities relative to long-term government bonds. ATCO noted that its methodology added to the previously determined equity risk premium an additional increment which reflects the changes in the observed risk between the only risk-free marker generally accepted to exist – long Canada Bonds – with the only directly observable indicator of the relative change in cost of equity of utilities which is the yield on comparable utility bonds. At the same time, ATCO noted there are several difficulties with determining the fair rate of return using the equity risk premium.

ATCO indicated that the challenge for setting rate of return for regulated utilities is that there is no observable, verifiable single standard for a "true" equity rate of return in the market. While various proxies traditionally have been explored to arrive at such a "true" rate of return, they are contentious and consume significant amounts of time and resources in light of unique circumstances of the individual utilities. ATCO considered that all experts and commentators agree that the only identifiable verifiable risk free rate is the long Canada Bond, the problem being however, that the benchmark has changed in response to a variety of financial market conditions.

ATCO submitted that the point of its evidence was whether or not the changes in that rate represented a sufficient basis upon which to determine a fair return for utilities, whose securities might have been differently affected by financial market conditions. In the Company's view, simply adding an equity risk premium calculated in the manner approved by the Board, would fall short of fair compensation to the utility. ATCO argued that this was true when one considers the substantial widening of the only other observable, verifiable market benchmark of the relative risk of utilities, namely the yields on their comparable corporate bonds.

ATCO submitted that its approach in this case answered many of these criticisms. Given the Board's predisposition to rely upon the equity risk premium test, ATCO reviewed the changes in the financial markets since the Board's review of the risk premium in Decision 2000-9. In order to establish the recommended equity risk premium, ATCO provided evidence that the spread between long-term Government of Canada Bonds (long Canada Bonds or long Canadas or GOC Bonds) and Utility Debentures had increased by 85 to 100 basis points between 1997 and June

[25] Decision 2002-096 – ATCO Pipelines South, 2001/2002 General Rate Application, and Part A: Asset Transfer, Outsourcing Arrangements, and GRA Issues – Compliance Filing, dated November 19, 2002

[26] Decision 2002-097 – ATCO Gas South, 2001/2002 General Rate Application, Carbon Storage Transfer and Part A: Asset Transfer, Outsourcing Arrangements, and GRA Issues – Compliance Filing, dated November 19, 2002

[27] Utility Cost Order 2002-69 – ATCO Gas South, 2001/2002 General Rate Application, Phase I, dated October 11, 2002

[28] Utility Cost Order 2002-70 – ATCO Gas and Pipelines South Ltd., 2001/2002 General Rate Application, Phases I and II, dated October 11, 2002

2002. ATCO submitted that this trend demonstrated that the financial markets had changed since 1997, such that investors in Utility Bonds required an additional 85 to 100 basis points increased spread relative to long Canada Bonds. Based upon this increased investors' risk/reward requirement and the premise that the rate of return and equity risk premium awarded by the Board in Decision 2000-9 was fair and reasonable, the equity risk premium for 2003 and 2004 should be 460 to 475 basis points.

With respect to the risk free rate, ATCO submitted that the forecast 10-year long Canada Bond from the June 2002 Consensus Forecast was 6.10%. Adding the 30 basis point normal spread between 10-year and 30-year long Canada Bonds would result in a forecast long Canada Bond of 6.40%.

Based on a forecast risk free rate of 6.40% and an equity risk premium of 4.60% (representing the lower end of the recommended range), ATCO's analysis indicated that a fair rate of return for 2003 and 2004 would be 11.0%. Accordingly, ATCO applied for a fair rate of return on common equity of 11.0%.

Justifying use of the June 2002 Consensus Forecast for 10-year long Canadas, ATCO pointed out that, while later forecasts including some completed in 2003 were available, it was contrary to prospective ratemaking to use them. ATCO considered that if the Board were to rely upon that later data, however, it should also make reference to the NEB approach to the spread between 10-year and 30-year Canada's, which had increased to 48 basis points. That adjustment would result in a rate anywhere between 6.2% and 6.7%.

ATCO noted that Calgary did not take issue with the underlying premise of the Company's methodology, only the specific data relied on to apply it. ATCO indicated that the non-comparability of the use of shorter-term bonds was clearly rebutted by the Company. Equally, the critique based upon the spreads observable under split ratings did not show the bias as suggested by Mr. McCormick. ATCO submitted that the Company's evidence showed that if only bonds which had been rated A throughout the period of analysis were used, the increase in spread was 94 basis points, compared to the 85-100 basis points cited by ATCO for a broader sample of utilities.

ATCO noted that the evidence sponsored by Drs. Booth and Berkowitz raised technical issues, which were beyond the capability of Company witnesses to deal with, so the Company sponsored Ms. McShane to reply with respect to those technical issues.

ATCO noted that Ms. McShane's evidence indicated that a beta of 0.50 as estimated by Drs. Booth and Berkowitz significantly understated the relative risk of an average risk Canadian local distribution company (LDC) like ATCO and therefore its equity return requirement. ATCO indicated that Ms. McShane believed that the appropriate range for beta was 0.60 to 0.65. ATCO submitted that this range was reasonable in light of the observed long-run average beta for the gas and electricity sub index in the TSE 300, which was 0.62, a fact observed as well by the Calgary witnesses.

With respect to the market risk premium, Ms. McShane contended that the sample period was somewhat distorted and placed too little weight on US market premiums resulting in an underestimation by approximately 1.5%. Similarly, Ms. McShane contended that the Booth and

Berkowitz application of their multi-factor model was of little or no use to the Board in estimating expected returns.

ATCO noted that Drs. Booth and Berkowitz increased their recommended ROE to 8.5% in the present GRA compared to 8.25% in the last GRA, for an increase of 25 basis points. However, they agreed that the long Canada forecast is 6% versus 5.75% at the time of the last GRA, which is itself an increase of 25 basis points. ATCO noted that, further, in the current GRA they increased their initial equity return estimate from 7.85% to 8.50%, which was equivalent to an "add on" of 65 basis points.

ATCO noted that Messrs Booth and Berkowitz identified a much broader range for the betas, 0.45 to 0.55, for a mid-point of 50, whereas in the last GRA the recommendation was a much narrower range of 0.50 to 0.54, for a mid-point of 0.52. ATCO noted that the effect of that larger range was to reduce the ROE by about 10 basis points.

In addition, ATCO noted that Drs. Booth and Berkowitz gave 50% weight to the multi-factor model, whose results were biased downward by the distortions caused by the stock market "boom and bust." The results of this model, using data through 2001 and a 6% long Canada yield, were in the range of 7.32-7.54%. By comparison, the model, as used during the 2001/2002 GRA, using data only through 1999 and a lower long Canada yield (5.75%), gave a result of 7.68-8.13%, almost 50 basis points higher despite the lower long Canada yield at the time. ATCO noted that using their current forecast long Canada yield of 6%, the model results were 75 basis points higher when the 2000-2001 data was excluded. Drs. Booth and Berkowitz's response was to add 15 basis points to their cost of equity to recognize the problems of the recent market data, despite the fact that the market distortions reduced the model results by close to 75 basis points.

ATCO noted that Drs. Booth and Berkowitz rejected recent betas in their classic Capital Asset Pricing Model (CAPM) model due to the distortions brought about by Nortel and the internet bubble, and chose not to use the instrumental variables model for the same reason. ATCO indicated that for these same reasons, the multi-factor model should be rejected.

ATCO further noted that the 12- point difference between the observed long-run average beta and the Booth and Berkowitz recommendation times the market risk premium (4.5%) equated to a difference of 0.54%. ATCO submitted that this was a material underestimation of a fair and balanced rate of return.

ATCO submitted that the Board should prefer an objective, observable and verifiable measure of the relative risk of utilities securities to the conventional risk-free benchmark. ATCO stated that in the absence of a generally accepted benchmark for measuring the change in fair and reasonable equity returns from one period to a subsequent period, the spread between utility debentures and long Canada Bonds was the best proxy. ATCO considered that relationship to be supported by financial theory and by many other methodologies which rely upon long Canadas as a risk-free starting point.

ATCO submitted that failure to reflect the fact of the market's assessment of relative risk and the determination of a fair and reasonable rate of return would render the result arbitrary. As a result, ATCO urged the Board to supplement its traditional approach in determining the fair rate of return. In this regard, the evidence before the Board was that the change in market's perception of relative risk implied an 11% rate of return, based upon the forecast available at the time of filing the Application.

ATCO expressed concern with interveners' reliance on forecasts prepared within the test period as opposed to judging the reasonableness of forecasts contained in the Application. ATCO cited the example of the misrepresentation of Ms. McShane's evidence with respect to the forecast long Canada Bond rate of 6.40%. ATCO pointed out that, while various interveners contended that Ms. McShane supported a 6% rate, they neglected to acknowledge the qualifier that her 6% rate was based upon a different forecast at a different point in time.

ATCO submitted that the Board should note, however, that Ms. McShane did not support a 6% rate, but stated that the current forecast was in the range of 6 – 6¼%. As stated on previous occasions, ATCO believed that reliance on 2003 information was contrary to prospective ratemaking and procedurally unfair. ATCO stated that, if the Board was going to rely on such 2003 evidence, then fairness dictated that the Company should be permitted to identify other updated information, which could have the effect of increasing the revenue requirement. ATCO pointed out that one such adjustment would be the NEB's most recent calculation of the spread between 10-year and 30-year Canada's, which had increased to 48 basis points. ATCO noted that that adjustment would result in a long Canada rate anywhere between 6.2% and 6.7%. As a result, ATCO argued that reliance on the forecast prepared in 2003 should only be permitted if ATCO was also able to update additional factors.

With respect to the approach recommended by ATCO and the adjustment it would make over and above the simple Equity Risk Premium approach, ATCO noted the claim of several interveners that there was no academic or other support for the Company proposal. ATCO indicated that, as a matter of process, the Company's evidence was filed approximately mid-year 2002. ATCO submitted that interveners had ample opportunity to ask questions and to provide their own evidence if they took issue with the theoretical underpinnings of the Company's approach. ATCO indicated that no evidence was adduced to indicate that the approach was flawed on a theoretical basis. Further, after reviewing the ATCO approach, Mr. McCormick concluded that although he disagreed with the application of the methodology, it was "both similar and different" to the NEB adjustment mechanism.

ATCO submitted that Ms. McShane stated that there was academic support for the theoretical approach adopted by the Company, notwithstanding the fact that she herself was not involved in providing advice in that respect. ATCO indicated that the fact that Ms. McShane had not presented any evidence that was similar to the Company's approach did not mark a deficiency in that approach. ATCO noted that Ms. McShane also testified that the approach that the Company took to looking at the spread between long Canada to utility debentures and using that as a methodology for adjusting the equity-risk premium represented a viable approach.

ATCO stated that, with respect to the comparability of U.S. LDC and Canadian LDC returns, Ms. McShane confirmed that the Canadian utilities had comparable risk profiles to U.S. utilities. ATCO noted that it did not request that Ms. McShane identify a specific "fair return, " but submitted that the fact remained that the evidence was not contradicted that comparability between U.S. LDC investment and Canadian LDC investment had been demonstrated. ATCO indicated that the evidence was clear that the returns in Alberta needed to be increased significantly to recognize what had changed elsewhere in the capital markets.

ATCO disagreed with Calgary's suggestion that the Company's evidence was flawed in assumptions and analysis. ATCO stated that firstly, the issue of whether the change in utility debenture spreads widened as a result of the impact of non-regulated operations was not relevant to the analysis. ATCO pointed out that the analysis proved that for "A" rated utilities, the required debenture spread over long Canadas had increased by 85 to 100 basis points and as a result the fair return required by investors had also increased.

Secondly, ATCO stated that the concern Calgary raised over the utilities contained in the sample represented a red herring. ATCO responded that the fact that CBRS discontinued its A-rated utility data series in 2000 was unfortunate, but the utility sample maintained by Foster Associates was comparable to CBRS data series and the resulting 85 to 100 basis points increase in the utility debenture spread was real. This was confirmed in the Rebuttal Evidence, which showed that the indicative 30-year new issue spreads on four "A" rated utilities had widened by 94 basis points over the period 1997 to February 2003.

Thirdly, ATCO submitted that the claim by Calgary that 1997 was selected as the starting point because it was the low point in a cycle was false. As was explained in the Application and Rebuttal Evidence, 1997 was selected as the starting point because it was the last year for which the Board completed a "full" review of the fair rate of return.

Finally, with respect to whether a one-to-one relationship existed between the widening of the utility debenture spread and the equity risk premium, ATCO argued that Calgary appeared to ignore the Board's previous determinations on this matter. In two previous decisions the Board indicated that there was insufficient evidence to establish an inverse relationship between interest rates and the equity risk premium. ATCO further noted that no Calgary evidence was produced to refute the direct relationship between the utility debenture spread and the equity risk premium. Calgary's argument that the NEB and British Columbia Utilities Commission (BCUC) formula was evidence of an inverse relationship was a circular argument, but was not evidence. As a result, ATCO submitted that there was no evidence that supported anything except a one-to-one relationship between the utility debenture spread and the equity risk premium.

With respect to the CG's suggestion that there needed to be adjustments to the ATCO ROE in 2004 to track adjustments to the risk free rate, ATCO noted that there was no discussion of this proposal at the hearing. In addition, there was a lack of any evidentiary support for such a proposal. ATCO further argued that focusing solely upon one variable was flawed when it is widely acknowledged that "fair return" involves consideration of numerous variables.

Views of AUMA/EDM

AUMA/EDM noted that in the AGS 2001/2002 GRA, the Board determined that the fair rate of return on common equity should be set at 9.75%, based upon a forecast long Canada rate of 6.0% and an equity-risk premium, inclusive of flotation, of 375 basis points. AUMA/EDM noted that in the Application, ATCO applied for a fair rate of return on common equity of 11.0% for 2003 and 2004, based on "significant changes in financial markets since the equity risk premium was determined for 1997/98."

AUMA/EDM noted that the changes to which ATCO referred related to the fluctuation in spread between the yields on long Canadas and Canadian A-rated utility debentures during the period 1997 to June 2002. AUMA/EDM submitted that the relevance of these changes to investors' expectations regarding equity returns was illusory and did not stand up to scrutiny. AUMA/EDM noted that ATCO's position was that if the spread between the long Canada Bonds and utility debentures has widened then the equity risk premium between long Canada Bonds and fair rate of return on utility common shares should also have increased. AUMA/EDM argued that this position could not be substantiated and did not appear to be a concept that had ever been considered by the Board in arriving at a fair rate of return for a regulated utility. In addition, AUMA/EDM submitted that ATCO's position did not justify an increase in return of 125 basis points from the last approved rate.

AUMA/EDM noted that ATCO's position was based on the data set forth in the table at page 3.1-3 of the Application, which indicated that ATCO took the increase in spread of 85 to 100 basis points between 1997 and today and factored this into its recommendation. AUMA/EDM submitted that this factor had little, if any, relevance and was not something considered by other rate of return consultants appearing before this Board, including ATCO's rate of return consultant, Ms. McShane. AUMA/EDM stated that even if the data provided was relevant, it was at best, selective for several reasons.

AUMA/EDM noted that the starting point or base year of ATCO's evidence, that being 1997, was the year of the lowest spread in the 13-year period 1990 to 2002. Next, although the most recent spread shown on the table (for June 2002) was 1.36%, the average spread for the 6-year period was 1.0%. In addition, spreads for the period prior to 1997 were actually higher than for the years selected for that table. Finally, AUMA/EDM noted that during this period, the yield on Canadian A-rated utility debentures moved a total of only 9 basis points (from 6.94% to 7.03%) while the yield on long Canadas moved by a total of 75 basis points (from 6.42% to 5.76%). AUMA/EDM stated that, if anything, the latter point should be indicative of the fact that investors had not abandoned utility debentures as an investment option.

AUMA/EDM submitted that, to the extent the Board considered that the data contained in the table at page 3.1-3 of the Application had any relevance, its use in this proceeding should be limited to the changes which had occurred since the Board last reviewed the return on common equity for AGS (being the AGS 2001/2002 GRA). AUMA/EDM noted that the table referred to actually showed a reduction in spread of 23 basis points (7.26% - 7.03% = .23%) from that point in time to the current date shown, being June 2002. Thus, to the extent that this information was relevant, this would justify a return of only 9.5%.

AUMA/EDM noted that all of the data on which ATCO relied for determining its recommended equity risk premium for 2003 and 2004 was based on historical information and, as a result, was not reflective of investor's expectations.

As a result, AUMA/EDM submitted that, in addressing issues relating to ROE, the Board needed to be cognizant of the fact that ATCO chose to put forward a novel, but previously untested, methodology. AUMA/EDM indicated that the Company had not presented any direct evidence regarding the generally accepted tests for determining a fair ROE, reflected in the equity risk premium, DCF or comparable earnings models. The evidence of its expert witness, Ms. McShane, was presented solely for the purpose of rebutting the evidence of Calgary expert witnesses, Drs. Booth and Berkowitz. AUMA/EDM noted that, other than challenging the data which they provided, and the manner in which it was used, Ms. McShane made no recommendations of her own. Also, although her firm assisted in preparing the data on which ATCO relied, she did not appear to endorse the methodology used or the conclusions it reached.

AUMA/EDM expressed support for the evidence and endorsed the conclusions on ROE of Calgary's expert witnesses, Drs. Booth and Berkowitz.

AUMA/EDM considered that the additional increment, as calculated by ATCO, represented 85 to 100 basis points to reflect the change in spread between the yields on long Canada Bonds and Canadian A-rated Utility debentures. AUMA/EDM submitted that the concept of an add-on for this particular purpose did not appear to be used or endorsed by any of the witnesses currently appearing before the Board.

AUMA/EDM further submitted that there was no evidence to suggest that investors' expectations of common equity return for a regulated utility was in any way related to the yields on utility debentures. Specifically, ATCO did not provide anything of consequence to demonstrate the linkage between experienced yields on utility debentures and investors' return expectations on utility common equity. In addition, AUMA/EDM stated that there was no evidence to support the suggestion that the relationship related to the spread between utility debentures and long Canada Bonds had any basis in financial theory, or was even relevant to determining rate of ROE. As a result, ATCO's recommended rate of return was not realistic in the current market.

AUMA/EDM noted ATCO's position that simply adding an equity risk premium calculated in the manner "approved by this Board," would fall short of fair compensation to the utility. AUMA/EDM submitted that this statement was not supported by the evidence. Further, AUMA/EDM emphasized that its regular Rate of Return and Capital Structure witness, Ms. McShane, continued to use the methodology approved by the Board in her equity risk premium analyses, and that regardless of her conclusions, she did not include an "additional increment".

AUMA/EDM noted that ATCO's add-on of 85 to 100 basis points represented the historical change in spread between yields on long Canada bonds and utility debentures during the period 1997 to 2001/2002. AUMA/EDM submitted that even if this add-on were appropriate, the period selected was inappropriate and unnecessarily short. By comparison, AUMA/EDM observed that Ms. McShane employed calculations of Canadian risk premiums covering the period 1947 to 1999. AUMA/EDM further noted that the rate-of-return consultant whom Mr. Edmondson claimed supported his reliance on long-term utility debentures, Dr. Roger A. Morin, stated that a period covering a minimum span of 25 years should be employed when dealing with historical returns.[29]

AUMA/EDM argued that, even if this methodology were to be adopted by the Board, the data supplied represented a short-term downward trend in yields on Canadian long-term bonds, which resulted from what was described as a "flight to quality." AUMA/EDM noted that the response to CAL-AG-6(c) confirmed that the base or starting point for the data, being 1997, represented the year of the lowest spread during the thirteen year period 1990 to 2002 and a period during which there was an unprecedented decline in yields on long Canadas.

AUMA/EDM submitted that the related table provided by ATCO in the Application simply confirmed that yields on Canadian long-term bonds had declined since 1997 and by implication

[29] Text, Utilities' Cost of Capital, o. 172.

that investors' expectations had similarly reduced. However, AUMA/EDM considered that this table did not justify the view that utility investors' return expectations for A-rated utility equities had increased.

AUMA/EDM noted that, in an attempt to justify a significantly higher return, ATCO raised the question: "What should the regulated ATCO utilities do if Standard & Poor's (S&P) follows through on its threat to require CU Inc. to decrease its leverage?". AUMA/EDM responded that it should be noted, firstly, that the "list of the issuers with ratings that are most likely to be affected by this review" did not include CU Inc. Secondly, S&P indicated that "…some or all of the ratings listed below could end up remaining at their current levels" and, of the 15 utilities listed, ATCO Ltd. enjoyed the highest credit rating.

AUMA/EDM noted that ATCO had requested an equity risk premium of 460 to 475 basis points, whereas Ms. McShane recommended a risk premium of 4.25% - 4.5% in the AGS 2001/2002 GRA. AUMA/EDM submitted that ATCO's evidence and resulting recommendation should be disregarded in favor of Calgary witnesses, Drs. Booth and Berkowitz.

Views of Calgary

As noted in Calgary's Evidence, its evidence with respect to cost of capital was influenced by several factors:

1) The evidence of ATCO Gas, which utilized internal evidence on matters such as risk, debt costs, capital structure and return on common equity.
2) The filing by ATCO Electric of its 2003 – 2005 General Tariff Application (GTA), which utilized essentially the same cost of capital evidence as ATCO Gas.
3) The filing of AltaLink's 2002/2003 – 2003/2004 GTA utilizing a combination of internal evidence on matters such as risk and debt costs, and external evidence from Dr. Evans on capital structure and ROE, and from Mr. Carmichael on financing costs.
4) The anticipated filings of an ATCO Pipelines GRA and an EPCOR GTA in the near future. These proceedings would require cost of capital evidence.
5) The Calgary application to the Board for a Generic Cost of Capital Proceeding. The Board's first Notice with respect to the Generic hearing was issued prior to information requests being sent to ATCO Gas, and the matter was still under consideration by the Board when intervener evidence was filed.
6) Comments from the Board in Decisions 2001-096 and 97 on the ATCO Gas and ATCO Pipelines 2001/2002 GRAs (and the related Costs Orders 2002-069 and 070) with respect to the cost of capital evidence presented to it in those proceedings.

With respect to the first and last factors, Calgary initially had to consider whether or not the Board's comments in the 2001-96 and 97 proceedings obligated Calgary to follow the ATCO Gas (and ATCO Electric) approach of rejecting conventional financial approaches to ROE and utilizing an internally developed method. It was Calgary's conclusion that ROE was simply too important an element of revenue requirement to disregard financial theories that had been recognized by regulatory tribunals for many years. Calgary also considered that the use of independent recognized experts in the field was preferable than the use of "internal" witnesses.

This decision also took into account the consideration that Calgary would have to deal with other GRAs/GTAs, which did not use the "made in the ATCO Treasury Department" approach.

Taking the first four factors into account, and following consultation with its experts, Calgary instructed its experts that in developing cost of capital evidence for the ATCO Gas, ATCO Electric and AltaLink proceedings, the general approach should be such that as much as possible of the evidence could be used in the other upcoming GRAs/GTAs, and in the Generic Proceeding (if one was directed). Calgary's objective was that this approach would both minimize costs across the various proceedings, and that consistency in the evidence would be of assistance to the Board in the various proceedings before it.

With respect to the Board's earlier comments regarding cost of capital evidence, and having decided that the use of recognized independent experts was the preferred approach, Calgary submitted that it decided to deal with these comments using the following approach:

- Drs. Booth and Berkowitz were asked to look at alternative methods of analysis and whether there was other material, which could substantiate or confirm the "conventional" approach to ROE analysis.
- Mr. McCormick was retained to examine ROE from what could be considered a "market based" perspective. While this was a new approach for Calgary in presenting cost of capital evidence to the Board, Mr. McCormick had recently presented similar evidence to the NEB in a TransCanada PipeLines hearing. Calgary was also aware that Applicants had presented "capital market" experts to the EUB on many occasions in the past.
- Mr. Johnson, C.A., Mr. VanderVeen, and Mr. Matwichuk, C.A. were asked to examine risk factors that affect cost of capital in greater depth than in past proceedings. This was to deal with problems Calgary had encountered in past proceedings, where experts such as Drs. Booth and Berkowitz had been criticized for not being as familiar with Alberta risk factors as Company witnesses.

Calgary noted that the approach taken by ATCO was to prepare a recommendation based on an approach not previously relied upon and based on data as discussed further below, which was obtained from Foster Associates, one of ATCO's consultants, and which had significant computational and conceptual problems. Calgary noted that subsequently, ATCO filed rebuttal testimony by Ms. McShane and by Company officers, which respectively critiqued Drs. Booth and Berkowitz' evidence and Mr. McCormick's evidence.

Calgary submitted that in this hearing, only Drs. Booth and Berkowitz presented expert rate of return and capital structure evidence. Calgary pointed out that, based on their use of the Risk Premium over long Canada Bond methodology and a Multi-factor Risk Premium Model, together with a set of dividend mutual funds, which confirmed the reasonableness of the their beta estimate, they recommended an all-in return on common equity of 8.5%. Calgary indicated that this recommendation exceeded their fair rate of return due to the inclusion of a cushion for items such as flotation, flexibility, and market breaks. Calgary summarized details of their recommendation in the following table:

Table 4. Calgary's Cost of Capital Recommendation

	Drs. Booth and Berkowitz
Common Equity Ratio	35%
Long term Government of Canada yield	6.00%
Risk Premium Method	8.02-8.47%
Multi-factor Model	7.32–7.54%
Overall Recommendation	8.50%
Inherent equity risk premium in final recommendation	2.50%

Calgary submitted that Drs. Booth and Berkowitz attempted to be responsive to the Board's concerns stated in Decision 2001-96, where the Board found it difficult to distinguish between Company and intervener evidence, indicated that it was disturbed by the wide range of estimates that resulted from the application of professional judgment, and suggested that it might entertain alternative estimation techniques. Drs. Booth and Berkowitz also explained why they departed from strict statistical evidence and applied professional judgment in order to assist the Board.

Calgary noted that specifically, Drs. Booth and Berkowitz addressed the Board's concerns by submitting abbreviated evidence that did not unduly duplicate their recent evidence submitted in the AltaLink hearing, and developed two alternative estimation techniques. Appendix B of their evidence provided beta estimates looking at the performance of mutual funds that invested heavily in high dividend yield securities, like regulated utilities.

Calgary indicated that Drs. Booth and Berkowitz also developed a DCF model of U.S. utility risk premiums in Appendix D of their evidence to determine whether U.S. required rates of return were higher than in Canada. The model produced a utility risk premium in the 1.89-2.57% range, which for a recommended return would be added to the risk free rate and increased by a cushion. Drs. Booth and Berkowitz considered the results of the DCF model and the dividend mutual funds as corroborating evidence, consistent with their estimates from both the CAPM and the Multi-Factor Models.

Calgary stated that, in response to the Board's comments, Drs. Booth and Berkowitz expanded their discussion of the market risk premium in their testimony, including a detailed discussion of recent work on the market risk premium in both the U.S. and Canada.

Calgary indicated that Drs. Booth and Berkowitz used the Risk Premium over long Canada Bond methodology and a Multi-factor Risk Premium Model to determine a fair ROE for ATCO. To the results of their modeling, consistent with the Board's custom, Drs. Booth and Berkowitz added a 50 basis point flexibility/adjustment cushion.

Calgary noted that it was important to reiterate that Drs. Booth and Berkowitz did not use a classic CAPM, which would have involved determining a risk premium based on a risk-free rate – Treasury Bills (T-Bills). Calgary noted that, in her Rebuttal Testimony, Ms. McShane listed a series of papers concluding that the CAPM did not estimate fair returns accurately, but failed to point out that these studies used the current Treasury Bill yield as the risk free rate. Calgary stated that Drs. Booth and Berkowitz agreed in their Opening Statement that if anyone used the current Treasury Bill yield of 3.0% in a CAPM estimate, the fair return would be understated. At the same time, however, Drs. Booth and Berkowitz pointed out that they did not use the Treasury

Bill yield, but instead used a forecast of the long Canada yield as the risk-free rate, which was forecast to be 6.0% based upon Consensus forecasts. Therefore, Calgary submitted that Drs. Booth and Berkowitz's use of the Risk Premium did not suffer from understatement.

Calgary noted that the Risk Premium over long Canadas was an approach for determining a fair rate of return, or the investors' required rate of return, based upon the concepts in the CAPM. Calgary pointed out that the risk premium method had two basic components, a risk free interest rate, which in regulatory proceedings was usually the long-term Government of Canada (GOC) rate and a risk premium. The long-term GOC bond yield was not a true risk free rate, but was used because the time horizons of utility investors were generally longer than the lower risk rates of 30 or 90-day T-Bills, which would be used in the classic CAPM. Calgary observed that, in her Rebuttal Testimony, Ms. McShane accepted the estimate of the long Canada Bond yield of 6.0% used by Drs. Booth and Berkowitz in their evidence.

Calgary noted that the disagreement between Drs. Booth and Berkowitz and Ms. McShane related to the size of the equity risk premium added to the 6.0% long Canada rate. Based upon their 8.50% ROE recommendation (from their models described in their evidence), Drs. Booth and Berkowitz's inferred utility equity risk premium was 2.50%. This compared to the Board's award to ATCO of an utility equity risk premium of 3.75% in Decision 2001-96.

Calgary stated that in Appendix E of their testimony, Drs. Booth and Berkowitz estimated the market risk premium from 1957-2001 at 2.09-2.82% and from 1924-2001 at 4.10-5.36%, depending on the estimation technique used, i.e. geometric, arithmetic, or least squared. They based their estimates on a market risk premium of 4.50%. Calgary noted that it was misleading for Ms. McShane to state that they "focus on a very specific time period 1956-2001," and that if they did this, their market risk premium would be half the level they actually used in their testimony. Calgary stated that as a result, it was evident from their testimony that Drs. Booth and Berkowitz looked at data prior to 1956, as well as data from the U.S.

Calgary submitted that it was clear from the evidence that the market risk premium estimate provided by Drs. Booth and Berkowitz of 4.50% was quite reasonable when one examined the recent studies estimating the market risk premium. Calgary submitted that the Canadian market risk premium was significantly less than the market risk premium implicit in the Board's use of a 3.75% utility risk premium in Decisions 2001-96 and 2001-97. Calgary noted that in contrast, Ms. McShane indicated a market risk premium of 6.0%, which was clearly at the high end of the range based upon the current studies presented in the summary table of Drs. Booth and Berkowitz's evidence.

Calgary noted that Drs. Booth and Berkowitz also introduced a new study, based upon Canadian Dividend Mutual Funds, to test their beta estimate of .45-.55 for ATCO. Calgary noted that Ms. McShane argued only for an adjustment to the raw betas using a process based on the assumption that the average utility beta regressed toward the overall market beta of 1.0. As a result, Ms. McShane provided the raw betas and Value Line adjusted betas for a sample of U.S. gas distributors in a table in her Rebuttal Testimony. Calgary observed that while the average raw beta over the years 1993-2002 was .34, the adjusted beta was .64. Calgary argued that it was clear that when one examined the raw beta data and the adjusted betas in Ms. McShane's table, there was no formulaic approach used to adjust the raw betas. Moreover, if the Value Line stated approach of weighting the raw beta by two-thirds and the market beta by one-third was applied, the mean adjusted beta in the table would produce a beta of .56 (not .64 as shown on Table 4 of

Ms. McShane's Rebuttal Testimony), which was at the high end of Drs. Booth and Berkowitz' .45-.55 range.

Calgary submitted Drs. Booth and Berkowitz had demonstrated before this Board, and in other Canadian jurisdictions that Canadian utility betas regressed toward the average utility beta, and not 1.0.

Calgary noted that Drs. Booth and Berkowitz also used a Multi-factor model, and submitted that Multi-factor models had been around in the finance literature for over 30 years, and had been used to compute the cost of capital for utilities as early as 1983 by Roll and Ross. The two factors in the Multi-factor models were the market risk premium and a premium for the term risk associated with holding a long bond relative to one with a short maturity.

Calgary noted that, in cross-examination, Dr. Berkowitz provided the Multi-factor Model estimates based upon the 1982-1999 estimation period. Calgary noted that using the 1982 to 1999 period the overall average of the estimates would increase by approximately 14 basis points. Calgary stated that with the elimination of the Nortel effect, the model's estimate increased from 7.43% to 7.70%, or 27 basis points, and given that this model accounted for 50% weight in Drs. Booth and Berkowitz's overall recommendation, elimination of the Nortel effect increased their recommendation by approximately 14 basis points. In turn, their 50 basis point cushion would be reduced by the same 14 basis points, resulting in their 8.50% ROE estimate for ATCO.

With regard to ATCO's evidence, Calgary noted that although Ms. McShane presented Rebuttal Testimony to critique Drs. Booth and Berkowitz, she did not directly provide a ROE recommendation. In addition, no independent expert evidence was provided by ATCO. Calgary pointed out that instead, ATCO's evidence consisted of the internally produced 15 pages found in Section 3.1 of the Application.

Calgary noted that ATCO's only ROE evidence in the proceeding was a table showing the spread between long Canada Bonds and certain Canadian A-rated Utility Debentures in each of the five years 1997-2001. Calgary noted that ATCO argued that since the historical spread between these two series had increased between 85 and 100 basis points, the equity risk premium should increase from 3.75%, awarded in Decision 2000-9, to 4.60-4.75% for 2003 and 2004.

Calgary submitted that, aside from problems with the composition of the long Canada Bond and Canadian A-rated Utility Debenture series, discussed below and in Mr. McCormicks' Evidence, the primary problem with the analysis put forward by ATCO was that it was ill-founded. Calgary stated that the comparison between promised yields (yield to maturity) on bonds and a required ROE was not appropriate.

In contrast, Calgary considered that the expected or fair return on the firm's equity, which had no maturity, was the return required for the risk undertaken by the investor. Calgary stated that, for example, CAPM determined the investor's required compensation for the systematic or market risk. Calgary stated that when a risk premium was added to the risk free rate, this became the fair rate of return (investor's required rate of return). Consequently, Calgary submitted that ATCO's comparison of spreads on promised yields to infer a fair ROE was flawed. Calgary noted that the argument presented in ATCO evidence in support of its request for a ROE of 11% was based on a table, which demonstrated that the spreads had widened for certain utility bonds from 1997 to 2002. Calgary submitted that this argument was based on flawed assumptions and analysis.

Calgary pointed out that, among ATCO's flawed assumptions, was the assumption that 1997 was a "normal" year and an appropriate starting point for this analysis. Calgary submitted that the extended table attached as CAL-AG.6(a1) demonstrated that the 1997 average was the low point for Canada to utility bond spreads. As a result, ATCO appeared to have picked the low point in a cycle, and then argued for an increase from the low point to justify a change in the equity risk premium. Calgary submitted that in starting its analysis in 1997, ATCO ignored the more recent Decision 2001-96, which came to a similar conclusion as to equity risk premium for 2001 and 2002 at a time when this table showed wider bond spreads more similar to the recent market.

Finally, Calgary disputed the assumption that the equity risk premium over government bond yields increased directly, basis point for basis point, as the annual average spread between utility and government bond yields increased. Calgary argued that there was no proof of this relationship on the record. Contrary to the views expressed by ATCO, Calgary pointed out that there was evidence on the record that others who had studied the relationship had reached differing conclusions. Calgary further noted that in cross-examination Ms. McShane agreed to a 25 basis point change in return for a 1% change in risk free rates.

Calgary noted that in Rebuttal, Ms. McShane was called on by ATCO to comment on the various methodologies used by Drs. Booth and Berkowitz. While Ms. McShane did not directly provide a ROE recommendation, Mr. Edmondson said that he believed an analysis by Ms. McShane would have reached the same conclusions as the ATCO approach. Calgary submitted that this view did not agree with Ms. McShane's evidence. Instead, the record showed the following with respect to Ms. McShane's views on a CAPM analysis:

- Ms. McShane did not disagree with the 6.0% risk free rate used by Drs. Booth and Berkowitz;
- Ms. McShane did not disagree with the 0.5% cushion which had been typically applied by the Board and was used by Drs. Booth and Berkowitz;
- Ms. McShane believed the market risk premium was 6%, which had been higher than that used by Drs. Booth and Berkowitz; and
- Ms. McShane believed the appropriate beta would be in the range of 0.6 – 0.65, instead of the lower numbers indicated by Drs. Booth and Berkowitz.

Calgary noted that applying the high end of Ms. McShane's beta range to her 6% market risk premium would have resulted in a utility risk premium of 3.9% which, when added to the risk free rate and flotation allowance, produced a ROE of 10.4%. If the lower end of her beta range was used, the result would have been a ROE of only 10.1%. Calgary concluded that neither of these recommended rates of return supported ATCO's requested ROE of 11%.

Calgary noted that, in ATCO's Argument in support of its new methodology, ATCO suggested that "the only directly observable indicator of the relative change in cost of equity of utilities … is the yield on comparable utility bonds." Calgary responded that this assertion did not stand up to any detailed scrutiny. First, Calgary offered compelling evidence that the bonds in ATCO's sample were not "comparable," having different and changing ratings and terms to maturity than the Canada benchmark. Second, Calgary pointed out that the bonds in ATCO's sample were issued by utility holding companies whose other non-regulated operations had blurred the connection that ATCO sought to establish. Third, Calgary observed that ATCO provided no evidence of a one-for-one relationship between spreads and increases in the equity risk premium. Calgary indicated that the "observable" indications from the market to book ratio observations were more proximate to the question at hand, for the simple reason that they were drawn from an observation of the performance of the equity most closely tied to ATCO. As a result, Calgary concluded that the verdict on this methodology based on utility holding company bonds must be that the methodology is "Not Proven."

Calgary observed that ATCO appeared to enjoin the issue of the effectiveness of the NEB and BCUC formulas, as well as the Board and every other regulator that had used the equity risk premium method for many years. Calgary stated that the flaw in this line of thinking was that the companies governed by the NEB and BCUC formulas had been successful in accessing the capital markets for years. While ATCO was of the view that it had reached an "inescapable" conclusion, based on widening spreads from the low point in a decade, the success of NEB and BCUC companies belied the conclusion.

Calgary submitted that the record was clear that the promised yields on bonds represented the maximum return an investor would get if he held a corporate bond to maturity, and as such overstated the expected market rate of return on the bond which would recognize the risk of default. As a result, Calgary expressed the view that the only "inescapable" conclusion was that the reason regulatory tribunals and utilities across Canada had not shared ATCO's statement regarding the shortcomings of the equity risk premium method, was that these others understood the difference between promised yield and expected return while ATCO did not. Consequently, Calgary submitted that there was no adequate foundation for the ATCO methodology.

Calgary noted that ATCO built its argument for increased returns on the basis of a 1997 Decision of the Board and changes in the bond spreads. In its Evidence, Calgary presented observations about the lack of resiliency in the new ATCO method, the choice of the low point in spreads as the starting point of ATCO's analysis, the issue of the corporate bond series, ATCO's refusal to consider later Board decisions, the failure to produce any study or supporting literature to bolster the novel methodology and the assumption of symmetry between the bond and equity markets. Calgary noted that these flaws were discussed in detail in the Calgary Argument. Calgary concluded that while individually each of these issues was problematic, collectively they were fatal to the ATCO position.

Calgary noted that the Application was based on a long Canada forecast of 6.4% at the time of filing. Calgary further observed that when faced with the evidence that the long Canada rate had fallen significantly since the Application was filed, ATCO's response was its refrain that to acknowledge this trend was "contrary to prospective ratemaking" and an attempt to mix data from two time periods in an effort to create the impression of higher market rates for long Canada bonds. Calgary responded that neither approach was proper.

Calgary argued that the ATCO view of prospective ratemaking asked the Board to adopt the proposition that the world stopped the day that the Applicant filed its evidence. ATCO suggested that using information, in particular the "later forecasts" that become available, "is contrary to prospective ratemaking". Calgary submitted that prospective ratemaking was not introduced so that the utility could control the process and restrict information relevant to making an informed decision. Calgary indicated that the acceptance of this point would have far reaching consequences in every aspect of the regulatory process, far beyond the issue of the ROE for this test period. Calgary submitted that in terms of fairness, the Board should use the best information available.

Calgary noted that in the Application, ATCO used the average long term 10 to 30-year long Canada spread of 30 basis points to produce its 6.4% long Canada rate. While acknowledging that long Canada forecasts had changed, the ATCO Argument suggested that if these subsequent forecasts were used, the Board should also use the higher 10 to 30-year spread for November 2002. Calgary argued that if the ATCO methodology was truly based on some basic concepts, it would not be necessary for ATCO to abandon the long-term average 10-year to 30-year spread in its Application, for an actual but historic data point.

Calgary noted ATCO's statement that the Company relied on the June 2002 Consensus Forecast in determining its requested ROE. Calgary observed that as a result of using this forecast, ATCO was continuing to rely on information that was over six months old. However, Calgary noted that Drs. Booth and Berkowitz provided an updated Consensus forecast based upon the December 2002 Consensus forecast. In addition, Calgary indicated that ATCO also provided a February 2003 Consensus forecast. Calgary submitted that one of these forecasts should be used for purposes of the Board's determination since they provided the best information available to the Board at the time of the hearing.

Calgary noted that in its Argument, ATCO suggested that the Board should regulate to maintain a credit rating. Calgary indicated that CAL-AP-18 demonstrated the fallacy of such an approach, since CU's activities had resulted in changes in the bond ratings over the years, from a high of AAA to A currently.

Calgary referenced ATCO's statement in Argument in which the Company claimed that Drs. Booth and Berkowitz had concerns accepting the DBRS and S&P reports issued prior to the test period. Calgary responded that, as noted by Dr. Booth, one of the factors impacting ATCO, and implied by Mr. Smith in his question that referenced Canadian Utilities, was the unregulated portion of these holding companies. Calgary argued that these holding companies would have to reduce their leverage, but the greater concern of the bond rating agencies seemed to be the leverage of the non-regulated activities.

Calgary noted ATCO's claim in its Argument that Drs. Booth and Berkowitz failed to reflect the interest of shareholders and customers. Calgary responded that Table 3 to the Calgary Argument provided further clarification to ATCO's concern.

Calgary observed that ATCO attempted to take an explanation that the market in the last two years had some anomalies due to Nortel and the internet bubble, recognized by Drs. Booth and Berkowitz, and used that evidence to suggest that all their studies should be rejected. Calgary stated that it was clear that Drs. Booth and Berkowitz increased their multi-factor model estimate to reflect the circumstances of the last two years. Further they did not reject betas in their "classic" CAPM. Instead, Drs. Booth and Berkowitz adjusted the pure statistical betas to reflect the circumstances in the market based upon their judgment and evaluation of the data. As a result, Calgary considered that this judgment increased the statistical results, and did not reduce the results as implied by ATCO.

Calgary noted that this contrasted sharply with Ms. McShane who suggested that the Value Line and Bloomberg adjusted betas should be used, but did not know how they arrived at their adjustments. Calgary speculated that the only conclusion from that acceptance was that Ms. McShane was seeking to achieve a result rather than provide an expert opinion, since her adjustment for the Canadian raw betas at least had some theoretical underpinning.

Calgary observed that ATCO continued to assert that a few comments in published documents established that there was a "perception in the investment community" that "regulatory risk has increased." Calgary submitted that in addition to showing confidence in the Alberta regulatory environment, the AltaLink (a limited partnership) purchase of the TransAlta assets at a material premium to book value also demonstrated the high level of regulated returns relative to the market required rate of return.

In its discussion of the sale of retail operations to Direct Energy, Calgary noted that ATCO ignored the fact of legislative change. Calgary agreed that in the absence of the legislative change, the function would earn no return and, Calgary submitted, would be unable to attract capital, which would be one reason why the sale was conditional on the legislative change going through. Calgary considered that now that legislative change would allow a return on sourcing gas, the function was obviously attractive. At the same time, Calgary stated that none of this would have an impact on the conclusions reached by Mr. McCormick with respect to capital being attracted to the high returns allowed utilities.

Views of the CG

The CG noted that, based on the Board Findings in Decisions 2001-96 and 2001-97 concerning the relevance of the expert evidence filed, ATCO initially did not file any external, expert witness testimony. The CG noted that ATCO applied for an 11.00% rate of return on a capital structure containing a ratio of 37% to 42% common equity, but later filed the Rebuttal evidence of Ms. McShane supporting ATCO's recommendations.

The CG noted that, having determined that the cost of capital matter would be fully canvassed in this proceeding, at least for 2003, Calgary filed the evidence of Drs. Booth and Berkowitz on January 3, 2003. The CG noted that Drs. Booth and Berkowitz recommended a rate of return of 8.5% on equity and a capital structure containing no more than 35% equity. In addition, all three sets of evidence (i.e., ATCO, McShane, Booth & Berkowitz) relied on the equity risk premium test.

The CG argued that, although ATCO stated that it did not use an equity risk premium test, its internal cost of capital witness agreed that the method used consisted of determining a current forecast risk-free rate, and then calculating the change in the equity-risk premium by adding the change in GOC Bond/Utility Debenture spread to the equity-risk premium as previously determined by the Board.

Since all witnesses used and agreed on the risk premium test as appropriate for these proceedings, the CG organized its argument to address the components of an equity risk premium test.

With regard to the risk-free rate, the CG noted that Drs. Booth and Berkowitz employed a 6% risk-free rate based on their forecast of long Canada Yields (%) for both 2003 and 2004. In the

Rebuttal evidence, Ms. McShane agreed with the forecast risk-free rate of Drs. Booth and Berkowitz. However, the CG noted that, at the hearing, Ms. McShane indicated her current forecast would be between 6.0% and 6.25%, “depending on what you use for the spread between 10 and 30-year Canadas.”

The CG noted that, in contrast, ATCO’s internal witness used a risk-free rate of 6.40%, based on a forecast 10-year long Canada Bond yield from the June Consensus Forecast of 6.10% and a 30 basis point normal spread between 10-year and 30-year GOC Bonds. The CG questioned the reliability of this estimate of the risk-free rate, as it was an indirect measurement of the risk-free rate. The CG responded that a direct measurement of the long Canada bond was preferred as long as it was available with reasonably long terms remaining. Further, the CG noted Ms. McShane’s previously filed evidence, indicating that direct measurements were more accurate than indirect ones. Consequently, the CG submitted that Ms. McShane was being inconsistent in her testimony, giving credence to an indirect measurement of risk-free rate when viable direct measures were available and used in her own Rebuttal Evidence.

The CG noted that the 30-point spread between long and short Canada’s apparently rested on a historical average of 10-year versus 30-year spreads. However, the CG submitted that relying on historical averages was also inconsistent with Ms. McShane’s preference for forward-looking measures over historical data. The CG noted that, given the inherent problem with historical averages, Ms. McShane used a current spread when forecasting a risk-free rate based on a 10-year long Canada bond.

Finally, the CG noted that ATCO’s own evidence suggested the actual yield of long Canada Bonds was less than 6% at the time of filing, which would lend support to the 6% forecast of the expert witnesses as an appropriate forecast for the 2003 test year. Based on the consideration that all expert witnesses in this proceeding agreed in their written evidence that 6.0% was the appropriate risk free rate to use for the current test period, the CG submitted that 6.0% was the risk-free rate that the Board should apply to the equity risk premium test.

The CG noted ATCO’s statement that “all experts and commentators agreed that the only identifiable verifiable risk free rate was the long Canada Bond.” However, the CG submitted that this was a misstatement of fact not supported by the evidence or economic literature. The CG noted that the long Canada Bond rate had been accepted in Canadian jurisdictions as a proxy measurement of the risk free rate, and that other jurisdictions might use other securities as a suitable proxy. The CG stated further, that the equity risk premium needed to be measured relative to the proxy chosen to simulate the risk-free rate. Otherwise, the CG submitted that the equity risk premium might become a meaningless concept.

The CG observed that the expert witnesses in this proceeding, Drs. Booth and Berkowitz and Ms. McShane, agreed that an appropriate proxy measurement for a risk-free rate was 6.0%, based on a forecast of the long Canada rate. In the CG's view, this should have been the end of the matter. Nonetheless, ATCO presented further evidence to indicate that the risk-free rate should lie between 6.2% and 6.7%. In this regard, the CG noted that ATCO relied on a proxy (the 10-year Canada rate) of a proxy (the 10-year/30-year spread) of a proxy (the long Canada rate itself). In the CG’s submission, this approach demonstrated a complete misunderstanding of the theoretical underpinnings of the equity risk premium method.

The CG noted that the ATCO theory that one should build proxy on proxy to arrive at a risk-free rate appeared to mimic the methods employed by the NEB and BCUC to determine an appropriate risk-free rate for automatic adjustment mechanisms. The CG submitted that, unless one adopted the entire equity risk premium method with the adjustment mechanism accompanying the NEB or BCUC choice of risk-free-rate, one would merely be engaged in financial cherry-picking.

As a result, based on the foregoing and the evidence of the expert witnesses in this proceeding, the CG submitted that the appropriate risk-free rate for the test period was 6.0%.

With respect to the equity risk premium, the CG noted ATCO's statement that it had accepted the equity risk premium of 375 points determined in Decision 2000-9, which was appropriate at the time. However, the CG noted that ATCO considered that the equity risk premium had since increased by 85 to 100 basis points, based on an increase of 85 to 100 basis points in the spread between utility debentures and long Canada Bonds. In summary, ATCO's proposed increase in the equity risk premium relied on the proposition that an increase in the GOC Bond/Utility Debenture spread should equate to the same increase in the calculation of the equity-risk premium.

The CG noted that ATCO was unable to cite any support in academic literature for such a relationship or any precedents from other regulatory bodies. The CG noted that ATCO also stated that the relationship could not be proven because of the difficulties in performing an equity risk premium test. However, despite the impossibility of determining the utility bond spread/risk premium relationship, the CG noted ATCO's claim that Dr. Morin filed such a study in an earlier GRA. The CG noted that Ms. McShane also attempted to support ATCO's proposition by claiming that academic papers she cited in earlier testimony supported ATCO's proposition. Further, she suggested that ATCO's position was supported by Dr. Morin's book and used with utility regulators in the United States. In the absence of Dr. Morin's evidence and any opportunity to examine its contents or Dr. Morin, the CG submitted that such reference or reliance on Dr. Morin's evidence should be disregarded as support for ATCO's method.

With respect to Ms. McShane's reference to studies cited in the AGS 2001/2002 GRA, the CG stated that it was clear that such support was a new discovery. The CG further noted that the studies footnoted in Exhibit 2-35 were intended as support for the proposition that there was a negative relationship between interest rates and equity risk premium and provided no such support for ATCO's proposition. The CG submitted that Ms. McShane's discussion of the footnoted studies concerned only a relationship between interest rates and risk premiums. In addition, the CG stated that none of Ms. McShane's 2001/2002 evidence suggested that risk premiums were related to the utility/risk-free spread.

The CG submitted that Ms. McShane's retroactive discovery of a relationship between equity risk premium and utility bond spread raised the question whether ATCO, in its form of the equity risk premium test, had focused solely on one financial variable. The CG noted that ATCO's evidence in the AGS 2001/2002 GRA indicated a negative relationship between equity risk premium and the risk-free rate. As a result, the CG considered that to be consistent with the previous evidence of its rebuttal witness and with its affiliate, ATCO should have included a negative offset for this factor to any positive relationship between equity risk premium and utility bond spreads.

Based on the foregoing, the CG submitted that ATCO's proposition was unsound and should be rejected. Further, the rebuttal evidence of Ms. McShane did not serve to support ATCO's position. In the CG's submission, ATCO had failed to provide any compelling reason why the Board should revisit the equity risk premium set for ATCO in Decision 2000-9 and affirmed in Decision 2001-96.

Therefore, the CG submitted that the Board should affirm the equity risk premium of 3.75% for ATCO, set in Decision 2001-96, as appropriate for the 2003 test year, only. Alternatively, the Board could accept the recommendation of Drs. Booth and Berkowitz (i.e., 2.75% for 2003).

With regard to the 2004 test year, the CG noted that Drs. Booth and Berkowitz recommended that the Board adjust the prospective ROE by 75% of the change in the forecast, should the forecast long Canada Bond yield change by more than 1.0% in late 2003.

The CG submitted that Drs. Booth and Berkowitz's proposal to adjust the ROE in the 2004 test year to reflect any changes in the risk-free rate merited consideration. The CG considered adjustment of ROE to current conditions fair to both customers and the utility and mitigated upside and downside risks at little regulatory cost. However, the CG noted that the merits of the proposal were best discussed in the context of the Generic Cost of Capital proceeding, as per the Board's Ruling of May 28, 2003. The CG submitted that adjustments due to the risk-free rate had to be considered along with all other elements of the cost of capital.

The CG noted that despite her criticisms of Drs. Booth and Berkowitz' CAPM model, in these proceedings, Ms. McShane concluded that she would only recommend the Company's applied-for rate of return method or a "modified CAPM" model. The CG noted that, with regard to the modified CAPM model, the modification Ms. McShane proposed involved an "adjusted" beta of 0.70 and some unspecified weighting of U.S. data. The CG noted that both modifications would result in a higher equity risk premium. The U.S. data yielded a higher result because of a higher market risk premium. Further, the CG indicated that a higher beta yielded higher results because a utility equity risk premium is the product of utility beta times market risk premium under the CAPM model.

The CG noted that the use of U.S. data had been dismissed in numerous previous decisions and warranted no further discussion. Ms. McShane used "the Value Line, Bloomberg, Merrill Lynch adjustment, taking one-third of the market beta and two-thirds of the stock beta itself." Ms. McShane considered that the adjusted beta was preferable because it was employed by investors. At the same time, the CG noted that the math of an adjusted beta was simplistic enough, since any investor could mentally "readjust" to the raw beta (i.e., subtract 1/3 and multiply by 1.5). Hence, an adjusted beta of .70 equated to a raw beta of .55, slightly higher than the result of Drs. Booth and Berkowitz. Notwithstanding the math, the CG submitted that there was no actual evidence that investors paid any heed to the adjusted beta or actually made investment decisions on that basis.

The CG noted that in Decision 2001-96 the Board rejected the adjusted beta method of Ms. McShane, and did not need to give it further consideration in this proceeding.

The CG noted ATCO's statement that the challenge for setting rate of return for regulated utilities was that there was no observable, verifiable single standard for a "true" equity rate of return in the market.

The CG agreed that an appropriate ROE might be calculated by a number of different methods, each requiring an element of judgment. However, the CG submitted that the various methods should still be based on financial models tested for real-world results and generally had a verifiable regulatory track record. In contrast, the CG submitted that the form of equity risk premium test chosen by ATCO was speculative and had no verifiable track record.

With regard to the ATCO method used to calculate the equity risk premium, the CG noted that counsel for the FGA, on behalf of the CG, raised serious doubts about the theoretical underpinnings of ATCO's initial evidence on cost of capital. The CG also observed that Mr. Edmondson confirmed that the ATCO method was not mentioned in any academic research and had never been used by any regulatory body. The CG also noted that ATCO's expert witness, Ms. McShane, did not provide any additional support to the ATCO method in her rebuttal evidence.

With regard to Ms. McShane's evidence, the CG also noted ATCO's attempt to restrict examination of Ms. McShane to her rebuttal evidence. The CG speculated that the reason why ATCO attempted to impose this artificial restriction was that Ms. McShane had filed evidence in previous proceedings for ATCO and predecessor companies which did not support the method adopted by ATCO. In particular, Ms. McShane filed evidence asserting an inverse relationship between equity risk premium and the risk free rate in both the 1998 CWNG GRA and the AGS 2001/2002 GRA.

Related to this matter, the CG noted that ATCO did not make required adjustments to the risk-free rate such as the inverse relationship between interest rates and the equity risk premium, also advocated by Ms. McShane. As a result, the CG submitted that since ATCO assumed a positive, one for one, relationship between utility bond spread and equity risk premium, any inverse relationships should also be taken into account. This would include the inverse relationship between the equity risk premium and the risk-free rate.

The CG observed that ATCO questioned the statistical validity of the beta measurement proposed by Drs. Booth and Berkowitz. However, the CG noted that Ms. McShane's "adjusted" beta was based on much the same method as that employed by Drs. Booth and Berkowitz. The CG noted that the reason an "adjusted" beta was higher than a raw beta was because the adjustment consisted of calculating the arbitrary addition of .33 to two-thirds of the raw beta. In this regard, Ms. McShane had not shown that the raw betas used by Value Line had any more statistical validity than those calculated by Drs. Booth and Berkowitz.

The CC noted that the similarity between the raw betas of the two sets of expert witnesses in this hearing was confirmed by the "readjustment" carried out in the CG argument. The raw beta results were almost identical, namely 0.55 for Ms. McShane and 0.50 for Drs. Booth and Berkowitz. The CG noted that Ms. McShane's higher raw beta was based on a sample of U.S. LDCs. However, the CG considered that U.S. data was inappropriate for use in setting the rate of ROE for the reasons set out in previous Board Decisions.

Based on the foregoing and submissions previously made in Argument, the CG submitted that 0.5 was the appropriate beta to use for a Canadian-based utility financing its capital needs in a Canadian market.

Views of the Board

The Board notes that in Decision 2001-96, the Board made the following statement with respect to the evidence that was presented in the proceeding regarding the equity risk premium test:

> The Board has reviewed the evidence of Ms. McShane for ATCO, and Drs. Booth and Berkowitz for Calgary. The Board is concerned that, despite its volume, the nature of the expert evidence provided is ultimately of little probative value to the Board in establishing this important determinant of the utility's revenue requirement.[30]

The Board further notes that ATCO initially elected not to file expert witness testimony, as a result of the Board's concern in the AGS 2001/2002 GRA that the nature of expert testimony was of little probative value in establishing the appropriate return on equity. Instead, ATCO responded to the Board's concern by developing an alternative approach to estimating the equity risk premium.

However, the Board notes that Calgary provided several external independent expert witnesses in response to Board comments in the Decision 2001-96 and 97 proceedings. Calgary believed that return on equity was too important an element of revenue requirement to disregard financial theories that had been recognized by regulatory tribunals for many years.

The Board notes that in response to Calgary, ATCO had submitted that the evidence sponsored by Calgary's expert witnesses, Drs. Booth and Berkowitz, raised technical issues, which were beyond the capability of the Company witnesses to deal with. As a result, ATCO submitted that it was necessary to sponsor Ms. McShane in order to reply to those technical issues. The Board notes that Ms. McShane's evidence follows the more traditional approach to determining the equity risk premium.

The Board commends ATCO's attempt to respond to the Board's concern originally presented in Decision 2001-96. Based on ATCO's response, as presented in the Application, the Board examined ATCO's alternative approach to estimating the equity risk premium. As well, the Board examined the traditional approach, as presented by Ms. McShane and Drs. Booth and Berkowitz, and by the CG in argument.

The Board notes that parties in general did not support ATCO's alternative approach. The Board notes ATCO's response to BR-AG-38, which asked ATCO to provide an explanation of the historical relationship between the GOC Bond/Utility Debenture spread and the equity risk premium between GOC Bonds and the fair rate of return for utility common shares:

> While the spreads between utility bonds and GOC bonds are observable, the same is not true of the spread between the fair rate of return for Canadian utility common equity shares and GOC bonds or between the overall equity market return and GOC bonds. The reason for this is that there is no single accepted method that measures the return on equity consistently over time. It is for precisely this reason that the determination of the methodology for calculating the fair return has been the topic of previous rate of return evidence before this Board.

[30] Page 57

The Board observes that ATCO concedes in this statement that there is no observable relationship between the fair rate of return for Canadian utility common equity shares and long Canada Bonds or between the overall equity market return and long Canada Bonds. It is not clear to the Board on what basis ATCO's methodology was arrived at. In addition, the Board notes that no mathematical or scientific proof was presented for ATCO's methodology.

The Board also notes AUMA/EDM's argument that there was no evidence to suggest that investors' expectation of common equity return for a regulated utility was in any way related to the yields on utility debentures. The Board also notes AUMA/EDM's argument that ATCO provided no evidence to demonstrate the linkage between experienced yields on utility debentures and investors' return expectations on utility common equity. In addition, the Board notes AUMA/EDM's argument that there was no evidence to support the suggestion that the relationship in the spread between utility debentures and long Canada Bonds has any basis in financial theory. Further, the Board notes the CG's argument that ATCO did not cite any support in academic literature for such a relationship or any precedents from other regulatory bodies.

The Board notes Calgary's comment that the ATCO methodology was flawed, inappropriate and unsound since it made a comparison between promised yields (yield to maturity) on bonds and a required ROE. The Board considers that if ATCO could demonstrate that there was a relationship or linkage between experienced yields on utility debentures and investors' return expectations on utility common equity (as AUMA/EDM stated in argument) or between long Canada Bonds and the fair ROE for Canadian utility common equity shares or the overall equity market return (as discussed by ATCO in BR-AG-38), there would still be the need to prove that there was a one-for-one relationship between changes in the GOC Bond/Utility Debenture spread and changes in the equity risk premium.

In summary, the Board considers that there is insufficient supporting evidence for ATCO's alternative approach, and that it cannot be supported on theoretical grounds. In addition, the Board is of the view that several factors can influence the equity risk premium, as opposed to ATCO's alternative approach, which had a narrow focus and only addressed a single factor. For these reasons the Board has determined ATCO's alternative approach to establishing the equity risk premium in setting ROE to be without sufficient merit.

The Board will now discuss the balance of the evidence, focused on the traditional approach of determining a fair estimate of the equity risk premium.

The Board notes that Drs. Booth and Berkowitz used a Multi-Factor Risk Premium Model in part to determine a fair ROE for ATCO. The Board further notes that Drs. Booth and Berkowitz specifically applied a 50% weighting to the Multi-Factor Model and the CAPM respectively. However, the Board observes that the Multi-Factor Model has not been considered in past Board Decisions and has rarely been presented or found support in regulatory hearings in other Canadian jurisdictions.[31] Also, based on the evidence presented, the Board considers that the statistical significance of Drs. Booth and Berkowitz's Multi-Factor Model appears to be relatively low. For all of these reasons, the Board focused only on the evidence regarding the CAPM.

[31] See BR.CAL-6(c)

With regard to the market risk premium, the Board notes that Ms. McShane included U.S. data as well as Canadian data in her estimate of the market risk premium. The Board is of the view that the inclusion of U.S. data normally raises the equity risk premium estimate. In the past, the Board notes that it has not accepted the use of U.S. data, and considers that there are sound reasons for adhering to this point of view, including differences in monetary and fiscal policies, tax treatment, currency risk, country risk, together with particular differences between Canadian and U.S. equity and bond markets. For these reasons, the Board determined that for purposes of this proceeding, it would focus solely on the evidence regarding Canadian data in the determination of market risk premium.

The Board notes that Drs. Booth and Berkowitz estimated a market risk premium of 4.5%, based on statistical evidence from the Canadian market over the period 1956-2001. This estimate included an adjustment of 0.50% to account for the under-performance of the Canadian equity market and the anticipated lower returns on Canadian bonds.

The Board notes that Ms. McShane presented some recent studies, which support a risk premium of 4.0-6.0% for the Canadian market, before any adjustments for the under-performance of the Canadian market. Adding Drs. Booth and Berkowitz's estimated adjustment of 0.50% to account for the under-performance of the Canadian market, the Board notes that Ms. McShane's estimate would be revised to a range of 4.5-6.5%. As a result, having regard to the revised estimated range of 4.5-6.5% for Ms. McShane's risk premium studies and Drs. Booth and Berkowitz's 4.5% estimate, which is at the lower end of Ms. McShane's range, it appears that based on the expert evidence, it is reasonable to take the approximate midpoint estimate for the market risk premium for the Canadian market, or approximately 5.5%. Accordingly, the Board will apply a market risk premium of 5.5% in determining an appropriate equity risk premium.

With regard to the beta estimate, the Board notes that Ms. McShane's estimate was in the range of 0.60-0.65, in contrast to the estimate of Drs. Booth and Berkowitz in the range of 0.45-0.55, which yields an estimated average of 0.50. The Board notes that the CG also recommends a beta of 0.50 based on the evidence in the proceeding.

The Board recognizes that there is always a debate surrounding betas, including the use of raw or adjusted betas. The Board considers that there are pros and cons on each side of the debate, in addition to concerns about the volatility and sensitivity of beta. As a result, the Board considers that it is reasonable to compute the average of the estimates to arrive at an approximation for beta. Using Booth and Berkowitz's estimated average of 0.50 (based on an original estimate in the range of 0.45-0.55), the CG's recommended estimate of 0.50 and Ms. McShane's estimated range of 0.60-0.65, and applying an equal weight to each, the average of the three estimates results in a beta of approximately 0.55. Accordingly, the Board will apply a beta of 0.55 in its estimate of the appropriate equity risk premium.

The Board notes that applying a market risk premium of 5.5% and a beta of 0.55, the equity risk premium or utility risk premium would be 3.0% (5.5% x 0.55), which the Board considers is appropriate for the purpose of determining the fair ROE for ATCO.

With respect to the argument that ATCO should acknowledge that there is an inverse relationship between interest rates and the equity risk premium, the Board considers that there is insufficient evidence to prove that there is such a relationship between the two factors. In keeping with past

Board determinations, the Board remains unpersuaded that it should reflect any inverse relationship between interest rates and the equity risk premium.

With regard to the flotation cost allowance, the Board notes that Ms. McShane's adjustment is 0.50%, compared to Drs. Booth and Berkowitz's implied adjustment for their CAPM estimate of 0.25%.[32] In past Decisions, the Board has generally applied an adjustment of 50 basis points for flotation cost allowance. For example, the Board notes that it approved a flotation cost allowance of 50 basis points in the recent AltaLink decision, Decision 2003-061.[33] Accordingly, the Board finds Ms. McShane's recommendation for a flotation cost allowance to be in keeping with prior Board practice and will apply a flotation cost allowance of 0.50% for the purpose of determining the fair ROE for ATCO.

In addition, the Board notes that in Decision 2003-061, the Board stated that it was of the belief that there were economic reasons to suggest that its historic treatment of flotation cost should be reviewed. In the Board's view, some assessment should be made to determine whether it would be fair and reasonable to address the costs of equity issuance on an as incurred basis. The Board further noted in Decision 2003-061 that a logical forum to address flotation costs could be in the current Cost of Capital proceeding.[34]

With regard to the risk free rate in the equity risk premium test, the Board considers that, in theory, prospective ratemaking normally implies that the Board uses the forecasts filed by the Applicant. However, there can be exceptions to this practice, when particular circumstances arise. With regard to this proceeding, the Board notes that there was a long lag between the start of the proceeding, as marked by ATCO's Application in August 2, 2002, and the start of the hearing, which commenced on March 10, 2003. In addition, as a result of overall delays at the start of the proceeding, intervener evidence was filed in January 2003, approximately five months following the August 2002 filing of the Application by ATCO.

The Board recognizes that the total time lapse between the filing of the Application and filing of intervener evidence was long enough that parties had the opportunity to use an updated Consensus Forecast to estimate the appropriate risk-free rate. The Board notes that while ATCO relied upon the June 2002 Consensus Forecast to determine the risk-free rate, Drs. Booth and Berkowitz determined the rate based on the December 2002 Consensus forecast. As a result of the decline in long-term bonds between the two Consensus Forecasts, ATCO has forecast a risk-free rate of 6.4% compared to the Booth and Berkowitz forecast of 6.0%.

The Board notes that ATCO's expert witness, Ms. McShane, stated that she did not disagree with Drs. Booth and Berkowitz's updated risk-free rate estimate. In addition, the Board considers that ATCO had the opportunity to comment on and rebut the new evidence while under cross-examination during the hearing. In this regard, the Board notes that ATCO indicated in response to cross-examination[35] that, based on a February 2003 Consensus forecast, the risk-free rate

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32 Ms. McShane's adjustment of 0.50% is found on Tr., p.1893; Drs. Booth and Berkowitz's implied adjustment for their CAPM estimate of 0.25% is found on Tr., pp 2366-2367.

33 Decision 2003-061 – AltaLink Management Ltd. and TransAlta Utilities Corporation, Transmission Tariff for May 1, 2002 – April 30, 2004; TransAlta Utilities Corporation, Transmission Tariff for January 1, 2002 – April 30, 2002, dated August 3, 2003, page 116.

34 Ibid

35 Cross-examination of Owen Edmondson

would be in the range of 5.6-6.2% during the period 2003-2004. In terms of further evidence, the Board notes that the CG also recommended a 6.0% risk-free rate.

Given that parties have had the opportunity to provide an updated forecast of the risk-free rate prior to the time of the hearing, that the evidence has been tested, and that ATCO and Ms. McShane appear to generally agree that the updated forecast was within the range that they expected, the Board approves a forecast risk-free rate of 6.0% for the test years 2003-2004, which is unchanged from the comparable rate approved in Decision 2001-96.

Based on a risk-free rate of 6.0% and an equity risk premium of 3.0%, the bare-bones equity rate of return is 9.0%. Adding 50 basis points to account for a flotation cost allowance, the final equity rate of return increases to 9.5%. Accordingly, the Board approves a fair rate of return on common equity of 9.5% for ATCO for the test year 2003-2004 and directs ATCO to revise the test year forecasts to reflect the rate of 9.5%.

Finally, the Board notes that there were several alternative approaches presented during the course of these proceedings regarding the most appropriate way to determine a fair ROE for ATCO. These included reviewing market-to-book ratios, market based experience with Income Funds and Trusts, the DCF method, the Multi-Factor Model, and other alternative approaches or methods. Based on the evidence, none of these other approaches appear to be appropriate in the circumstances before the Board. Some of these alternative approaches were either impractical to use, had unproven application to Alberta utilities, or had no basis in financial theory.

3.2 Business Risk and Appropriate Capital Structure

Views of ATCO

ATCO noted that its business risk was most recently assessed in Decision 2001-96 for the test years 2001 and 2002. ATCO submitted that as there were no significant risk differences between AGS and AGN, it was reasonable to assume that although Decision 2001-96 applied specifically to AGS, it could equally be applied to ATCO Gas as a whole.

ATCO observed that in Decisions 2000-9 and 2001-96, the Board reviewed the change in risk since its last decision, concluding that the risks had not changed for ATCO. As a result, the Board did not alter ATCO's common equity ratio. Given the determinations regarding business risk and capital structure in these decisions, ATCO concluded that the Board effectively based its decision as to the appropriate capital structure for ATCO on its belief that the business risk of ATCO had not changed since 1993. In response to this determination, ATCO submitted that its business risk had materially increased since 1993 as evidenced by two principle factors currently faced by ATCO, an increased risk of franchise loss and the investors' perception of increased regulatory risk in Alberta.

With regard to the risk of franchise loss, ATCO noted that throughout the 1990's, the Company had some concerns over the potential that certain municipalities might elect to discontinue their franchise agreements and acquire the distribution system and operate as a municipally owned system. In the current environment, ATCO expressed the view that this risk was significantly enhanced. For example, ATCO noted that several municipalities were exploring their options for acquiring both gas and electric distribution systems with the intention of replacing the incumbent utilities. ATCO also stated that it was incontrovertible that Alberta municipalities were currently exploring new sources of revenue including the acquisition of gas and electric distribution systems. As a result, the risk of losing franchises was significantly higher in the present environment than in 1993.

With regard to regulatory risk, ATCO considered that the key to determining investment risk (representing a combination of the business risk and financial risk) of a utility was to assess the risk from the investors' perspective. ATCO submitted that given a review of the external evidence available to the investor, the evidence was clear that investors perceived an increase in risk in the Alberta regulatory environment. ATCO noted that this increased perception of risk came from two sources. The first source was the structural changes occurring in the gas utility industry as the government headed down the path towards customer choice for natural gas customers. The second source related to the change in investors' perception of the Board's decisions, which arose from the potential concern that utilities and their investors were not being treated objectively.

In determining its appropriate target capital structure, ATCO confirmed that it had factored in the increased regulatory risks related to the structural changes it would face as the industry moved towards customer choice. However, the Company had not factored in the impact of the change in the investors' perception of Board decisions. Consequently, in the Application, ATCO had not applied for an increase in its common equity ratio as a result of this second source of increased regulatory risk. ATCO further submitted that its recommended target capital structure represented the minimum capital structure required to maintain the Company's creditworthiness given the evolving natural gas utility industry in which ATCO operated.

ATCO concluded that its business risks had increased substantially since 1993, with the majority of the increase occurring in the last few years. Over this same period, the capital structure had evolved as well. With the elimination of the *Public Utilities Income Tax Transfer Act* in 1995, the cost effectiveness of preferred shares was reduced from a regulatory standpoint, resulting in a new target capital structure. ATCO noted that this led to a significant replacement of the preferred shares existing in 1993 with a combination of debt (80%) and equity (20%).

ATCO requested approval of target capital structure ratios based upon an analysis using S&P benchmark debt rates. This analysis indicated that based upon an assumed business risk profile of "2" and maintenance of an A+ debt rating, the appropriate target capital structure (along with the comparative original 1993 target capital structure) for ATCO was:

Table 5. Target Capital Structure

	1993 (%)	2003/2004 (%)
Debt	38 – 43	50 – 55
Preferred Shares	22 – 26	5 – 10
Common Equity	32 – 37	37 – 42

ATCO submitted that the actual capital structure upon which the revenue requirement would be based was within the target ratios for both 2003 and 2004.

ATCO submitted that maintaining this target capital structure would permit ATCO to contribute its fair share to the financial stability of its parent, CU Inc. CU Inc., the vehicle which accessed the financial markets on behalf of ATCO, was rated A (high) by DBRS and A+ by S&P. In keeping with the "stand-alone" principle, ATCO needed to maintain its financial integrity at an A (high)/A+ level in order to assist CU Inc. in maintaining its credit rating. ATCO submitted that its proposed capital structure, in conjunction with its embedded debt and preferred share costs, a ROE of 11.0% and a marginal tax rate of 37.1% (35.1% in 2004) indicated a pre-tax interest coverage ratio for both years of 2.6 times, which was within S&P's benchmark range of ratios for an A+ rated company with relatively low business risk.

Based on its assessment of increased business risk, ATCO's forecast capital structure ratios during the test period were:

Table 6. Forecast Capital Structure Ratios

	2003 (%)	2004 (%)
Debt	55.1	55.6
Preferred Shares	6.9	6.2
Common Equity	**38.0**	**38.2**
	100.0	100.0

ATCO noted that these forecast capital structure ratios were within the range of the Company's target capital structure and were reasonable, given the increased business risk faced by ATCO. ATCO also submitted that maintaining these capital structure ratios would permit ATCO to contribute its fair share to the financial strength of CU Inc. and allow it to obtain the required financing to complete its capital expenditure program.

ATCO noted that the principal aspect of business risk discussed at the hearing related to the franchise risk. The Company stressed that the loss of a franchise such as Edmonton would have a very significant impact upon the balance of the utility. The most notable change in circumstances was identified as the highly competitive environment, which had developed for securing franchises. ATCO noted Aquila's current concerns with respect to certain potential arrangements being discussed between ENMAX and the Town of Airdrie. In addition, ATCO submitted that discussions involving the Edmonton franchise were also ongoing. As a result, ATCO argued that it was this change, which significantly increased the risk of franchise renewal. Specifically, municipal councils had unleashed their municipal utilities, which were advantaged in terms of their tax status and the credit support from their parents, the cities of Edmonton and Calgary. In these circumstances, ATCO submitted that the historical loss of a franchise was irrelevant.

ATCO noted that the potential for loss of franchise was explored in light of the current standard of replacement cost, new less depreciation "RCN minus D." ATCO's position was that the applicability of such a formula might be in doubt due to the proceeding surrounding the Airdrie situation currently pending before the Board. ATCO noted that for the 2003/2004 test period, it was not known what the price would be until that case was resolved. At the same time, ATCO stated that it would expect a higher price for a forced sale. That consideration would demonstrate that the Company was exposed to a loss of additional value above net book value in the event of the loss of a franchise, even under the interveners' interpretation of the RCN minus D standard. ATCO further noted that while the Airdrie decision might shed some light on the feasibility of purchases of certain franchises, the Edmonton franchise was not governed by that standard.

ATCO submitted that a review of the Termination clause of the Edmonton Franchise Agreement disclosed a different standard, thereby highlighting the continued risk of significant franchise loss.

ATCO also responded to those parties taking issue with the materiality of the increased franchise loss risk on the basis of what was reflected in the Canadian Utilities Limited Annual Information Form, prepared to satisfy the requirements of securities legislation. ATCO submitted that the National Instrument Form 44-101F1 required disclosure where a trend existed which was both known and had a material effect. ATCO acknowledged that franchise risk fell within a gray area in terms of disclosure since no trend of franchise loss could yet be identified. In addition, since the securities law disclosure policy guidelines did not direct such a discussion, the Company avoided increasing the perception of risk surrounding this development. ATCO indicated that the existence of franchise risk was well founded given the actions of municipally owned utilities such as ENMAX and municipal councils such as Edmonton, which had made clear their intention to pursue these options.

With regard to the investors' perception of increased regulatory risk in Alberta, ATCO submitted that it should be borne in mind that what was relevant was not what the Company believed to be the risk, but what the investment community viewed to be the risk.

The evidence that ATCO filed with regard to regulatory risk identified earlier expressions of concern from the investment community about the regulatory environment and the adequacy of protections offered to an Alberta utility in terms of its ability to earn its allowed return. For example, Drs. Booth and Berkowitz confirmed that it was the DBRS Report dated October 20, 2000 that coined the phrase "unfavourable regulatory environment." In addition, ATCO noted that S&P revised its outlook on CU Inc. to negative from stable in November 2002. ATCO further submitted that it was not necessary to refer to what Standard & Poor's issued in 2003 in order to establish that bond rating agency's assessment of the increased business risk and "low deemed equity allowances and comparatively low ROEs that largely dictate a Canadian utility's financial profile."

ATCO noted that while Drs. Booth and Berkowitz attempted to suggest that DBRS restricted its concerns to the electric side of the business, a plain reading of the words used in the report made clear that the concerns expressed related to the existing scheme of regulation on the gas side as well. Similarly, both Drs. Booth and Berkowitz attempted to suggest that S&P restricted its concerns to the "non-core" or non-regulated business, however, the plain language of the report stated otherwise. As a result, ATCO submitted that S&P was changing its outlook on CU Inc., the regulated holding company, to negative from stable. ATCO further noted that the report focused on "utility" ratings and "deemed equity allowances", concepts that did not apply to non-regulated entities. In addition, the reference to comparatively low returns on equity was a reference to the regulated side of the business. ATCO concluded that, on the basis of the information available prior to the test period, it was obvious that the rating agencies believed a down grading was "highly likely" and that a serious concern existed that CU Inc. might have to reduce its leverage in order to retain its ratings.

ATCO noted that three Calgary expert witnesses and a policy witness contended that there was a major risk associated with electrical deregulation and that this factor had an impact on investors' perceptions. On the gas side, Mr. Johnson indicated that investors had concerns due to the "storm clouds" related to electric deregulation, while Ms. Sharp expressed Calgary's concerns about ongoing gas deregulation. In light of the foregoing, ATCO submitted that its description of the concerns expressed by the investment community was founded not just on the actions of the regulator, but on the intervention of the government as well. The existence of those third-party expressions of serious concern were a fact, which reinforced ATCO's assertion that the investment community perceived increased regulatory risk in connection with its operations.

ATCO submitted that they provided the only analytical evidence related to the question of capital structure. ATCO noted that Calgary only reviewed the existing common equity ratios of a number of Canadian utilities and based on this review concluded that a 35% common equity was appropriate. ATCO argued that this conclusion was both circular in that it relied totally on what other regulators had approved and was subjective. ATCO submitted that while the Company's approach based its conclusions on the external benchmarks of S&P, the Interveners' evidence was based upon an opinion. For example, ATCO noted that Calgary's evidence did not reflect the current concern expressed by S&P that the equity ratios currently allowed by Canadian regulators were consistently below those of similarly rated utilities in other countries, and despite this factor argued that ATCO's common equity ratio should be reduced.

ATCO noted that with regard to franchise risk, Calgary had attempted to set up a straw man with respect to "expropriation." Calgary appeared to suggest that there was no risk to a utility whose franchises were not renewed. ATCO argued that this view ignored the evidence about the effect of losses of economies of scope and scale on the ability to remain competitive in the remaining franchises. The discussions with respect to the Airdrie and Grande Prairie situations also belied what ATCO had always contended was the more serious danger, which was the loss of a major franchise such as that of the City of Edmonton. The evidence showed that the Edmonton franchise was governed by a different standard than Airdrie. ATCO stated that the logical extension of Calgary's submissions was that even if the utility lost its entire business through non-renewal, Calgary would contend there was no business risk. ATCO responded that the risk existed and that the loss of any franchise made more difficult the retention of the balance due to the compounding effect of the loss of economies of scope and scale.

With respect to AUMA/EDM's observations that the Edmonton franchise "…does not come up for renewal during the test years," ATCO noted that this argument would circumscribe any business risk to only exist at the point in time when the risk identified actually materialized. ATCO submitted that, as had been well accepted, the existence of a business risk was not predicated upon the actual occurrence of it. ATCO noted the CG indicated that CWNG was able to successfully retain the Cochrane franchise by building a new service centre in that town, and ATCO had proposed several new service centres in the current GRA. The CG pointed to this as an example of how ATCO was able to mitigate the risk of franchise loss.

ATCO expressed the view that it should clarify these matters for the Board. In the response to FGA-3 of the CWNG 98 GRA, CWNG indicated that it decided to build rather than lease the Cochrane facility to show a long-term commitment to the community. CWNG also indicated several other reasons throughout the proceeding as to the need for the facility. The Board, in Decision 2000-9 required ATCO to adjust the utility rate base to only include an alternative lease cost for the facility. ATCO also noted that the CG indicated in Argument that they did not view that the Sherwood Park operating centre was required.

ATCO disagreed with the CG's views that these circumstances demonstrated that the Company had the ability to mitigate the risk of franchise loss. ATCO submitted that the Board indicated that the least cost alternative with respect to the Cochrane facility was the route for CWNG to have taken, regardless of any franchise considerations. The CG argued against the development of a facility, which was required by ATCO in Sherwood Park. In general, ATCO wondered at what point had ATCO been afforded the opportunity to mitigate the risk of franchise loss.

With regard to regulatory risk, ATCO noted Calgary's argument that because the stock price of Alberta utilities had not dropped, there had been no change in investors' perceptions of the regulatory climate in Alberta. ATCO argued that this argument neglected the evidence on the record, which was a clear indication of the change in investors' perceptions. ATCO noted that it presented evidence of the investors' concerns. The evidence included DBRS' comments as the result of the changing regulatory climate, published comments about the increased risk of deregulation made by the financial community and comments of the funding bank and the Securitization Investigation Group which identified the regulatory risk as the primary risk to completing the securitization of the Alberta electric utilities' deferral account balances, and the concerns expressed by S&P about the low common equity ratios and low rates of returns experienced by Canadian utilities. Based on these examples, ATCO submitted that there was substantial evidence on the record that the investors' perceptions had changed. ATCO further stated that the share price of Canadian utilities was the result of many factors, not the least of which is the level of the dividend yield in relation to interest rates.

Views of AUMA/EDM

AUMA/EDM noted that in the AGS 2001/2002 GRA, Phase I, the Board determined that there had been no significant change in the business risks facing AGS and consequently determined that a common equity ratio of 37% was appropriate for the test years 2001 and 2002. In this Application, AUMA/EDM further noted that ATCO acknowledged that as there were no significant risk differences between AGS and AGN, it was reasonable to assume that although the decision applied specifically to AGS it could equally be applied to ATCO Gas as a whole.

In an attempt to revisit the Board's conclusions in two prior decisions, AUMA/EDM observed that ATCO premised its request for a higher equity ratio based on the fact that business risk had materially increased since 1993 as evidenced by two threats currently faced by ATCO; an increased risk of franchise loss and the investors' perception of the Alberta regulatory environment.

With regard to franchise risk, AUMA/EDM observed that ATCO's witness summarized his concern that "… several municipalities were exploring their options for acquiring both gas and electric systems", and went on to acknowledge that in a similar situation "we would look at our options."

In support of its position related to franchise risk, ATCO referred to the Application of the City of Airdrie and comments attributed to one of the City of Edmonton councilors. In response, AUMA/EDM noted that Airdrie's Application related to its electrical distribution system, which had no direct implications for ATCO Gas, and, at this stage, no decision had been made to purchase.

AUMA/EDM submitted that any further discussion regarding the increase in business risk resulting from "concerns over the potential that certain municipalities might elect to discontinue their franchise agreements and acquire the distribution system and operate as a municipally owned system" should be disregarded unless and until such time as the required application was made to the Board by an interested municipality. AUMA/EDM indicated that in the current proceeding, the issue of franchise risk appeared to be more imagined than real.

With regard to investors' perception of the regulatory environment, AUMA/EDM noted that ATCO suggested that investors might "… interpret some recent EUB decisions as reflecting a fundamental change in the Board's balancing of the interests of the utility customers with the interest of the investors" and additionally made specific reference to the Calgary Stores Block Sale decision.[36]

With reference to the Calgary Stores Block Sale decision, AUMA/EDM noted, firstly, that the Board did not accept the AGS Argument regarding expropriation and the cases cited were stated as being not "particularly helpful". Secondly, of the net sale proceeds, approximately 2/3 or $4.0 million were to be credited to customers. By comparison, AUMA/EDM noted that AGN did not appear to be particularly concerned regarding a similar sharing of the net proceeds of the sale of its production and gathering facilities, which had a value in excess of $400 million.

AUMA/EDM submitted that ATCO had overstated this issue and had not provided any evidence to suggest that investors had changed their attitude toward the Alberta regulatory environment. Similarly, while ATCO addressed this issue in the Application, it did not increase its common-equity ratio as a result of this perceived risk.

AUMA/EDM noted that in establishing its target capital structure, ATCO relied entirely on Standard & Poor's rankings and "guideline debt ratios for those business risk ratings". However, in considering the relative risk of ATCO's fund-raising parent, AUMA/EDM further noted that of the fifteen major Canadian gas and electric utilities referred to in Ms. McShane's evidence, CU Inc. had the highest bond rating by both DBRS and S&P. Of this group, the A-rated gas distributors (B.C. Gas Utility, Enbridge Consumers Gas, Gaz Metropolitain and Union Gas) had an average common equity of 33.85% for 2001, which increased to 37.35% in 2002. AUMA/EDM observed that this was consistent with the common equity ratio of 37% approved by the Board in Decision 2001-96, given the marginally higher rating for CU Inc.

With regard to business risk, AUMA/EDM submitted that, given the larger size of the amalgamated entity (AGN and AGS), ATCO's business risk had in fact, been reduced.

AUMA/EDM submitted that since ATCO had not provided any evidence to suggest that there had been an increase in the business or financial risk of ATCO or its parent, CU Inc., there was therefore, no justification for increasing its common equity ratio. With regard to the specific equity ratio to be employed for the test years, AUMA/EDM expressed support for the argument of Calgary, based on the evidence of Drs. Berkowitz and Booth.

AUMA/EDM observed that, in response to a Board IR, ATCO also provided a copy of S&P's November 12, 2002 report, which indicated that its outlook had been "Revised to Negative". However, AUMA/EDM noted that this was a credit rating for ATCO Limited, which had considerable non-regulated activities, and not CU Inc., which was the fund-raising entity.

[36] Decision 2002-037 – ATCO Gas and Pipelines Ltd., Disposition of Calgary Stores Block and Distribution of Net Proceeds – Part 2, dated March 21, 2002

AUMA/EDM submitted that it was clear from this report that the increasing business risk of ATCO Ltd. was a function of its non-regulated operations.

Based on the evidence, AUMA/EDM submitted that ATCO should not be compensated, in any way, for the risks associated with the non-regulated businesses of its affiliates.

AUMA/EDM noted that ATCO described the principal aspect of its business risk as being related to franchise risk and stated: "The most notable change in circumstances was identified as the highly competitive environment which has developed for securing franchises." AUMA/EDM submitted that there was no evidence presented regarding "securing franchises" and limited if irrelevant hearsay evidence that several municipalities might be considering "exploring" other alternatives.

AUMA/EDM submitted that ATCO's statement that municipalities "have unleashed their municipal utilities" and "are actively hunting down existing franchises" was not supported by the evidence. AUMA/EDM noted that this argument had been advanced by the ATCO Group of companies on numerous occasions and, in each instance, found to be without merit. AUMA/EDM considered that even if the concerns expressed were real, it would not justify enhancing the return to which ATCO would otherwise be entitled.

AUMA/EDM noted ATCO's comments suggesting that it might not receive compensation based on "RCN-D" for the loss of a franchise. However, AUMA/EDM submitted that this was inconsistent with the position taken by Mr. Beckett, on behalf of the Company, when he stated, during the course of cross-examination, that: "If ATCO Gas was forced to sell its assets, ATCO Gas would expect more than RCN minus D." AUMA/EDM indicated that on the assumption that ATCO would expect to keep the excess, it would receive a windfall gain over that which it could earn by retaining the assets in regulated service.

With regard to regulatory risk, AUMA/EDM noted that ATCO's reference to the "unfavorable regulatory environment" appeared to be based on a DBRS Debt Rating Report for CU Inc. made in October 2000. AUMA/EDM submitted that whether or not it was relevant at the time, it could hardly be described as indicative of current investors' perceptions in the investment community.

AUMA/EDM observed that, in support of its position, ATCO appeared to take comfort from general comments made from time to time by S&P. However, AUMA/EDM noted that these S&P comments did not appear to have, in any way, translated into a lack of acceptance of CU Inc. securities by real market participants. This was demonstrated by the markets' recent acceptance of CU Inc.'s 6.145% debt issue in November 2002 and the lower than average yields on its long-term bonds.

AUMA/EDM noted ATCO's conclusions regarding regulatory risk were evidenced by its assertion that the investment community perceived increased regulatory risk in connection with its operations. AUMA/EDM submitted that the relevance of this concern and the extent, to which, if at all, it influences real-market participants was unknown and not identified in any way in the evidence. In addition, AUMA/EDM noted that CU Inc. continued to maintain higher than average ratings and clear market acceptance as an issuer of debt and equity.

With respect to the equity ratio, AUMA/EDM noted ATCO's submission that it "… provided the only analytical evidence related to the question of capital structure." This "analytical evidence" was the S&P's benchmarks referred to at page 3.1-14 of the Application. AUMA/EDM noted that these "guidelines" attempted to assign an appropriate range of debt ratios based on the debt rating and business profile of a particular utility.

AUMA/EDM observed that, in relying on these guidelines, ATCO simply stated that "gas distribution utilities were typically assigned a 2 or 3 on the S&P scale." However, AUMA/EDM submitted that ATCO had not been assigned a business profile number by S&P and that it was a quantum leap to suggest that this constituted "analytical evidence" supporting a particular capital structure. As a result, AUMA/EDM argued that this was hearsay evidence, further noting that no witnesses were presented who had a direct knowledge of the manner in which the guidelines were determined, how they would apply to a particular utility and into what "business profile" category ATCO, or its parent CU Inc., should be assigned.

AUMA/EDM considered that, given its higher than average ratings, CU Inc. might well be assigned a 1 on the S&P scale (Business position) which, for an A-rated utility would justify a debt ratio of 55% - 60.5%. At the same time, AUMA/EDM stated that clearly it was a mistake to reply on the Business position "typically assigned" to distribution utilities in general.

AUMA/EDM submitted a general comment that given the heavy reliance of ATCO on the comments of unidentified S&P sources, it would be helpful to the Board and interveners if parties having a direct knowledge of these matters were presented as witnesses. In general, AUMA/EDM considered that this type of "evidence" must be viewed with a large degree of skepticism.

Views of Calgary

Calgary noted that ATCO's Application contained a series of assertions to support its proposition that its business risk had increased since 1997. Through the evidence of its experts, Calgary submitted that it addressed these assertions and found no increase in the risk facing ATCO since the time of the last hearing into the business risks of AGS.

With regard to franchise risk, Calgary noted that ATCO had submitted that there were increased risks of franchise loss, and that there were major consequences to the loss of a single franchise "no matter how small." In addition, ATCO had asserted that the exercise of one of the rights included in the franchise agreements "would challenge the viability of the Company." Calgary submitted that the increased of franchise loss, as presented by ATCO, had little factual support, and did not withstand analysis.

First, Calgary submitted that a franchise loss was not a "forced taking" or an "expropriation," but rather the exercise of an option for termination under a franchise agreement, to which the utility was a party. Calgary noted that ATCO had benefited from the agreements for many years and should hardly be allowed now to enhance its capital structure by raising concerns about one element of the package deal.

Calgary noted that franchise agreements were long-term arrangements with negotiated expiry or renewal terms. The price of exercise of the option, embedded in the franchise agreement, was to be set by the regulator in the absence of a negotiated agreement. Calgary further observed that ATCO appeared to view the mere exploration of an option right granted to a party to a contract as the "threat" of loss. In addition, ATCO appeared to ignore the content of the Airdrie letter, which suggested that the price under which options of this sort might be exercised effectively represented a material impediment to anyone considering exercising the option. For example, Calgary noted that on page 2 of the Airdrie letter to Grande Prairie attached to CAL-AG-13 (a), the author observed that in the event that the cost of purchase was “replacement [cost] of a system under existing development conditions.., no municipality, or business for that matter, could make a business case to purchase its system.”

Calgary further noted that this allegedly new risk to ATCO had not been reflected in its public disclosure documentation, and submitted that there was also no probative evidence with respect to the impact of franchise loss. The record showed that “No formal analyses have been performed in the past to determine the impact of a franchise loss” by ATCO. For example, Calgary noted that the Grande Prairie franchise represented approximately 1.5% of revenues and 0.86% of rate base of ATCO, and observed that a year in which capital expenditures were less than depreciation could bring about a reduction of the ATCO rate base of 0.86% or more. Calgary argued that by comparison, the assertion that a decrease in rate base of less than 1%, or the loss of revenues of approximately 1.5% would threaten the Company’s viability was without foundation, and as a result should be given no weight by the Board.

Calgary also noted that in the one case of a franchise being lost in the last 30 years, ATCO received an amount greater than its book value. Calgary submitted that there was little or no harm to ATCO in the sale of certain of its franchise assets under one of these options at a price above book. Calgary indicated that in this instance, ATCO could alternatively take the proceeds and search for alternative investments, or return the proceeds to the investors and let them do the same.

With regard to investor perceptions of the regulatory environment, Calgary argued that there was even less substance to ATCO’s assertion that the Company was being adversely impacted by the possibility that some investors could form a negative view of the Alberta regulatory environment. Calgary noted that in ATCO’s evidence, it raised concerns about the “potential for investors” to reach certain conclusions, including forming “the opinion that there had been a material change in the regulatory risk profile faced by ATCO Gas.” Calgary responded that were investors to have formed this opinion, this concern would extend beyond ATCO to many Alberta utilities. Calgary considered that in addition, were investors to have formed this opinion, this perspective would be reflected in the prices at which the securities of Alberta based utilities were trading.

Calgary concluded that in regard to ATCO’s argument that there had been an increase in regulatory risk, ATCO had not proven this to be the case based on the evidence.

With regard to financial risk, Calgary submitted that the evidence was clear that ATCO was already doing its share to maintain the financial stability of its parent, CU Inc. Calgary was also of the view that the alleged need to meet certain S&P’s benchmarks to obtain or maintain a particular rating had been proven illusory.

Calgary noted that while the S&P’s rating outlook was revised to negative for ATCO Ltd. and subsidiaries Canadian Utilities Ltd and CU Inc. on November 12, 2002, the comments made in that document were illuminating as to the role of ATCO’s distribution assets in supporting the rating. In that announcement, S&P focused on the increase in “ATCO’s business risk” including "growing investments in non regulated independent power … growing merchant power exposure … and the growth of non utility operations."

Calgary observed that while S&P had commented on what it perceived to be the relatively thin equity layer allowed regulated Canadian utilities, the specific statements in the November 12, 2002 S&P comment demonstrated that the increasing business risk was due to the "growth of non utility operations" and independent and merchant power investments. Further, the degree of erosion of the more solid base of regulated operations could be seen in the reply to CAL-AG-26, which demonstrated that the regulated portion of the assets of CU Inc. had fallen from 99.99% to 79.29% from 1999 to 2001. Calgary noted that in the case of Canadian Utilities Limited, the regulated portion of assets had fallen from 97.23% in 1990 to 56.83% in 2001.

Calgary also noted that in BR-AG-47, the Board was provided with the S&P's rating report for ATCO, Canadian Utilities and CU Inc, which noted a "Stable regulatory environment" and that the non-regulated businesses "could impact ATCO's consolidated leverage over the long term."

In terms of capital structure, Calgary submitted that it addressed capital structure in different ways in its evidence. Drs. Booth and Berkowitz looked at it and concluded the appropriate level for an LDC like ATCO would be 35%. Calgary also provided business risk evidence, which it compared ATCO to other gas LDCs, gas pipelines and oil and product pipelines and an Alberta transmission facility owner. On the basis of that analysis, Calgary concluded that ATCO was somewhat less risky than the average gas LDC. At the same time, based on their independent risk assessment, Drs. Booth and Berkowitz indicated that they believed that ATCO was equivalent in risk to the average Canadian LDC. Calgary argued that since the average equity ratio of Calgary's LDC sample was 35% and Drs. Booth and Berkowitz recommended a 35% equity ratio for ATCO, the risk assessments were consistent.

Calgary noted that Drs. Booth and Berkowitz had shown that the business risk of ATCO was low, primarily because gas costs represent approximately two thirds of the firm's revenue requirement in the years 2003 and 2004. Further, Calgary stated that while the variability of gas supply costs would constitute a major part of the competitive firm's business risk, the use of deferral accounts for gas costs had largely insulated ATCO's shareholders from these risks in a way that would be extremely difficult for a competitive firm to duplicate.

Calgary submitted that if an LDC was no longer selling gas, and its revenue was based upon fixed charges, the common equity ratio could be as low as 30%. In keeping with the assumption in the Application, i.e., ATCO continued to be in the retail business, Calgary recommended a common equity ratio of 35% for ATCO.

Calgary noted that ATCO's submission that the Company provided the only analytical evidence related to the question of capital structure, and that Calgary merely reviewed the existing common equity ratios of a number of Canadian utilities, concluding that a 35% common equity was appropriate. Calgary disagreed with this statement, stating that Drs. Booth and Berkowitz had analyzed the capital structure of ATCO in the context of other utilities and comparative business risk, and that Mr. McCormick had also reviewed ATCO's capital structure. Calgary submitted that Calgary was the only party to analyze data with respect to the appropriate common equity ratio. Calgary further noted that there was no such analysis in ATCO's Application.

Calgary noted that Drs. Booth and Berkowitz looked at other companies and at the relative business risk of ATCO and determined on the basis of that analysis that the appropriate common equity would be 35%. Calgary indicated that in contrast, ATCO stated its requested equity ratio, and that no analysis was provided to support this request. In addition, Calgary noted that ATCO did not present any comparison of the relative business risks of ATCO and other regulated companies.

Calgary disagreed with ATCO's argument that Calgary's evidence did not reflect the current S&P comments on debt ratios. In this regard, Calgary considered that this was not surprising since the Calgary evidence was filed in January 2003 and the S&P comments made on March 6, 2003. Calgary noted that those comments were discussed by Mr. McCormick and Drs. Booth and Berkowitz in testimony. Mr. McCormick and Drs. Booth and Berkowitz, as expert witnesses, explained why, in their views, the S&P comment should not be of concern. Calgary also expressed the concern that ATCO raised this new evidence in argument, given ATCO's views on prospective ratemaking.

Views of the CG

The CG noted that ATCO started from the Board's evaluation of Business Risk as set out in Decision 2001-096 and 2000-9, and then set out changes in business risk that it claimed increased the risk to the Company, and that although Decision 2001-96 applied specifically to AGS it could equally be applied to ATCO Gas as a whole. The CG did not object to ATCO's proposal to determine an appropriate capital structure for the Company as a whole.

The CG noted that ATCO set out two sources of increased business risk, namely risk of franchise loss and investors' perceptions of the Alberta regulatory climate, indicating that these factors had significantly increased the Company's risk since Decision 2001-96 and warranted an increase in deemed equity ratio to a 37 - 42% range. Since the actual capital structure of ATCO was 38.2%, the Company proposed setting the capital structure equal to the actual capital structure.

The CG noted that in terms of supporting evidence regarding loss of franchise areas, ATCO cited the Cities of Airdrie and Grande Prairie as examples of potential losses for Aquila Networks Canada Ltd. (Aquila) and ATCO Electric, respectively and the possible loss of the City of Edmonton and Grande Prairie for ATCO Gas. The CG submitted that neither electrical proceeding was relevant to the risks faced by ATCO. The CG observed that ATCO adhered to the stand-alone principle and defined it as a concept where the utility was viewed as an entity separate and independent from its parent or any other activities of the Corporation. The CG noted ATCO's position that the utility was viewed as if the financial community could invest directly in the assets of that utility only.

As a result, the CG submitted that the risks faced by a corporate affiliate were not relevant to these proceedings. Further, the CG argued that the risk of franchise loss by another company, in another industry, was even more irrelevant.

Acknowledging that the possible loss of the City of Edmonton would be a risk, the CG argued that investors would rightly view it as such since it would reflect poorly on management abilities, but only if such an event were imminent and probable. However, the CG noted that the only information concerning this potential risk was a reference to the musings of a nameless member of City Council. The CG further noted that, even if verified, speculation by a public official did not constitute public policy nor was it indicative of a municipality's willingness to complete the actual purchase the franchise. Similarly, there was no evidence placed before the Board as to the nature of the meetings between officials of Grande Prairie and ATCO. Consequently, the CG submitted that, at this point in time, ATCO's concern regarding franchise loss appeared to be mere speculation in relation to possible, but not probable risk.

In addition to the foregoing, CG noted that the speculative nature of the franchise issue was amply demonstrated by the fact that it was not disclosed as a possible risk to risk rating agencies such as S&P. The CG also noted ATCO's statement that the rules for disclosure required an issue be material and a continuing trend. In this regard, ATCO indicated that, while the loss of a franchise would be material, there was no known trend concerning loss of franchises. However, the CG observed that the progress of the Airdrie franchise hearings should give investors sufficient notice that a significant franchise was at risk.

The CG submitted that even if there were substance to ATCO's assessment of business risks, ATCO could and would take steps to mitigate the risk of loss of franchise. In addition, the CG noted that ATCO acknowledged that it had the ability to offer better quality of service and response to customers in comparison to a situation in which a municipality ran the distribution franchise. The CG also stated that ATCO might forestall a loss of franchise by insisting on a method of valuation resulting in a price well above book value. In addition, the CG observed that ATCO's predecessor, CWNG, successfully retained the Cochrane franchise by building a new service centre in that town. With regard to the current Application, the CG noted that ATCO was proposing several new service centres.

The CG noted that ATCO submitted that the Board must give "significant weight" to the risk of any loss of franchise on a prospective basis because of investors' perception privately-owned assets might be "expropriated". However, the CG submitted that ATCO failed to provide any evidence that the financial community had taken any note of the franchise question for any of the CU companies, or for any other Alberta utility. Investors' perceptions are part of the financial risk of a company and investors will balance the potential risk of franchise loss with the mitigating steps the Company can take. However, the CG stated that this would only be a concern if there was a serious and probable risk of franchise loss in the foreseeable future. The CG submitted that there was no evidence of such a probable risk in the foreseeable future.

With respect to investors' perceptions of regulatory risk, the CG stated that since the "perceptions" had not been used by ATCO to determine an appropriate capital structure, then that should be the end of the matter. However, despite the fact that ATCO claimed not to give any weight to this factor, it still set out a long list of concerns with past Board decisions.

The CG questioned why ATCO introduced evidence, which it did not use. The CG submitted that, other than notifying the Board that the Company did not receive everything requested in certain Decisions or received "a less objective treatment of the utilities and their investors," ATCO's evidence concerning perceptions around regulatory risk is, by its own admission, was irrelevant.

The CG noted that while ATCO considered that it "factored in the increased regulatory risks related to the structural changes it will face as the industry moves towards customer choice," this did not appear to be the case given that ATCO had not addressed the matter of the sale of its retail business to a third party, which definitely represented a structural change for the gas industry.

Based on the Board's determination that the 2003/2004 GRA would proceed based on the assumption that the distribution business continued to include the retail function, with the potential for approval of the revenue requirement on that basis, the CG agreed that ATCO did not need to incorporate the sale of retail assets until such time as the sale were approved.

Absent any sale of retail assets, the CG submitted that ATCO had not submitted any evidence on changes in business and/or finance risk sufficient to warrant a change in the deemed equity ratio of 37% set for AGS in Decision 2001-96 for the 2003 test year. The CG further submitted that since the sale of retail assets might not be approved until 2004 and ATCO would be in the gas retailing business during 2003, an equity ratio of 37% was appropriate for 2003.

With regard to 2004, the CG submitted that any changes to business risk for ATCO could not be effectively evaluated until all aspects of the sale were examined. The CG also stated that, if the sale were approved, ATCO would effectively divest itself of the competitive, and the riskiest, portion of the utility industry and in turn would likely reduce its business risk.

The CG submitted that interveners had amply demonstrated why the business risk of ATCO had not increased and, in all likelihood, might have decreased.

Views of the Board

The Board notes ATCO's submission that as there are no significant risk differences between AGS and AGN and that it is reasonable to consider that the finding of Decision 2001-96 issued with respect to AGS, could be applied to ATCO Gas as a whole. The Board further notes that parties appeared to accept this position. Based on the evidence and lack of clear and complete evidence to the contrary, the Board considers that there do not appear to be significant risk differences between AGS and AGN. In this respect, the Board agrees with ATCO that it is appropriate to assume that the Board determinations regarding AGS in Decision 2001-96 could equally apply to ATCO Gas as a whole. As a result, the Board will make its determinations regarding business risk and capital structure in relation as if AGS and AGN were consolidated.

Based on this determination, the Board notes ATCO's submission that its business risk has materially increased since 1993, as evidenced by an increase in the risk of franchise loss, and investors' perception that regulatory risk has increased in Alberta.

The Board notes that in Decisions 2000-9 and 2001-96, the Board determined that business risk had not significantly changed since the relevant prior Decisions.[37] The Board sees no basis to reconsider the views expressed in Decisions 2000-9 and 2001-96. The Board considers that business risk for ATCO did not significantly change during the period 1993 to 2001. Consequently, the relevant period under review in regard to business risk is the time frame since Decision 2001-96.[38] For this reason, the Board does not accept ATCO's view in the Application that the period under review in regard to business risk includes the years 1993 to 2001.

[37] The relevant prior decision for Decision 2000-9 was E93004. The relevant prior decision for Decision 2001-96 was Decision 2000-9.
[38] Issue date was December 12, 2001.

Accordingly, the Board will consider the two risks that ATCO has identified, as well as overall business risk, for the period since 2001, the year that Decision 2001-96 was issued.

With regard to franchise risk, the Board notes ATCO's concern that several municipalities are exploring their options for acquiring both gas and electric distribution systems with the intention of replacing the incumbent utilities. The Board notes that ATCO cited the examples of Aquila's current concerns with respect to certain arrangements being discussed between ENMAX and the Town of Airdrie, as well as the upcoming franchise renewal with the City of Edmonton.

The Board notes Calgary's statement that franchise agreements are long-term arrangements with negotiated expiry or renewal terms. The Board recognizes that, based on the evidence, in the event that the cost of purchase is the replacement cost of a system under existing development conditions, it is probable that no municipality, or business, could make a business case to purchase its distribution system. The Board acknowledges that it is presently uncertain whether the current standard of replacement cost new less depreciation "RCN minus D," will be changed in the Airdrie proceeding, or be revised in a future proceeding. The Board recognizes that, the exercise price under which options in a franchise agreement might be exercised effectively may continue to represent a material impediment to exercising the option. In addition, the Board encourages ATCO to continue to take appropriate actions and measures to effectively mitigate the potential risk of franchise loss.

In general, the Board considers that franchise risk has always been an issue, noting that the last time ATCO lost a franchise was approximately 30 years ago. While the loss of another franchise could potentially be significant for a utility, based on the evidence in this proceeding, the Board considers it difficult to determine if the risk related to this issue has increased for ATCO. In this respect, the Board also agrees with Calgary that there has been no probative evidence with respect to the impact of franchise loss in the proceeding, and that no formal analyses have been performed to determine the impact of a franchise loss by ATCO.

For the above reasons, the Board considers that franchise risk has not significantly changed. Further, if circumstances change and ATCO actually loses a franchise, the Board notes that ATCO has the option of filing an application with the Board to request a change to cost of capital.

With regard to investors' perceptions of the regulatory environment, the Board notes AUMA/EDM's comments that the relevance of this concern and the extent to which it has influenced real-market participants was unknown and not identified in any way in the evidence. In addition, the Board notes AUMA/EDM observation that CU Inc. continues to maintain higher than average ratings and clear market acceptance as an issuer of debt and equity.

The Board also notes Calgary's observation that while the S&P's rating outlook was revised to negative for ATCO Ltd. and subsidiaries Canadian Utilities Ltd. and CU Inc. on November 12, 2002, as shown in BR-AG-47, the comments made in the S&P document are illuminating as to the role of ATCO's distribution assets in supporting the rating. The Board notes Calgary's comments that S&P focused on the increase in "ATCO's business risk" including "growing investments in non regulated independent power … growing merchant power exposure … and the growth of non utility operations." In the report, S&P noted that these operations are higher risk than core regulated operations. In addition, the Board notes that in BR-AG-47, ATCO provided another S&P report for ATCO, Canadian Utilities and CU Inc. dated June 26, 2001, and in that report S&P noted a "Stable regulatory environment" and that the non-regulated businesses "could impact ATCO's consolidated leverage over the long term."

In this regard, the Board agrees with Calgary's argument that there is insufficient evidence with regard to ATCO's assertion that the Company is being adversely impacted by the possibility that some investors could form a negative view of the Alberta regulatory environment, and considers that if investors have developed this view, this perspective would be reflected in the prices at which the securities of Alberta based utilities were trading.

The Board also notes ATCO's statement that it has excluded its interpretation of investor perceptions of regulatory risk in making its recommendations for capital structure.[39] As a result, the Board agrees with the CG that since the "perceptions" have not been used by ATCO to determine an appropriate capital structure, that should be the end of the matter.

Based on all of the factors, the Board considers it appropriate that ATCO has excluded the issue of investors' perceptions from the determination of capital structure.

In summary, based on the evidence, the Board is of the view that ATCO has not proven that franchise risk and regulatory risk have significantly changed or increased during the period under review. In addition to this determination, the Board notes that in Section 4.2.6 of this Decision, approval has been granted related to components of the Reserve for Injuries and Damages, which will effectively act to reduce risk. Specifically, the Board has allowed the inclusion of insurance premiums in the Reserve and has granted ATCO's request to include insurance premiums for Carbon working gas. As a result, these two factors, which have acted to reduce business risk, have been reflected in the Board's overall assessment of ATCO's business risk.

Overall, the Board considers that ATCO's business risk has not significantly changed since the issuance of Decision 2001-96. In addition, the Board considers that some factors, as discussed above, have acted to reduce business risk, and in turn have mitigated any potential incremental increase in risk.

Accordingly, Board directs ATCO to maintain a common equity ratio of 37% for the test years, in line with the common equity ratio last approved in Decision 2001-96.

3.3 Establishment of a Placeholder

Views of ATCO

Regarding the use of a placeholder in 2004 for ATCO as suggested by the CG, ATCO noted that the CG was attempting to reopen the Board's procedural decision dated October 18, 2002 and to further expand the scope of the Generic Cost of Capital Hearing, for which evidence was due in less than a week. In the circumstances, ATCO submitted that the CG's suggestion should be dismissed.

Views of the CG

The CG observed that the Board's Ruling of May 28, 2003 suggested three alternatives for GRAs involving the 2004 test year currently underway. In those proceedings, the participants in

[39] Application, Section 3.1, p.13

the CG advocated use of a placeholder in the GRA. The CG urged the divisions of the Board dealing with the various 2004 GRAs to set a placeholder for rate of return matters. In this regard, the CG submitted that a placeholder would not, in the case of ATCO, delay finalizing 2004 matters, particularly given the number of placeholders already requested by the Company. For convenience and efficiency, the CG stated that it would accept the Board's cost of capital determinations for 2003 as an appropriate placeholder for 2004.

The CG noted that the sale of retail assets was not part of the current GRA and would be addressed in a separate Board proceeding. The CG further noted that the actual impact could only be known when the terms and conditions surrounding the sale were examined (e.g., the supplier of last resort agreement). Consequently, the CG submitted that the most reasonable and rational way to proceed was to determine the 2003 capital structure and use it as a placeholder for 2004, pending completion of the Generic Cost of Capital proceeding currently in progress. In CG's submission, the risk aspects of the sale of retail assets would be best examined in the Board proceedings dealing with approval of the sale.

Views of the Board

The Board notes the recommendation of the CG to use the Board's cost of capital determinations for 2003 as an appropriate placeholder for 2004. Support for this recommendation is based on the consideration that there are already a number of placeholders that have been requested in the Application and that the Generic Cost of Capital proceeding is currently in progress.

However, in the Board's letter dated October 18, 2003, the Board stated the following:

> The Board is not convinced that postponing the cost of capital issues in the ATCO Gas 2003-2004 GRA until the Generic Cost of Capital Hearing would simplify matters. The Board is concerned that attempting to incorporate the results of the Generic Cost of Capital Hearing into the GRA may unnecessarily complicate the current proceeding, and unduly delay the final determination of ATCO's revenue requirements. Accordingly, the Board will continue to deal with cost of capital issues in this proceeding. As ATCO has already filed cost of capital evidence, no Board direction on this point is necessary.[40]

Consistent with this view, the Board continues to believe that the CG's recommendation to establish a placeholder could still potentially delay the final determination of ATCO's revenue requirements. Accordingly, the Board does not accept the CG's recommendation and will make all of its determinations for both 2003 and 2004 regarding the cost of capital in this Decision.

3.4 Return Enhancing Methodologies

Views of ATCO

ATCO noted that Calgary requested that the Board indicate the maximum common equity ratio that ATCO should be allowed to have, and if there were less, customers would not have to pay return on non-existent equity. ATCO responded that it had addressed this in Rebuttal. ATCO indicated that the Company had a deemed capital structure, as a result of the requirement to balance the capital structure to rate base through use of short term financing. ATCO stated that this balancing requirement caused differences between utility and financial common equity ratio. ATCO pointed out that differences between capital structure and rate base did change over time,

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and as such, the short term financing used to balance the capital structure must be able to be both positive and negative. As a result, ATCO submitted that Calgary's request failed to balance the interests of customers and the utility. ATCO also noted that Calgary indicated that there was no capital structure deemed to be supporting CWIP. ATCO responded that the Company either had or had not a deemed capital structure. ATCO further noted that the differences between capital structure and rate base had been reviewed in both the CWNG 1998 GRA and the AGS 2001/2002 GRA, and that the Board's decision with respect to the matter in both instances was to introduce short term financing into the capital structure to balance it to rate base. ATCO finally noted that Calgary expressed a concern with respect to differences between utility and financial short-term and long-term interest. ATCO responded that it addressed these concerns in Rebuttal.

ATCO addressed the issue with respect to using the financial interest in the utility income tax calculation, in both Rebuttal Evidence and Argument, and noted that this issue was addressed in the discussion on Income tax forecasts (Section 6 of this Decision).

Regarding the short-term interest difference and the capital financing CWIP, ATCO noted that these matters related to the fact that the Board deemed a capital structure for AGS, which ATCO Gas has complied with in this Application. ATCO further noted that this matter was thoroughly reviewed in the previous two GRA's related to the South and the Board made consistent decisions addressing the matter. Due to the use of a deemed capital structure, which required that the utility capital structure be equal to the rate base, ATCO submitted that it was not earning on the capital required to finance CWIP.

ATCO noted that it had addressed the concerns of Calgary with respect to differences between the actual common equity and the deemed common equity in Rebuttal Evidence. ATCO indicated that, due to the fact that AGS had a deemed capital structure, the impact of balancing the capital structure to rate base resulted in a different common equity ratio financing rate base from the financial common equity. In the 2003 forecast for ATCO, the financial common equity ratio was higher than the utility, whereas in the 2004 forecast, it was lower. ATCO observed that given that differences between the capital structure and the rate base change over time, the balancing amount included in rate base must be able to be both positive or negative. As a result, ATCO submitted that Calgary's recommendation failed to balance the interests of customers and the utility.

Views of Calgary

Calgary expressed concern about ATCO's continual use of methods that were utilized for the purpose of enhancing return, which were discussed in Questions 28 and 29 of Calgary's Evidence. These were:

- The mismatch of long-term interest expense collected in the revenue requirement and the amount deducted in computing the income taxes in the revenue requirement.
- The mismatch of short-term interest expense resulting from the interest on the deemed short-term debt and the actual short-term debt.
- The failure to provide any capital to finance the construction work in progress (CWIP) so that AFUDC is essentially all return on equity since there is no debt or preferred costs allocated to it, not withstanding that it is based upon the average cost of capital.

- As noted because ATCO has disallowed costs such as rent and signature rights included in the ATCO costs ATCO should, on a forecast basis, make less than the return allowed on the portion of common equity financing the rate base - not more, as is shown on Schedule 3.2-E.

Calgary noted that a further issue related to the matter of equity ratio was expressed in question 28 of the Calgary evidence. In that portion of the evidence, Calgary expressed concern with a situation where the approved common equity was in excess of the actual common equity and as a result a portion of the deemed common equity was actually long-term debt. In this instance, ATCO was earning equity return and taxes and paying interest, thereby enhancing its return. Calgary submitted that the approved level of common equity should be the maximum and that when the compliance filing is made, if the actual is less than the approved, then only the actual should be used for purposes of determining the revenue requirement. Calgary stated that to do otherwise would be essentially approving a higher return on common equity than that which the Board determined to result in just and reasonable rates.

Views of the Board

In previous Decisions, the Board has addressed the issues raised by Calgary concerning ATCO's use of potentially return enhancing methodologies.

The Board notes that the differences between capital structure and rate base have been reviewed in both Decision 2000-9,[41] which addressed the CWNG 1998 GRA, and Decision 2001-96,[42] which addressed the AGS 2001/2002 GRA. The Board's determination with respect to the matter in both Decisions was to include short-term debt financing in ATCO's capital structure or capitalization to balance it to rate base. The Board notes that ATCO has complied with this direction in the Application, as shown in Section 3.2, Financing, and Schedule 3.2-A of the Application, which presents the components of the 2003 and 2004 Mid-Year Cost of Capital. The Board notes that these schedules were subsequently updated on November 14, 2002.

The Board has addressed Calgary's concern about the use of the financial interest in the utility income tax calculation in Section 6.1 of this Decision.

With respect to Calgary's concern about the short-term interest difference and the capital financing CWIP, the Board notes ATCO's comments that due to the use of a deemed capital structure, which requires that the utility capital structure be equal to the rate base, ATCO is not earning on the capital required to finance CWIP. The Board notes that the matter of CWIP was addressed in Decision 2000-9 and 2001-96.

3.5 Preferred Share Cost

Views of ATCO

ATCO forecast a mid-year cost rate on preferred shares of 5.523% for 2003 and 2004. This represented the embedded cost of ATCO's preferred shares based on forecast mid-year balances of $65.741 million for 2003 and 2004.

[41] See Section 4.5 Rate Base vs. Capitalization
[42] See Section 5.6 Treatment of Short Term Debt

Views of the Board

The Board approves ATCO's forecast preferred share cost for the test years 2003 and 2004.

3.6 Debt Cost

Views of ATCO

ATCO forecast a mid-year cost rate on long-term debt of 8.005% (2003) and 7.850% (2004). This represented the embedded cost of ATCO's long-term debt based on forecast mid-year balances of $521.129 million for 2003 and $586.351 million for 2004.

With regard to future financings, ATCO forecast financing requirements of $100 million and $85 million in 2003 and 2004 respectively, indicating that the financing requirements would be met with 20-year debenture issues in December 2003 and 2004 respectively, at a coupon rate of 7%. ATCO submitted there were also scheduled financing retirements for 2003 or 2004. In 2003, the retirement consisted of a $22.2 million 7.25% debenture at its maturity. In 2004, the retirement consisted of a $31.5 million 8.73% debenture at its maturity.

ATCO noted that in Decision 2001-96, AGS was directed to balance its capital structure to rate base through the inclusion of short-term debt. ATCO submitted that it had complied with this direction in the Application, and had forecast a short-term debt rate of 4.5% for 2003. However, in 2004, ATCO submitted that the balancing amount was in an investment position. As a result, ATCO forecast a short-term investment rate of 4.0 percent for 2004.

Noting that Calgary presented several concerns with respect to debt costs, ATCO indicated that financing requirements change over time, which sometimes resulted in a higher interest expense than forecast, and at other times a lower interest expense than forecast. ATCO submitted that this was no different from any other component of the forecast revenue requirement, and that over time, these differences would likely balance out. Based on the actual short-term position of ATCO in 2002, ATCO indicated that it was entirely possible that the financing requirement for 2003 would be higher than forecast. However, consistent with prospective ratemaking, ATCO had not requested a change to its forecast.

ATCO submitted that further support for the appropriateness of the forecast debenture rate of 7% was provided in during cross-examination, but noted its concern that debt costs in the test period could escalate beyond the levels forecast should the Board fail to grant the relief sought in respect of rate of return on common equity and capital structure. ATCO indicated that failure to increase returns and thicken common equity would place debt ratings at risk, thereby increasing debt costs beyond those forecast. ATCO submitted that should the Board approve a lower rate of return or a lower common equity ratio, there must be provision for recovery of increased debt costs over the test period.

ATCO submitted that it did not issue eight-year debt in 2002, and that AGN did not issue any debt in 2001, as indicated by Calgary in Argument. ATCO pointed out that the 2002 debenture issue (allocated 100% to the South) was a 15-year issue, which was considerably higher than the five-year issue of CU Inc. in November 2002. While the term of the 2002 debenture was shorter than forecast in the 2001/2002 AGS GRA, ATCO noted that the amount of the debenture issued was $19 million higher than forecast in that GRA. ATCO noted that circumstances could change which would impact not only the debenture rate, but also the amount of the debenture issue.

ATCO further noted that a review of the various debentures outstanding of ATCO, as shown on Schedule 3.2, indicated that there were significantly more issues with terms of 20 years or more. As a result, ATCO submitted that there was no reason to believe that a 10-year debenture issue in 2003 or 2004 was more likely than a 20-year debenture issue.

ATCO observed that AUMA/EDM asked the question “why 20-year debt?” ATCO indicated that one of the fundamental tenets of financing was that the term of any financing should match the life of the asset being financed. ATCO noted that this principle was not denied by any of the five expert witnesses that Calgary presented in the proceeding.

ATCO argued that the natural extension of AUMA/EDM’s Argument was that all financing should be completed for the shortest term available, and noted that given a normal sloping yield curve this would produce the lowest cost of debt. ATCO pointed out that, as Exhibit 13-4 showed, CU Inc. debentures with a remaining life of less than three years were trading at a yield some 90 to 180 basis points below the 10-year bonds. Accepting AUMA/EDM’s Argument, ATCO submitted that it should be seeking financing with a term of less than three years.

ATCO submitted that a utility which financed its long-term assets with short term debt would be considered materially more risky than one which financed its long term assets with long term debt. In this regard, ATCO argued that AUMA/EDM’s Argument was extremely simplistic and did not consider the longer-term implications of its suggested actions. ATCO stated that acquiescence to AUMA/EDM’s proposal would increase the Company’s financial risk. That additional risk also would have to be reflected in a further upward adjustment of the equity ratio and ROE.

ATCO concluded that it had provided support for its forecast long-term debt cost at the time at which the forecast was prepared, and additionally explained why that forecast remained appropriate in light of changing circumstances. As a result, ATCO submitted that the suggestion of AUMA/EDM to reduce the forecast rate to an amount not in excess of 6.5% was unfounded.

ATCO noted that AUMA/EDM indicated that the forecast short term debt (investment) rate used in the capital structure should be adjusted to 3.76%, based on the 2002 actuals for Canadian Utilities Limited. ATCO responded that AUMA/EDM did not provide any evidence as to why the 2002 actual rate was the appropriate rate to be used for the 2003 and 2004 forecast. Furthermore, ATCO stated that the proposal of AUMA/EDM did not take into consideration the fact that the short-term investment rate would always be lower than the short term borrowing rate. As a result, ATCO submitted that the suggestion of AUMA/EDM should be rejected.

ATCO noted that in discussing the S&P’s Credit Watch action related to Canadian utilities, AUMA/EDM arrived at several erroneous conclusions. Firstly, ATCO was not requesting compensation for any risks associated with the risks of its non-regulated affiliates. ATCO did ask that the Board consider the implications for CU Inc.’s bond rating when establishing the fair return on common equity and the appropriate capital structure for ATCO.

Secondly, ATCO observed that AUMA/EDM had selectively excerpted parts of S&P’s reports in order to attempt to change the meaning of the report. By way of example, ATCO cited AUMA/EDM’s comment that the issue was one of degree in terms of how much bond holder protection was conferred by regulated capital structures in light of the operational risks borne by the companies. ATCO stated that it was clear that S&P's concern related to the regulators' decisions on the capital structures approved for the utilities.

ATCO noted that the final selective reading of the S&P's report by AUMA/EDM was its characterization that the bond-rating agency was concerned only with ATCO and not CU Inc. or Canadian Utilities. ATCO responded that while a literal reading of AUMA/EDM's argument could lead to this conclusion, a reading of Exhibit 13-66, where both CU Inc. and Canadian Utilities Limited were listed as "Watch Neg", and S&P's November 12, 2002 bond rating report clearly indicated that all the concerns expressed in Exhibits 13-66 and AUMA/EDM's argument applied equally to CU Inc. and Canadian Utilities Limited.

Views of AUMA/EDM

With regard to short-term debt/investment, AUMA/EDM noted that the short-term debt rate used by ATCO for 2003 was 4.5%. For 2004, (the "balancing amount") was an investment position for which ATCO expected to receive a return of 4.0%. The mid-year short-term debt was forecast to be in the amount of $23.4 million for an annual cost of approximately $1.0 million.

AUMA/EDM observed that, by comparison, note 7 to the Consolidated Financial Statements of Canadian Utilities Limited for 2002 indicated short-term borrowings were obtained at an interest rate of 3.76%.

AUMA/EDM noted that ATCO did not provide any specific support for its forecast of 4.5%. As a result, AUMA/EDM submitted that the short-term debt approved by the Board should be capped at 3.8% to reflect 2002 actuals.

With respect to long-term debt, AUMA/EDM noted that ATCO forecast financing requirements of $100 million and $85 million in 2003 and 2004 respectively, and indicated that this would be met with 20-year debenture issues in December of each of the test years at a coupon rate of 7%. AUMA/EDM submitted that it did not agree with this forecast rate, which having regard to the evidence, was unnecessarily high.

AUMA/EDM noted that in the past, ATCO's forecasts of long-term debt costs had been different from the actuals. For example, AGS forecast the cost of its proposed 15-year debenture issue for 2002 in its 2001/2002 GRA and the current Application (dated July 2002) at 7.05% and 7.0% respectively. However, AUMA/EDM observed that the actual cost of this debt was almost a full percentage point lower at 6.145%. AUMA/EDM also noted that the 6.145% debt issue, which was in the amount of $54 million, was closed by CU Inc. in November 2002, well after the date of the Application. Although this debt was issued for a term of fifteen years, AUMA/EDM expressed the view that it was relevant information as to the current cost of long-term debt for ATCO. AUMA/EDM noted that the Board approved this issue on March 18, 2003.

AUMA/EDM noted that the market was prepared to accept a yield of approximately 6.5% on CU Inc. 20 year debentures. Using the midpoint (6.12%) of the yield on fifteen year debentures, indicated a spread of approximately 36 basis points between 15 and 20 debenture yields which, when added to the cost rate of 6.145% of the $54 million issue in 2002, again implied a return of approximately 6.5% on the longer term debentures.

In addition, AUMA/EDM observed that, in its response to CAL-AG-34(f), ATCO indicated that its forecast 7% coupon rate was a management decision based on economic data received from "a number of independent parties." AUMA/EDM noted that this information was provided "in late summer 2001" and was a year old at the time the Application was filed.

AUMA/EDM stated that additional support for a rate not in excess of 6.5% could be found in the evidence provided by ATCO's witness. During the course of cross-examination, he stated "Right now [March 18, 2003], CU Inc. was facing about 105 to 110 basis points over long Canadas." At the same time, AUMA/EDM observed that long Canadas with a term of 30 years to maturity were yielding 5.34%, which would imply a market expectation for CU Inc. of something in the order of 6.42% (5.34% + mid point of 105-110 basis points).

AUMA/EDM submitted that based on the foregoing, and the evidence provided by ATCO, a rate not in excess of 6.50% would be justified for its cost of new long-term debt in both 2003 and 2004.

AUMA/EDM noted that, in attempting to explain the historical relationship between long Canada Bonds and utility debentures, ATCO stated "The increase in spread between GOC bonds and Utility Debentures was likely the result of investors fleeing to quality." AUMA/EDM indicated that specific evidence was provided in support of this statement, which appeared to be inconsistent with the market acceptance of its November 2002 6.145% 15-year debenture. AUMA/EDM further noted that, based on its bond ratings, CU Inc. had a higher market acceptance than other similar regulated utilities. This was reflected in its lower yields.

AUMA/EDM noted that ATCO confirmed that CU Inc. bonds having a ten-year remaining life were yielding between 5.38% and 5.5%, which AUMA/EDM observed was more than 100 basis points lower than the prevailing yields on CU Inc. twenty- year debentures. Given this significantly lower rate, AUMA/EDM submitted that the question arises as to "Why 20-year debt?"

AUMA/EDM observed that in the Application, ATCO confirmed that utility spreads were at a historic high and had risen dramatically over the past six years. AUMA/EDM stated that this raised the question, "why lock in spreads that are very high compared to recent experience?" AUMA/EDM noted that locking in financing for 20 years would provide the Company with reduced rollover risk, but this would come at considerable cost to customers. In this regard, AUMA/EDM submitted that the cost could be observed by comparing the yields on CU Inc. 10-year debentures or the recently approved 6.145% - 15-year debenture issue to ATCO's forecast of 7.0% for 20-year money. AUMA/EDM finally commented that it was not aware of any legitimate reason why ATCO could not take advantage of the relatively attractive rates currently available on 15-year debentures (as reflected in CU Inc.'s November 2002 offering) and 10-year debentures currently yielding 5.50%.

Views of Calgary

Calgary expressed concern with respect to two matters related to the cost of debt. The first was related to the poor forecasting of new issues and their cost that had transpired in past proceedings for AGS and the second was the rate applied to the Company.

Calgary submitted that the result of the poor forecasting had been that AGS had historically over-collected its debt cost. Calgary noted that, in rate proceedings, AGS had forecast that it would issue long-term debt and then subsequently issued debt for a shorter term generally at a lower rate. Calgary further noted that in the current proceeding, ATCO had forecast an issue in 2002 at 7%, yet its financing arm, CU Inc., actually issued two debentures in November 2002, one at 4.801% and the other at 6.145% at 5 and 15-year terms.

In addition, Calgary noted that all of the 4.801% issue was allocated to a non-utility affiliate, while the 6.145% issue was allocated in part to ATCO. Calgary observed that ATCO stated that the reason that none of the five- year 4.801% was included in its debt structure was because its term was too short for the ATCO type assets. However, Calgary argued that this did not reconcile with the issue of eight-year debt in 2002 and the issue of five-year 4.84% debt by AGN and ATCO Pipeline North in 2001. Calgary submitted that if five-year debt could be allocated to those entities in 2001, there was no valid reason not to allocate some or all of the 2002 5-year issue to ATCO.

Calgary noted that for 2003, ATCO forecast the issue of $100 million 7% 20-year debenture. For 2004, ATCO forecast an issue of $85 million 7% 20-year debenture. Calgary submitted that recent financings by CU Inc. had been for shorter terms. Calgary noted that, with only one issue maturing between June 2011 and August 2019, the maturity calendar appeared open to shorter issues and the maturity curve would allow ATCO to issue a 10-year bond, which could potentially save ratepayers between 50 and 70 basis points, depending on market conditions.

Calgary noted that in Argument, ATCO amended its Application seeking potentially higher debt costs if the Board did not accept its return and capital structure request. Calgary submitted that if ATCO was intending to amend its Application, it should have made a formal request and not included such amendment in Argument.

Views of the CG

The CG submitted that it had reviewed the Argument prepared on behalf of AUMA/EDM. Rather than reiterating the points addressed in that Argument in its submission, the CG agreed with, and supported the submissions and recommendations put forward by AUMA/EDM in connection with Cost of Debt.

Views of the Board

The Board notes parties' concerns that ATCO's forecasts of long-term debt costs differ from actuals. At the same time, the Board agrees with ATCO that the Company's financing requirements do change over time. The Board also agrees that, during some periods those changes will result in a higher interest expense than forecast, while in other periods the changes will result in a lower interest expense than forecast. In this regard, debt costs are similar to other components of the forecast revenue requirement in that forecasting error is always prevalent. However, the Board considers that over time, forecasting differences or errors should potentially balance out.

The Board notes that another factor that may have contributed to past forecasting error in terms of debt costs is the consideration that interest rates have been in a general declining trend in recent years. This factor could potentially result in a high forecast of interest rates, relative to actual interest rates, and a subsequent over-estimation and over-collection of debt costs.

However, when interest rates are in a rising trend, the opposite is true. This opposite trend could potentially result in a low forecast of interest rates, relative to actual interest rates, and a subsequent under-estimation and under-collection of debt costs.

With regard to the issue related to the appropriate term of debt, the Board also agrees with ATCO that a fundamental tenet of financing is that the term of any financing should match the life of the asset being financed. The Board acknowledges that a utility which finances its long term assets with short term debt would be considered materially more risky than one which finances its long term assets with long term debt.

Based on an examination of ATCO's long-term debt, as shown in Schedule 3.2-F, the Board notes that a majority of ATCO's outstanding debt for the year 2002 comprises issues with terms of 20 years or more. Of this long-term debt, approximately half is comprised of issues with 30-year terms. At the same time, there are some debt issues with terms of approximately 10 years. With regard to the shortest term of the long-term debt, there are no debt issues with terms of less than eight years.

The Board is of the view that there are many factors that help to determine the appropriate term of debt, and that it would be difficult for the Board to provide direction to the utility with regard to this matter. Based on this consideration, the Board is also of the view that it is logical and fair that the utility should be in control of its financing plan, and in turn should be allowed to determine the appropriate term of debt for new debt issues.

For all of these reasons, subject to the terms of the applicable legislation, the history of an applicant before the Board and the circumstances of any particular application, the Board considers that unless there is evidence that a utility is being imprudent in terms of its financing plan, the utility should be allowed to take its own course of action with regard to its ongoing financial plan, including the ability to choose the appropriate term of debt for all new debt issues.

4 REVENUE REQUIREMENT

Views of ATCO

In the Application, the Revenue Requirement forecasts for the test years were $1.533 million (2003) and $1.550 million (2004), calculated as follows:

Table 7. Revenue Requirement Forecasts – 2003 and 2004

	2003 Forecast ($000)	2004 Forecast ($000)
Utility Income	85,967	93,215
Operation & Maintenance Expense	231,850	245,495
Taxes – Other than Income	966	961
Depreciation	65,460	67,192
Income Taxes	9,644	31,988
Delivery Service Component	393,887	438,861
Gas Supply	1,035,787	1,007,708
Franchise Fees	103,601	103,889
Utility Revenue Requirement	**1,533,275**	**1,550,458**

4.1 Labour

Views of ATCO

ATCO indicated that the Company had always looked for ways to become more efficient and that changes in the marketplace since the mid-1990's had accelerated these endeavours. ATCO referred to a restructuring in the mid to late 1990's, which resulted in employee reductions and early retirement programs being offered, during which time, there was very little new hiring. The continuing evolution to becoming a pipes-only company between 2000 and 2002, and the sale of the Viking properties, which reduced the Company's involvement in the production function significantly, also resulted in additional staff reductions.

ATCO indicated that efficiencies within the evolving structure continued to be found by working with ATCO Electric to review areas where combining individual Gas and Electric departments would result in efficiencies and benefits to customers, as well as create common and consistent practices wherever appropriate.

ATCO pointed out that this history of change, which included staff reductions, along with a general aging of the workforce had contributed to the situation where the average age of the Company's workforce has increased to the point where at least 45% of the workforce will retire within the next 10 years. ATCO stated that it is taking action to ensure that the workforce is kept whole and that younger workers are added to the work force. In 2002, in conjunction with restructuring into four business units and addressing growth in the Company, 68 new permanent positions were added. Of the 68 positions, 28 reflected a change from seasonal to year round permanent work. In addition, two significant initiatives starting in 2002 would result in an increased number of positions. The combined effect of these two initiatives, monthly meter reading (131 positions), and the relocation of meters to outside locations (119.4 positions) in 2002 and 2003 would allow ATCO to hire approximately an additional 250 young, skilled employees.

In response to Calgary's submission that the Company was unable to provide information with respect to capitalized labour to facilitate testing capitalized costs, ATCO pointed out that information could not be provided on gross labour costs by O&M function and the amounts capitalized, given the Company's internal accounting process.

ATCO pointed out that labour was just one component of the O&M and capital forecasts, and that caution should be used in testing forecasts by looking only at a single component of total costs. ATCO pointed out that its focus was on managing capital projects and O&M activities. ATCO stated that staff is trained to work on both capital and O&M activities and depending on how workloads changed throughout the year, that work would be managed using the resources available at the time. ATCO pointed out that those resources could include outside contractors, increased overtime or increased use of seasonal labour.

ATCO considered that the table provided by Calgary comparing total O&M, capital labour costs, and certain capitalized costs relating to meter refurbishment and administration to be inappropriate. The table suggested that ATCO had attempted to conceal changes in the treatment of certain costs, and that capital labour costs were increasing as a result of new programs such as MRRP. ATCO submitted that this was simply not the case, and pointed out that 2002 actual data included the impact of Decisions 2002-69 and 2002-72. ATCO noted that for the South, they included the impact of those decisions for 2001 and 2002, making it inappropriate to use those amounts as a comparison to other years.

ATCO submitted therefore that all of the information required to assess the impact of changes in capitalization policy had been provided, and that the total capitalized labour costs and associated fringe benefits had been identified.

Views of AUMA/EDM

AUMA/EDM noted that ATCO's total labour costs were relatively consistent and averaged approximately $86.7 million for 2001 and 2002, and that test year forecasts were 21% and 27% in excess of this amount for 2003 and 2004 respectively. AUMA/EDM noted that the largest increase was capital related, and considered that the forecasts required detailed review, on the basis that the labour inflation rate was overstated and that a number of the projects reflected in these costs could not be justified.

Views of Calgary

Calgary expressed concern that ATCO was capitalizing costs previously expensed giving an appearance of control over O&M costs when in fact, without increased capitalization, these costs would be increasing at a higher percentage.

Calgary submitted that it was not easy to test the veracity of costs capitalized, and in particular, labour cost capitalized, noting that ATCO claimed to be unable to provide total labour costs, on the basis that the Company did not charge amounts on a gross basis (including capitalized costs) to operating expense prime accounts.

Calgary submitted that the Board should require utilities to fully disclose their policies and practices for capitalizing O&M costs from one year to the next, and require all filings to disclose gross O&M costs by component including Administrative and General costs, amounts capitalized by component and the resulting net O&M expense by component. Calgary considered that, absent such a requirement, utilities would be free to change capitalization policies and procedures from year to year and use the capitalization process to smooth the growth in cost on a net basis, and that comparisons on a gross basis would not be available to the Board and Interveners.

Calgary stated that, in the Application, ATCO showed an increase of 9.2% for labour, 2003 forecast over the 2002 forecast, with supplies increasing by 1.2% for a total increase in O&M of

3.5%. Calgary presented a table which reinstating capitalized administration costs and meter refurbishment costs in the North and indicated that the 3.5% increase became 14.21%, when compared to the 2002 actual data including a 16.5% increase in labour cost. Calgary noted that the increase between the 2003 and 2004 O&M forecasts increased slightly from 2.6% to 2.74% when viewed on a comparable basis.

Views of the CG

The CG expressed concern with the labour forecasting process, which included labour as O&M to be recovered fully during the test years through rates if some of this labour component would later be capitalized during the test years, with the result that ratepayers would pay for the additional capitalization through the increase in rate base during the ensuing years. The result, in the CG's view, was that ratepayers effectively paid for this labour twice, once through the forecast O&M and, again, through the increased rate base. Therefore, the CG submitted that ATCO should be required to record labour expense as a gross amount in the appropriate O&M accounts with an offsetting credit to those accounts for the actual amount of labour capitalized, which would allow a ready reconciliation between expense and capitalization in future and provide a basis for comparison in future forecasts.

To the extent capital projects are estimated on a unit basis, the CG stated that there had to be a clear delineation between projects estimated on the basis of in-house labour and those estimated on the basis of out-sourced contract labour. The CG indicated that the unit costs of out-sourced projects would generally be higher because out-sourced labour includes overhead loading, which is excluded with in-sourced projects. The CG submitted that this separation on a project basis for capital projects would facilitate understanding of the net O&M estimates for the test years, namely the gross labour estimates less the capitalization of in-house labour.

Views of the Board

The Board notes the observations of the interveners that there is a significant increase in O&M Expense for the test years over historical levels, despite ATCO's proposal to capitalize a portion of O&M Expense, and agrees with the observations that, absent the transfer of those costs from O&M, the increase in test year O&M forecasts would be significantly higher than indicated in the Application. This fact will be considered further in the evaluation of individual revenue requirement components in this Section of the Decision.

The Board also notes intervener concerns with respect to the difficulties experienced in verifying the costs capitalized given that ATCO did not charge amounts, including capital amounts, to O&M functions on a gross basis, for subsequent allocation between capital and operating. In this regard, the Board accepts ATCO's position that it is not possible, using the Company's present accounting processes, to provide information on this basis. The Board also accepts ATCO's submission that all of the information required to assess the impact of changes in capitalization policy had been provided in evidence, and that the total capitalized labour and associated fringe benefits had been identified.

Accordingly, the Board does not accept intervener suggestions that ATCO be directed to provide at future rate proceedings, information on gross O&M costs by component prior to allocation to capital programs.

4.1.1 Labour Forecasts

Views of ATCO

In the Application, the Labour forecasts for the test years were $102.5 million (2003) and $106.8 million (2004), calculated as follows:

Table 8. Labour Forecasts – 2003 and 2004

	2003 Forecast ($000)	2004 Forecast ($000)
Operating & Maintenance	65,993	68,796
Capital	31,966	33,347
Other	4,549	4,728
Total Labour	102,508	106,871

Requirement for Monthly Meter Reading

ATCO noted AUMA/EDM's position that the new meter reading positions were a direct result from the MRRP, and that the new meter reader positions and the MRRP were linked and that none of the new positions should be approved and no cost included in revenue requirement unless and until the MRRP project was endorsed by the Board. ATCO indicated that both these statements were totally incorrect, and that while the MRRP did facilitate monthly meter reading, it also provided a number of other benefits that have been discussed throughout the GRA process. ATCO indicated that all the benefits of the MRRP would be realized whether or not monthly meter reading proceeds.

ATCO agreed that monthly meter reading could proceed without the MRRP, and noted that having meters outside merely improves meter reading effectiveness.

Views of AUMA/EDM

131 New Meter Readers

Referring to the proposed initiation of monthly meter readings, requiring the addition of 131 meter readers and related positions, AUMA/EDM noted that the loaded labour cost, including fringe benefits, for these positions is $4.183 million in 2003. AUMA/EDM noted that historically, the number of meter reading positions had been 80 or less, and that only "in the neighborhood of between 30 and 35" of the 131 new meter reader positions had been filled by the end of 2002 and, only 77 of the total number of 202.5 meter reader positions. AUMA/EDM submitted that this gave rise to concerns regarding the accuracy of ATCO's labour expense. AUMA/EDM argued that since monthly meter reading was scheduled to commence April 1, 2003, this represented an over-forecast of an average of 50 full-time equivalents (FTEs) for the three-month period January 1 to March 30, 2003 and that the avoided cost for the 50 FTEs for the period January 1 to March 30, 2003 would be $467,000.

Requirement for Monthly Meter Reading

AUMA/EDM pointed out that, following the introduction of performance based rates on the AGN system, ATCO was able to reduce its meter reading positions from 40 to 33, and increase its meter reading interval from two to three months.

Given that AUMA/EDM considered that the new meter reader positions and the MRRP were linked, AUMA/EDM submitted that none of the new positions should be approved unless and until the Board endorsed the MRRP.

119 Staff for MRRP

AUMA/EDM noted that, as part of the MRRP, ATCO was forecasting an in-house labour complement of 119.4 positions "five of which will be filled in late 2002 and 114.4 in January 2003." As with the 131 new meter readers, AUMA/EDM submitted that these positions were collateral to and a result of the as-yet unapproved MRRP project.

AUMA/EDM questioned the wisdom of proceeding to fill a total of 250 positions without any approval for a project of marginal benefit and for which customers had not indicated any support. AUMA/EDM submitted that neither the cost of these positions nor the new meter reader positions should be included in revenue requirement unless and until the MRRP project was approved by the Board, and that ATCO should be directed in a refiling to re-forecast all of its MRRP-related costs to reflect the pilot project and staging recommended by AUMA/EDM in the discussion surrounding MRRP.

4.1.2 Other Labour-related Issues

Views of ATCO

Inflation Factors

ATCO indicated that the labour inflation rate used in the test years was 4% for both supervisory and in-scope employees. ATCO stated that the rate was forecast using data from the Consumer Price Index (CPI), salary surveys, and reviews of other collective agreements in Alberta.

ATCO submitted that the labour inflation rate of 4% used in the GRA forecast was reasonable, and that various information responses[43] provided supporting data and analysis of the rate. ATCO indicated that more detail with respect to various external wage settlements used in the analysis was provided in Exhibit 13-42, and that no intervener filed evidence to contradict the 4% rate.

ATCO disagreed with the CG proposal for use of the forecast CPI rates as the forecast labour inflation rates. ATCO pointed out that the response to BR-AG-57 indicated that a number of information resources were used to assist in forecasting the labour inflation rate, including external surveys, labour market salary forecasts, economic indicators, such as CPI and GDP, External Company Wage Settlements, and ATCO Wage Settlements.

ATCO indicated that CPI was not used in isolation to determine labour inflation rates, but was one piece of information to be considered. However, ATCO stated that the overall review of the labour market through surveying wage settlements in collective agreements and supervisory increases determined ATCO's labour inflation rate. ATCO pointed out that the labour inflation rate was set for the test years by relying on the market, which supported an increase ranging from 3½ to 4½%.

[43] AUMA/EDM-AG-48, AUMA/EDM-AG-91, BR-AG-57, and CG-AG-81(a)

ATCO referred to the observation of the CG that the Company had achieved efficiency gains of approximately 2% per year since 1995, based on information provided in the response to CAL-AG-02-5. ATCO submitted however, that the CG appeared not to have understood the meaning of the comparison provided in that response. ATCO pointed out that, in late 1998, the ATCO gas utilities undertook a significant structural change through the merging of CWNG and NUL into one legal entity, and creation of ATCO Gas and ATCO Pipelines. ATCO noted that there were also other significant changes in that time frame, such as the corporate downsizing in CWNG and NUL, and the elimination of departments within CU, which also contributed to those savings. ATCO pointed out that the comparison provided in the information response was designed to indicate the level of savings achieved to a great extent as a result of those significant changes. ATCO stated that it would not be possible to achieve the same level of savings on some annualized basis through best practice reviews, and that market forces were responsible for much of the cost increases being experienced. ATCO submitted that these market forces impair the ability to stave off the effects of inflation, customer growth and labour pressures.

Views of Calgary

Calgary noted that at Tr. p. 506, ATCO discussed the 4% inflation factor and confirmed that the CPI forecast inflation rate was 2.6% for 2003 and 2004 based on a November 2001 forecast. Calgary noted that ATCO also testified that a later forecast estimated the CPI at 2.8% (2003) and 2.7% (2004). Calgary submitted that data available to ATCO at the time the forecast was prepared, indicated an inflation rate 1.4 to 1.2 percentage points below the values used in the forecast. Calgary submitted that, based upon the information available there was no justification for the 4% used by ATCO.

Views of AUMA/EDM

AUMA/EDM noted that ATCO forecast a 4% labour inflation rate for both supervisory and in-scope employees for each test year, based on the CPI, salary surveys and reviews of other collective agreements in Alberta.

AUMA/referred to the response to BR-AG-57, where AE's wage settlement of 3.25% and the Alberta CPI forecast of 2.6% were provided in the analysis to determine these forecast rates. AUMA/EDM also referred to the response to AUMA/EDM-AG-91, where ATCO provided a list of the entities with 2002 settlements, which were used in arriving at the base salary increases of 3.5% to 4.0%, for that year. The AUMA/EDM submitted that, based on this information and information from ATCO witnesses, increases were excessive and not supported by the evidence.

AUMA/EDM noted that ATCO also indicated that its proposed 4% inflation factor was based on other collective agreement wage settlements, which its witness stated were in the range of 3.5% and 4.5%. AUMA/EDM pointed out however, that in response to an undertaking, ATCO provided the actual percentage increases for the 14 entities studied for the years 2002, 2003 and 2004, noting that the average increase was for 3.61% for 2002 and 3.48% for 2003. AUMA/EDM considered it interesting that AltaGas, the only other utility included in the study, which carries on a business similar to ATCO, was able to hold its wage increase to 3.25% for both 2002 and 2003, consistent with the ATCO Electric increase of 3.25% for 2003.

AUMA/EDM submitted that the labour inflation forecast for ATCO supervisory and in-scope employees should be no greater than 3.5% based on the following:

- the revised CPI forecast of 2.8% and 2.7% for 2003 and 2004, respectively;
- the AltaGas increase of 3.25% for 2003;
- the ATCO Electric increase of 3.25% for 2003; and
- the Alberta Utilities salary forecast increase of 3.6% for 2003; and
- the average increases for the 14 entities, being 3.48% for 2003.

AUMA/EDM submitted that a proper interpretation of the evidence provided by ATCO did not support use of an inflation factor that exceeded 3.5%.

Views of the CG

The CG noted that at Tr. p. 1133, ATCO confirmed that the inflation rate used for estimating IT charges for the MSA was 3% per year. The CG also noted ATCO's confirmation at Tr. p. 514 that the only data on the record for 2003 related to the forecast CPI of 2.6% and the ATCO Electric increase of 3.25%. The CG also referred to Exhibit 13-42, where ATCO provided actual 2003 labour settlements for somewhat comparable utilities, indicating settlements of 3% for ENMAX and Red Deer and 3.25% for AltaGas. The CG considered it difficult to take one or two-year snapshots of labour settlements given that they depend to a certain degree on past settlements. The CG therefore, considered that the applicability of a global indicator such as CPI is a preferable approach for adjusting labour forecasts. The CG noted ATCO's acknowledgement that CPI estimates were in the 2.6% to 2.7% range[44] for 2003.

Referring to the response to CAL-AG-02-5, the CG noted that efficiency gains achieved by the Company approximated 2% per annum since 1995. Considering the efficiency gains and the projected inflation rates, the CG considered that a maximum escalation rate of 3% for labour for the test years was reasonable, and recommended that the Board adopt this rate for test year labour forecasts.

Views of the Board

The Board notes that the forecast increase in labour costs is due to new labour intensive activities, such as MRRP and monthly meter reading, combined with the application of a 4% inflation factor for the test years for both supervisory and in-scope employees. In this Section of the Decision, the Board will address the forecast inflation factor.

The Board notes that ATCO's main support for its labour forecast that included an escalation factor of 4% appeared to be a settlement with ATCO Electric of 3.25% for 2003 and the analysis contained in Exhibit 13-42. The Board also notes, based on information provided by ATCO that the CPI was 2.8% (2003) and 2.6% (2004).

The Board considers that these lower inflation factors are more consistent with the majority of evidence on the record and referred to specifically by AUMA/EDM, and agrees with the AUMA/EDM proposal for application of a 3.25% rate as a reasonable escalation factor to determine the labour forecasts for the test years. Accordingly, the Board directs ATCO to adjust its labour forecasts to reflect a 3.25% labour inflation rate.

[44] BR-AG-57

Vacancy Rates/FTE's

Views of ATCO

In the Application, staff complement forecasts for the test years were 1,911.4 (2003) and 1,911.9 (2004), calculated as follows, with comparisons to 2001 actuals and 2002 forecasts:

Table 9. Staff Complement – 2001 Actuals and 2002 - 2004 Forecasts

	2001 Actuals	2002 Forecast	2003 Forecast	2004 Forecast
Full Complement at December 31	1,433.1	1,601.9	1,717.2	1,717.7
Full-Time Equivalents				
Permanent Full Time Equivalents	1,406.3	1,460.3	1,717.2	1,717.7
Vacancies	(96.9) 6.9%	(58.4) 4.0%	(68.7) 4.0%	(68.7) 4.0%
	1,309.4	1,401.9	1,648.5	1,649.0
Seasonal Full Time Equivalents	268.6	250.5	262.9	262.9
Total Full Time Equivalents	1,578.0	1,652.4	1,911.4	1,911.9

ATCO indicated that "seasonal" or temporary employees filled in the peaks of the summer and fall work load primarily related to maintenance of the system and construction work (equipment operators, gas utility operators, line locators, etc.) and to fill vacant permanent positions on a short-term basis. The number of seasonal workers was forecast to remain relatively stable over the forecast years.

ATCO used a 4% vacancy rate in the calculation of permanent FTE's, and indicated that there were circumstances in 2002, which increased the permanent vacancy rate to higher than normal. ATCO pointed out that these circumstances resulted from the delay in filling of meter reading and growth positions and the holding of positions for redundant employees impacted by the production property disposition. ATCO submitted that these circumstances did not impact the test years.

Referring to comments by Calgary and the CG that forecast vacancies should be based on two years of actuals and not on the Company's forecast, ATCO agreed that use of historical information was useful in the forecast process but should not be used in isolation. ATCO stated that the circumstances that affected the historical information and its impact on the forecast needed to be considered.

Referring to the CG's comment that labour levels should be consistent with prime utility drivers such as customer and throughput levels, ATCO indicated that this suggestion had not been expressed in evidence or at the hearing. Nevertheless, in response, ATCO stated that on the surface, testing labour costs against these measures was reasonable as a start to analyzing costs at a high level. However, ATCO considered that, only looking at labour costs compared to customer growth and throughput oversimplified what was required to manage the organization.

Views of Calgary

Calgary noted that, while actual vacancies in 2001 and 2002 averaged approximately 100, ATCO appeared to hold the view that vacancies would be approximately two thirds that average in the test years. Calgary submitted that forecast vacancies should be based upon the two years of actual data, thereby reducing labour costs. Calgary noted that, in 2002 ATCO's forecast was out about 80%.

Calgary noted that ATCO identified that there were circumstances in 2002 which increased the permanent vacancy rate to higher than normal, and that those circumstances in 2002 resulted from the delay in filling meter reading and growth positions and the holding of positions for redundant employees impacted by the production property disposition.

Calgary indicated that the meter reading program had not been approved by the Board and that ATCO should be held at risk if it desires to hire meter readers to meet a perceived need for monthly meter reading without Board approval. Calgary also indicated that it should be expected that if the proposed sale of the retail operations was approved, there would be a further reduction in FTEs as ATCO would be out of the gas commodity business.

Views of AUMA/EDM

AUMA/EDM pointed out that, from evidence on the record, the actual vacancy rate after adjusting for jobs held open pending the sale of production assets and the retail business had consistently been in the range of 4.8% to 5.5% over the four years preceding the test years (an average of 5.15%). AUMA/EDM submitted that the 4.0% forecast of vacancies by ATCO could not be substantiated on the evidence provided and that a more reasonable forecast would be a 5.0% vacancy rate. AUMA/EDM considered that this meant that the vacancy rate had been understated by 1.0% in each test year, representing 17.2 FTE's. AUMA/EDM noted that 31% of those positions were charged to capital leaving the vacancies about 12 FTE's too low for O&M and other.

AUMA/EDM noted that based on total GRA labour and filled (permanent and seasonal) FTE's, the average salary per FTE was $53,500 (2003) and $53,600 (2004). Including fringe benefits of 12.9%, AUMA/EDM indicated that the loaded costs reflected in the Application were $60,400 and $60,500 per FTE. Accordingly, based on the 12 FTE's identified above, AUMA/EDM submitted that labour and fringe benefits charged to O&M should be reduced by $725,000 in each test year.

Views of the CG

The CG expressed concern that forecast labour levels and associated costs were disproportionate to the level of increased service required, and noted ATCO's continued reference to the need to satisfy safety and reliability concerns on the system. The CG did not dispute the need for a safe and reliable system, but was extremely concerned with the disproportionate increase in forecast labour costs to maintain the existing service level for a minimal increase in customers and throughput.

South

The CG provided a table setting out customer growth and throughput from 2001 to 2004 for the South, which indicated that the actual number of customers had increased from 2001 to 2002 by 12,600 or 3%. The CG pointed out that the annual change forecast for the test years was 10,700 customers or an annualized increase of 2.5%. On the other hand, the CG pointed out, that on a throughput basis, the increase between 2001 and 2002 was even less at 1.8% and that there over the two test years an annualized increase of 0.5% was indicated.

The CG considered that these modest increases in customer numbers and throughput suggested the expectation of a somewhat stand pat labour budget. The CG provided another table summarizing the levels of permanent FTEs (P FTE), seasonal FTEs (S FTE) and vacancies for the South.

With respect to the vacancy rate, the CG pointed out that the rate was 7.4% for 2001 and 7.7% for 2002, whereas ATCO's forecast vacancy rates dropped to 4% for the test years. The CG submitted that there was no basis for the change in approach for the test years, and recommended use of the average rate experienced for 2001 and 2002, calculated at 7%.

The CG noted that ATCO was suggesting an increase in P FTEs of 101.0 for 2003 and a further increase of 82.7 FTEs for 2004, resulting in an additional 183.7 FTEs on a cumulative basis over the two-year test period. The CG pointed out that this represented an extraordinary overall increase of 26% relative to 2002, suggesting that approximately one-fifth ($1/5^{th}$) of ATCO's proposed labour force at the end of 2004 was forecast to be acquired during the test period.

The CG submitted that these types of increases were more synonymous with small start-up companies experiencing significant growth, not mature utility companies experiencing limited growth. The CG expressed concern that the extremely disproportionate increase in FTEs requested over the test periods was inconsistent with the reality of the ATCO situation and could not be substantiated.

The CG pointed out that a large part of the projected increase related to the increase to monthly meter reading, which the CG did not consider cost effective or warranted. Therefore, the CG submitted that additional meter readers were not required.

The CG submitted that, based on this factor, and the need for a cap on the level of labour increases taking into account customer growth and throughput, labour growth over the test years should total no more than 5%, or 2.5% per year. The CG pointed out that this cap translated into 18 additional P FTEs per year (2.5% of 716.4), and that the level of S FTEs should be similarly increased by the customer growth rate of 5% over the test years or 2.5% per year, translating to 3.1 additional S FTEs per year (2.5% of 125.9).

On this basis, and maintaining the vacancy rate at 7.5% per year to reflect historical experience, the CG calculated FTEs as follows for 2003 and 2004:

Table 10. CG Calculation of South FTEs

	2003F	2004F
Permanent FTEs, 716.4 plus 18 additions per year	734.4	752.4
Vacancy at 7.5%	(55.1)	(56.4)
Seasonal FTEs, 125.9 plus 3.1 additions per year	129.0	132.1
Total FTEs	808.3	828.1

The CG provided another table demonstrating the impact of its recommendations on labour costs, and unit labour costs per FTE. The table indicated that, while ATCO's forecast incremental cost for FTEs in 2003 was $40,800 per FTE, this included a significant portion of the 131 additional meter readers. Accordingly, in terms of estimating the unit costs of additional FTEs, the CG considered it more reasonable to use the average cost of $54,600 per FTE in 2002 as a base, and apply an estimated inflation factor of 3%. The CG pointed out that this resulted in a base unit cost per FTE in 2003, for forecast purposes, of $56,300 (54,600 x 103%). The CG indicated that, applying the same inflation factor for 2004 resulted in $58,000 (56,300 x 103%) per FTE.

The CG provided a calculation of a revised labour forecast assuming the elimination of $1.4 million (2003) and $1.5 million (2004) in costs for AGS associated with the move to monthly meter reading as identified in response to CAL-AG-162 (a). The CG calculated that this would reduce the forecasts for the South to $46.8 million (2003) and $ 48.7 million (2004).

The CG further calculated that, for the South, the Company's forecast of O&M labour expense after removing expense related to the move to monthly meter reading exceeded any increase attributable to customer growth and labour escalation by $0.8 million (2003) and $0.4 million (2004). The CG recommended that the O&M portion of labour forecast for AGS be reduced by these amounts, on the basis that this would be consistent with customer growth, including an escalation rate of 3% per year.

The CG calculated that, for the South, the total labour forecast for the test years should be reduced by $2.7 million (2003) and $2.2 million (2004), and therefore recommended a total labour forecast for the South of $45.6 million (2003) and $48.1 million (2004).

North

As was the case for the South, the CG provided a table setting out customer growth and throughput from 2001 to 2004 for the North, which indicated that the growth in the number of customers was 4.1% over the two test years or 2.0% per year, somewhat less than forecast for the South. The CG pointed out that the throughput increase was 2.4% over the test years or 1.2% per year, and submitted that these drivers suggested growth in labour FTEs should be no more than 2.0% per year.

With respect to the vacancy rate, the CG pointed out that rate for 2001 was 6.4% and 6.8% for 2002, suggesting an average of 6.6%.

The CG noted that in 2003, the increase in permanent FTEs was principally for meter readers, and since it did not accept or approve of this proposed program, the CG submitted that those additional meter reading positions should not be included in the current test year forecasts.

On this basis, and maintaining the vacancy rate at 6.6% per year to reflect historical experience, the CG calculated FTEs as follows for 2003 and 2004:

Table 11. CG Calculation of North FTEs

	2003F	2004F
Permanent FTEs, 729.2 plus 14.6 additions per year	743.8	758.4
Vacancy at 6.6%	(49.1)	(50.1)
Seasonal FTEs, 144.2 plus 1 addition per year	145.2	146.2
Total FTEs	839.9	854.5

The CG provided another table demonstrating the impact of its recommendations on labour costs, and unit labour costs per FTE. The table indicated that applying a 3% inflation factor to the 2002 unit cost of an FTE yielded a 2003 cost of $57,700 and $59,400 for 2004.

The CG provided a calculation of a revised labour forecast assuming the elimination of $3 million in costs for AGN associated with the move to monthly meter reading as identified in response to CAL-AG-162 (a). The CG calculated that this would reduce the forecasts for the North to $51.4 million (2003) and $53.5 million (2004).

The CG further calculated that, for the North, the Company's forecast of O&M labour expense after removing expense related to the move to monthly meter reading exceeded any increase attributable to customer growth and labour escalation by $1.9 million (2003) and $1.7 million (2004). The CG recommended that that the O&M portion of labour forecast for AGS be reduced by these amounts, on the basis that this would be consistent with customer growth, including an escalation rate of 3% per year.

The CG calculated that, for the North, the total labour forecast for the test years should be reduced by $5.9 million (2003) and $5.8 million (2004), and therefore recommended a total labour forecast for the North of $48.5 million (2003) and $50.8 million (2004).

The CG noted that ATCO's actual permanent vacancy rate was much higher in 2001 and 2002 than the current forecast, and considered that this historical data provided the best evidence on ATCO's operation and should not be ignored. Consequently, the CG submitted that historical circumstances should be taken into consideration when evaluating the reasonableness of the test year forecast. Specifically, the CG recommended adjusting the permanent vacancy rate to the historical norm.

The CG indicated that the impact of the vacancy rate was not inconsequential. By way of example, the CG pointed out that the recommended permanent vacancy rate on the basis of both actual data for 2001and 2002 was 7.5% (South) and 6.6% (North), or roughly 7% overall, a 3% difference from ATCO's unsupported recommendation. The CG pointed out that this could translate into an overstatement of labour costs of around $2.9 million (3% x 1670 employees x avg. labour salary of 57,000). The CG further submitted that these types of adjustments to the forecasts were necessary to reflect the best available information at the time. Contrary to ATCO's assertion, these types of adjustments do not remove efficiency gains from the utility in a prospective rate-making environment.

The CG noted that the major difference between it's recommendations and the AUMA/EDM recommendation appeared to be the treatment of 2001 and 2002 vacancies held vacant pending the sale of production and retail businesses. The CG noted that in the AUMA/EDM Argument these vacancies were excluded.

The CG stated that, as the labour forecasts would include staffing required for the retail function, these would presumably continue as held vacancies for the current test years. The CG stated therefore, that for consistency, the higher experienced vacancy rate should be utilized or the forecast permanent FTEs reduced to account for the retail component. However, the CG noted that ATCO indicated that such adjustments would be more appropriately addressed in the upcoming Unbundling proceeding.

Views of the Board

With respect to the vacancy rate built into the test year labour forecasts, the Board notes that, while ATCO considered use of a 4% rate appropriate, the interveners pointed out that historically, the Company's vacancy rate has not been sustained at this level. The Board notes AUMA/EDM's suggestion that, after adjusting for production and retail sale provisions, a reasonable rate would be 5%, and the suggestions of Calgary and the CG for use of the average of the last two years. The Board notes that Calgary suggested an average of 7.1%, and the CG recommended use of 7.5% in the South and 6.6% in the North.

The Board agrees with the interveners that a rate of 4% is not supported by historical experience, and considers that, while there is merit in the recommendations for a rate based on the average of the previous two years, it is not necessary to use a different value for North and South. On the other hand, the Board accepts ATCO's position that a higher than normal rate in 2002 resulted from unique circumstances that did not impact the test years. Recognizing the recommendations of the interveners and the position of ATCO the Board considers use of a 6% vacancy rate would be appropriate to reflect a reasonable balance of history and ATCO's efforts to maintain a full complement of staff.

Accordingly, the Board directs ATCO to adjust its test year labour forecasts to reflect a vacancy rate of 6%. The Board expects ATCO to apply this rate to all areas after separating out capital related staffing and adjusting for the level of FTE's relative to projects, such as MRRP, that may be affected by this Decision.

The Board notes that interveners took issue with the forecast FTEs of 1911.4 (2003) and 1911.9 (2004) used in determination of labour expense for the test years. Specifically, the Board acknowledges the detailed North/South analysis provided by the CG supporting the recommendation that total FTEs be reduced by 262.8 (2003) and 311.4 (2004) after adjusting for vacancy rates, new programs, customer growth rates and throughput. The Board also acknowledges ATCO's position that key drivers such as growth in customers and throughput should be viewed merely as a starting point, and that increase in staff complement and consequently FTEs is also affected by new initiatives such as the MRRP and monthly meter reading initiative.

Having evaluated the respective positions, the Board considers that the numbers of permanent and seasonal FTEs included in the forecast are reasonable, before accounting for vacancies and 250 new positions related to the MRRP and meter reading project. The Board notes that the forecast permanent FTEs, after reduction of the 250 new positions would be 1467.2 (2003) and 1467.7 (2004) and considers that this level of permanent FTEs and the forecast of 262.9 seasonal FTEs are reasonable to recognize growth.

The Board directs ATCO, in its Refiling, to revise the calculation of forecast O&M labour expense for the test years after application of the findings with respect to the inflation rate, vacancy rates and final FTE numbers as determined in this Section of the Decision. The Board also expects ATCO to revise the capital component of the labour forecasts to reflect the conclusions in this Section of the Decision, and in other Sections dealing specifically with staffing for new programs.

The Board also directs ATCO, in future GRAs, to present support for the determination of forecast FTEs setting out the relationship to customer growth, throughput and productivity or efficiency as a starting point, before reflecting any increase in response to new projects or other drivers.

4.2 Operating and Maintenance

Views of ATCO

ATCO indicated that the Company serves a projected 880,000 customers in 291 communities throughout Alberta, and has offices in 59 communities to provide service to customers.

ATCO pointed out that the Company incurs O&M costs for four main functions, which include the cost of transporting gas, operating and maintaining the gas distribution system, providing customer service work at customers' homes and businesses and customer accounting activities including meter reading, preparing bills and customer contact. In addition there are a number of areas in the Company that provide support for these main functions and to the Company as a whole.

Specifically, the transportation function includes transportation costs to ATCO Pipelines to transport high-pressure natural gas from natural gas producers and other transmission pipelines to Company gate stations and 'farm taps', which is the starting point of the gas distribution system.

ATCO stated that the Company also incurs O&M expenses for areas that provide support to the four main functions, including repair and maintenance of vehicles, heavy work equipment, tools and communications equipment. ATCO stated that operating costs in support of the Company as a whole include Human Resources, Purchasing, Financial Services and Planning, and IT services. ATCO performs all of these support functions except for IT Services, which are contracted to ATCO I-Tek.

4.2.1 Overall O&M Forecasts

Views of ATCO

ATCO submitted that the continuing development of Alberta's deregulated energy industry and the maintenance of a healthy infrastructure to ensure that the needs of customers are met are critical drivers to the revenue requirement forecast for 2003 and 2004.

Operating expenses increased significantly in the year 2001 as a result of the high cost of gas and deregulation, notably in the areas of customer relationship management costs, bad debt expense and fuel related costs. ATCO pointed out that items impacting operating expense forecasts related to communication and education of customers, the commencement of monthly meter reading, inspection and repair of the aging pipeline system, significant increases in fringe benefit and insurance costs, the sale of the Viking production assets and capitalization of additional administrative charges.

ATCO indicated that a 4% inflation rate had not been used for both labour and supplies, but that a 4% rate had been used for the wage increase forecast, as opposed to an inflation rate for general supplies of 2% (2003) and 2.2% (2004).

In the Application, O&M Expense forecasts for the test years were $231.9 million (2003) and $237.9 million (2004), calculated as follows:

Table 12. O&M Expense Forecast

	2002 ($000)	2003 ($000)	2003 vs 2002	2004 ($000)	2004 vs 2003
Labour	60,415	65,993	9.2%	68,795	4.2%
Supplies	163,570	165,857	1.4%	169,062	1.9%
Total	223,985	231,850	3.5%	237,857	2.6%

The following is the detail of O&M Supplies by function, with comparisons to 2001 actuals and 2002 forecasts:

Table 13. O&M Supplies by Function

	($000)					
	Actual 2001	Forecast 2002	Forecast 2003	2003 vs 2002	Forecast 2004	2004 vs 2003
Development & Acquisition	-	-	-	-	-	-
Production & Gathering	7,950	1,649	1,193	(456)	1,224	31
Gas Management	1,056	1,005	1,005	-	1,005	-
Underground Storage	4,423	4,001	4,914	913	4,649	(265)
Transmission	51,638	47,333	48,108	775	48,555	447
Distribution	15,706	15,419	15,987	568	16,436	449
General	2,867	3,136	3,277	141	3,522	245
Sales & Transportation Promotion	2,015	3,318	6,101	2,783	6,148	47
Customer Accounting	40,728	44,827	44,842	15	46,840	1,998
Administration & General	37,794	42,882	40,430	(2,452)	40,683	253
Total	164,177	163,570	165,857	2,287	169,062	3,205

The following is the detail of O&M Labour by function, with comparisons to 2001 actuals and 2002 forecasts:

Table 14. O&M Labour by Function

	($000)					
	Actual 2001	Forecast 2002	Forecast 2003	2003 vs 2002	Forecast 2004	2004 vs 2003
Development & Acquisition	-	-	-	-	-	-
Production & Gathering	1,470	777	641	(136)	665	24
Gas Management	240	260	271	11	282	11
Underground Storage	570	615	624	9	648	24
Transmission	-	-	-	-	-	-
Distribution	34,053	35,012	37,018	2,006	38,635	1,617
General	1,109	1,322	1,374	52	1,429	55
Sales & Transportation Promotion	1,353	1,490	1,493	3	1,543	50
Customer Accounting	8,353	10,822	13,963	3,141	14,543	580
Administration & General	8,863	10,117	10,609	492	11,050	441
Total	56,011	60,415	65,993	5,578	68,795	2,802

ATCO indicated that market forces were responsible for much of the cost increases being experienced by the Company. ATCO cited various cost drivers such as the commencement of monthly meter reading, the requirement for an education program for customers, the conversion to Windows and Office XP, fringe benefit increases, insurance cost increases and ongoing impacts of inflation, customer growth and labor pressures. ATCO pointed out however, that customers had enjoyed significant cost savings since the restructuring of the delivery service of NUL and CWNG into ATCO Gas, as outlined in the response to CAL-AG-02-5, noting that a simpler, but consistent comparison would be to compare the rates customers were paying in 1995 to what they paid in 2001 and 2002.

ATCO submitted that the Board must recognize the cost drivers impacting the Company when reviewing the appropriateness of the revenue requirement forecast, and indicated that it would not be appropriate to simply take a previous year actual operating expense and increase it for inflation as was the case in Decision 2001-96. ATCO submitted that many changing circumstances in the forecast period make this type of adjustment inappropriate. ATCO considered that something as simple as the timing of the restructuring undertaken by the Company in 2002 prevents that year from being considered as starting point for the determination of the test year forecasts.

ATCO noted that the CG submitted tables comparing various operating accounts, the purpose of which appeared to be to draw into question the accuracy of the forecast.

ATCO indicated that the reasons for the variance from forecast in the Advertising account had been addressed in Exhibit 14-10a, and pointed out that the Company had also proposed a customer education campaign, which accounted for the increase in costs in the test years.

With respect to the lower 2002 actual costs for Meter Reading and Bill Delivery (Account 712), ATCO indicated that it did not commence the monthly meter reading program as forecast in

2002. ATCO also noted that Decision 2002-069 also had an impact on this account in 2002 (two years in the South, and one year in the North).

ATCO indicated that the reduction in the 2002 actuals from forecast for Customer Billing and Accounting (Account 713) was also the result of the impact of Decision 2002-069 being reflected, as for Account 712 as discussed above.

ATCO pointed out that this was also the case in the Administrative Expense category, which was also impacted by a reduction in IT costs as discussed in Exhibit 14-10a. ATCO indicated that the conversion to Windows XP in 2003 and 2004 caused an increase in these costs. ATCO referred to Section 4.2.16.3 for further information with respect to Administrative Expense, and to Section 4.2.16.2 for matters related to fringe benefits.

ATCO indicated that it was dangerous to perform "simple" year over year comparisons without taking into consideration unique or changed circumstances, and that the attempt by the CG to link the level of operating increases to customer growth and throughput was inappropriate. ATCO indicated that, as discussed further in Section 4.2.16.3, not all cost increases are driven by these variables, but are related to changes in service levels, or simply market pressures.

Views of Calgary

Calgary submitted that, based on the variance between the 2002 forecast in this Application, and the 2002 actual data, ATCO's forecasting lacked credibility. Calgary pointed out that forecasts were out by more than 5% for the North and 10% for the South.

Views of the CG

The CG did not accept that the marketplace and deregulation necessitated increases in operating expenses in 2003 for such items as monthly meter reading, and expressed concern with the projected increase of $25 million (2003) and $30 million (2004) relative to 2002 actual expenditure. The CG indicated that consideration of forecast expenditure in the following areas further illustrated problems with the Application.

South

The CG provided a table highlighting the variances between 2003 and 2004 test year forecasts and 2002 actual expenditures for Compressor costs, Advertising, Meter Reading and Bill Delivery, Customer Billing and Accounting, and Administrative Expense.

The CG pointed out that the table showed that actual expenditure for 2002 on an aggregate basis was $7.1 million less than the 2002 forecast, or 22%. The large difference caused the CG to question the quality of ATCO's forecast. The CG also indicated the excessive increase of some $12.9 million in the test years compared to 2002 actual data on an aggregate basis. Given that the variance was approximately 40%, the CG reviewed the individual accounts separately.

The CG indicated that the Advertising Account included costs in connection with Customer Relations, including ATCO's proposed new customer education program. The CG referred to its concerns with this program discussed in another section of this Decision, and recommended the advertising budget for the South be reduced to reflect the elimination of the customer education program.

With respect to the Meter Reading and Bill Delivery Account, the CG pointed to the 15% decrease in 2002 actual expenditure compared to forecast, and the significant increases proposed for the test years compared to 2002 actual expenditure. The CG opposed the increases, which were in excess of 48% higher than the 2002 actual expenditure. As discussed in another section of this Decision, the CG submitted that the proposed move to monthly meter reading was not supportable, and recommended that the test year forecasts be adjusted to simply reflect 2002 actual expenditure levels with an increase for inflation of 3% per year.

The CG noted the large decrease of 12% in actual expenditure for 2002 compared to forecast for Administrative Expense, and the increase of 23% in the 2003 forecast compared to 2002 actual expenditure.

North

The CG provided a table highlighting the variances between test year forecasts and 2002 expenditures for Advertising, Meter Reading and Bill Delivery, Customer Billing and Accounting, Administrative Expense and Employee Benefits.

The CG pointed out that the table showed that actual expenditure on an aggregate basis was $6 million less than the 2002 forecast, or 15.6%. The CG submitted that this indicated that ATCO's trend of estimating high was continuing in the North, as well as in the South.

The CG pointed out that, with the exception of the Compression Account, which did not pertain to the North, each of the North accounts exhibited the same characteristics as the accounts in the South. Consequently, the CG recommended reduction of the test year forecasts for the North in the same manner as recommended for the South.

Overall, the CG was concerned with the disproportionate increases in O&M forecasts, particularly when customer and throughput growth did not justify such increases.

Views of the Board

The Board notes that ATCO used an inflation rate for general supplies of 2% (2003) and 2.2% (2004), compared to CPI forecasts of between 2.4%-2.8% between 2002 and 2004, as indicated in the response to BR-AG-57. The Board considers the inflation factors used by ATCO for test year general supplies to be reasonable, noting that none of the interveners took issue with the inflation factors used.

The Board acknowledges ATCO's concern with reducing test year forecasts by application of an escalation factor to historical results, particularly the results for 2002. The Board agrees that applying an escalator to 2002 actuals would be inappropriate given the unique circumstances in that year and the many changing circumstances in the forecast period. The Board also notes comments and observations of interveners with respect to specific O&M components, and will address the evaluation of individual O&M categories in the following subsections of this Decision.

4.2.2 Proposal for Increased Meter Reading Frequency

Views of ATCO

In the Application, ATCO indicated that the changing regulatory environment, government concern regarding utility billing, the use of a monthly GCRR, and the forecast level of gas prices had made metering accuracy and increased meter reading frequency a requirement to accurately bill customers for their gas usage.

ATCO stated that the Company had been reading meters once every two months in the South and every three months in the North, using estimates for the months when reads were not taken or when the meter reading attempt was not successful. ATCO pointed out that, when the gas prices rose dramatically in the winter of 2000/2001, the Company responded to customer concerns over billing accuracy by increasing the frequency of meter readings to every month for several months. In ATCO's view, monthly meter reading assisted in providing customers a higher degree of billing accuracy.

ATCO considered it difficult to understand why so much confusion and misunderstanding had been generated over an initiative, the purpose of which was to parallel a practice directed by the Alberta Government for the benefit of electric customers, particularly in view of the Government's intention to converge the gas and electric markets no later than the first year of the test period. ATCO considered it difficult to reconcile the CG's assertion that there was no evidence to suggest that more than the current level of accuracy was required at this stage, with the clear evidence that Alberta expects that its utility consumers would receive bills based on accurate individual consumption information.

ATCO pointed out that the Application and the transcripts were replete with references to EPCOR and Aquila billing problems, which led to the *Billing Accuracy Deficiency Correction Regulation*, Alberta Regulation 239/2002. ATCO considered that these references made it clear that accurate individual consumption information is a matter of serious concern to customers, government, regulators, retailers and utilities alike. Referring to the requirements of the Electric System Settlement Code, which mandates actual meter reads at least every two months, ATCO indicated that as a practical matter, this means that utilities had to move to monthly meter reading in order to meet the two month requirement of the Regulations. ATCO submitted, that while there may be distinctions between gas and electric markets, those distinctions made no difference when it came to the right of utility customers in the province to receive an accurate account of their individual consumption.

ATCO submitted that its assessment of responsible practice for the test period reflected the need to assure its customers that, despite what other uncertainties might exist in the marketplace, the consumption information upon which each of their bills is based, would be accurate.

ATCO indicated that retailers also had a particular interest in ensuring that accurate actual consumption data was available due to their obligation to ensure that the actual consumption needs of their customers were met with adequate physical supply. ATCO pointed out that the situation for retailers in fact, is of greater concern due to the wider standard deviations, which affect small numbers of customers. ATCO indicated that the effect of estimating consumption for retailers based upon the existing estimating formula would result in greater errors than for the much larger group of customers currently on the GCRR.

ATCO indicated that the average billing estimation error and the standard deviation must both be analyzed to properly evaluate billing accuracy. Referring to its Rebuttal Evidence, ATCO pointed out that the standard deviation for January 2002 for the North was 5.55, 6.23 and 7.15 GJs for periods of one, two and three month between reads respectively. ATCO indicated that 68% of customers would fall within the range of one standard deviation, 95% would fall within the range of two standard deviations and the balance would fall within a range greater the two standard deviations. ATCO submitted that these facts confirmed the existence of significant differences in actual versus estimated individual customer consumption, with material effects on the amounts actually payable by individual customers. Referring to its Rebuttal Evidence, ATCO indicated that this could make a difference of $40 to $50 on an individual customer's monthly bill.

In response to comments of Calgary that the meter reading issue would transfer to the new commodity service provider when the Company is out of the commodity business, ATCO indicated that this "head in the sand" suggestion was irresponsible. ATCO considered it critical to adopt service levels that avoid customer dissatisfaction situations like those experienced by Aquila and EPCOR.

Referring to Calgary's recommendation to provide customers with a card to read their own meter, ATCO submitted that there was not a shred of evidence that this approach could work. ATCO stated that customers expect the Company to read the meter as part of the service that customers pay for. ATCO also considered that Calgary appeared to "switch gears" by indicating that there was an accuracy problem related to the forecasting algorithm. ATCO indicated that its estimating formula is based on the customer's annual consumption, and that if the consumption pattern is consistent year after year the formula will provide reasonable estimated meter reads. ATCO stated however, that this does not ensure accurate individual consumption information, since issues such as installation of energy conservation measures, addition or deletion of gas appliances, or changes in the number of people in the household, make it very difficult to estimate the change in consumption pattern. ATCO submitted that accordingly, monthly metering reading is the only way to ensure the most accurate individual customer consumption information.

ATCO submitted that the Board should reject Calgary's claim that the burden of proof had not been met by ATCO on this issue, and that the evidence on meter reading estimating error clearly supported the need for monthly meter reading.

With respect to AUMA/EDM's suggestion that the Company implement a new rate to "compensate" for temperature variations in standard meters, ATCO submitted that this approach would not eliminate the issues associated with ensuring that individual customer consumption was accurately metered, that retailers received correct information about their customers' consumption, and would not deal with the issues of safety and replacing aging infrastructure fundamental to this program.

ATCO noted that the CG and AUMA/EDM claimed that an over or underestimation of a customer's bill is not a concern as it is trued up the next time an actual read is obtained. ATCO submitted that the interveners were missing the point. While acknowledging the potential that, over time the pluses and minuses would leave a customer indifferent, ATCO pointed out that with the higher level of gas prices and greater volatility, customers want assurance that they are paying for the right amount of gas each month. ATCO stated that Aquila and EPCOR's experiences over the past year reinforced the importance of accurate individual consumption information.

While acknowledging the CG and AUMA/EDM's argument that monthly meter reading would not eliminate the need to prorate consumption related to price changes, ATCO stated that accuracy of the billing is increased where it is prorated based on actual as opposed to estimated consumption value.

Views of AUMA/EDM/CG

AUMA/EDM/CG pointed out that there was no evidence regarding the requirements of the retail market in terms of billing accuracy and meter information, and no evidence to suggest that more than the current level of accuracy was required at this stage. AUMA/EDM/CG considered it questionable whether or not a greater level of consumption information would be required in the future, and how that requirement might be met.

AUMA/Edmonton/CG noted that ATCO had withdrawn its position that the MRRP project was justified by the need for monthly meter reading, which appeared consistent with the view of the expert witnesses of AUMA/EDM/CG, who could not see how the supposed need for monthly reads justified the program in the first place.

AUMA/Edmonton/CG considered it clear that Direct Energy had made no case to ATCO for increased meter reading frequency or accuracy, and submitted that ATCO presented no direct evidence on the need for increased reading and billing accuracy other than evidence that was clearly speculative in nature.

AUMA/EDM/CG referred to ATCO's suggestion that increased meter-reading frequency would result in greater billing accuracy, and that customers could avoid a monthly cost of up to $40 or $50 if provided with actual monthly reads. AUMA/EDM/CG submitted that this analysis is flawed and failed to include the effects of the ultimate true up provided by actual meter reading. AUMA/EDM/CG pointed out that if a customer's use was overestimated by 7 GJ and gas was $7/GJ, the customer would overpay $49 on the estimated bill, and would underpay by the same amount if use were underestimated by 7 GJ. AUMA/EDM/CG stated that, if the same customer received an actual read the following month and gas prices remained at $7/GJ, the customer would be held harmless on both volume and price. AUMA/EDM/CG indicated that, for the period between actual meter readings, the customer would always be kept whole with respect to volume, and would only be permanently impacted, either positively or negatively, by errors in estimated readings for any differential in gas prices during the period between actual readings, and not by the absolute level of gas prices within this period. AUMA/EDM/CG submitted that over time, one could reasonably assume, with fluctuating gas prices and being randomly subject to both under and over estimates, customers might well be indifferent to price impacts from estimated bills, in addition to being indifferent to volume impacts.

AUMA/Edmonton/CG submitted that there was no clear billing accuracy benefit to be derived from monthly meter reading.

AUMA/Edmonton/CG pointed out that ATCO could give consideration to design of a separate rate for customers with standard, non-temperature compensated meters. AUMA/EDM/CG considered that ATCO should look into developing an approach whereby an appropriate conversion factor could be established to provide compensation through rate design in the absence of temperature compensated meters.

Views of Calgary

Calgary considered that ATCO had provided no evidence that its current meter reading program produced either inaccurate consumption data or erroneous bills, and had provided no data concerning customer dissatisfaction with the current meter reading program. In Calgary's view, the data on meter reading accuracy results provided in response to AUMA/EDM-AG-26 (a), did not appear to support ATCO's claim that current meter reading practices were providing inaccurate information or causing erroneous billings.

With respect to ATCO's argument that monthly meter readings were required due to increased customer sensitivity in light of higher and fluctuating gas costs, Calgary noted that by mid year 2003, ATCO proposes to be out of the commodity business, at which time, responses to fluctuating commodity prices would no longer be an actual or perceived obligation of ATCO but would fall upon the new commodity service provider.

Calgary submitted that ATCO's evidence in this proceeding did not support the reasons given for the move to monthly meter reading, that the burden of proof had not been met by ATCO on this issue and that the current meter reading program is meeting the needs of customers.

Calgary considered that the alternative to more frequent meter reading would be to improve the forecasting model and provide customers with a card to enable them to read their own meters as a regular option.

Calgary submitted that ATCO's argument that that the EPCOR and Aquila billing issues are what is driving the move to monthly meter reads failed in there was no evidence in this proceeding that these issues had created dissatisfaction among ATCO customers and no complaints from customers regarding either the meter read interval or the accuracy of the bills. Calgary noted that there had there been no demand by marketers for monthly meter reading, and that neither customers nor marketers appeared at the hearing to support the ATCO position.

4.2.3 Increased Costs of Monthly Meter Reading

Views of ATCO

ATCO pointed out that meter reading costs in the forecast years increased by approximately $5.48 million due to the move to monthly meter reading, and reflects increases in labour, supplies and benefits.

ATCO indicated that alternatives to monthly meter reading suggested by interveners, such as paying customers to read their own meters were not deemed appropriate due to lack of control over ensuring meters are read and the accuracy of the reads. ATCO submitted that meters could be read monthly for an additional $0.53 per reading while achieving the same high standards of accuracy as currently experienced.

Views of AUMA/EDM/CG

AUMA/EDM/CG stated that clearly, if the need for monthly meter reading did not exist, the costs associated with monthly meter reading could not be justified and should not be borne by ratepayers. AUMA/Edmonton/CG considered that all direct and indirect costs associated with the move to monthly meter reading should be excluded from revenue requirement and customer rates. AUMA/EDM/CG indicated that this should include labour costs, associated fringe benefits and capital costs related to additional hand held meter reading equipment, and noted that ATCO had identified total meter reading cost for monthly reading of $5.5 million, and capital costs of $577,000.

Views of Calgary

Calgary submitted that ATCO's rationale for the move to monthly meter reading did not justify the associated increase in cost. Calgary indicated that ATCO was asking ratepayers to fund its perceived priorities of enhancing the competitive market through monthly meter reading, at an increased labour cost in excess of $4 million (2003) and almost $5 million (2004). In Calgary's view, the current state of the competitive market on the ATCO system did not merit expenditures of this magnitude. Calgary also noted that no retailer or marketer appeared at the hearing to support the ATCO contention.

Calgary noted that with the combined North and South zones systems serving approximately 800,000 customers, only 35,000 or 4.4% were taking advantage of the deregulated competitive marketplace. Calgary considered ATCO forecast growth of approximately 10,000 transportation customers over the October to December 2002 period in the North and approximately 5,500 in the South to be an unrealistic projection of customers moving to the deregulated market based on 2002 history and did not justify moving to monthly meter reading at this time.

Calgary stated that ATCO could stage in monthly meter reading to meet the needs of the marketplace as it develops over time and when demands, if any, for monthly meter reading become defined.

Calgary noted, that according to ATCO, an additional 131 meter readers and related positions would be required to implement monthly meter reading, and noted that total cost increases would be in excess of $9 million combined for the test years. Calgary noted that this did not include the cost of vehicles and related items required to implement monthly meter reading. Calgary submitted that the foundation set forth by ATCO, the lack of any cost benefit analysis and the lack of support from the competitive marketplace and customers did not justify the cost of moving to monthly meter reading.

Views of the Board

The Board notes that none of the interveners supported ATCO's proposed move to monthly meter reading from bi-monthly in the South and tri-monthly in the North, and acknowledges ATCO's submission that provision of actual meter readings on a monthly basis would improve accuracy in customer billings.

The Board recognizes that ATCO has used an estimating process for many years and has expressed satisfaction with the accuracy of the estimates in the past, and acknowledges intervener submissions that monthly meter readings will not eliminate the need for estimates. The Board understands that, even where there is an actual read, it will still be necessary to estimate the month-end reading to accommodate the change in the monthly GCRR.

The Board agrees with intervener concerns that ATCO has not presented compelling evidence of significant estimating error, and notes that ATCO moved from bi-monthly to tri-monthly reading in the North during the period of the recent negotiated settlement, which suggests that the Company had significant confidence in the estimating program at that time. The Board acknowledges the submissions of the interveners that during recent years, which included the change in reading frequency in the North, ATCO has not provided any evidence of a large volume of complaints, and that the need for reading meters on a monthly frequency has not been demonstrated.

Based on ATCO's stated objective of having a single revenue requirement, and the lack of any evidence that would justify a different frequency of meter reading in the North and the South, the Board considers that it would make sense that both North and South zones receive the same level of service.

Given the overwhelming opposition to ATCO's proposal for monthly meter reading, the Board questions the need to significantly increase costs to customers who apparently have little concern with the present level of service. The Board agrees with interveners that the need for reading meters on a monthly frequency has not been demonstrated at this time. Accordingly, the Board directs ATCO to revise each of the test year forecasts for the meter reading program to reflect the costs of reading meters every two months.

The Board recognizes the significant challenges faced by ATCO as a result of the changing environment in the transition to a competitive marketplace, and expects that ATCO will continue to monitor the appropriateness of meter reading frequency during the transition. The Board therefore would be receptive to revisiting the issue of meter reading frequency in a subsequent GRA based on information brought forward in light of experience gained in the monitoring process.

The Board notes that the response to AUMA/EDM-AG-46 shows that in 2001, ATCO (South) was able to read meters bi-monthly with nine less staff than in 1993, and one less than in 1997, despite growth in the number of customers. Based on historical experience, the Board would expect that both North and South would have a similar requirement for the total number of meter reading staff, and considers it of concern that the Company is forecasting 143 meter readers in the North and only 92 in the South. The response also shows that a similar number of meter readers had been employed in both the North and South to read a similar number of customer meters between 1993 and 1997, at a time when both zones used a bi-monthly meter reading frequency. Specifically, the average number of customers in 1997 was 361,388 in the South and 348,015 in the North[45], while the number of meter readers was 42 and 40 respectively, averaging 8,651 customers per meter reader (361,388 + 348,015 customers ÷ 82 meter readers). In the period from 1997 to the end of 2002, customer growth has been similar in each zone, although slightly higher in the South when the average number of customers reached 462,773 (South) and 419,861 (North).

Given the historical experience, customer growth, the use of AMR, productivity gains and relevant inflationary factors, the Board directs ATCO, in the Refiling, to indicate with appropriate supporting evidence, the number of meter readers required in the North and South in light of the Board's conclusions with respect to meter reading frequency.

[45] Annual EUB Financial Filings

The Board therefore directs ATCO to decrease O&M test year forecasts to recognize direct and indirect labour costs, associated fringe benefits, supply costs related to the reduction in the number of meter readers, and to reduce all capital costs related to additional hand held meter reading equipment and vehicles to the level required to accommodate the appropriate level of staffing consistent with this Decision.

4.2.4 Pension and Post Employment Expense

Views of ATCO

ATCO indicated that Decision 2001-105[46] approved the Negotiated Settlement for Pensions between ATCO Gas, Pipelines and Electric and their customers. As a result of that Settlement, ATCO has recognized pension and other post employment expenses on a cash basis, effective as of the year 2000. Due to the fact that AGN had already adopted the accrual basis for supplemental pension and other post employment expenses in the year 2000, an adjustment was made in 2001 to reflect those expenses on a cash basis. ATCO indicated that this Application is consistent with the Negotiated Settlement in that the expense had been forecast on the cash basis.

In the Application, the history and forecast for pension and other post employment expense was provided in the following table. The forecast incorporated the capitalization of supplemental pension expense commencing in 2003, consistent with the capitalization of additional administrative charges as discussed elsewhere in the Application.

Table 15. Pension and Other Post Employment Expense

	Actual ($000)			Forecast ($000)		
	1999	2000	2001	2002	2003	2004
Pension Expense	618	1,546	(951)	472	493	509
Other Post Employment	614	1,109	19	684	797	922

ATCO noted the CG's submission that customers had over funded the defined pension plan and that use of the funding excesses to cover other pension requirements was appropriate. ATCO noted that the CG suggested that this transfer of pension assets would reduce the revenue requirement by $703,000 in 2003 and $724,000 in 2004.

ATCO indicated that the employer funding requirement for the money purchase section of the Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies (the Plan) was currently being funded by a transfer of assets from the defined benefit portion of the Plan. ATCO submitted that the supplemental pension plans were not part of the Plan and that the Actuarial Valuation for Funding Purposes contained no suggestion that the funding excess could be used to cover supplemental pension funding requirements. ATCO indicated that the employer funds the supplemental pension plans out of general revenues.

[46] Decision 2001-105 – ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., and Northwestern Utilities Limited (ATCO Companies), Pension Filing – Negotiated Settlement, dated December 31, 2001

ATCO pointed out that the “Funding” line in the Deferred Pension Continuity schedule represents the funding requirement for supplemental pensions only and does not include any employer deposit requirement for the money purchase section of the Plan.

ATCO noted that the CG suggested that the Company be directed to provide details with respect to retirees from regulated operations, due to the possibility that an employee working in non-regulated activities might transfer to regulated operations shortly before retirement. ATCO was uncertain whether the CG was referring to employees within the Company, or employees within the ATCO Group, or both. ATCO pointed out that, with respect to employees within the ATCO Group, it was highly unlikely that an employee would transfer to a different affiliate of the ATCO Group shortly before retirement. ATCO also indicated that employees who move between companies are generally seeking a broadening of opportunities for future growth and development, which are not attributes often associated with staff close to retirement. ATCO considered that most companies would not wish to undertake the learning curve associated with a new employee if that employee was close to retirement. ATCO stated that with respect to employees within the Company, fringe benefits, including pension and other post employment benefits are charged to non-utility operations each year based on the corporate average, not the fringe benefits specific to the employee. ATCO stated that, given the insignificant number of employees involved in non-regulated activities, it would be more likely that the Company is charging a higher level of pension expense than required to non-regulated activities based on the specific employees, as the non-regulated activity attracts a portion of all the Company’s pension expense.

With respect to the pension gain treatment discussed by the CG, ATCO noted that, once again, the CG chose to identify this as an issue for the first time in written argument. ATCO indicated that the pension gain was applied against restructuring costs, thereby reducing the amount of costs recovered from customers. ATCO pointed out that the accounting entries were recorded as a debit to the Deferred Pension Account, to reflect the fact that future pension expense would be lower as a result of the restructuring, and as a credit to the restructuring cost account, resulting in a reduction to the amount of costs to be recovered from customers. ATCO pointed out therefore that customers had received this benefit, and that the suggestions of the CG on this matter were inappropriate.

Views of the CG

The CG argued that it was appropriate to use part of the $423,470,000 funding excess exceeding the prescribed limit under the income tax act by $334,432,400 to cover the money purchase or supplemental pension employer deposit requirement for the test years. The CG noted that this was the suggestion of ATCO’s actuarial consultant, Mercer Human Resources Consultants. The CG argued that customers had over-funded the defined pension plan and the use of the funding excesses to cover other pension requirements was appropriate. The CG argued that the transfer of pension assets would reduce the revenue requirement by $703,000 in 2003 and $724,000 in 2004.

The CG argued that in order to prevent customers from being harmed from this policy, ATCO should be directed, in all future GRAs, to provide details for all retirements from regulated operations, including the number of years the retiring employee worked in each division and the total number of years of employment used for pension purposes.

The CG submitted that if the $5.0 million gain being carried in the Pension Deferral account could not be satisfied by a transfer of assets from the defined pension plan, which was considered unlikely, it should be removed from the deferral account. Alternatively, if it was not removed, the CG argued, it should not attract any return. Finally, the CG argued that the return associated with this gain since 1999 should be refunded to customers.

Views of the Board

The Board notes that the CG acknowledged that customers had over-funded the defined pension plan and that use of the funding excesses to cover other pension requirements was appropriate. The Board also notes the CG's concern that, in order to be certain that customers are not harmed by this policy, given the possibility that an employee working in non-regulated activities might transfer to regulated operations shortly before retirement, ATCO should be required to provide details of all retirements from regulated operations, including the number of years the retiring employee worked in each division and the total number of years of employment used for pension purposes.

The Board acknowledges ATCO's statement that fringe benefits, including pension and other post employment benefits are charged to non-utility operations each year based on the corporate average, and not the fringe benefits specific to the employee. The Board notes ATCO's position that, given the insignificant number of employees involved in non-regulated activities, it would be more likely that the Company is charging a higher level of pension expense than required to non-regulated activities based on the specific employees, since non-regulated activity attracts a portion of all the Company's pension expense. While acknowledging ATCO's assertion that there should be little or no concern, the Board considers that it would not be an onerous task for the Company to provide at the next GRA, a list of retirees, without identifying the names, showing years of service for pension purposes in both regulated and un-regulated positions.

Accordingly, the Board directs ATCO to provide in future GRAs, details of all retirements from regulated operations since the preceding GRA, specifying years worked in regulated and non regulated divisions, the related chronology and the total number of years of employment used for pension purposes.

With respect to the $5 million gain included in the Pension Deferral Account, the Board notes the concern of the CG that if the gain could not be satisfied by a transfer of assets from the defined pension plan, it should be removed from the deferral account. The Board notes the CG's comment that, if the gain is not removed, it should not attract any return, and that the return associated with this gain since 1999 should be refunded to customers.

The Board acknowledges ATCO's position that the pension gain was applied against restructuring costs, thereby reducing the amount of costs recovered from customers. Specifically, the Board notes ATCO's comment that the accounting entries were recorded as a debit to the Deferred Pension Account, to reflect the fact that future pension expense would be lower as a result of the restructuring, and as a credit to the restructuring cost account, resulting in a reduction to the amount of costs to be recovered from customers.

Nevertheless, the Board considers that, while customers received the benefit in terms of reduced restructuring costs, there appears to be merit in the CG questioning the fact that ATCO is earning a return on the surplus amount returned to ratepayers. The Board notes that, based on ATCO's response to BR-AG-35 and CG-AG-84 (c), the amount returned to customers amounted to approximately $15.5 million between 1997 and 1999.

The Board acknowledges that the deferred pension balance has been carried in NWC in the amount of $16.028 million since 2001, consistent with the terms of Decision 2001-105, approving the Pension Negotiated Settlement. The Board notes that Clause 7 of the settlement indicated:

> The ATCO Companies will use the cash basis of accounting for all pension costs, effective January 1, 2000 for purposes of utility revenue requirements. Related Canadian Utilities Limited charges will be accounted for on the same cash basis. The ATCO Companies' Deferred Pension Balances existing at January 1, 2000 (refer to Schedule 1) will be dealt with in future regulatory proceedings.

The Board notes that the settlement was silent on the administration of the resultant ATCO deferred pension balances, other than that they would be dealt with in future regulatory processes. The Board notes that ATCO has presented no proposal for resolution of this issue in this Application, and that the issue with respect to disposition of the surplus balance was raised for the first time by the CG in Argument.

The Board directs ATCO to re-examine the treatment of the deferred pension balance in the next GRA and provide a detailed explanation and rationale for treatment of the pension plan surplus.

4.2.5 Hearing Cost Reserve

Views of ATCO

The Application had anticipated payments of $7.2 million in 2002 related to proceedings that had already occurred. ATCO did not include any payments in 2002 for new proceedings, with the exception of the North Core Agreement negotiations. In addition, ATCO indicated that payments of $3.6 million (2003) and $1.2 million (2004) were forecast relating to anticipated proceedings. Based on the number of regulatory proceedings anticipated, as well as historical levels of hearing costs, ATCO stated that this level of payments could very well be understated. ATCO pointed out that the forecast payments were based on the assumption that the Board would approve the merger of the North and South for regulatory purposes and that lower hearing costs would be one result.

ATCO pointed out that the 2001/2002 GRA forecast for the South hearing account did not contemplate the Gas Cost Methodology and Unbundling proceeding or the Carbon proceeding, resulting in additional costs of $2.7 million. Also, the GRA forecast anticipated that the hearing costs for the Affiliate proceeding would be split fairly equally between the North and South, which had not occurred. ATCO noted that, in addition to these proceedings, the forecast payments in 2003 and 2004 for the other proceedings would once again find the deferred hearing account in a significant receivable position of $5.7 million. ATCO therefore requested a one-time recovery of hearing costs from its South customers in the amount of $3.4 million, based on the forecast 2002 closing balance.

ATCO also requested that the Board approve an annual expense for hearing costs of $700,000, noting that this level of expense was lower than what customers were paying today ($878,000), and was based on the assumption that the Board would approve the combining of the two ATCO business units into one for regulatory purposes. ATCO submitted that this lower level of expense also anticipated that there would be a diminishing of regulatory activities from recent historical levels, and approval of the one-time recoveries as discussed above.

In the Application, ATCO provided the following details of forecast and actual amounts for the Deferred Hearing Costs Reserve:

Table 16. Deferred Hearing Costs

	Actual ($000)			Forecast ($000)		
	1999	2000	2001	2002	2003	2004
Opening Balance	988	1,173	3,546	5,389	7,233	10,133
Expense	(575)	(878)	(878)	(878)	(700)	(700)
Payments	1,364	3,251	2,721	7,174	3,600	1,200
Sub-Total	1,777	3,546	5,389	11,685	10,133	10,633
Decision Adjustments	(604)	-	-	(4,452)	-	(7,300)
Closing Balance	1,173	3,546	5,389	7,233	10,133	3,333

ATCO indicated that, in the event that the Company was required to maintain separate revenue requirement forecasts, the hearing cost forecast should be increased by $350,000 in each test year.

ATCO indicated that the forecast of legal and consultant costs related to regulatory activity had been reduced, based on the assumption that the Board approves one revenue requirement, and that in the event that ATCO is required to maintain separate revenue requirement forecasts, the forecast for legal and consultant expenses should be increased by $300,000 (2003) and $600,000 (2004).

While acknowledging that the Board might question why these costs should be increased in the test years given that the 2003/2004 GRA proceeding was essentially complete, ATCO noted that given the level of attention to combination of North and South revenue requirements in the current proceeding, ATCO anticipated that the forecast of these costs was insufficient for the current proceeding. ATCO pointed out that if the Board approved a single revenue requirement, this would become a forecast risk, but in the event that the Board did not grant the relief sought, the forecast should be adjusted as indicated.

ATCO stated that the GRA forecast also did not incorporate the cost of separately auditing the North and South information for 2003 and 2004, pointing out that the estimated cost per year of this activity was approximately $12,000. ATCO submitted that, should the Board deny the relief sought, these additional costs should be added to the revenue requirement forecast.

ATCO also requested a one-time recovery of hearing expenses from both North and South customers in the 2004 forecast, on the basis that, in Decision 2001-96, the Board agreed that customers who benefit from the costs related to hearing expenses should also be the customers who pay for those costs.

Referring to discussion during cross-examination, ATCO noted that AUMA/EDM proposed that the one time adjustment for the North could be adjusted to $2.9 million, rather than the $3.9

million proposed by ATCO. ATCO indicated that the result of this change would be that the forecast balance in the hearing account in 2004 for the North and South would be closer together. ATCO agreed that it would be willing to alter the one time recovery from North customers, but that the amount of the adjustment would depend on all other forecast amounts in the deferred account being approved. ATCO noted that this adjustment would also impact the NWC related to hearing costs, and pointed out that the Company had also made the commitment to continue to maintain separate North and South hearing accounts for any proceedings specifically related to the North and South, and to address the recovery of these costs at the next GRA.

ATCO pointed out that the lower than forecast amount of hearing costs actually paid in 2002 related to the South should be viewed as a timing issue only, and should not be used to alter the one time recovery of hearing costs. ATCO indicated that even with the one time recovery, the receivable balance in the hearing account at the end of 2004 was forecast to be $3.3 million, which is significant.

Referring to Calgary's suggestion that it would prefer to have a separate rider to collect the one time hearing cost adjustment, ATCO indicated that this was consistent with the proposed treatment in Section 6.1 of the Application. ATCO noted that Calgary did not indicate any objections to the one time recovery.

ATCO indicated that the CG's argument that only the North Core Agreement negotiations were included in hearing cost payments for the North in 2002 was incorrect as explained in response to AUMA/EDM-AG-02-127.

Referring to the CG's suggestion that the one time recovery of hearing costs for the North and South should be spread over two years to avoid rate shock, ATCO noted that if the Board agreed with this treatment, NWC related to the deferred hearing costs would require adjustment.

ATCO noted that the CG agreed with the reduction in annual expense for hearing costs in recognition of the fact that regulatory activities should diminish with the combination of North and South. ATCO clearly indicated that this level of reduced expense was only appropriate if the Board approved one revenue requirement commencing in 2003. In the event that the Board considered s that separate revenue requirements remained appropriate, the hearing expense should be increased by $350,000 in each test year.

While having acknowledged willingness to alter the one time recovery of hearing costs from North customers, ATCO noted that the amount of the adjustment would be dependent on what the Board approved with respect to the forecast hearing expense and payments. ATCO therefore wished to clarify that it only agreed to reducing the North one time recovery to $2.9 million in the event that the Board approves the expense and payment amounts as forecast for 2002–2004. ATCO stated that, if the Board approves something different than forecast, the amount of the one-time adjustment must also be altered, with the desired goal of bringing the 2004 closing deferred hearing account balances for the North and South closer together.

Views of AUMA/EDM

AUMA/EDM referred to the one-time adjustments to the Deferred Hearing Costs Accounts in 2004, and noted that the deferred hearing accounts were in receivable positions at the end of 2001 in the amount of $3.9 million leaving a closing balance of $1.06 million. AUMA/EDM noted that the rationale for the one-time adjustments was set out in AUMA/EDM-AG-65 and AUMA/EDM-AG-100 essentially said that the one-time adjustment reflected the 2002 closing balances. The AUMA/EDM was unable to follow that rationale.

The AUMA/EDM submitted that a more reasonable approach would be to make the necessary one-time adjustment using the 2004 forecast closing balances, which would then be reflective of forecast account activity for the test years. AUMA/EDM noted that, in response to AUMA/EDM-AG-100, ATCO indicated that it would not be opposed to this suggestion, and that it could be achieved by reducing the one-time charge in the North to $2.9 million.

AUMA/EDM noted ATCO's willingness to accept the AUMA/EDM proposal to reduce the one-time adjustment for the North so that the 2004 closing balance, for North and South, "would be closer together." AUMA/EDM noted that acceptance was conditional on all other forecast amounts in the deferred account being approved.

AUMA/EDM interpreted this to mean approval of the forecast amounts in this proceeding but subject to final approval and authorization of payment in Board Cost Orders. This was acceptable to AUMA/EDM.

Views of Calgary

Calgary considered that, if the Board was inclined to allow ATCO a lump sum in order to reduce the reserve for hearing costs, Calgary's preference would be to have the amount collected as a separate rider to avoid having it embedded in the rates for 2004.

Views of the CG

The CG considered that, based on the number of anticipated regulatory proceedings, the level of payments forecast by ATCO could be understated. The CG noted that the current level of approved hearing expense for AGN was $354,000 per year, and that due to the fact payments for regulatory proceedings/negotiations in the North had exceeded this level of expense to a considerable degree, the deferred hearing account in the North was in a receivable position of $2.1 million as at the end of 2001. The CG noted that it is anticipated that, by the end of 2004, this balance would climb to a receivable position of $5 million. The CG noted that ATCO requested a one-time recovery of hearing costs from its North customers in the amount of $3.9 million.

The CG noted that the current level of approved hearing expense for AGS was $524,000 per year, and that in the 2001/2002 GRA, ATCO requested that this expense level be increased to $1 million per year to address the significant level of regulatory proceedings forecast for the future. The CG noted that the Board did not approve the requested increase, and that at that time, ATCO also requested recovery of $4.5 million to address the significant receivable position for the South deferred hearing expense account. The CG noted that this was approved in Decision 2001-96, and that as at the end of 2001, the South deferred hearing account was in a receivable position of $3.3 million. The CG considered that, while the one time recovery of hearing costs of $4.5 million would address this receivable position, it would not address the significant level of payments anticipated to occur in the future. The CG also noted that the 2001/2002 GRA forecast for the South hearing account did not contemplate the Gas Cost Methodology and Unbundling, or the Carbon proceedings resulting in additional costs of $2.7 million. The CG considered that the forecast payments in 2003 and 2004 for the other proceedings would result in a significant receivable position of $5.7 million in the deferred hearing account. The CG noted that ATCO requested a one-time recovery of hearing costs from its South customers in the amount of $3.4 million.

The CG noted that, in addition to the one time adjustments, ATCO requested approval of an annual hearing costs expense of $700,000. The CG indicated that this was lower than the amount that customers were paying today (i.e. $878,000) and was based on the assumption the Board would approve the combining of the two ATCO business units into one, for regulatory purposes. The CG considered that this lower level of expense also anticipated a diminishing of regulatory activities and approval of the one-time recoveries.

The CG considered it appropriate to recover hearing costs in the South and the North for accumulated amounts, but that the amount should be spread over a minimum of two years to avoid rate shock. The CG also considered it appropriate to reduce the annual expense for hearing costs from $878,000 to $700,000, and agreed with ATCO that regulatory activities should diminish and the eventual combining of ATCO Gas North and South should lead to lower costs.

The CG did not consider it appropriate for amounts to be charged to the hearing cost reserve account until ATCO received Board approval, or the agreement of parties in the case of negotiated settlements. The CG considered it important for deferral accounts to remain as simple as possible to minimize regulatory activity associated with review of the accounts, and that the hearing cost reserve account should only have an entry funding the account and entries associated with each negotiation or Board hearing cost order. The CG considered it inappropriate to charge any ATCO internal amount to the account without a hearing cost order or parties agreement, subject to Board review in the case of a negotiated settlement. The CG disagreed with ATCO's position that this would take away the deferral mechanism of the account. The CG stated that the account should not be used as a deferral of all ATCO regulatory expense, but only Board approved regulatory expense.

Views of the Board

The Board notes ATCO's proposal for a one-time recovery of hearing costs of $3.4 million in the South and $3.9 million in the North, based on balances as at the end of 2002 and its proposal that an amount of $350,000 be expensed for each of North and South in both test years, for a total of $700,000 in each test year.

The Board notes the CG's suggestion that the one-time recovery should be collected over a two-year period, and Calgary's recommendation that a separate rider be used. The Board also notes the AUMA/EDM recommendation that a more reasonable approach would be to make the necessary one-time adjustment using the 2004 forecast closing balances, which would then be reflective of forecast account activity for the test years. The Board notes ATCO's acknowledgement that this could be achieved by reducing the one-time charge for the North to $2.9 million. The Board acknowledges AUMA/EDM's observation that this would have the result of equalizing the remaining balance amount between North and South.

The Board notes that ATCO agreed that an adjustment could be made for the North, and considers that an adjustment is appropriate to equalize the North and South balances in the Deferred hearing Account, particularly given the desired objective of eventual combination of the revenue requirements. The Board also agrees with ATCO that $350,000 hearing expense or a total of $700,000 in each test year is reasonable. The Board is also of the view that the account rationalization should not be prolonged and therefore considers that a one-time lump sum recovery for North and South is appropriate. The Board agrees with AUMA/EDM that the amount should be $2.9 million in the North, resulting in a total recovery of $6.3 million.

Accordingly, the Board directs ATCO to recover the one-time hearing expense in amount of $3.4 million in the South and $2.9 million in the North effective January 1, 2004. However, noting that the actual closing balance for 2002 was $1.8 million less than forecast in the South, the Board directs ATCO to identify in the Refiling, any further adjustments that might be necessary to ensure equalization of North and South 2004 closing balances.

The Board also agrees with Calgary that the one-time lump sum recovery should be by way of a rate rider, noting that the lump sum amount for each of the North and South will be less than the amount approved in the AGS 2001/2002 GRA.

The Board does not agree with ATCO that there is a need to increase hearing costs in the event that a single revenue requirement is not approved, on the basis that the Board expects that ATCO will continue to file a single GRA even where separate revenue requirements are determined for North and South, as directed in Section 1.1.1 of this Decision.

4.2.6 Reserve for Injuries and Damages

Views of ATCO

ATCO indicated that, as a result of the incidents that occurred on September 11, 2001, there was significant volatility and uncertainty with respect to the reaction of the insurance industry. ATCO expressed concern that the ability to obtain certain insurance, such as coverage against terrorist acts, was becoming questionable.

ATCO requested that insurance costs be included in the reserve for injuries of damages commencing in the year 2003, until such time as the insurance industry returned to a more stable level of operation

ATCO stated that, historically, changes in insurance premiums and level of deductibles had been relatively stable and therefore relatively easy to forecast. Based on the recent experience of the ATCO Group in obtaining replacement insurance for the policies expiring on June 30, 2002, premiums and deductibles were increasing significantly while some coverage was no longer available. ATCO indicated that the Company also had a significant amount of uninsured risk. All of these factors resulted in making it extremely difficult to determine what the future cost of insurance premiums, deductibles and uninsured losses would be. ATCO submitted that the purpose of the Reserve for Injuries and Damages was to ensure that the utility was not exposed to the potentially catastrophic impact of significant unforeseeable events. Given the increased uncertainty surrounding the insurance industry, ATCO believed that it would be appropriate to charge all of these related costs to the Reserve for Injuries and Damages until such time as the insurance industry returned to a more stable level of operation.

ATCO requested an annual expense level of $1.137 million (2003), and $1.162 million (2004), intended to provide for both the cost of insurance premiums as well as maintenance of the reserve level of $600,000.

ATCO indicated that the current approved Reserve expense for NUL was $187,000 annually, of which the ATCO Gas share was $93,500. ATCO noted that this expense level has not increased in ten years and as a result, the balance in the Reserve account in 2001 was in a payable position of $38,000. ATCO therefore requested a one-time recovery from North customers of $338,000 to bring the reserve account balance to the desired level by the year 2004. ATCO noted that the reserve expense for the North had not been adjusted since the 1993/1994 GRA. ATCO noted that the currently approved expense for AGS was $175,000. In the Application, the composition of the reserve was set out as follows:

Table 17. Reserve Expense

	Actual ($000)				Forecast ($000)	
	1999	2000	2001	2002	2003	2004
Opening Balance	(529)	(573)	(329)	(340)	(269)	(269)
Expense related to Claims	(224)	(239)	(269)	(269)	(340)	(340)
Expense related to Premiums	-	-	-	-	(2,244)	(2,298)
Fleet Insurance Premiums charged to various functions	-	-	-	-	309	315
Total Reserve Expense charged to O&M	(224)	(239)	(269)	(269)	(2,275)	(2,323)
Payments related to Claims	276	483	258	340	340	340
Payments related to Premiums	-	-	-	-	2,244	2,298
Fleet Insurance Premiums charged to various functions	-	-	-	-	(309)	(315)
Total Payments	276	483	258	340	2,275	2,323
Sub-Total	(477)	(329)	(340)	(269)	(269)	(269)
One-Time Adjustment	96	-	-	-	-	(338)
Closing Balance	**(573)**	**(329)**	**(340)**	**(269)**	**(269)**	**(607)**

Referring to the CG's position that the purpose of the Reserve account is to ensure that the utility is not exposed to the potentially catastrophic impacts of unforeseen events, ATCO stated that this is not the only reason for the use of the reserve account. ATCO noted that, as determined by the Board in Decision E93004,[47] the reserve was also to be used for expenditures that are not reasonably foreseeable and therefore difficult to forecast.

ATCO indicated that, the fact that the Company was able to mitigate potentially significant claims through prudent use of legal avenues does not mean that these costs were not appropriately charged to the Reserve. ATCO stated that the guiding principle was whether these claims could have been reasonably foreseen and forecast, and/or whether those claims had the potential to be significant. ATCO stated that, even in the event that the Company was unsuccessful in defending a claim, it would generally incur legal fees with respect to these matters, and should not be castigated for the fact that it was prudently managing this potential expense to customers. ATCO submitted that the CG's proposal that legal fees and deductible

[47] Decision E93004 – Canadian Western Natural Gas Company Limited, 1992/1993 GRA Phase I, dated February 8, 1993

amounts and amounts under some materiality limit should not be charged to the Reserve was therefore inappropriate. Regarding the CG recommendation that charges related to incidents arising from normal wear and tear not be included in the Reserve, ATCO indicated that such claims could arise and there was no reason to treat them any differently from other claims.

In the event that the Board agreed with the CG recommendations, ATCO pointed out that operating expense must be increased to a level sufficient to take into consideration the significant variability and uncertainty associated with these types of incidents.

With respect to the appropriateness of charging insurance costs to the Reserve until such time as the insurance industry stabilized, ATCO indicated that it would not be averse to using a separate deferral account as recommended by the CG.

ATCO stated that the change in treatment of insurance costs in light of the rapid escalation of that cost in no way reduced the Company's operating or commercial risk. ATCO stated that it was the nature of the insurance industry that had changed, prompting the proposed change in treatment for insurance costs. ATCO submitted that, what was once a relatively stable and predictable industry had become uncertain and volatile, a condition that supported the change in the treatment of the costs.

ATCO indicated that the reason for the requirement for insurance for a portion of the working gas in storage was addressed in Rebuttal. ATCO indicated that due to the significant increase in gas prices, it was viewed as prudent to commence this insurance for Carbon again, and considered it appropriate that customers be responsible for the cost of this insurance. ATCO stated that the fact that there was gas stored in Carbon by third parties and that there were costs associated with providing that service was clearly within the contemplation of the Board in Decision 2001-75.[48]

Views of the CG

The CG did not support the one time adjustment for the North Reserve for Injuries and Damages as requested by ATCO, noting that the expense amount was last reviewed in the 1993/1994 GRA. The CG considered it inappropriate for balances accruing over a ten-year period in a reserve account to be made up through a one time adjustment. Therefore, the CG recommended that the North expense amount be increased by 20% to gradually recover any shortfall and help minimize rate spike effects.

The CG noted the requirements for the Reserve in the Canadian Gas Association's Uniform Code of Accounts, and considered it appropriate for the Board to direct ATCO to follow the treatment specified in the Code for the operation of the reserve for injuries and damages. The CG submitted that specifically, over the years it appeared that this reserve account and most other reserve accounts lacked definitive accounting treatment. By way of example, the CG noted two significant differences between the way ATCO operates the account and the Uniform Code of Accounts. The CG pointed out first of all, that Company owned or leased assets that had been damaged were not charged to the reserve account, but to the capital accounts. Secondly, the CG indicated that, under the Code of Accounts, legal fees were not to be charged to the reserve account although payments of awards to claimants for court costs and legal services are allowed.

[48] Decision 2001-75 – GCRR Methodology and Gas Rate Unbundling, Part A: Methodology and Unbundling Proceedings, dated October 30, 2001

The CG noted that ATCO includes legal fees in the account and in fact, in most years, legal fees had represented by far the greatest portion of the charges to the reserve.

Recently, in the ATCO Pipelines Phase I hearing, the CG became aware of a ruling of the Public Utilities Board in Decision E93004, that it was appropriate that CWNG charge against the Reserve the legal fees associated with occurrences causing charges to the Reserve.

While not aware of this ruling at the time of the ATCO hearing, the CG noted that this decision is over ten years old, and that arguably, a review of the issue concerning legal fees charged to account was not unreasonable. Further, the CG stated that it was unclear whether the Uniform Code of Accounts was taken into consideration at the time of the 1993 decision or whether the treatment under the Code of Accounts had changed over the last ten years with regard to this Reserve.

The CG considered that legal fees are generally not insured for minor claims as the cost of the insurance exceeded the cost and risk of the legal fees, and that legal fees faced no greater forecast risk than other expense items. Generally, the CG was concerned that there had been a drifting away from the Uniform Code of Accounts for this reserve account resulting in unnecessarily increased regulatory complexity in the operation of the account, which allowed unintended advantages to fall to ATCO.

Views of Calgary

As noted in the discussion on insurance in Section 4.2.8, Calgary argued that the insurance premium should not be included in the reserve for injuries and damages and should continue to be forecast.

Calgary acknowledged that there had been some changes in the insurance business since September 11, 2002, but saw no change in risk with respect to ATCO that would require customers to bear the added risk of forecast changes in insurance premiums in 2003 and 2004. Calgary argued that if ATCO obtained approval for this approach to the treatment of insurance premiums, there needed to be an adjustment to the rate of return on common equity to reflect the reduction and risk. Calgary argued that use of the reserve for injuries and damages by itself reduced ATCO's risk significantly relative to other companies.

Calgary also questioned why, after so many years, ATCO required insurance with respect to gas in Carbon storage commencing in 2001, particularly when the operator, Midstream, had approximately 60% of the capacity.

Views of the Board

The Board accepts ATCO's position that insurance costs are rising and are more volatile and less predictable as in previous years, and for the test years until re-evaluation at the next rate application, will allow ATCO to include insurance premiums in the Reserve for Injuries and Damages, noting that such treatment is a temporary deviation from the UCA. The Board also considers that there is merit in Calgary's position that ATCO's proposal should be rejected, but if considered appropriate by the Board, the related reduction in risk needed to be recognized in determination of an appropriate equity ratio. Accordingly, in Section 3 of this Decision, the Board will consider the impact on risk to the Company as a result of this approval.

The Board has considered ATCO's request to recover a shortfall of $338,000 from North customers by a one time lump sum adjustment and notes the CG's recommendation that the expense amount be increased by only 20% to recover any shortfall gradually and minimize rate spike. Given that ATCO has proposed to combine the North and South revenue requirements, the Board considers it appropriate to remove as many impediments as possible to the ultimate achievement of this goal. The Board therefore approves ATCO's proposal for recovery of the shortfall in the North, noting that the amount involved is relatively small.

The Board notes that because of rising gas prices ATCO found it prudent to insure the working gas in Carbon storage against loss. The Board also notes that Calgary questioned why, after so many years, ATCO required insurance with respect to gas in Carbon storage commencing in 2001, particularly when the operator, Midstream, had approximately 60% of the capacity.

The Board accepts ATCO's assertion that insurance is necessary in this case, and as with other insurance premiums discussed above, grants ATCO's request to include this insurance in the Reserve pending re-evaluation at the next GRA. The Board will also consider the resulting impact on risk to the Company in Section 3 of this Decision.

However, notwithstanding the approval of the treatment of insurance on gas stored at Carbon, the Board is concerned that the additional expense to be paid by customers is being absorbed in the current Carbon storage fee of $0.41/GJ of capacity. The Board therefore expects that ATCO will include, at the time of the next fee review, a discussion of the extent to which the fee compensates customers for the insurance expense.

With respect to legal fees, the Board acknowledges ATCO's submission that the guiding principle is whether or not potentially significant claims could have been reasonably foreseen and forecast, and accepts the inclusion of legal fees in the reserve account on that basis. However, the Board notes the CG's observation that in most years these fees have represented, by far, the greatest portion of the charges to the reserve, and that there had been a deviation from the UCA, which precludes inclusion of legal fees in the reserve account.

In view of the exclusion in the UCA, and the escalation in the level of legal fees charged to the reserve, and notwithstanding the findings in Decision E93004, the Board directs ATCO at the next GRA, to clarify its operating procedures with respect to the reserve with particular reference to legal fees, and provide an appropriate description of the legal fees charged against the reserve to ensure that expenses are prudently included.

4.2.7 Customer Communications

Views of ATCO

ATCO indicated that the Sales and Transportation Promotion function included expenses designed to promote or retain utility service including customer relations and communications, advertising, ATCO EnergySense and the ATCO Blue Flame Kitchen. ATCO pointed out that the increase in supply expenditures in this function related to increased customer relations and communications costs and the implementation of ATCO EnergySense.

ATCO submitted that the continuing development of Alberta's deregulated energy industry resulted in the need to enhance communication efforts with customers. As ATCO's ability to communicate effectively with all of its customers by way of the customer bill diminished due to retailers, new ways of communication needed to be found to ensure that all customers are treated fairly and kept informed. ATCO submitted that, to help consumers become comfortable with deregulation, they needed to understand what deregulation meant to them and where it is going in the future. ATCO also considered that they needed to understand the roles of their local delivery company versus energy retailers, and the options available to them, and be able to make informed choices about dual-fuel offerings from retailers, given the fact that gas/electric convergence would continue to advance.

ATCO stated that customers, particularly core market customers, did not currently have the information or the background to assess their options and make informed decisions. ATCO submitted that it had a clear role to fill in this regard, and research indicated that customers feel that their utility has higher credibility than the government as a source of information. ATCO indicated that, in response to the need for enhanced communications, the Company would incur costs related to increasing consumer research to determine what information consumers were seeking and how to best provide it to them, and an increasing focus on advertising and printed material. ATCO pointed out that the forecast for advertising was $2.5 million in each test year.

ATCO indicated that the Company and ATCO Electric recently introduced ATCO EnergySense, a service to assist consumers to evaluate the energy efficiency of their homes and businesses in order to manage and reduce their energy costs. ATCO pointed out that the services provided by EnergySense included a toll-free customer enquiry line, an interactive web site, print and web resource materials, and energy audits. ATCO indicated that forecast labour costs associated with ATCO EnergySense were approximately $350,000, and forecast supplies costs approximately $800,000, comprised mainly of contractor costs to perform the energy audits. Offsetting these costs ATCO also forecast additional revenues related to EnergySense audits from customers, government grants and ATCO Electric of approximately $1 million per year.

ATCO included forecasts costs of $3 million related to consumer education campaigns in each test year, of which $2.5 million related directly to the communication effort, and $500,000 to support functions such as research to ensure the information is communicated in the most effective manner possible. ATCO stated that education of customers had always been and would continue to be a responsibility of the Company. ATCO pointed out that education was provided when the Core Market regulations were introduced, when new retailers like Apollo entered the marketplace, when customers experienced significant increases in energy costs in 2001, and with the introduction of the rebate program. ATCO indicated that customers look to the Company for explanations and information about issues in the marketplace that impact them.

ATCO submitted that customers were wary and confused about the basic concepts of deregulation, and the options available to them, and that there was an elevated level of concern on the part of customers with respect to deregulation, which was likely driven to some extent by the increase in energy prices.

ATCO stressed that the education campaigns were not related to the retail sale, and believed that both retailers and government also had a role to play in the education of customers, although the focus of that education would likely be different. ATCO submitted that, while the amount that the Company was proposing to spend might appear significant, it was only a small proportion of the total investment in customers that should be made in support of continuing deregulation.

ATCO identified the introduction of the government rebate program as a driver of communication costs in the past, and stated that continued questions over whether, when, or how the government might actually implement new rebates, made it clear that additional communication would be required. ATCO stated that the recent changes to government legislation and implementation of the One-Bill model would only increase customer needs for such education.

ATCO noted the CG's suggestion that there was no evidence to indicate an increase in matters related to customer safety, and that such matters would be better addressed by retailers. ATCO had not indicated an increase in expenditures related to conservation and safety matters, merely that these matters were ongoing, and that most importantly, they continued to be the responsibility of the Company. ATCO stated that the Company, not the retailers, was responsible for safety issues, and must therefore continue to be responsible for ensuring that customers were well informed about safety related matters, and the responsible use of natural gas.

Referring to AUMA/EDM's position that it was hard to imagine that a customer who had elected to change suppliers would not expect to receive a bill from the new supplier, ATCO considered that the statement ignored the fact that under the One Bill Model, the bill from the supplier would also include the ATCO delivery charge. ATCO submitted that as it was currently responsible for billing customers for delivery service charges, it would be inappropriate for a different party to explain to customers why someone else would now be charging for those services.

ATCO was unable to confirm if the $1.1 million of Customer Communications costs for the South from the 2001/2002 GRA referenced by Calgary was consistent with the $2.9 million from the current GRA, as no reference was provided for the $1.1 million. ATCO submitted that the two amounts were therefore not properly comparable, since they could not be related to the same functions.

With respect to the AUMA/EDM's statement that the Company intended to conduct another Customer Satisfaction Survey in 2003 with a forecast cost associated with research and print materials of $500,000, ATCO clarified this misconception in the response to AUMA/EDM-AG-57(a). ATCO pointed out that the cost of the survey was forecast to be $75,000, and clarified that the $500,000 related to research and printed materials as stated in the Application should have read $800,000 in the response to AUMA/EDM-AG-96.

ATCO submitted that the recommendations by interveners for reductions in the forecast for Customer Communications did not recognize the significant changes that were occurring with respect to deregulation of the natural gas market. ATCO submitted that the level of costs suggested by interveners would not allow the Company to properly fulfill its responsibility to educate customers about the impact of the changing marketplace.

ATCO submitted that education of customers had always been and would continue to be a responsibility of the Company, and that contrary to the allegations of the CG that customers would pay for the same education campaigns three times, the close coordination of the ATCO, government and retailer education programs would ensure that customers got the highest quality information at reasonable cost.

Views of AUMA/EDM

AUMA/EDM noted that ATCO forecast Customer Relations costs to jump from \$2.1 million (2002) to \$4.9 million (2003) and \$5.0 million (2004), and that the cost averaged \$1.7 million for the three preceding years.

AUMA/EDM considered that ATCO's rationale for the increased expenditure appeared to imply that retailers had no obligation in regard to consumer education and totally ignored the potential sale of ATCO's retail business to Direct Energy. AUMA/EDM considered that, if anything, the obligation to communicate had shifted to other parties, and that ATCO's position seemed to ignore the responsibility of the government, Direct Energy and marketers choosing to participate in retail sales.

Referring to the six areas that ATCO identified as requiring continuing education and education efforts on its part, AUMA/EDM submitted that of the items listed, several were already included in existing "customer communication activities," one was speculative (the introduction of uniform rates across the province) and others required minimal additional information (e.g. introduction of the one-bill module). AUMA/EDM stated that ATCO Gas had not provided any quantifiable details of the additional advertising included within its forecast.

AUMA/EDM considered that there was no justification for an almost tripling of the historic amounts and submitted that as a pipes-only LDC, ATCO would have a reduced need to communicate with customers of third-party retailers such as Direct Energy.

AUMA/EDM submitted that ATCO customers should not be required to pay the cost of communications, which would benefit and should more appropriately be borne by retailers (and the government). While acknowledging the possibility that additional funds would be required to address some of the issues relating to unbundling and deregulation, AUMA/EDM considered that those issues could not justify the increases proposed. In addition, in AUMA/EDM's view, ATCO had underestimated customers' knowledge and understanding of the evolving retail market or alternatively, overestimated the need for further customer education.

Based on these considerations, AUMA/EDM submitted that the Customer Relations costs for each of the test years should be capped at \$2.5 million, which represented more than a 20% increase over historical amounts.

AUMA/EDM noted ATCO's statement that "Education of Customers has always been and will continue to be a responsibility of ATCO Gas" and "Our customers look to us for explanations and information about what is happening in the marketplace that has a direct impact on them."

AUMA/EDM considered it inappropriate for ATCO and therefore, its customers, "… to ensure a well functioning, open, deregulated market." AUMA/EDM submitted that ATCO had over-estimated the need for these communications and was assuming a disproportionate share of the responsibility.

AUMA/EDM submitted that the more than doubling of costs for the test years was excessive and should be restricted.

Views of the CG

The CG considered that the forecast cost of approximately $3 million dollars for each of the test years for customer education was excessive, and that it was inappropriate for customers to fund consumer education campaigns related to deregulation or the sale of retail functions to Direct Energy or any other retailer. The CG considered that in this case, it appeared that the bulk of the communication costs forecast related directly to the sale of the retail function. While the sale of the retail function would likely result in some customer confusion and concern, the CG submitted that the costs of customer communication associated with the retail transfer should be borne by ATCO as the beneficiary of any gain from the transfer.

Further, contrary to ATCO’s suggestions, the CG did not consider the forecast customer communication costs in line with the expenditures associated with the introduction of the core market regulation, the Apollo entry or the rebate program. The CG submitted that customer education concerning the effects of deregulation was properly the responsibility of the provincial government and retailers, noting that the provincial government had budgeted significant increased financial resources for deregulation education. The CG submitted that arguably, ATCO’s customer communication forecast expenditures would only serve to duplicate the actions of the provincial government and retailers and benefit ATCO through increased brand advertising. Accordingly, the CG submitted that it was not needed.

The CG noted that ATCO was also taking other steps, which should help minimize customer reaction, other than communication expenditures, such as including both the ATCO and Direct Energy logos on the one bill model. Consequently, the CG stated that the level of communication expenditures forecast should not be necessary as the changes would be minor and incremental.

The CG did not agree that customers expected or believed that ATCO would provide the most unbiased information with respect to deregulation. The CG pointed out that consumers were unlikely to be sold on deregulation or gain a full understanding of its perceived benefits through increased communication budgets, since advertising, flyers, bill stuffers, etc. could not reduce the effects of the current pricing volatility and market trends.

Based on the foregoing the CG submitted that Customer Communication expenditures should at most, be maintained at present levels.

The CG noted that the Application indicated significant increases in the area of Customer Relations, including a considerable increase in the ATCO Energy Sense program introduced in 2001. The CG noted that expenditures on Customer Relations in the North and South were forecast to increase for 2003 by $1.428 million and $1.385 million over the 2002 forecast, an increase of 57% and 58%, respectively, and represented an even greater increase compared to 2002 actual expenditure. The CG noted that on a total basis, the increase in the 2003 forecast over actual was $3.356 million, or 68.6%.

Having reviewed ATCO’s justification for the immense increase in customer education costs, the CG took issue with a number of points provided by ATCO in support, and submitted that there was no justification for the proposed increase in costs. The CG stated that first, a number of the issues addressed in ATCO’s current education program were either no longer issues (e.g. introduction of the Government Rebate Program) or addressed matters that the public was already largely aware of due to the passage of time and completion of previous years’ education programs. By way of example, the CG cited the impact of supply and demand market forces on energy prices. The CG stated that furthermore, other elements of the current program were on-going (e.g. on-going conservation and safety information), and submitted that there was no evidence to suggest that most of the above areas needed continuing coverage as part of a Customer Education program.

The CG also considered that there was no evidence to suggest a need for an increase in matters related to customer safety, which at any rate would be better addressed by the end retailer. The CG considered therefore, that if the sale of the retail function were to proceed, those costs would be better borne by Direct Energy and removed from ATCO's revenue requirement.

The CG submitted that secondly, while ATCO might consider it is the role of the Distribution Company to provide customer education on the changes in the energy market, this was a matter best left to Government, given its responsibility for formulating the underlying policy.

Third, in terms of retail billing and end rates, the CG submitted that the company sending the bill to customers was the party best suited to address concerns regarding the bill and issues around rates. Accordingly, the CG submitted that other than addressing some matters related only to the distribution wires costs, ATCO should not be involved in educating customers on billing mechanisms. This would not only minimize overall "education" costs but avoid the possibility of conflicting and confusing messages from two different parties, namely the Distribution Company and the Retailer.

Fourth, the CG considered that since government and the retailer would no doubt be undertaking some form of customer education, there would also be costs associated with each of those programs. The CG submitted that customers should not have to pay for ATCO to effectively duplicate the efforts of two other parties.

As a final point, the CG noted ATCO's suggestion that since the Company was a more neutral party, customers would place greater reliance on information provided by the Company, rather than the government and any retailer. The CG submitted that, if this was true, ATCO should be the only party distributing information, or at least the only one whose costs are eventually picked up by consumers. However, the CG did not consider ATCO to be any more neutral than the government or the retailer. The CG submitted that the level of expenditure suggested by ATCO could only result in unnecessary and inefficient duplication, or potentially conflicting and confusing, information to customers and was unwarranted.

Based on the foregoing, the CG submitted that Customer Relations expenditures should, at most, be maintained at present levels. Specifically, the CG recommended using the average actual expenditures over the period 1999-2001 as a base for Customer Relation costs, noting that this equated to $882,300 (North) and $860,000 (South). Applying its recommended inflation factor of 3% for each test year and for 2002, the CG submitted that the Board should not approve forecast expenditures for Customer Relations any greater than $936,050 and $964,150 (North) and $912,375 and $939,750 (South) in 2003 and 2004, respectively.

The CG noted that, in addition to Customer Relations, ATCO proposed an increase in the Energy Sense program, which was introduced in 2001 and appeared to generate revenues offsetting most, if not all, costs related to the program. Provided that revenues continued to offset expenditures, the CG did not object to continuation of this program. However, the CG believed that much of the information and features of this program should also serve as an offset to the customer education requirements. While not proposing any specific recommendation with respect to such an offsetting reduction, the CG did provide further support for not approving any increase for Customer Relations. Furthermore, the CG submitted that interactive programs, such as Energy Sense, provided a better form of communication and customer education than the current or proposed mail outs, bill stuffers and media ads. The CG submitted that the majority of its constituent members did not actually receive much, if any, benefit in terms of information and education from these sources and primarily viewed it as another form of advertising.

Views of Calgary

Calgary expressed concern with the major increases in the cost of "mass media advertising," which increased from $703,000 in 2002 (more than a 100% increase over the $320,000 in 2001) to $3.1 million in 2003. Calgary indicated that, based on the response to AUMA/EDM-AG-57 it appeared that much of the proposed advertising was directed more to assisting ATCO and the purchaser of the retail function than in assisting customers. Calgary also noted that, while ATCO had charged the cost of a customer survey to its customer accounting function in 2002 and proposed another one in 2003, the survey provided in support of the claim that ATCO was the most trusted source of information was directed at electric customers.

Calgary noted that the 2002 forecast for AGS was approximately $1.1 million, which the Board reduced as part of its overall reduction in Decision 2001-96. Calgary suggested that the total amount for sales and transportation promotion in 2002 should have been no more than $2.2 million for ATCO Gas North and South rather than the $2.9 million shown in the response to CG-AG-113 (m). Calgary submitted that the amounts for the test years should be no more than 10% higher in each of the two years ($2.42 million in 2003 and approximately $2.66 million in 2004).

Calgary considered that the issue was not whether some communication might be required but the proposed level of expenditure, which for the test years, was over twice the 2002 actual amount. Calgary submitted that the advertising amount for 2003 should not exceed the 2002 actual, as shown in Exhibit 14-10 (a), by more than 20% and that the 2004 forecast should not be higher than the 2002 adjusted for two years of inflation at approximately 2.2 to 2.4 % per year.

Views of the Board

The Board has considered ATCO's position that education of customers had always been and would continue to be a responsibility of the Company, and that the budget for customer communication must be increased. The Board notes ATCO's submission that education was provided when the Core Market regulations were introduced, when new retailers like Apollo entered the marketplace, when customers experienced significant increases in energy costs in 2001, and with the introduction of the natural gas rebate program.

The Board has also considered the position of the interveners, all of whom take issue with the forecast increase in costs for customer education. The Board notes that AUMA/EDM argued that the more than doubling of costs for the test years was excessive and should be restricted, and that ATCO customers should not be required to pay the costs of communications, which would benefit and should more appropriately be borne by retailers (and the government). The Board notes AUMA/EDM's submission that Customer Relations costs for each of the test years should be capped at $2.5 million, which represents more than a 20% increase over historical amounts.

The Board notes Calgary's submission that the advertising amount for 2003 should not exceed the 2002 actual, as shown in Exhibit 14-10(a), by more than 20% and that the 2004 forecast should not be higher than the 2002 adjusted for two years of inflation at approximately 2.2 to 2.4% per year.

The Board acknowledges the CG's submission that Customer Communication expenditures of $3 million in both North and South forecasts for each test year were excessive and should, at most, be maintained at present levels. Specifically, the CG recommended use of the average actual expenditures over the period 1999-2001 as a base for Customer Relation costs, noting that this equated to $882,300 (North) and $860,000 (South). The Board also acknowledges the CG's submission that application of its recommended inflation factor of 3% to 2002 and the test years would result in forecast expenditures for Customer Relations of approximately $936,050 and $964,150 (North) and $912,375 and $939,750 (South) in 2003 and 2004, respectively.

The Board notes that expenditures in account 701 (Advertising Expense), has been reasonably constant at $2.4 to $2.5 million from 1999 to 2002. The Board acknowledges ATCO's submission that this was during a time of high gas prices, the introduction of the rebate program and the presence of retail suppliers, and is not convinced that the Company has demonstrated a need to increase its budget to the proposed levels, given that customer communication on these numerous and significant issues was handled at a significantly lower cost. The Board therefore agrees with the interveners that ATCO has not provided compelling rationale to support a significant increase from historical levels. In this regard, the Board recognizes that incorporation of inflation factors of 2%-2.4% to historical amounts would result in test year forecast approximating the amount of $2.5 million proposed by AUMA/EDM.

However, the Board acknowledges that the transition to a competitive marketplace could present certain unique challenges to ATCO in terms of customer education, and considers that this justifies incorporation of an additional $500,000 in each test year, on the understanding that expenditures on customer communications will be directed solely towards the education of customers with respect to the evolving market, as opposed to corporate branding.

Accordingly, the Board directs ATCO, in the Refiling, to revise the test year forecasts for Account 701 to $3 million in each test year, appropriately allocated between North and South.

4.2.8 Customer Services (ATCO Singlepoint)

Views of ATCO

ATCO maintained that since all matters related to the ATCO I-Tek Business Services Master Service Agreement would be dealt with in other proceedings, the forecast was not reviewed in this proceeding.

With respect to the placeholder for the costs related to ATCO I-Tek Business Services ATCO noted that Calgary considered that as a result of the Retail Sale, the separate module to address these costs might not occur. ATCO stated that this is simply not the case, and indicated that, while the Retail Sale would have an impact on the ATCO customer service costs, the Company would continue to incur costs from ATCO I-Tek Business Services, and a proceeding to address the placeholder for those services will take place.

ATCO indicated that the Company decided to address the issues customers were facing as a result of high energy prices and uncertainty in the marketplace in 2001/2002. A task force was created to determine what actions needed to be taken to monitor the progress of these initiatives and to address new issues as they arose. ATCO pointed out that ATCO Singlepoint hired additional call takers, extended their hours or service and installed additional voice communication equipment to manage the staggering level of call volumes. Monthly meter reading was implemented to address customer concerns about bill accuracy. Credit options and arrangements for customers were enhanced to enable customers to manage the impact of the high prices. ATCO noted that the cost of these actions amounted to approximately $4 million, which included ATCO Singlepoint, monthly meter reading and other costs at shareholders' expense.

ATCO submitted that these actions were undertaken for the benefit of customers. ATCO stated that, it could be viewed that as a result of taking these actions, the Company was able to preserve the potential value that could be realized as a result of a sale of the retail operation. As a result, the cost of these actions was deferred to the Company's balance sheet in 2001, to potentially be applied against a future gain on sale. Consistent with the assumption in this Application that there was no sale of the retail operation, ATCO pointed out that these costs had been reflected in the 2002 O&M forecast.

Referring to the CG's statement that it was likely that the high cost of energy included in the 2002 O&M forecast was also included in the test year forecasts, ATCO noted that the CG had every opportunity to confirm if this was the case, and did not do so. ATCO pointed out that the impact of the initiatives undertaken in the year 2001 related to high energy costs had not been included in the test year forecasts. ATCO stated that this could be seen by comparing the 2001 Customer Assistance and Credit Centre costs of $12.6 million, which includes the cost of the initiatives undertaken by the Company, to the 2002-2004 charges, which were at least $2 million lower.

ATCO noted that for purposes of the table provided at page 4.4-31(a) of the Application, the charges from ATCO I-Tek Business Services were included in the year they were incurred (2001), although these costs were actually included in the 2002 forecast. ATCO pointed out that furthermore, the response to CAL-AG-162(a) clearly showed the removal of the costs associated with the high cost of energy monthly meter reading initiative in order to explain the difference between the 2003 and 2002 forecasts. ATCO submitted that the CG's assertion therefore, was contradicted by the evidence.

Views of Calgary

Calgary recommended that I-Tek Business Services costs be reduced in the test years by the same percentage (11.1%) as shown in Decision 2002-069, Direction 11. Calgary argued that should an I-Tek Business Services benchmark be completed before the ATCO transactions with Direct Energy are approved, the costs should revert to the billing and customer care benchmark costs rather than in accordance with ATCO's suggestion that the Singlepoint charges be moved to a separate module. Calgary noted that this separate module might never happen as a result of the Retail sale process, and argued that its recommendation avoided the potential loss of the Board ordered reductions and placed the onus on ATCO to account for them during the Retail Sale process.

Calgary estimated that the 11.1% reduction, when applied to the ATCO Singlepoint (I-Tek Business Services) forecasts, of $39,354,000 (2003) and $41,450,000 (2004) would result in a reduction of $4,368,294 (2003) and 4,600,950 (2004) in Customer Service costs.

Views of the CG

The CG noted that the placeholder amount for ATCO Singlepoint charges for purposes of this application was still an issue. The CG submitted that the Singlepoint charge, reduced to reflect Decision 2002-069 as set out in Table 4.4-31(a) for 2002, should be used as a placeholder until the final amount for Singlepoint charges is determined. The CG argued that this was reasonable since no evidence on new charge out rates or billing determinants recognizing the sale of retail operations had been filed or tested.

The CG referred to ATCO's position that about $4 million associated with the high cost of energy incurred in 2001 was deferred in 2001. However, the CG noted that based on the assumption there is no sale of retail for purposes of the application, ATCO had included the high cost of energy in the 2002 O&M forecast. The CG argued that since the 2002 forecast was used to forecast O&M expenses for 2003 and 2004 the same expenses were likely forecast for 2003 and 2004.

The CG noted that the costs were incurred in 2001 as a result of abnormal gas cost increases in that year. The CG argued that the same level of costs were not likely to be incurred in 2003 and 2004. The CG argued that these costs must be identified and excluded from the test year O&M forecasts to the extent they were not part of other adjustments, which would be dealt with separately such as the meter reading costs referred to in Sections 4.2.3 and 4.2.4 of this Decision and ATCO Singlepoint costs.

Views of AUMA/EDM

AUMA/EDM noted that ATCO had included $39.35 million (2003) and $41.45 million (2004) as placeholders for ATCO Singlepoint charges. AUMA/EDM also noted that ATCO's letter of February 7, 2003 to the Board indicated that the Company was negotiating a new contract with ATCO I-Tek for 2003 and beyond which would facilitate the unbundling of rates and the retail sale. AUMA/EDM noted that the ATCO letter advised that the billing volumes and pricing, prior to the sale in 2003, would be dealt with in a separate module that was also expected to include a benchmarking study.

Views of the Board

The Board recognizes that a benchmarking study has yet to be performed to establish rates for transactions with ATCO I-Tek Business Services (Singlepoint), and that the test year forecast amounts will be held as placeholders in the revenue requirement pending completion and approval of the results of the benchmarking process. In the meantime, the Board agrees with intervener submissions that the placeholder should reflect the rates last approved by the Board in AGS 2001-2002 GRA, inclusive of the 11.1% reduction, noting that the rationale provided by ATCO for the proposed increase in expenditure levels was not persuasive.

Accordingly, the Board directs ATCO, in its Refiling, to adjust the test year forecast for ATCO I-Tek Business Services to reflect the 11.1% reduction to rates approved in Decision 2002-069.

4.2.9 Capitalization of Administration Expense

The views of the parties on this issue are set out in Section 2.3.1 of this Decision.

Views of the Board

As indicated in Section 2.3.1 of this Decision, the Board does not accept ATCO's proposal for capitalization of administrative expense, and directs ATCO to adjust capital and O&M test year forecasts to reflect the re-instatement of the $6.5 million to Administration and General Expense, adjusted for the reduction to labour increases as directed elsewhere in this Decision.

Based on this conclusion, the Board notes that the adjusted forecast for O&M expense (before adjustments to labour increases) in the test years will be $57.518 million (2003), and $58.233 million (2004), an increase of 19.4%-20.6% over 2002 actual expense of $48.184 million. The Board notes that the O&M test year forecasts include a placeholder for Executive Compensation, and directs ATCO, in the Refiling, to confirm the amount of the placeholder for Executive Compensation, which will now be included in full in O&M expense.

4.2.10 Transactions with Affiliates

Transmission Services from ATCO Pipelines

Views of ATCO

ATCO stated that the Company received transmission delivery service from ATCO Pipelines, the cost of which is charged to distribution customers. ATCO indicated that the transmission charge used in the development of the 2003/2004 forecast was $1.63/GJ for the South, based on the interim rate approved in Decision 2002-049[49] for ATCO Pipelines, and $2.10/GJ for the North based on the rate that was negotiated through the North Core Agreement. ATCO submitted that any changes to this rate as a result of regulatory decisions for ATCO Pipelines would be flowed through to the forecasts. ATCO pointed out that the 2002 forecast included a reduction to the transmission charge of $2.1 million related to the interim rates approved for ATCO Pipelines (South) in the year 2001.

ATCO took exception to Calgary's accusation that ATCO had not disclosed whether the placeholders for this cost are based upon the new billing demand or the currently Board approved billing demand determination methodology."

ATCO pointed out that the response to AUMA/EDM-AG-53(a) clearly laid out the rates used and billing demands used in the forecast of the placeholder transmission service charge forecast. ATCO indicated that it was also clear that the Company would flow thorough the results of regulatory decisions applicable to ATCO Pipelines. ATCO disagreed that this was a matter that needed to be addressed in the ATCO Gas Phase II, but considered that it was a matter to be addressed in the ATCO Pipelines 2003/2004 GRA.

ATCO noted that the placeholder charges were based on the approved ATCO Pipelines' rates ($2.10/GJ in the North and $1.63/GJ in the South) at the time of preparing the forecast. Referring to the CG suggestion that rates in the North should be reduced by 14% as a result of the 1999 Negotiated Settlement re-opener, ATCO stated that North customer rates had already been

[49] Decision 2002-049 – ATCO Pipelines South, 2001/2002 General Rate Application Compliance Filing, dated May 30, 2002

reduced by 14% as a result of that re-opener. ATCO indicated that this took into consideration the entire revenue requirement of ATCO Gas and ATCO Pipelines (North), not just the distribution service. ATCO submitted that the Board should reject the CG's suggestion to change the rates used to develop the placeholder charges, as there was no evidence on the record to support any change. Furthermore, ATCO considered this an issue to be reviewed in the ATCO Pipelines proceeding, rather than the ATCO Gas proceeding.

Views of AUMA/EDM

AUMA/EDM noted that ATCO had used the existing transmission charges applicable to AGN and AGS of $2.10/GJ/month and $1.63/GJ/month respectively and the annual design requirements that ATCO Gas provides to ATCO Pipelines. AUMA/EDM considered that these rates should be considered placeholders since ATCO had undertaken to flow through any changes in rates as a result of regulatory decisions applicable to ATCO Pipelines.

Views of Calgary

Calgary expressed concern with ATCO's failure to disclose the proposed revisions to the billing demand to be used for transportation services provided by ATCO Pipelines. Calgary questioned why ATCO had not disclosed whether the placeholders for this cost were based on the new billing demand or the currently approved billing demand determination methodology. Calgary submitted that, since it was too late to address the issue in this proceeding, it must be addressed in the ATCO Phase II proceeding. Calgary argued that Phase II would provide the only remaining opportunity to address this issue, and noted that an ATCO Pipelines Phase II proceeding is mandatory.

Views of the CG

The CG noted that, as a result of the 2001/02 North Core Re-opener Agreement a 14% reduction in rates was negotiated for the North, which applied to AGN as well as ATCO Pipelines North (APN). The CG argued that if the 14% reduction were applied uniformly to APN and AGN costs, the APN rate of $2.10/GJ would be reduced to $1.806/GJ for 2001 and 2002.

The CG submitted that, for purposes of the placeholders, the last approved or negotiated rates should be used. Specifically, the CG indicated that the rate of $1.63 approved in Decision 2002-049 for AGS and $1.806 for AGN reflecting the North Core Re-opener rate reduction should be used.

Views of the Board

The Board recognizes that the amount of the fee for transmission services from ATCO Pipelines is included as a placeholder in the test year forecasts pending the outcome of ATCO Pipeline's 2003-2004 GRA. The Board acknowledges the submission of the CG that the placeholder should reflect the last approved or negotiated rates, which are $1.63/GJ of demand approved in Decision 2002-049 for AGS and $1.806/GJ of demand for AGN reflecting the North Core Re-opener rate reduction of 14%.

The Board agrees with interveners that, until the results of the ATCO Pipelines 2003-2004 GRA are known the placeholder for the South should be based on a rate of $1.63/GJ of demand, and a rate of $1.806/GJ of demand for the North. With respect to the rate for the North, the Board considers that there is merit in the CG's position that one would expect that the reduction of 14%

approved in the North Core Re-opener Negotiation for the combined AGN and APN would include a reduction in revenue requirement to all areas of operations. However, while having approved the negotiated settlement that included the 14% reduction, the Board is unable to distinguish the extent to which the reduction in revenue requirement is applicable to AGN and APN. Therefore, until ATCO Pipelines' 2003-2004 GRA is completed and the transmission fee determined, the Board agrees that the placeholder for the North should be based on a rate of \$1.806/GJ of demand (\$2.10 x 0.86).

The Board considers it important to point out that there was an assumption that the placeholder for the transmission fee would be calculated using the rates noted above times the appropriate billing demand. The Board notes that the terms of agreement for transmission service, as filed in the Affiliate hearing, stipulates that 12 months in advance of each calendar year ATCO will provide ATCO Pipelines with demand requirements to meet ATCO's 4-hour peak system demand requirements and that the Billing Demand will be based on the theoretical 24-hour peak demand. The Board therefore expects ATCO to ensure that the 4-hour demand and 24-hour billing demand are provided to ATCO Pipelines in a manner consistent with the terms of the agreement, as noted.

Therefore, the Board directs ATCO, in its Refiling, to stipulate the ATCO Gas 4-hour peak demand that ATCO Pipelines will use for its system design and operational planning purposes and the ATCO Gas 24-hour billing demand that ATCO Pipelines will use for its cost allocation purposes.

ATCO I-Tek Information Technology

Views of ATCO

In the Application, charges from ATCO I-Tek were forecast at \$13.555 million (2003) and \$12.445 (2004). ATCO indicated that the forecast cost associated with the licensing and implementation of Windows XP on workstations was approximately \$500,000 per year for three years, commencing in 2003. There were also one-time charges forecast for 2003 of \$1.4 million in costs related to the upgrading of existing applications to run on the new platform and related training.

With respect to the charges from ATCO I-Tek for IT services, ATCO noted that Calgary evidence focused mostly on the use of benchmarking ATCO IT costs to the Gartner study. ATCO also noted that the Gartner Report itself contained a number of qualifiers on the use of the study and that cross-examination of Calgary's witness identified some of these concerns that must be taken into consideration. ATCO submitted that Calgary's witness freely admitted that the Board should be cautious about having companies arbitrarily change to conform to the survey. Since the Gartner study did not indicate how many respondents had implemented a new billing system in the past five years, or the amortization rates used by various utilities for their IT applications, ATCO recalculated the Gartner KPI's used by Calgary excluding costs related to the CIS system in Table 3 of the Rebuttal Evidence. ATCO argued that the resulting KPI's for ATCO were favorable when compared to the Gartner KPI's that Calgary focused on in evidence.

ATCO argued that the Board must take into consideration the various limitations identified with respect to the use of the Gartner study. ATCO submitted that it was not reasonable to simply compare the Company to the average of other utilities, as this masked the fact that not all companies operate at or near the average, and might operate under very different circumstances.

ATCO submitted that, as discussed in Exhibit 14-10a, the Company continually seeks to find efficiencies with respect to its IT costs. By way of example, ATCO cited actions to reduce the number of applications residing on Company workstations, and development of the Virtual Private Network to replace the use of the Wide Area Network in its agency.

ATCO argued that the level of cost required to operate and maintain the CIS system was reasonable, given the complexity, capability and reliability of the CIS system, and the numerous functions that it was expected to perform. ATCO stated that the CIS system contributed significantly to the fact that the Company was not experiencing the billing problems of EPCOR and Aquila. ATCO noted that CIS operating costs had been reduced due to completion of system development, customer conversions, and optimization of the system.

ATCO noted that much of the reduction in 2002 actual IT expenditures compared to forecast, related to efficiencies that the Company was able to generate after development of the forecast. ATCO argued that it had already expressed concern with respect to the use of information not available when the forecast was developed. ATCO indicated that different circumstances in the forecast period as discussed in Exhibit 14-10a, such as timing of filling new staff positions in 2002, the impact of monthly meter reading, and implementation of Windows and Office XP, had to be taken into consideration when reviewing the test year IT forecasts.

ATCO indicated that the timing of filling new positions in 2002, the impact of monthly meter reading on the CAD system, the age of its current systems and their inability to easily meet changing requirements and the implementation of Windows and Office XP all impacted the forecast IT costs. ATCO submitted that the CG and AUMA/EDM appeared to be ignoring these changing circumstances when recommending that the central processing unit (CPU) units in the forecast period be held to 2001 levels and adjusted for customer growth.

Referring to the CG's position that other unit forecasts should take into consideration the impact of productivity gains achieved in the year 2002, ATCO indicated that its views on the inappropriateness of the use of the 2002 actual information had already been discussed.

ATCO did not agree that the prudence of the dollars related to the Windows XP upgrade would be tested as part of the benchmarking module, as suggested by the CG, indicating that the appropriateness of proceeding with that upgrade was reviewed in this proceeding. ATCO responded to all information requests and cross-examination related to this program in this proceeding, which it would not have done, if it had viewed that these matters were more appropriately addressed in a different proceeding. ATCO considered that the CG was basically asking for "another kick at the cat" with respect to this matter.

While viewing the CIS system as a necessary part of operating the business, ATCO did not view that the inclusion of the costs to develop and operate that system were appropriately included in the KPI comparisons to the Gartner study. ATCO considered it impossible to know where other utilities that participated in the Gartner study were with respect to the replacement of a major operating system such as the CIS system, and on that basis it was not appropriate to include the CIS costs in the KPI's. ATCO considered that the costs of the CIS system should be considered based on the merits of that system, as evidenced by the lack of billing problems experienced.

Views of AUMA/EDM

AUMA/EDM noted that ATCO had included $13.55 million (2003) and $12.45 million (2004) as placeholders for ATCO I-Tek charges. AUMA/EDM also noted that the only matter related to I-Tek charges remaining to be heard in the GRA was activity volumes or billing determinants. AUMA/EDM pointed out that ATCO had been asked to provide actual and forecast billing determinants and unit and fixed charges in AUMA/EDM-AG-62. AUMA/EDM indicated however that ATCO provided billing determinants for hardware, voice and wide area network but only provided the dollars for mainframe and distributed applications. AUMA/EDM noted that ATCO's witness indicated that the Company could not forecast the number of CPU minutes but rather took historical costs and adjusted them for anticipated changes in production and development processing.

AUMA/EDM however observed that Exhibit 13-27 provided estimated mainframe billing determinants. AUMA/EDM pointed out that ATCO's witness advised that Company personnel had discussed their intended use of the system and the costs and that I-Tek in turn calculated the CPU minutes and data acquisition and storage device units. AUMA/EDM noted that, when asked why CPU minutes were forecast to increase by 22% in 2002 and 9% in each test year, ATCO's witness again undertook to respond and did so in Exhibit 13-60. AUMA/EDM noted that while the primary reason given was that ATCO CIS impacted the information being input, edited, stored, retrieved and processed and passed to feeder applications, the CIS volumes themselves were not included in the totals. AUMA/EDM noted that the other reasons given included the increase in requests for information and reports, continuing uncertainty with deregulation of the industry, and the increasing numbers of customers.

AUMA/EDM argued that the generic and after the fact explanations did not provide sufficient justification for the large increases in CPU minutes and that ATCO had several opportunities to provide more detailed information and could or would not do so. AUMA/EDM noted that the only factor that could really be substantiated was the increase in number of customers, and argued that it would not be unreasonable to increase the CPU minutes based on 2001 levels adjusted for the increase in number of customers.

AUMA/EDM did not take exception with the placeholders and separate modules as described by ATCO. However, AUMA/EDM clarified a statement in its Argument with respect to Gas Management Services. AUMA/EDM stated that, to be clear, it would still be necessary to fix the compensation for these services for that portion of 2003 prior to the date of the transfer of the GCRR to a retailer.

Noting that ATCO had not commented on the ATCO I-Tek billing volumes, AUMA/EDM reiterated the position that ATCO had not sufficiently justified the large increases in CPU minutes over 2001 levels and that any increases should be based on the increases in number of customers over the period 2001 to 2004.

Views of Calgary

Calgary submitted that some of the I-Tek transaction volumes provided showed mainframe CPU minute volumes as actual 157,538 in 2001, forecast 192,219 in 2002, 208,826 in 2003, and 227,217 in 2004. Calgary estimated that this represented an average compound mainframe CPU minute growth of 13.0 %, while customer growth was an average compound growth of 2.3%. Calgary argued that the I-Tek transaction volumes provided did not appear to be reasonable and given that ATCO did not provide sufficient I-Tek volume information, Calgary had determined that the Gartner-defined ATCO budget for IT was $33.613 million (2003) and $33.729 million (2004). Calgary indicated that this represented an IT budget per end user that was approximately 150% of the Gartner utility industry average.

Based on cross-examination, it was clear to Calgary that ATCO considered the CIS system a necessary part of operating its business and as such, the Board should reject the ATCO recommended approach of excluding CIS related costs. Calgary argued that once CIS costs were included, it was clear from Calgary's Evidence that the ATCO IT budget, including its I-Tek operating costs was too high.

Calgary noted that a specific recommendation with respect to the ATCO IT budget and I-Tek operating costs would be made when the results of the I-Tek MSA and benchmarking module were known.

Calgary stated that, since the reasonableness of forecast IT forecast volumes was difficult to determine, interveners were generally forced to examine higher-level indicators such as the IT budget per end user. As a result of ATCO's failure to provide requested information on specific volumes, Calgary, using information available from the record, provided a high-level summary of its understanding of the I-Tek volumes.

Calgary pointed out that the table supported the view that ATCO had not provided the essential information with respect to I-Tek transaction volumes. In particular, Calgary pointed out that the table showed no CIS-related mainframe or data acquisition and storage device volumes and no project resource volume estimates, and that it was not possible for the Board or Interveners to follow and understand the I-Tek transaction volumes. Accordingly, Calgary considered that ATCO's resistance to providing the necessary information had left the Board with an insufficient evidentiary record.

Calgary noted that further insight into ATCO's strategy was provided when ATCO removed the CIS-related costs and I-Tek volumes associated with customer billing services from their recreated Schedule 1, despite acknowledgment of CIS as a necessary part of Company business. Calgary stated that not including the CIS-related I-Tek pass through costs would inevitably benefit the shareholders of ATCO I-Tek, at the expense of utility ratepayers, which strongly suggested that the ATCO strategy was to reduce the identified IT volumes thereby increasing the I-Tek service charges to the ATCO Utilities for both I-Tek IT services and I-Tek Business Services.

Calgary submitted that, when determining the I-Tek services fees from the benchmark, the Board should:

- specify use of the available 2002 actual volumes as the test year forecast volumes;
- require ATCO to file the 2002 actual pass through volumes from ATCO Business Services (Singlepoint) and then specify these 2002 actual volumes as the test year I-Tek pass through volumes; and
- require ATCO to file the I-Tek Statements of Work for all project activities and use the projected labour volumes from those Statements to determine the test year project labour volumes.

Calgary also submitted that the Board should clarify that the ATCO I-Tek Information Services Benchmark proceeding consider both actual and forecast volumes for all ATCO Utilities and be aggregated across multiple affiliate agreements so that there is no harm to the customers of the Utilities, even if a new I-Tek Business Services MSA is structured to include the IT costs as part of a service fee rather than as a pass through I-Tek charge.

Views of the CG

The CG noted that, although the CPU units were forecast to increase significantly, the dollar increases for mainframe applications were not nearly as high. The CG submitted that this raised questions as to the accuracy of the forecast CPU units.

The CG therefore recommended use of 2001 as the base year and adjustment of CPU units for activity levels based on customer growth for 2003 and 2004. The CG argued that ATCO should be directed to re-file its forecast of CPU units accordingly.

The CG submitted that the productivity on other billing determinants (other than CPU time) as set out in the response to CAL-AG67 (j) should be adjusted to reflect historical productivity gains. The CG argued that since no historical statistics other than 2002 actual data had been provided, the forecast billing determinants for other items should have reflected at least the productivity gains achieved in 2002 actual over 2001.

The CG noted that since examination in this proceeding was confined to billing determinants, the CG expected the prudence of the dollars related to the proposed Windows XP upgrade to be tested as part of the benchmarking module and therefore, did not address this issue in Argument.

The CG recommended that, for purposes of the placeholder amounts for I-Tek Charges, ATCO be directed to use the unit rates approved by the Board in Decisions 2002-069 and 2002-097.

Views of the Board

The Board recognizes that a benchmarking study has yet to be performed to establish rates for transactions with ATCO I-Tek IT Services, and that the test year forecast amounts will be held as placeholders in the Revenue Requirement pending completion and approval of the results of the benchmarking process. In the meantime, the Board agrees with intervener submissions that the placeholder should reflect the rates last approved by the Board in AGS 2001-2002 GRA, inclusive of the 7.5% reduction.

Accordingly, the Board directs ATCO, in its Refiling, to adjust the test year forecast for ATCO I-Tek IT Services to reflect the 7.5% reduction to rates approved in Decision 2002-069.

With respect to volume levels for ATCO I-Tek Services, the Board considers that there is merit in the submissions of interveners, that the volume levels for the test years are overstated and should be reduced. The Board agrees with the interveners that ATCO has not presented a compelling case in support of the significant volume increase. The Board considers that the increase in volumes should be more in line with customer growth, and should reflect the fact that the Board has not accepted ATCO's proposal for a move to monthly meter reading, as discussed in Section 4.2.3 of this Decision.

Accordingly, the Board directs ATCO to reduce the test year forecast I-Tek volumes (CPU minutes) to 165,996 for 2003 and 169,647 for 2004. The Board expects that the volumes, as adjusted will be confirmed subsequent to the determination of service levels, which are to be addressed in a separate Master Service Agreement benchmarking module. The Board has determined these forecast amounts, using 2001 CPU minutes of 157,538 as a reference point, adjusted by customer growth forecasts of 3.0%, 2.3% and 2.2% from 2001 to 2004 respectively.

With respect to the Windows and Office XP project, the Board notes that the bulk of the expense represents license fees and therefore does not lend itself to benchmarking. The Board agrees with ATCO's argument that it was understood that the expense for this project would be examined within the GRA process and notes that there were no objections from interveners with respect to the magnitude of the expense. Although it is noted that the CG was of the view the project would be part of the I-Tek benchmarking, the Board notes that the CG made no further comment in reply argument, with respect to its understanding of the forum within which this expense would be considered or the magnitude of the expense. Under the circumstances, the Board is satisfied that the rationale and forecast expenses for the Windows and Office XP project are reasonable.

Head Office Rent

Views of ATCO

ATCO disagreed with the CG inference that the Company had acted inappropriately with respect to the renewal of the head office lease for the ATCO Centre – Edmonton, and AUMA/EDM's concerns with respect to the renewal of the lease.

ATCO noted that the renewed lease was not available at the time that the Application was filed, and that there was nothing in the renewal of that lease that impacted the 2003/2004 forecast revenue requirement, or prevented interested parties from testing the reasonableness of ATCO continuing to use the Board approved rates for that lease, as determined in Decision E87002.[50] ATCO further noted that the Board reviewed the appropriateness of the Company continuing to use those approved lease rates in the ATCO Affiliate proceeding, and that if interested parties had a concern with respect to the Board approved rates they had every opportunity to ask information requests, file evidence and cross-examine the Company on the matter.

ATCO referred to the table submitted by the CG that calculated the lease cost based on different lease rates, and noted that there was no reference provided as to where these lease rates were derived, or why the Board should view them as appropriate. ATCO submitted that no evidence was entered on the record by the CG to support alternative lease rates, although they had ample opportunity to do so. ATCO submitted that the Board must ignore this information as once again, the CG was using the Argument process to introduce new evidence into the proceeding, which was patently unfair and offered a faulty analytical basis that had not been properly tested.

Views of the CG

The CG expressed concern with ATCO's view that the head office lease renewal did not warrant early disclosure in the GRA filing.

[50] Decision E87002 – Northwestern Utilities Limited, 1984/1985 General Rate Application, dated February 6, 1987

The CG submitted that long-term contracts, such as leases of office space, had an effect similar, if not identical, to any rate base addition. The CG indicated that the contract terms, including price, effectively bind the utility and its ratepayers for subsequent years.

The CG submitted that this non-disclosure frustrated any attempt by the Board and customers to test the relevance of the rental rate to current market rates. Additionally, the CG stated that issues within the lease in addition to rent, such as landlord improvements and maximization of space used, could not be examined and, hence, could not be properly tested.

The CG argued that the ultimate question facing the Board was whether or not the 2002 Head Office lease renewal was proper and prudent within the parameters of utility regulation. The CG submitted that the renewal was neither proper nor prudent. The CG argued that ATCO did not abide by what amounted to a direction from the Board in this regard in Decision E87002, and noted that the identical issue arose in the ATCO Electric GRA, simultaneously before the Board. The CG submitted that the Board should separate the issue of Head Office rents to a separate and continuing module and direct ATCO to file evidence supporting the rental rates used in the sublease.

Views of the Board

The Board notes ATCO's statement that the renewed lease was not available at the date the Application was filed, and that the renewed lease was effective on April 1, 2002[51] and executed as a sublease from CU to ATCO Gas. The Board notes ATCO's submission that there was nothing in the renewal of the lease that impacted the test year forecasts or testing the reasonableness of ATCO continuing to use the Board approved rates for that lease. The Board acknowledges that the term of the lease is for six years and eight months and that the rate per square foot per annum (psfpa) is $16.95.[52]

The Board notes CG's submission that late disclosure of the lease renewal frustrated any attempt by the customers to test the lease rate and other terms to current market rates.

The Board considers that the sublease of office space is a direct rent item comprising a significant portion of the total revenue requirement and that it may have been appropriate for ATCO to disclose this issue in the Application as an estimated amount in lieu of an amount based upon a consummated sublease.

The Board notes that ATCO has not provided evidence that its parent CU, sought tenders on leasing space from other building owners. In Decision E82194,[53] the Board stated:

> Every effort must be made to obtain necessary goods and services at the least cost. It is usually in the interest of the utility and its customers to call for tenders for the supply of significant materials and services to be provided by outsiders. This practice is even more important when the supplier may be an associated company, for not only may justice be done but justice will also appear to be done.

[51] Exhibit 13-65
[52] Ibid
[53] Decision E82194 – In the Matter of an Application to the PUB by APL, an owner of an electric utility, for an Order or Orders approving changes in existing rates, tolls or charges for electric light, power or energy supplied and service rendered to its customers within Alberta and those customers within the corporate limits of the City of Lloydminster, Saskatchewan, dated August 18, 1982, p.72

The Board concurs with the position set out in Decision E82194.

Furthermore, the Board noted in that in Decision 2002-069, AGS confirmed its use of previously approved rental rates for 2001 and 2002 of $13.58 psfpa and agreed that the rates previously approved in Decision E87002 were $13.58 psfpa for the Edmonton ATCO Centre. In Decision, 2002-069, the Board was concerned that regulated utilities in the ATCO Group should not be permitted to do indirectly what they could not do directly in that customers would indirectly pay more than the approved rates for rent.

The Board understands that ATCO purports that, for revenue requirement purposes, an extension of the former lease using the former Board approved rates is reasonable. Therefore, the Board understands that ATCO has proposed continuation of the former approved rate of $13.58 psfpa in determining the test year forecasts in this Application. The Board is prepared to accept application of the rate of $13.58 psfpa in determining head office rent expense for the test years, and will expect ATCO to provide support for a market-based rate at the next GRA. Therefore, for clarification, the Board directs ATCO, in its Refiling, to confirm the head office rental rates and the calculation of the test year forecast amounts included for sublease costs in ATCO's submissions.

Other

Views of ATCO

ATCO noted that Calgary indicated that either costs were overstated, or revenues understated with respect to the UFG work for ATCO Pipelines. ATCO indicated that it did not know to what extent ATCO Pipelines would be relying on ATCO with respect to the North UFG meters, and accordingly had not forecast any revenues or costs related to the performance of this work for ATCO Pipelines in the test years. ATCO pointed out that, as indicated in Exhibit 15-3, revenues received from ATCO Pipelines related to the South UFG meters in 2002 were for the most part offset by the costs, and that it would therefore be inappropriate to adjust the revenue forecast as suggested by Calgary.

Regarding the forecast security service costs from ATCO Frontec, ATCO pointed out that no information requests for additional information with respect to these services were requested. ATCO indicated that the agreements governing these services were filed in Section 7.2 of the Application. ATCO indicated that a comparison of the scope of the Facilities Monitoring and Card Access Administration services from ATCO Frontec as filed in the current Application to those same agreements filed in the ATCO Affiliate proceeding indicated the following changes:

- the number of sites covered by the Facilities Monitoring agreement had increased from 66 to 69;
- Video Alarm Verification, Video Patrol and Cellular Uplink Service at the Nanton office had been added; and
- eight new sites have been added to the Card Access agreement.

ATCO indicated that the new agreements simply provide for an extension of the services that ATCO Frontec was already providing to the Company as filed and approved in the ATCO

Affiliate proceeding, and in no way represent new services. ATCO pointed out that the impact on the revenue requirement as a result of the change in the level of service forecast amounted to slightly over $40,000. ATCO submitted that there was no basis on which to exclude these amounts from the revenue requirement forecast, as suggested by Calgary, and that the materiality of the amounts raised questions not only about micromanagement but also excessively detailed intervention.

ATCO advised that it was preparing a benchmarking study with respect to gas management services to be filed during the summer.

Views of Calgary

Calgary argued that costs were overstated and/or revenue understated since ATCO anticipated the provision of services to ATCO Pipelines for UFG meters, while no revenue had been forecast. Calgary noted that in 2002, ATCO had received $302,000 from ATCO Pipelines for assisting in installation of these meters. Calgary considered therefore, that it should have been expected that when ATCO Pipelines North installed the new meters in 2003, the revenue from this service would be at least the amount received by AGS from ATCO Pipelines in 2002 (a minimum of $302,000).

Calgary argued that there was no information to determine if the increased payments to Frontec in 2003 were at fair market value and therefore, should be excluded from revenue requirement.

Calgary was concerned with the Midstream charges included in the ATCO cost of service, noting that ATCO had forecast payments of $1.950 million to Midstream in each of the two test periods. Calgary argued that, while the level was consistent with prior years, the payment for Carbon Storage Management continued to be of concern when Midstream was able to enhance its use of the storage field beyond that of a normal user and be paid by the utility.

Views of AUMA/EDM

AUMA/EDM noted that the Board had recently issued Decision 2003-040,[54] dated May 22, 2003, which included a Code of Conduct (Code) for the ATCO Group of companies.

AUMA/EDM noted that the ATCO Group had indicated its acceptance of the "onus and burden placed on it" regarding these transactions. However, AUMA/EDM argued that the cost of establishing that the Code had been met should not be borne by customers. By way of an example, AUMA/EDM pointed out that the AGS Application to dispose of Carbon Storage facilities to an affiliate resulted in hearing costs in a total amount of approximately $4.8 million, much of which related to the affiliate nature of the transaction. It appeared to AUMA/EDM that the matter was not yet at an end.

AUMA/EDM expressed concern that a major affiliate transaction, that being the leasing arrangements between Canadian Utilities Limited and ATCO, referred to in Section 8.2 of the AUMA/EDM argument, was not specifically identified in the Application in time to allow interveners to determine whether it had been entered into at "reasonable rates". AUMA/EDM

[54] Decision 2003-040 – ATCO Group, Affiliate Transactions and Code of Conduct Proceeding, Part B: Code of Conduct, dated May 22, 2003

argued that the September 1, 2003 effective date for the Code should not be a reason to ignore its obvious purpose and intent.

AUMA/EDM noted that ATCO paid $500,000 for each of AGN and AGS to ATCO Midstream Services for gas management services.[55] AUMA/AEDM also noted that Decision 2002-072, directed AGS to establish future agreements for gas management services through use of an request for proposal or alternatively to use consultants to determine the fair market value of the services. AUMA/EDM noted that the amounts in ATCO's gas management benchmarking study were placeholders pending resolution of that module and argued that even though ATCO would not require any gas procurement services if the retail sale application was approved, it would still be necessary to fix the compensation from expiry on December 31, 2003 through to the date of the transfer of the GCRR to a retailer.

Views of the Board

The Board accepts ATCO's position that the Company cannot forecast the extent to which it will be asked to provide services to ATCO Pipelines for the UFG metering project and therefore cannot provide a test year forecast. The Board notes that for the work done to date, ATCO has recorded revenues that cover the costs plus an allowance for overhead. The Board therefore expects that any future expense for unplanned work will be offset by revenue and that there will be little or no impact to the revenue requirement.

The Board notes ATCO's statement that the services provided by ATCO Frontec had not changed and that the new agreement only provides for an extension of the services. Accordingly, the Board accepts the forecast security expenses payable to ATCO Frontec.

With respect to the Gas Management Services provided by ATCO Midstream, which was to be finalized subject to a benchmarking study, the Board notes that ATCO requested relief from the requirement to perform the study in a letter to the Board, dated June 17, 2003. In a letter dated July 29, 2003, the Board granted ATCO's request and indicated that the Company was at risk for its 2003 forecast since the estimate had not been tested or supported as contemplated by the benchmark study. Also, the Board indicated that should the proposed retail sale not be approved, ATCO would be expected to complete the benchmarking study.

By letter dated August 28, 2003, ATCO expressed doubt with respect to the cost effectiveness of proceeding with a benchmarking study for 2003 alone, given the potential sale of the retail function, and questioned whether or not this would be in the best interests of customers. ATCO therefore requested Board approval of the $1 million Midstream fee for the 2003 test year, indicating that the amount could be prorated in the event that the Application for Transfer of Retail Functions were approved with an effective date prior to the end of that year. On the other hand, if the Retail Sale Application should be denied, ATCO indicated that the Company would proceed with the benchmarking study for 2004 and beyond.

Pending establishment of a process to address ATCO's request, and the outcome of the Retail Sale Application, the Board considers it reasonable to reflect the expenditures of $1 million as placeholders in each test year. Accordingly, the Board accepts the placeholder amounts included in the test year forecasts.

[55] Table 7.2.2(c)

4.2.11 Shared Services and Cost Allocations

Views of ATCO

ATCO stated that it had addressed the suggestion by Calgary that a Cost Allocation Manual should be developed with respect to the maintenance of North/South accounts in Rebuttal Evidence. ATCO argued that the matter of pricing of services to Affiliates and development of a Cost Allocation Manual for affiliate transactions had been addressed in response to Board Direction No.18 in Decision 2001-96, and that these matters were not addressed by interveners in cross-examination.

ATCO indicated that the concerns of Calgary and the CG with respect to the inclusion of revenues related to energy had been addressed in Rebuttal and in Argument. ATCO indicated that, while fluctuations in commodity prices might not directly influence the level of corporate overhead costs in total, activities of the corporate office do encompass matters related to the sale of energy to customers. ATCO pointed out that inclusion of energy revenue in the determination of the allocation of corporate charges was therefore appropriate, as it took into consideration the fact that it was one of the drivers of the activities performed by the corporate office.

Views of Calgary

Calgary noted that, in the AGS 2001-2002 GRA, it had raised the issue of including gas commodity costs, fuel and purchased power costs in the allocation factors used to allocate Head Office and Corporate costs. Calgary argued that inclusion of volatile commodity prices tended to skew results over time frames, and that fluctuations in commodity prices did not influence the level of corporate overhead costs. Calgary argued that, since ATCO did not have the data to support changes in corporate office costs related to changes in commodity prices, it was obvious that inclusion of commodity and energy costs in the allocation factors skewed the results in terms of allocation of costs to ATCO. Calgary further argued that, with the proposed sale of the merchant function to Direct Energy, ATCO would no longer incur commodity costs. Calgary therefore recommended that determination of allocation factors for Corporate Overhead costs should not reflect the inclusion of energy prices. Calgary submitted that, pending such a change, ATCO should use those amounts, excluding energy costs, as set out in CAL-AG-145. Calgary pointed out that this would reduce revenue requirement by almost $1 million in each test year.

Views of the CG

The CG noted that commodity and energy costs were essentially pass through items and that any direct costs associated with commodity/energy sales were reflected in ATCO’s revenue requirement. The CG argued that by including commodity costs in the corporate allocations, ATCO was essentially seeking a “management fee” for a pass through item. The CG noted that ATCO acknowledged that fluctuations in commodity prices might not influence the level of corporate overhead costs. Accordingly, the CG submitted that there was little or no relationship between ATCO/CU Corporate overhead costs and commodity costs. The CG therefore recommended that the allocation factors for ATCO/CU corporate overhead should not reflect commodity or energy costs. The CG submitted that the revenue requirement for the test years should be reduced by $1 million in accordance with Calgary’s recommendations.

Views of the Board

The Board notes ATCO's position that activities at head office encompass matters related to the sale of energy to customers, and ATCO's acknowledgement that management involvement in the merchant function is unlikely to fluctuate to any noticeable degree as gas prices rise or fall.

The Board also notes the concerns of interveners that inclusion of volatile commodity prices tends to skew results over time frames, and that fluctuations in commodity prices do not influence the level of corporate overhead costs. The Board notes intervener recommendations that, inclusion of commodity and energy costs in the allocation factors skewed the results in terms of allocation of costs to ATCO, and that the determination of allocation factors for Corporate Overhead costs should not reflect the inclusion of energy prices, particularly since the proposed sale of the merchant function to Direct Energy, would result in ATCO no longer incurring commodity costs.

The Board considers that purchasing energy from the marketplace for sale to customers on a flow through basis eliminates the need to direct attention to matters such as contract management, contract credit risk and regulatory uncertainty with respect to energy costs. The Board is of the view that while energy related cash flow and financing management concerns may remain, these concerns are much less significant than other components of revenue requirement in that they are components of NWC items rather than expense items. The Board is also not convinced that customer credit risk and customer relations concerns would occupy head office management attention.

The Board agrees with Calgary's observation that if the proposed sale to Direct Energy is approved with an effective date prior to 2004, there would be no energy costs included in ATCO's revenue requirement in 2004.

Under these circumstances, the Board directs ATCO in its Refiling, to exclude forecast energy costs in the determination of the allocation of corporate charges and use the reduced amounts to allocate corporate costs for 2003 and 2004.

4.2.12 Gas Supply

Views of ATCO

ATCO took exception to Calgary's characterization of the Gas Supply forecast as "careless", and submitted that the approach of using the forward market prices at the time the GRA forecast was being developed was appropriate. ATCO stated that even if a more recent forecast had been used, it is doubtful whether that forecast would have captured the significant increase in gas prices that had been experienced in 2003.

Views of Calgary

Calgary argued that ATCO's forecast of gas supply costs was another example of a failure to provide up to date forecasts. Calgary submitted that gas supply prices were based on April 2002 prices rather than on forward prices at a time close to the filing and updating of the Application. Calgary recognized that gas supply costs were not recovered in revenue requirement but through the GCRR. However, Calgary argued that this should not provide an excuse for ATCO to be careless in its forecasting.

Views of the Board

The Board acknowledges that when a GRA application is filed, the most current gas price forecast available prior to filing should be used, particularly given the volatility of gas prices. In this regard the Board will rely on ATCO to incorporate a forecast, which reflects the most recent market price of gas when finalizing its application.

4.2.13 Other O&M Issues

Carbon Compressor Fuel

Views of ATCO

ATCO noted that while there was some cross-examination about the level of fuel use in November of past years, the Application forecast did not include any forecast fuel use in November of either year of the test period.

ATCO noted that according to Decision 2001-075, all owning and operating costs of Carbon were to be included in rates and all revenues were to be credited to customers bearing those costs in Rider H. ATCO also referred to comments of its witness that as a practical matter, it was not possible to track the fuel used for withdrawal of the 16.7 GJs of gas to be stored for customers in 2003 as directed by the Board. ATCO submitted that withdrawal patterns vary among users making any allocation arbitrary. ATCO stated that moreover, such allocation would be inappropriate and contrary to the Board's recent Carbon related Decisions. ATCO stated that those Decisions clearly contemplated the fact that there was third party gas stored at Carbon with costs associated with providing that service. ATCO submitted that the revenue recorded in Rider H from third party use of the facility was intended to offset those costs.

ATCO argued that there had been no suggestion that the forecast compressor fuel use was inappropriate, and that the forecast should be accepted as filed.

ATCO disagreed with the CG's argument that compressor fuel costs in the 2003/2004 forecast should be reduced by 148,000 GJ's to reflect 2002 actual results. ATCO pointed out that storage capacity other than the 16.7 PJ's used for AGS customers, was contracted to third party customers, who have the right to withdraw all of this gas. ATCO indicated that these customers control when and how much gas will be withdrawn based on their requirements. ATCO indicated that, according to Board decision 2001-75, all owning and operating costs of Carbon are to be included in rates and all revenues are to be credited to customers bearing these costs in Rider H. ATCO considered it prudent to reflect the costs associated with withdrawal of all gas and re-injection of gas for a "full storage cycle". ATCO submitted that using a single year of history as a base for forecasting is not logical considering the rights these customers have to withdraw this gas.

Views of the CG

The CG indicated that the Compressor Account showed a substantial increase of $1.3 million, which could not be totally attributed to the increase in forecast gas prices from 2002 to the test periods. The CG noted that forecast compressor usage in 2003 of 432,000 GJ compared to actual usage of 248,147 GJ in 2002, an increase of 74%. The CG submitted that ATCO had not substantiated the reason for this inordinate increase other than through claims that the forecasts are for a full storage cycle and based on historical use. The CG pointed out however, that there was no evidence that 2002 was not a full storage cycle. The CG therefore suggested that the test year compressor fuel forecasts should be scaled back to reflect the forecast gas price, and the actual storage cycle usage of 247,147 GJ. The CG calculated that the forecast amounts should be reduced by $832,000 based on reduced usage of 148,000 GJ (432,200 – 248,147) and a forecast gas price of $4.50/GJ.

Views of the Board

With respect to compressor fuel cost forecasts, the Board is concerned with the issue of fairness to customers given that they are expected to pay for all fuel use, which is a variable cost not under ATCO's control, in the absence of inclusion of an offsetting component in the revenue for the uncontracted capacity at Carbon. The Board acknowledges that this is a matter that should have relevance in the context of upcoming review of the 2004-2005 Carbon Storage Plan, and expects ATCO to identify this matter for consideration in conjunction with all other issues when reviewing the 2004-2005 Carbon Storage Plan.

Fringe Benefits

Views of ATCO

ATCO argued that significant increases in health care costs, industry safety experience, and Canadian Pension Plan (CPP) experience had led to increased costs for the 2003/2004 GRA forecast years. ATCO submitted that in preparation for the GRA filing, information was gathered from government sources and the Company's benefit provider (Sun Life) to assist in the development of the benefit forecasts.

ATCO argued that the information obtained from benefit providers regarding the utilization of supplementary health and dental care by employees supported the increase in benefit costs in this area. ATCO submitted that the general increase in health costs supported the forecast increase in Alberta Health Care costs.

ATCO also argued that the GOC and the Workman's Compensation Board (WCB) supply forecast information supported the forecasted increase in CPP and WCB benefit costs.

ATCO argued that additional staff included in the forecast, also increased the fringe benefit costs in all areas.

ATCO indicated that capitalization of fringe benefits charged to Account 725 in 2002-2004 had been reflected contrary to the position of the CG. ATCO stated that this was set out in response to CAL-AG-119(b).

ATCO noted the statement of the CG that a three-year average with actual experience from 1999 to 2001 should be used to determine the forecast for account 725, and the tables provided with calculations of the forecasts of CPP, Employment Insurance, Health Claims and Other Benefits using FTE increases and their own estimates of increases based on increases in 2002 actual experience over 2001. ATCO submitted that the premise used to prepare the tables was incorrect, as the tables did not reflect forecast information provided by government sources, insurers and utilization. ATCO noted that the tables only accounted for changes in employees and the difference between actual and forecast results for certain years, which was therefore incomplete. ATCO stated that for example, CPP forecasts provided by the GOC, WCB forecasts from the

WCB and the impact of increased health care costs along with the utilization by employees obtained from the insurers for other health benefits was used as the best information available to determine the benefit forecasts in the Application. ATCO pointed out that this information along with the increase in staff, provided for a logical and reasonable forecast methodology. ATCO submitted that it would be irresponsible to only use historical information and not use the forecast information from these sources to determine the benefit forecast.

Views of the CG

Employee Benefits - Account 725

The CG submitted that employee expense associated with capitalized labour should continue to be capitalized as in 1999, 2000 and 2001 and that ATCO should reflect the capitalization of employee benefits in its refiling.

The CG noted that regular FTEs were forecast to increase by 7% in 2003 compared to the 2002 forecast, whereas account 725 was forecast to increase by 19%. The CG also noted that in 2004, FTEs were forecast to increase by 0% whereas employee benefits were forecast to increase by 12% over 2003 forecast.

While acknowledging that certain increases in account 725 might be related to forecast increases in the number of regular FTEs, increases dictated by statutory requirements or to demographics of the workforce and increasing healthcare costs, the CG considered that the increases forecast by ATCO appeared to exceed reasonable levels that could be expected, given these factors.

The CG noted that the FTEs used for these recommendations reflected the Company's forecasts and should be adjusted to reflect the FTEs finally approved by the Board.

Canada Pension Plan

The CG argued that the CPP increases should not exceed $2.248 million in 2003 ($1.951*1.07*1.077) and $2.421 million in 2004 ($2.250*1.077).

Administrative Labour– Account 721

Views of ATCO

ATCO noted that the CG's recommendation with respect to reduction to the administrative labour costs was based solely on the assumption that customer growth was (or should be) the only driver of administrative costs. ATCO submitted that use of an average 3% labour escalation factor (for which no evidence was filed by the CG) also ignored the fact that the Company must pay staff at market rates if staff has to be retained. ATCO indicated that customer service and changing reporting requirements were also drivers of administrative cost. ATCO stated that high employee turnover is a strong indicator that previous staff levels had been insufficient to meet the administrative requirements of the Company. Referring to the CG's position that that there should be a reduction in administrative costs as a result of the production dispositions in the North, ATCO indicated that it had committed to a reduction in administrative costs as a result of the sale of Beaverhill Lake and Fort Saskatchewan in the response to BR-AG-149. Finally, ATCO noted that the CG's proposal ignored the fact that not all new staff in 2002 was hired on January 1, 2002, and that use of 2002 as the base year in the CG calculations was inappropriate.

Referring to the table provided by the CG indicating that the ratio of administrative labour to non-administrative labour in the year 2004 was only slightly higher than in 1999, ATCO pointed out that the significant level of change and growth that the Company had undergone since that time was a strong indication that the administrative labour cost forecasts for 2003 and 2004 were reasonable.

Views of the CG

The CG referred to the ratios of administrative labour to all other labour costs set out in its analysis based on actual and forecast data from 1999 to 2004. The CG noted that administrative labour productivity achieved by ATCO for 1999, 2000 and 2001, was essentially lost as a result of staff additions in 2002. The CG also noted that not all non-administrative labour cost increases in the test years would have a direct impact on administrative labour. By way of example, the CG pointed out that there was an approximate $5 million increase in labour costs due to the move to monthly meter reading effective November 1, 2002. The CG argued that it was questionable whether this increase would have a one-to-one impact on administrative labour.

The CG submitted that the reasons ATCO provided for the increase in administrative labour in the 2002 forecast over 2001, did not justify an approximate15% step increase, particularly in consideration of the fact that there should be offsetting reductions in administrative costs due to disposition of production assets in the North and productivity improvements. The CG submitted that the proposed step increase in administrative labour of $1.3 million for 2002 should be reduced.

The CG argued that, since ATCO was primarily in the business of providing gas retail and distribution services to customers, the number of customers served was a reasonable measure of the level of administrative labour required. The CG submitted that administrative labour should be reduced by $723,000 (2003) and $642,000 (2004) to better reflect 2000 and 2001 productivity levels. The CG noted that this reduction was a specific labour cost reduction applicable to administrative labour. The CG supported the general labour reduction recommended in Section 4.1.1.

Views of the Board

The Board notes intervener observations that the increase in administrative labour and fringe benefit costs should reflect the trend in FTE and customer growth. The Board also notes ATCO's position that additional factors that contribute to the increase in these cost categories, such as changes in customer service levels, reporting requirements and government policy changes must also be taken into account. In this regard, the Board accepts that forecasts provided by the GOC and the WCB should be a reliable source for preparation of forecasts for health care, CPP and WCB costs and will therefore accept use of this information as a basis for determination of fringe benefit forecasts. On the other hand, while the Board accepts ATCO's position that intervener recommendations for reductions in fringe benefits fail to take account of all relevant factors driving the forecasts, the Board considers that an increase in fringe benefit forecasts that exceeds increases in staff levels is questionable. However, the Board recognizes that it will be necessary for ATCO to adjust the fringe benefit forecasts to recognize the reductions in levels of staffing approved elsewhere in this Decision.

Accordingly, the Board directs ATCO to revise the fringe benefit forecasts for the test years to reflect any reductions in FTEs required as a result of Board findings with respect to staffing levels in other Sections of this Decision.

5 DEPRECIATION AND AMORTIZATION[56]

5.1 Overview

Views of ATCO

ATCO forecast Net Utility depreciation and amortization expense of $65,460,000 and $67,192,000 for 2003 and 2004 respectively. The forecasts were determined based on a consolidated depreciation study for ATCO Gas North and South, which established the proposed depreciation rates for the test years.

ATCO noted that the existing North depreciation rates were last approved by Decision E94001[57] with respect to the 1993 NUL GRA, based on a depreciation study up to December 1991. The rates remained unchanged as a result of the 1997 NUL Negotiated Settlement approved in Decision U98060.[58] The existing rates for the South were last approved in Decision 2001-96 issued with respect to the AGS 2001/2002 GRA.

ATCO's capital assets are depreciated or amortized using one of four methods of calculation:

1. Study Assets (Straight Line Method - Equal Life Group Procedure)
2. Unit of Production method (UOP)
3. Contract Life
4. Straight Line Fixed Rate.

ATCO submitted that, in order to perform a consolidated depreciation study, the depreciation historical databases for North and South were adjusted pursuant to the restructuring that had occurred in the Company over the past several years, and that subsequently, the data was merged into a common ATCO database. ATCO stated that a number of changes to depreciation procedures have also been recommended so that the procedures would be consistent for the Company as a whole.

During 2001, ATCO conducted a new depreciation study (North and South combined) based on data to the end of 2000. The following is a summary of the study process:

- All historical transactions (additions, retirements and net salvage) relating to assets that ATCO had either transferred or sold to affiliate companies were excluded from the study.

[56] Depreciation distributes fixed capital costs less net salvage over the forecast service life of the asset by allocating annual amounts to expense. Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, or over the life of the asset or liability to which the account applies, or over the period during which it is anticipated that the benefit will be realized. Normally the distribution of the total is in equal amounts to each year of the amortization period.

[57] Decision E94001 – Northwestern Utilities Limited, 1993/1994 GRA Phase I, dated January 21, 1994

[58] Decision U98060 – Northwestern Utilities Limited, Rates, Tolls, Charges and Terms and Conditions of Service for Core Customers for 1998 through to 2002 – Negotiated Settlement, dated March 31, 1998

These transactions will not recur, and therefore should not be included in the historical analysis nor used to forecast future asset lives or net salvage.

- Use of simulated analysis was phased out for certain accounts in the North where historical aged retirement data had not previously been used. The following changes were implemented for the North to standardize procedures and allow the consolidation of North and South historical data:
- The method of analyzing accounts 471 (Land Rights), 473 (Services), 478 (Meters) and 488 (Communication Equipment) was changed from simulation to actuarial in order that North and South historical data would be compatible.
- ATCO adopted the procedures currently approved in the South for accounts 483 (Office Furniture and Equipment), 486 (Tools and Work Equipment), 489 (Stores, Shop and Garage Equipment) and 491 (Laboratory Equipment). ATCO noted that the investment will be amortized over a specific number of years, and retirements will be recorded using vintage accounting procedures. ATCO submitted that these procedures are recommended as a more efficient manner of administering the large volume of small dollar items that are included in these accounts.
- Accounts were analyzed as of December 31, 2000, and recommendations developed for average service life (ASL), dispersion, and net salvage. The combined North and South historical data for each study account was analyzed using the straight-line method, equal life procedure. The recommendations were developed by Company staff based on the analysis of the Company's historical database, review of procedures, site visits and discussion with Company professional staff.
- New proposed rates and annual reserve amortization amounts were calculated based on plant balances as of December 2000. A minimum five-year period was used to amortize the surplus or deficit in the depreciation reserve for each account where the difference between the actual reserve and reserve requirement was greater than 5%. Use of a minimum period reduces short-term fluctuations in depreciation expense, and had previously been approved by the Board for CWNG in Decision 2000-9.

ATCO submitted that the recommendations of the latest study resulted in an increase in net depreciation expense for 2003 of $1.228 million (excluding production assets) compared to depreciation expense using currently approved rates. The increase resulted from the combined impact of two types of changes:

1. Existing depreciation parameters were approved in Decision 2001-96 for the South and Decision E94001 for the North. Assuming that these existing parameters were retained, and rates and/or reserve adjustments updated to December 2000 based solely on changes in vintage distribution of the capital investment, net depreciation expense would have increased by approximately $140,000 in 2003.

2. Recommended changes to the average service lives, curve and/or net salvage result in an increase of $1.088 million in net depreciation expense for 2003 and $392,000 for 2004.

Amortization of reserve differences by fixed asset account was calculated by comparing the actual accumulated depreciation to the theoretical accumulated depreciation. Differences greater than +/- 5% will be amortized over the remaining life of the fixed asset account using a five-year minimum period to amortize the surplus or deficit for each account.

Contributions were depreciated based on the approved life parameters of the corresponding fixed asset account, with a net salvage of 0%, and applied to contribution vintage balances.

Amortization of contribution reserve differences by contribution account was calculated by comparing the actual accumulated depreciation to the theoretical accumulated depreciation. Differences greater than +/- 5% would be amortized over the remaining life of the fixed asset account using a five-year minimum period to amortize the surplus or deficit for each account.

Views of Calgary

Calgary presented the evidence of Mr. Larry E. Kennedy of Gannett Fleming who recommended changes to the methods in which overall depreciation rates are calculated and also to the parameters for four individual accounts.

Calgary submitted that the combined impact of the changes recommended by Mr. Kennedy reduced depreciation expense by $5.750 million when applied against December 31, 2000 account balances. Calgary also recommended that the Board order ATCO to calculate separate North and South depreciation rates in a compliance filing.

Calgary noted that in making his recommendations, Mr. Kennedy also argued that ATCO was not following the prescribed accounting treatment with regard to refurbishment of customer meters.

Calgary pointed out that, although Mr. Kennedy also identified potential adjustments to an additional 11 accounts, he considered those adjustments minor and noted that, if adjusted, would result in an additional reduction to depreciation expense of approximately $1 million in total. However, Calgary did not pursue these small adjustments at this time.

Calgary considered that the lack of time provided to interveners to fully review the detailed depreciation study did not allow an opportunity for intervener information requests after the receipt of the depreciation data files. As was the case in previous proceedings, Calgary suggested that in future applications, the Board should require applicants to provide detailed depreciation data files and notes at the time the depreciation study is filed. Calgary argued that, in this regard, a proper information request process could be used to investigate depreciation prior to the submission of intervener evidence.

Views of AUMA/EDM

By agreement, the AUMA/EDM elected not to present depreciation evidence and adopted the changes proposed by Calgary. However, AUMA/EDM proposed specific recommendations for the treatment of the sale of Beaverhill Lake/Fort Saskatchewan and the impact of the Affiliate Transactions Decision 2002-069.

AUMA/EDM noted that in BR-ATCO-149, ATCO provided the impact on revenue requirement associated with the sale of the Beaverhill Lake and Fort Saskatchewan producing properties. AUMA/EDM noted that, with the closing of that sale on January 1, 2003, depreciation expense should be reduced by $1.759 million and $1.574 million respectively in 2003 and 2004 as confirmed by ATCO.

In addition, AUMA/EDM noted that ATCO included $1.333 million for AGN and $1.307 million for AGS in 2003 to amortize the loss on sale of computer assets to I-Tek. AUMA/EDM noted that, in Decision 2002-069, the Board reduced the loss on sale from $15 million to $14.35 million, and that in Decision 2003-006, the Board approved ATCO's revision of the loss down to $1.240 million. AUMA/EDM submitted that a similar reduction of some $67,000 should also be made to the $1.333 million included for AGN in 2003.

Views of the Board

The Board notes that ATCO, in its new depreciation study on the combined database, implemented a number of changes to the depreciation procedures and applied these changes on a consistent basis to allow for the consolidation of North and South data.

Specifically, the method of analyzing accounts 471 (Land Rights), 473 (Services), 478 (Meters) and 488 (Communication Equipment) was changed from simulation to actuarial in order that North and South historical data would be compatible. In addition, ATCO adopted the procedures currently approved in the South for accounts 483 (Office Furniture and Equipment), 486 (Tools and Work Equipment), 489 (Stores, Shop and Garage Equipment) and 491 (Laboratory Equipment). ATCO noted that the investment will be amortized over a specific number of years, and retirements will be recorded using vintage accounting procedures. ATCO submitted that these procedures were recommended as a more efficient manner of administering the large volume of small dollar items that are included in these accounts.

The Board considers that ATCO's changes to the depreciation study were reasonable for the combined depreciation analysis.

The Board agrees with Calgary that detailed depreciation data files and notes should be made available when rate applications are filed to provide additional time for data analysis and more complete evaluations. Therefore, the Board directs ATCO, in its next GRA, to make available upon request, the data files in electronic format and the accompanying field notes relevant to the data.

Also, as noted by AUMA/EDM, in BR-ATCO-149, ATCO provided the impact on the revenue requirement associated with the sale of Beaverhill Lake and Fort Saskatchewan producing properties. The Board directs ATCO, in the Refiling, to show the effects of the sales of these properties on the test years' revenue requirements in the amounts of $1.759 million for 2003 and $1.574 million for 2004 and reflect revisions to these amounts for the closing date of sale on January 1, 2003.

In addition, the Board directs ATCO to reflect the applicable amount of amortization related to the loss on sale of computer equipment to ATCO I-Tek as determined by the Board in Decisions 2002-069, 2002-097, and 2003-006.

5.2 Unified Depreciation Study

The depreciation study determines the depreciation parameters, which include:

- survivor curve,
- ASL,
- salvage value

From these parameters, deprecation rates are determined for each asset group.

Views of ATCO

ATCO stated that the benefits of a unified revenue requirement included lower administrative costs, lower regulatory and legal costs, less confusion for customers and avoided legacy system costs, and that a necessary step in achieving a single revenue requirement was the establishment of depreciation parameters for ATCO (combined North and South). ATCO submitted that maintaining two separate sets of depreciation parameters was an atavism, which should be rejected by the Board. ATCO noted that, even Calgary's witness was crystal clear that with a combined revenue requirement there must be a combined depreciation rate. ATCO pointed out that, in the event that the Board viewed that separate depreciation studies must be performed for North and South, the 2004 revenue requirement forecast should be increased by $100,000.

ATCO argued that depreciation rates between North and South should be regarded as being so similar that there was no reason to have separate rates even if operating practices were different.

ATCO noted that current depreciation and net salvage rates for the North were approved in the 1993/94 GRA for NUL. ATCO stated that, given the amount of change that had occurred since that time, if a separate North depreciation study had been performed, there would likely be significant changes to the current depreciation rates. ATCO therefore submitted that it would not be appropriate to assume that performing a combined depreciation study for North and South would be the major cause of significant changes to North depreciation rates.

Views of Calgary

Calgary recommended the following changes to the depreciation methodology used by ATCO in the depreciation study:

- Depreciation parameters determined from a combined database should be applied separately to the aged surviving balances to each company's segregated surviving age distribution. Due to operating differences and practices that resulted in a significantly different accumulated depreciation reserve in the North as compared to the South, calculation of the accumulated depreciation reserve variances on combined plant balances will result in across-subsidization between North and South. Calgary argued that the cross subsidization would not exist with calculation of specific North and South depreciation rates. Calgary recommended that the Board should order separate depreciation rates for both North and South service territories in a compliance filing.
- The relevant experience of a number of directly comparable Western Canadian Natural Gas distribution companies should be considered in the determination of the ASL and net salvage estimates. Calgary stated that ATCO relied solely on the review of internal

Company retirement experience and did not consider the significant amount of relevant peer experience in the determination of the depreciation parameters in a number of accounts.

- ATCO's depreciation recommendations were based on the retirement experience of a small percentage of investment retired. Calgary stated that ATCO attempted to justify the low percentages by pointing to the impacts of inflation, and replacement construction activity rather than admitting to the significant exclusion of the 45 years of retirement experience.
- Calgary stated that in the circumstances of ATCO having lost over half of its experienced life retirement experience from the depreciation databases, the lack of comparison to available industry data was a significant oversight in the completion of the depreciation study.
- Calgary stated that ATCO was not following AR 546/63 with regard to the prescribed cradle to grave accounting treatment for customer regulators and meters. As indicated in the response to CAL-ATCO-45 a retirement equal to 25% of the current weighted average cost of the meter was recorded when a meter was rebuilt. Therefore, Calgary argued that by definition, ATCO was not following cradle to grave accounting.
- Additionally, the Alberta Regulation prescribes specific criteria for accounting for operating expense account 673 – Removing and Resetting Meters and House Regulators.
- As indicated by Calgary in response to BR-CAL.18, review of accounting entries indicated that the treatment used by ATCO for the customers' meters was consistent with 'location life' accounting rather than 'cradle to grave' accounting. Calgary took no issue with the retirement of 25% of the current moving average cost being recorded, but recommended that proper accounting treatment would be to record a salvage entry in the accumulated depreciation account equal to 75% of the current moving average cost of meters. Only in this manner would the accumulated depreciation account be kept in appropriate balance over the moves of the meters from one location to another.

Views of the CG

The CG agreed that a combined database would provide a larger population for retirement data analysis, and that use of a larger database would also help smooth out the impact of any statistical anomalies appearing from time to time. The CG submitted therefore, that the larger database should be used to develop depreciation parameters. Furthermore, the CG submitted that the approved parameters should be applied to the separate plant balances and corresponding vintages of North and South to develop the depreciation rates and annual expense for the test years.

Views of the Board

The Board notes Calgary's recommendation that to eliminate cross-subsidization between North and South, the parameters should be developed from the combined database, which subsequently should be applied separately to the aged surviving balances of each division's asset accounts.

The Board also notes that the CG agreed with Calgary's recommendation that a combined database should be used to develop the depreciation parameters in that the larger database would also help to smooth out statistical anomalies.

The Board has examined the depreciation reserve differences[59] between the North and South zones and considers that the current difference between North and South is not sufficient to result in any appreciable cross-subsidization of costs between the zones when applying a uniform set of depreciation rates. Therefore, the Board does not agree with Calgary that separate depreciation rates are necessary to avoid cross-subsidization.

The Board considers that AGN and AGS operations are ostensibly similar. The Board agrees with Calgary and the CG that depreciation parameters should be developed from the combined databases and that therefore, separate depreciation studies are not required. The Board therefore, does not consider that the outlay of an additional $100,000 in revenue requirement for separate depreciation studies is required.

The Board notes that ATCO filed in evidence, the comparable parameters from the American Gas Association (AGA) data, and that the AGA data contains a wide range of results for the depreciation parameters. The Board considers that the data from the AGA provides general guidance when testing the results of specific depreciation studies.

The Board also notes Calgary's argument that ATCO did not consider the significant amount of relevant peer experience in the determination of depreciation parameters. While acknowledging that data from relevant peer companies also provides general guidance for testing the results of specific depreciation studies, the Board believes that development of specific parameters using Company specific life characteristics for Company property results in more accurate depreciation parameters for specific assets in contrast to an approach where industry-wide averages are used.

Therefore, the Board considers it appropriate to use one set of depreciation parameters developed from the combined life history of the assets of AGN and AGS and one set of depreciation rates to forecast depreciation expense. Accordingly, the Board accepts ATCO's recommended depreciation parameters and forecast depreciation rates developed from the combined North/South databases.

The Board however, directs ATCO, in its Refiling, to revise the Schedules in Section 4.7 of the Application to reflect the effect of adjustments required as a result of findings in other Sections of this Decision.

5.3 Account 473 – Distribution Services

Views of ATCO

ATCO pointed out that the Study recommended a historical best fitting R2.5 curve with an ASL of 52 years, noting that the old ASL parameter was 50 years for the North 53 and years for the South. ATCO noted that the recommended net salvage of -100% was identical to the previous Board approved net salvage rates for North and South.

ATCO noted that Calgary accepted the reasonableness of the historically developed Iowa 52-R 2.5 curve, but recommended a net salvage rate of -75%. ATCO noted that, in making this recommendation, Calgary made much of the retirement experience "of only 3.3%." ATCO indicated that Mr. Kennedy also took issue with the history of removals, positing the

[59] Section 4.9 Schedule 2

development of future economies of scale, and preferred the net salvage rates of four other utilities in preference to the actual experience of the Company.

ATCO argued that the cumulative retirement ratio was not particularly relevant in the case of a relatively young, long-lived asset account with a large historical amount of new construction. ATCO noted that in previous Decisions, the Board expressed concern with use of industry ratios, preferring to consider them a fall-back, in the absence of Company specific calculations.

ATCO noted that the Board's position on the usefulness of data from other utilities had not changed:

> While the Board considers it appropriate to check company specific findings against industry data, the Board does not consider it appropriate to base a utility forecast purely on industry data.[60]

ATCO submitted that there was no reason to vary the currently approved net salvage rate of -100% for the Company. ATCO argued that substitution of industry data for a Company specific study would be an error of principle and inconsistent with the Board's very recent directions on the use of Company specific data.

ATCO claimed that actual data and experience for this account was supportive of maintaining the net salvage rate. ATCO argued that net salvage experience from 1983 to 2000 had been very stable, with the five-year average ranging between -145% and -177%, and the full depth experience at -165%. ATCO pointed out that the major component of net salvage was the high removal cost of disconnecting and abandoning service lines, not the removal cost related to replacing a service line in the Bare Mains project.

Views of Calgary

Calgary noted that ATCO had proposed an IOWA 52-R2.5 to represent the service life estimate, and a net salvage rate of -100% for this account. Calgary did not disagree with the service life estimate, but recommended a reduction in the net salvage percentage from -100% to -75%. In making this recommendation, Calgary considered that:

- the ATCO salvage recommendation was based on only 3.3% of historic additions being retired;
- most other historic retirements to date have been "one-of" that did not include any economies of scale;
- the ATCO requested net salvage percentage was significantly higher than the range of peer Western Canadian natural gas utilities for this same account.

Calgary pointed out that as previously indicated, the retirement experience of 3.3% of plant additions was largely impacted by the loss of the retirement experience from 1912 through 1957.

However, Calgary indicated that, even the limited amount of retirement experience relied on in making the net salvage recommendations had the impact of skewing net salvage to a more

[60] Decision E91093, p. 95 – TransAlta Utilities Corporation, 1991/1992 Phase I GRA, dated December 16, 1991

negative amount. Calgary noted that the ATCO estimate " was based on recorded retirement activity since 1983 reflecting plant back to 1912 and as old as 88 years."

Calgary argued that in development of the net negative salvage estimates for this account, ATCO did not consider any industry or peer experience, having concluded that the Company had an adequate historical database from which to draw for salvage estimation, and made its forecast by relying on corporate experience.

Calgary considered it common practice of depreciation professionals to at least test the depreciation parameters against peer companies, to determine reasonableness. Calgary considered this test particularly critical, given the amount of missing retirement data. Calgary provided information on net salvage for four directly comparable Western Canadian natural gas utilities, which ranged from -15% to -65%.

Calgary indicated that while its recommendation of -75% was still outside the range of these comparable companies it did not completely discount the Company's historic experience. Calgary requested that the Board reduce the requested net salvage percentage from -100% to -75%.

Views of the CG

The CG agreed that a retirement analysis primarily reflecting "one-of" replacements could be misleading as an indicator of future negative net salvage for the account as a whole. Although ATCO indicated that the Bare Mains replacement was reflected in the retirement analysis, the CG considered the 3% retirement rate to be relatively low, and that, even if the impact of inflation on retirement rates was considered, the percentage retired appeared to be relatively low. The CG expressed concern that, given the wide difference between the AGA survey and ATCO's proposed negative net salvage, the retirement experience to date might not be reflective of the account as a whole, and submitted that the -75% recommended by Calgary was a reasonable compromise under the circumstances and should be adopted by the Board.

Views of the Board

The Board notes that ATCO's recommended net salvage rate of -100% falls inside the range of AGA data, although above the average of that data. The Board also notes that the -100% net salvage recommended by ATCO is the same rate as approved for the North and South in previous Decisions. The Board also notes that the actual depreciation reserve for Distribution Services account is in a deficit position as compared to the current depreciation reserve requirement, which indicates that existing depreciation and net salvage rates were slightly conservative in the past. The Board therefore does not consider that a reduction in depreciation net salvage requirements is directionally appropriate for this account. Accordingly, the Board accepts ATCO's recommended depreciation parameters for Distribution Services.

5.4 Account 474 – Customer Regulator and Meter Installations

Views of ATCO

ATCO noted that this Account contained the cost of customer regulator equipment and installation costs for both regulators and meters. ATCO indicated that the Study recommended an R4 curve with an ASL of 45 years identical to the current ASL parameters for both North and South. The study also recommended a net salvage rate of -25%. ATCO noted that the current net salvage parameters are -100% (North) and -5% (South). ATCO explained that the Study took into account the capitalization of the meter recall program, which would result in more interim early retirements of labour and higher negative net salvage in coming years due to the recall of old non-temperature sensitive meters and moving meters from indoors to outdoors.

ATCO argued that it was important to understand the nature of this Account in contrast to Account 478 and the effects that meter refurbishment and recall will have on each of these accounts. ATCO explained that meters are used to measure gas consumption at the customer's premises and Account 474 contains the installation costs for meters. ATCO pointed out that regulators are used to regulate gas pressure at the customer's premises and Account 474 contains both the cost of customer regulator equipment and the installation cost of the regulator equipment and meters. ATCO indicated that the meter equipment itself is contained in Account 478, and that meter recall is the replacement of a customer meter, the costs of which are charged to Account 474. ATCO stated that meter refurbishment is the major overhaul of the meter at the meter shop, the costs of which are charged to Account 478.

ATCO noted that at the time a meter or regulator is installed, the installation cost along with the cost of the regulator is capitalized. ATCO indicated that prior to issue of Decision 2001-96, a retirement would not occur until final disposition and costs associated with change outs and refurbishments were expensed.

ATCO indicated that meter refurbishment begins with the meter shop doing a major overhaul by removing internal components and replacing these worn out components with new parts. ATCO pointed out that the new parts are capitalized to Account 478 and the meter life is now extended. If the meter cannot be refurbished, ATCO noted that it is retired and junked.

ATCO considered that the existing confusion resulted from the wording of AR 546/63 for Account 673. ATCO stated that the work expensed to Account 673 was maintenance work intended to meet the original life of meters, and not the recording of costs related to increasing physical life. ATCO pointed out that costs that increase physical life are capital costs, and that meter refurbishment added value to a meter by extending the physical life.

Regarding the life change recommendation advanced by Calgary, ATCO noted that the Study exactly followed the old North and South parameters for ASL. ATCO explained that furthermore, an analysis of the historical data showed a downward trend, which was entirely consistent with the current approved and recommended 45-year ASL. Moreover, ATCO argued that Mr. Kennedy did not appear to fully appreciate that the meter recall program would result in more interim early retirements.

ATCO noted that Calgary's recommendation was to use either cradle-to-grave accounting with no recognition of refurbishment retirement activity or to use location accounting. ATCO argued that Calgary's recommendation of cradle-to-grave accounting with no recognition of refurbishment retirement activity would overstate rate base. ATCO stated however, that according to Calgary's recommendation, the replacement parts due to meter refurbishment would remain in Account 478. ATCO argued that the value of meters recorded to Account 478 would exceed the actual physical meter value by an amount equal to the original value of the replaced parts. Location accounting, as described by Calgary would result in a complete retirement of the meter upon meter recall with significant gross salvage credits to accumulated depreciation. ATCO argued that the life of the meter would decrease to the recall period of approximately seven years and result in a significant increase to the net salvage parameter (upwards of 75%). ATCO submitted that location accounting completely ignores AR 546/63 and would result in significant changes to the depreciation parameters for Account 478.

ATCO did not agree that the two Accounts should be aggregated, on the basis that under this approach, the salvage estimates would not be accurate for either of the two Accounts. ATCO argued that accounts 474 and 478 were different, since Account 474 recorded all the costs for regulators but only installation costs for meters.

Views of Calgary

Calgary noted that ATCO proposed an IOWA 45-R4 to represent the service life estimate, and a net salvage rate of -25% for this account. Calgary recommended use of an IOWA 47-R4 to represent the ASL estimate and a net salvage rate of -0%. In making this alternative recommendation, Calgary considered that the 47-R4 IOWA curve provided a better fit to the historic data, and that the salvage analysis in this Account should be combined with Account 478 – Distribution Customer Meters.

Calgary recommended that the net salvage indications for this Account should be combined with the historic net salvage indications of Account 478 – Customer Distribution Meters. Calgary argued that ATCO had not followed the prescriptions of AR 546/63 to account for customer regulators and meters in accordance with regard to the ‘cradle to grave’ accounting treatment.

Calgary submitted that, once the historic data was combined, a net salvage rate of -7% would be appropriate for both this account and for Account 478, and requested that the Board accept the recommendation for reduction of the net negative percentage percentages to 0% for both this account and Account 478.

Views of the CG

The CG noted that the Company recorded regulator and meter installation labour in this account, and that, for the majority of companies in the AGA survey, ASL was 35 years and negative salvage -10% for this account category. The CG was unsure if the AGA companies used a location life or cradle-to-grave approach for regulators, but noted that ATCO appeared to use the location life approach for installation costs and cradle-to-grave for regulators. For companies using the cradle-to-grave approach, the CG considered that gross salvage would be lower and ASL longer, and that the converse would be true for a company using the location life approach. The CG noted that ATCO’s proposed negative salvage of -25% was a change from the existing -100% for North and -5% for South and that ATCO indicated that negative salvage trended down in the North service area and trended up in the South service area. Considering all of the foregoing, the CG did not object to ATCO’s proposed parameters for this account at this time.

Views of the Board

The Board notes ATCO’s recommended net salvage rate of –25% for the combined databases in comparison to the former rates of -100% and -5% for the North and South respectively. The Board also notes that the CG did not object to this recommendation. The Board agrees with ATCO’s position that the nature of costs represented in account 474 – (regulators and installation costs for meters and regulators), versus account 478 – (metering equipment), is different and that aggregation of these two accounts could result in inaccuracies in net salvage. Furthermore, the

Board is satisfied that ATCO's accounting practices properly reflect the ongoing costs of metering equipment in account 478 and the costs of regulators and installation costs for meters and regulators in account 474. The Board believes that these practices conform to the intent of AR 546/63.

Therefore, the Board does not agree with Calgary's recommendation to combine accounts 474 and 478, or Calgary's recommended net salvage rate of 0% for these accounts.

The Board approves ATCO's recommended parameters for regulators and installation costs of meters and regulators.

5.5 Account 475 – Distribution Mains

ATCO noted that this Account included the installed cost of distribution system mains from the transmission line to the customer service line. ATCO recommended an R2.5 curve with an ASL of 62 years with a net salvage of -50% in comparison to old parameters of an R3 curve with a 65-year ASL and -35% net salvage (North) and an R3 curve with a 60-year ASL and -45% net salvage (South).

Table 18. Depreciation Parameters (Table 5.5.1)

	Proposed Parameters	Old Parameters (North)	Old Parameters (South)
Average Service Life	62 yrs	65 yrs	60 yrs
Curve	R2.5	R3	R3
Net Salvage Rate	-50%	-35 %	-45 %
Depreciation Rate	2.76 %	2.312 %	2.67 %

ATCO's recommendations took into account the historical data experienced in this Account, including durability of plastic pipe and backing out of some relocations arising from highway projects.

ATCO noted that Calgary recommended an R2.5 curve with a 65-year ASL and net salvage rate of -40% for this Account. ATCO argued that Calgary gave no weight to engineering staff expectations. Furthermore, ATCO stated that for other utilities, Calgary endorsed an adjustment to depreciation expense based on the consideration of gas reserve depreciation. ATCO submitted that the Study took a balanced view of historical experience, and current policy and outlook as determined in discussions with the engineers.

ATCO argued that instead of looking carefully at the historical experience, Calgary had seized on what was regarded as industry averages. ATCO was troubled by the willingness to rely on the averages of companies whose experience and physical plant are different from ATCO. ATCO referred to Calgary's submission that care must be exercised in using AGA survey results and admitted that there were "issues" with the use of AGA statistics.

ATCO noted that Calgary indicated that when removing pipe from easements, the surface restoration would be significantly less expensive than in circumstances where it was necessary to repave and make street and lane repairs. ATCO agreed that this relevant consideration was explicitly noted at page 4.9B-17 of the Study.

ATCO dealt with the comparisons drawn by Calgary to four western gas utilities' net salvage recommendations and submitted that the Company's recommendation of -50% was well within the range of the AGA Survey, and moreover, took account of the actual historical experience on this plant.

Views of Calgary

Calgary noted that ATCO proposed an IOWA 62-R2.5 to represent the service life estimate, and proposed a net salvage rate of -50% for this account. Calgary recommended an IOWA 65-R2.5 to represent the ASL estimate and a net salvage rate of -40%. In making this alternative recommendation, Calgary considered that:

- only 3.5% of the plant additions had been retired to date;
- the IOWA 65-R2.5 provided a superior fit to the limited retirement data to date;
- new installations were now in easements rather than streets and alleys, which would significantly reduce the future costs of removal; and
- ATCO did not consider the experience of peer Western Canadian natural gas utilities.

Calgary considered that the impacts of missing data discussed with respect to Account 473 – Distribution Services, were equally applicable to this Account.

Calgary argued that the Board should place little reliance on the unsubstantiated claims of engineering staff in forecasting that maximum physical life was not expected to exceed 100 to 110 years, since ATCO had not provided any evidence indicating the basis of the statements. Calgary expressed concern therefore, that neither interveners nor the Board were able to test the reasonableness of these unsubstantiated claims of the engineering staff.

Despite the complete lack of support for the maximum life expectations of this Account, Calgary noted that its life table plots indicated a maximum life of the 65-R2.5 only a few years longer than the maximum life indication of the ATCO proposed 62-R2.5. Calgary submitted that a review of the life table plots clearly highlighted the insignificant difference in the maximum life indications of the two IOWA curves.

Calgary did not understand how the historic trend of retirements beginning at age 60 were an important consideration for the development of the life estimation by ATCO, but not important enough to warrant the investigation by ATCO of the forces of the retirement. Calgary submitted that reviews of these types of changes in the retirement rates played an important role in the determination of whether similar retirement forces would repeat in the future. Calgary argued that, in circumstances where the witness responsible for the preparation of the depreciation study could not confirm the reasons for the significant increase in retirement activity, the Board should assign little or no weight to the Rebuttal comments. As such, Calgary requested that the Board accept that the 65-R2.5 IOWA curve was the most appropriate ASL estimate for this account.

Calgary considered that its alternative recommendation to reduce the net salvage percentage to -40% for this account recognized the fact that the future retirements of distribution mains, which were currently being installed in easements rather than streets and alleys, would require lower amounts of costs of removal. Referring to ATCO's claim that this factor had already been explicitly recognized, Calgary noted that no evidence was placed into the record to indicate the manner in which this factor had been considered, nor had ATCO provided any evidence to indicate the degree of moderation of the historic indications that had been made due to this factor.

Calgary pointed out that, in this Account, as in Account 473, the historic net salvage recommended by ATCO was significantly outside the range of 4 other Western Canadian natural gas distribution utilities, which ranged from -5% to -20%. Calgary indicated that in contrast, the ATCO recommendation of -50% was significantly divergent. Calgary argued that ATCO provided no reasons, nor had it attempted any justification for this significant difference, but held to the view that the internal analysis was sufficient.

Additionally, Calgary noted, that as discussed with respect to Account 473, the historic retirement experience to date had the effect of skewing the net salvage percentage more to the negative. Absent any justification of the ATCO experience compared to the rest of the Western Canadian experience, and given that the future retirements would likely result in lower costs of removal, Calgary requested that the Board accept its alternative recommendation to reduce the net salvage percentage for this account to -40%. Calgary considered that this recommendation, while still outside the range of Western Canadian peers, did provide a compromise between historic indications, future expectations, and was influenced to a small degree by the salvage indications of peer companies.

Views of the CG

The CG noted that ATCO stated that full depth net salvage (1983-2000) was -86%, whereas the latest five-year average was -61%. However, the CG pointed out that ATCO qualified this by stating that the lower negative salvage experienced in 1999 and 2000 was directly attributable to two major highway projects requested by the government. The CG submitted that there was no reason why the recorded trend in the last five years should be unique to that period.

Given the significant plant balance in this account and considering comparable AGA statistics as well as ATCO's observation that negative net salvage has been trending down, the CG submitted that consideration should be given to moderation in moving the negative net salvage to the proposed -50% level. Accordingly, the CG agreed with Calgary's recommended negative net salvage of -40%.

Views of the Board

The Board notes that ATCO's recommended net salvage rate of -50% falls inside the range of AGA data, and close to the average of that data. The Board also notes that the depreciation reserve for distribution mains account is in a deficit position as compared to the current depreciation reserve requirement, indicating that existing depreciation and net salvage rates were slightly conservative in the past. The Board considers therefore that reduction in depreciation net salvage requirements is not directionally appropriate for this account. Accordingly, the Board approves ATCO's recommended depreciation parameters for distribution mains.

5.6 Account 478 – Customers Meters

ATCO noted that the recommended ASL of 30 years with a R2.5 curve was in line with the old parameters for North (R3-30) and South (R2.5-30), and that the net salvage rate recommended of

+1% was identical to the old parameters for North and South. ATCO pointed out that, as previously noted, this account included the ATCO investment in meters and meter hardware, and that labour costs for installation and removal of meters at customers' premises were allocated to Account 474.

ATCO indicated that the Study noted that the design of new meters, which relied on smaller parts, was expected to result in the internal parts wearing out faster, and also took into account the meter replacement project to replace all old meters that were not temperature sensitive. Both of these developments would lead to a higher level of retirements in the near future.

ATCO noted that Calgary recommended an IOWA 33-R2.5 curve and net salvage rate of 0% for customer meters. ATCO argued that Mr. Kennedy ignored the advice of the ATCO engineers, something he himself paid close attention to when undertaking his own depreciation studies.

In connection with Calgary's proposal to combine net salvage data for Accounts 474 and 478, ATCO argued that these accounts were different with different history and subject to different expectations by the engineering professionals. ATCO requested that the Board maintain the current accounting treatment which records net salvage data accurately and separately for Accounts 474 and 478.

Views of Calgary

Calgary noted that ATCO proposed an IOWA 30-R2.5 to represent the service life estimate, and a net salvage rate of +1 % for this account. Calgary provided an alternative recommendation of an IOWA 33-R2.5 to represent the ASL estimate and a net salvage rate of 0%. Calgary did not repeat the basis for its position, as the issues were identical to those presented with regard to Account 474.

Views of the CG

The CG noted that ATCO proposed a 30-year ASL, an R2.5 Iowa curve and positive salvage of 1% for this account and that Calgary recommended that the ASL should be increased to 33 years and the salvage percent set at 0%.

The CG submitted that extending the ASL to 33 years proposed by Calgary from the 30 years proposed by ATCO was reasonable, as it would be reflective of current trends and historical indications.

Views of the Board

The Board notes that ATCO's recommended parameters for metering equipment are in line with the previously approved parameters for North and South. The Board also notes that the depreciation reserve for the meter equipment account is in a slight deficit position as compared to the current depreciation reserve requirement, indicating that the past depreciation parameters were accurate. The Board therefore sees no compelling reason to change the recommended parameters, and accepts ATCO's recommended depreciation parameters for metering equipment.

6 INCOME TAX

6.1 Income Tax Forecasts

Views of ATCO

In the Application, ATCO forecast income tax expense of $9.132 million (2003) and $29.581 million (2004). ATCO pointed out that the tax rates were based on the enacted tax rates at the time of the filing of the application. ATCO also continued the past practice, as approved by the Board, of fully deferring the tax effect of timing differences associated with the Deferred Hearing Costs, Deferred Gas Costs, and the Reserve for Injuries and Damages. With respect to the deferral of income taxes related to pension costs, ATCO proposed that this practice not be continued as long as the Company remained on the cash basis for these costs, due to the immateriality of the impact on income tax related to the capitalized portion of the expense.

ATCO noted Calgary's concern about the fact that the Company used the financial interest expense in the utility income tax calculation, rather than the utility interest expense, as the financial interest was the amount actually deductible for income tax. ATCO pointed out that the timing of new debenture issues and retirement of existing issues was the main reason for difference between these amounts. ATCO indicated that the issue date of a debenture has implications at the time of issue, and at redemption, and that the impact of the timing difference at each of these points would be in opposite directions. By way of example, ATCO indicated that if an issue occurs after July 1, there is a lower financial interest expense than utility expense in the year of issue, but when that same issue is redeemed, there will be a higher financial interest expense than utility expense. ATCO submitted that the differences therefore balance out over time, and that use of financial interest expense in the utility income tax calculation is a long-standing tradition for the ATCO gas utilities. ATCO considered that the danger in changing this methodology was that customers would always seek to use whatever methodology would provide the lowest cost in the test years, which would result in the shareholders continually bearing the cost of the timing difference, which would not balance the interest of customers and shareholders.

ATCO disagreed with the estimated impact on income tax expense related to the use of the financial interest expense in the utility income tax calculation as suggested by Calgary. ATCO had detailed the impact at $1.4 million in 2003 and $942,000 in 2004 in Rebuttal Evidence.

ATCO noted that Calgary's evidence also addressed the impact of the Canderel and Rainbow Pipelines tax appeals. ATCO indicated that the impact of these tax appeals had been incorporated in the current GRA forecast, as was done in the 2001/2002 AGS GRA. ATCO also incorporated the impact of the capitalization of additional administrative charges on the deduction of indirect expenses.

While ATCO had no formal policy with respect to determination of indirect costs deductible for income tax purposes, ATCO identified that the indirect costs deducted were based on guidelines established as a result of a review by CCRA. ATCO indicated that, as a result of the review process undertaken by CCRA, the Company did not require a formalized policy to determine what costs qualify. ATCO stated that the only time that a question might arise is in the event that there is a change in the types of costs being capitalized. ATCO noted that, as discussed in Rebuttal Evidence, a comparison of the amount of indirects deducted for income tax for 2002 and 2003 showed an increase in the amount being deducted of $6.7 million. ATCO stated that the majority of this increase was attributable to capitalization of additional administrative charges commencing in the 2003. In response to an observation by Calgary, ATCO indicated that the income tax treatment in the test year forecasts was that set out in Exhibit 13-10.

ATCO was at a loss to know how Calgary determined that there was no explicit amount included in the income tax forecast related to the Rainbow Pipelines tax case, as a result of the response to CAL-AG-49(f). ATCO pointed out that this information request addressed the indirects deducted for tax purposes pursuant to the Canderel case, and that there was no mention of expenditures related to the Rainbow Pipelines tax case in the question. ATCO pointed out that to be clear, for the Company, removal costs, which do not involve the replacement of assets are deductible and that generally, removal and abandonment costs related to service lines and production wells are the categories of expenditures that might result in this type of deduction. Due to the fact that a significant portion of these costs relate to abandonment of production wells, ATCO stated that there is significant volatility in the amount of deduction eligible in different years.

ATCO pointed out that this was clear from Schedule 4.10 provided in the 2002 Actual Filing, where the 2002 actual “Well Workovers and Abandonments” (line 26) was $1.4 million lower than forecast for the Company in total. ATCO also noted that the forecast of “Well Workovers and Abandonments” was impacted by the sale of Beaverhill Lake and Fort Saskatchewan, as identified in response to BR-AG-149. ATCO noted that Calgary recommended that the Board base the Rainbow deduction in 2003 and 2004 on the AGS deduction for the years 1998 and 1999, adjusted to recognize forecast increases in capital expenditures. ATCO noted that the $2 million guideline used by Calgary from the 2001/2002 AGS GRA related to the Canderel-type indirect costs deducted for those years, not the Rainbow Pipelines deduction. ATCO pointed out that, in the 2001/2002 GRA, the deductions related to Rainbow Pipelines were approximately $600,000 per year for the South. ATCO noted that this was considerably lower than the $1.1 million forecast in 2003 for the South, and in line with the $675,000 forecast for the South in 2004. ATCO also noted that the increase in forecast capital expenditures would not impact this deduction as those increased capital expenditures do not result in the Company incurring additional removal costs. ATCO submitted therefore that Calgary’s recommendations were inappropriate. With respect to the requirement of a formal policy regarding the Rainbow Pipelines tax appeal, ATCO stated that these expenditures are even more straightforward to identify than the indirects, and as such, no formal policy was required.

Views of Calgary

Calgary expressed concern with the effect of ATCO’s failure to deduct the same amount of interest expense for income taxes as was collected in the revenue requirement, and submitted that customers should not be required to pay income tax on interest expense that is collected through the rates. Calgary estimated that this extra income tax expense was about $2.7 million in 2003 and $1.0 million in 2004.

Calgary noted ATCO’s position that financial interest expense, rather than utility interest expense is reflected as a deduction in the utility income tax calculation, as the financial interest is the amount actually deductible for income tax. Calgary submitted that tax deductible items collected in the revenue requirement should not attract income tax expense, as these are income tax expense amounts that will not be paid by ATCO and simply enhance shareholder return.

Calgary also took issue with the matter of indirect costs that would qualify for deductions under the criteria of the Canderel and Rainbow tax cases. Calgary was surprised with ATCO's acknowledgement that it had no formal policy regarding the specific indirect costs eligible for deduction. In Calgary's view, it appeared that the determination of whether items were deductible for tax purposes was based on a "hit and miss" process, and that is was clear from the response to CAL-AG-49(f), that no explicit amount had been included for the Rainbow type expenditures. Calgary recommended that the Board add an amount of $800,000 to $1,000,000. Calgary calculated this amount based upon the $2 million in 1998 and 1999 increased by 40% to 50%, being the percentage that capital expenditures are forecast to increase in the test periods for Rainbow type expenditures. Calgary submitted that if ATCO were to follow the procedure set out in the attachment to Exhibit 13-10, Calgary's concern with respect to the under deduction of additional amounts capitalized would disappear.

Views of the CG

The CG noted that ATCO reflected income tax deductions for indirect costs of between $8.5 million and $9.2 million, and well workovers and abandonments of $0.7 million to $1.3 million in the test years. The CG acknowledged that these deductions, described as Rainbow and Canderel type expenses, are allowed as deductions for tax purposes, but capitalized for accounting and regulatory purposes.

The CG noted that ATCO defined the expenses included under the 'Indirects' category as costs common to various capital projects, which, due to the nature of the work performed, could not be charged to a specific project. The CG noted that these included supervisory labour charges, and administrative support costs.

The CG also noted ATCO's submission that deductions for well workovers and abandonments were reflected pursuant to the Rainbow Pipelines tax appeal decision dealing with the treatment of certain removal costs for tax purposes.

Given the significance of these deductions, the CG submitted that there should be clearly defined policies with regard to what constitutes an appropriate deduction under the Rainbow/Canderel deduction category, noting ATCO's acknowledgement that there was no written policy with regard to calculation of these deductions.

The CG considered that there should be transparency between these types of expenses, the amounts capitalized and the amounts deducted for tax purposes. The CG submitted that ATCO should be directed to file a written policy providing definition and transparency with respect to the Rainbow/Canderel type deductions at the time of the refiling, and ensure forecast deductions for the test years reflect these policies.

Referring to ATCO's position on treatment of indirect expenses for tax purposes, the CG strongly emphasized the need for clear policies defining what types of expenses can be included under indirect expenses, and well workovers and abandonment expenses, which are both expensed for tax purposes and capitalized for book purposes. The CG considered that ATCO's policies and practices should ensure the potential is minimized for variance between forecast and actual deductions for tax purposes arising from the nature of items included as deductions.

Views of the Board

The Board notes Calgary's concern that, in calculating income tax expense, ATCO deducts the amount of interest expense paid and recorded for financial statement purposes, rather than the interest expense determined for utility purposes and collected in rates. The Board acknowledges Calgary's concern that, deducting the higher utility interest amount in the tax calculation would result in a lower tax expense amount, thereby offsetting the additional income collected through customer rates.

The Board however notes ATCO's position that financial interest expense is the amount actually deductible for income tax purposes, meaning that deduction of a different amount in determination of tax expense for inclusion in the test year forecasts would not accurately reflect the Company's tax liabilities. The Board acknowledges ATCO's observation that determination of interest expense using the mid-year convention results in differences in utility and financial interest, which will average out over time depending on the timing of issues and redemptions of debt. The Board recognizes that the methodology used is consistent with accepted practice over the years, and considers that there is merit in ATCO's submission that changing the methodology could lead to the potential for ongoing debates in rate proceedings with respect to which interest amount represents the appropriate deduction.

Based on the foregoing, the Board does not accept Calgary's suggestion for revision to the interest deduction in determination of income tax expense.

The Board acknowledges that the issue of amounts eligible for deduction pursuant to the Canderel and Rainbow Pipelines cases has been raised in previous proceedings, and notes the concerns of Calgary and the CG with respect to the need for establishment of formal policies in this regard. The Board also notes Calgary's concern that ATCO might not have included an appropriate level of deductions for indirect expenses pursuant to the Rainbow Pipelines case.

The Board has examined the response to CAL-AG-49, and notes that ATCO has identified the types of indirect expenditures, such as labour and administrative support, capitalized for accounting and regulatory purposes, but allowed as deductions for tax purposes, pursuant to the Canderel case. The Board notes that ATCO has identified the amounts deducted of $19.8 million (2003) and $20.3 million (2004), which includes the amount of $6.5 million of capitalized administration costs in the test years. The Board also notes that ATCO has reflected deductions of $2.4 million (2003) and $1.9 million (2004) for well workovers and abandonments pursuant to the Rainbow Pipelines case.

The Board acknowledges ATCO's comment in response to intervener recommendations for increases to specific deductions, and considers it clear that interveners appear to have confused the two cases, and the amounts previously deducted or deductible pursuant to each case. The Board is satisfied that, consistent with previous years, ATCO has reflected the appropriate deductions in determination of income tax expense for the test years. However, given the obvious lack of clarity in this and previous proceedings with respect to the nature of items eligible for deduction and identification of these deductions, the Board considers that there is merit in the CG's recommendation for the need to provide transparency with respect to this issue.

The Board therefore directs ATCO, in the Refiling, to advise the Board on the process adopted to identify in the accounting records, those costs capitalized, but considered by the Company to be ordinarily deductible and being deducted for tax purposes in the year incurred.

6.2 ATCO Proposal for Same North/South Methodology

Views of ATCO

ATCO stated that one of the more significant areas of difference between the North and South historically had been the treatment of income tax. Since 1996, the North had deferred the impact of all federal timing differences, while the South had essentially been on full flow through for income taxes. ATCO submitted that maintaining two different tax methodologies within the same company adds complexity and administrative costs, and should therefore only be maintained if there is sufficient benefit to customers as a result. ATCO considered that there were no benefits to customers in maintaining distinct income tax methodologies, and therefore proposed to move to one income tax method commencing in the year 2003.

ATCO proposed to move to the full flow through method for income taxes commencing in the year 2003, with the exception of the specific deferral items referred to in Section 6.1 above. ATCO considered that doing so would result in an income tax calculation which was easier to understand, required less administration, and removed a potential obstacle to bringing the North and South together for regulatory purposes. As a result of this change, ATCO recommended a refund of the North Federal deferred income taxes accumulated to the year 2002, as discussed further in Section 6.3 below.

ATCO pointed out that due to the sale of the production assets in the North, the Class 10 and 41 production Capital Cost Allowance (CCA) pools had been fully depleted, resulting in the North reaching crossover federally, and that timing differences in future should be minimized, due to the fact that the majority of investments would have depreciation rates similar to the CCA rates.

ATCO noted Calgary's acknowledgement that use of the same income tax methodology between North and South would be of assistance, and that the CG did not object to the proposal to move to the flow-through method for income tax in the North. On this basis, and given that AUMA/EDM did not address this issue, ATCO considered that Board should approve the change in income tax methodology for the North as requested.

Views of Calgary

Calgary acknowledged that use of the same methodology for income tax within the corporate entity would be of assistance.

Views of the CG

The CG noted that for both North and South, annual depreciation expense exceeded the claim for CCA, indicating crossover where the book value of assets exceeded the tax value had occurred. Accordingly, the CG did not object to ATCO's proposal to move to a flow through method for both North and South.

Views of the Board

The Board accepts ATCO's proposal to adopt a common methodology for North and South, noting that interveners expressed support for ATCO's proposal to move to one income tax methodology commencing in 2003. The Board accepts ATCO's proposal to change the methodology for the North to the methodology utilized in the South.

6.3 Large Corporations Tax

Views of ATCO

In the Application, ATCO forecast Large Corporation Tax (LCT) of $2.339 million (2003) and $2.519 million (2004). ATCO noted that Calgary expressed concern with respect to the method of calculating the LCT, suggesting that a consistent approach should be used by all utilities with respect to the calculation of LCT. ATCO considered that, while this might be desirable, it was not realistic, as it did not take into consideration the varying characteristics between utilities.

ATCO stated that the CG's position that these varying characteristics are not a valid reason for differences in the way LCT is calculated, was a clear indication that the CG has misunderstood what was meant by this statement.

By way of example, ATCO includes consumer deposits (as required) in its LCT calculation, while other utilities might not have any consumer deposits. With respect to the CG's comments regarding the Company's interpretation of tax legislation, ATCO submitted that it should not be placed at risk for being asked to assume a more aggressive interpretation of the *Income Tax Act* than it believes is prudent.

Regarding the Federal Budget announcements impacting income tax, ATCO noted that there was no discussion of these matters in the record, and that Calgary was therefore introducing new evidence in Argument which should be ignored by the Board. Furthermore, ATCO considered that Calgary was seeking to update the forecast for information not available at the time the forecast was prepared, while ATCO is not afforded the same opportunity with respect to other circumstances that have changed.

With respect to the "stand-alone" principle applicable to the LCT credit available to the ATCO Group of companies, ATCO stated that the suggestion of Calgary was not credible. ATCO indicated that using Calgary's Argument, if the North and South are to remain separately regulated for some period, the revenue requirement should be increased to reflect the cost of operating those entities on a standalone basis.

Noting that the credit is only available to the ATCO Group of companies once, ATCO identified in Rebuttal Evidence the potential impact on the revenue requirement if a portion of the credit were allocated to the Company on the basis of the ATCO/CU corporate cost methodology. ATCO noted that, based on the $10 million LCT credit, the Company's income tax expense would be reduced by approximately $6,000.

Views of Calgary

Calgary expressed concern with the inconsistency in the calculation of LCT among companies under the Board's jurisdiction, and with the inclusion of certain items in ATCO's calculation. Calgary pointed out that the "capital reduction" of $10 million provided in section 181.5 of the

Income Tax Act, is claimed by TransCanada Pipelines Limited but not by ATCO. Calgary also submitted that federal budget changes in LCT tax rate and minimum threshold should be incorporated into the calculation of LCT, similar to other income tax rate changes discussed in Section 6.5 below. With respect to the calculation of LCT, Calgary submitted that the taxable capital should not exceed the rate base, and that there should be an allocation of the minimum threshold to ATCO. Calgary indicated that, if the Board accepted ATCO arguments on the "stand-alone" concept, the full minimum amount should be allocated to ATCO, which would be $50 million under the new budget, compared to the $10 million previously available.

Views of the CG

Referring to Calgary's concern regarding inconsistency in LCT treatment among utilities, the CG noted ATCO's position that, while a consistent approach to the calculation of LCT might be desirable, it was not realistic, as it did not take into consideration the varying characteristics between utilities.

The CG submitted that "varying characteristics between utilities" was not a valid reason for differences in the way LCT is calculated, and agreed with Calgary that the tax bulletins should be interpreted to minimize income tax expense included in revenue requirement. In addition, the CG suggested that if ATCO was successful in previous years in reducing the tax base for LCT on actual tax assessments, corresponding reductions should be reflected in forecast tax calculations. The CG recommended therefore that ATCO be directed to review its LCT tax base and reflect the necessary changes in its refiling.

Views of the Board

The Board notes the concern of Calgary and the CG with respect to inconsistencies in the calculation of LCT between utilities under the Board's jurisdiction, with particular reference to the fact that the capital deduction of $10 million provided for in Section 181.5 of the *Income Tax Act* has been claimed by TransCanada PipeLines Limited, but not by ATCO. The Board also notes that in Evidence (page 54), Calgary cited other specific examples where ATCO's calculation differs from those of AltaLink, Aquila and TransCanada PipeLines Limited.

With respect to the capital deduction of $10 million, the Board recognizes that ATCO's treatment is consistent with previous years, and acknowledges ATCO's submission that the credit is not a deduction that can be claimed by each company within the ATCO Group, but would have to be allocated among all companies in the group. The Board notes that ATCO calculates that if the capital deduction were allocated in this manner, the deduction available to ATCO would be $2.6 million, which translates to a LCT deduction of $6,000. With respect to the increase in the capital deduction to $50 million pursuant to the latest Federal Budget, referred to by Calgary, the Board calculates that the tax impact to ATCO would increase from $6,000 to $30,000.

The Board considers that on the basis of consistency with previous treatment of this deduction, recognition of the methodology adopted by ATCO Group, and lack of materiality to ATCO, the Company's treatment of the deduction is appropriate.

However, the Board also recognizes the benefits that ATCO realizes from the synergies of corporate costs as an affiliate of CU and directs ATCO to demonstrate in its Refiling the extent to which LCT credit benefits are shared among all affiliates in the same manner that corporate costs are allocated.

Regarding the other examples of inconsistency between utilities cited by the interveners, the Board notes ATCO's position that the differences in approach are not significant, and likely relate to the fact that ATCO may be eligible for certain deductions not available to the other utilities and vice-versa. The Board agrees with ATCO that, while consistency is desirable, it is probably not realistic, and accepts ATCO's assurance that its calculations are based on its interpretation of the *Income Tax Act*.

The Board notes Calgary's submission that any changes in capital tax rates enacted in the latest Federal Budget should be reflected in the determination of the LCT forecast for the test years. In Decision 2001-96, the Board concluded that AGS should "recalculate income tax expense for the test years using those rates announced or substantively enacted by the federal and provincial governments for those years." The Board considers that this determination also applies to the calculation of LCT.

The Board agrees with Calgary that, consistent with the direction in 2001-96, the Company's tax determination should be based on tax rates announced or substantively enacted affecting the test years. The Board notes that the rates of capital tax proposed in the 2003 Federal Budget were 0.225% for 2003 and 0.200% for 2004, whereas ATCO calculated LCT using the rate of 0.225% for both years. Based on the foregoing, the Board directs ATCO in its Refiling to use the rates that have been announced by the governments notwithstanding that the announced rates have not yet been enacted.

The Board therefore, directs ATCO to recalculate LCT for 2004 using the reduced rate of 0.200%.

However, in addition to using the announced rates, the Board considers that an appropriately constructed deferral account would be fair for both customers and the Company to capture any changes from Federal Government intentions over the test period. Accordingly, the Board directs ATCO to propose a deferral account in its Refiling that would account for any change in Federal LCT.

6.4 Deferred Tax Issues

Views of ATCO

ATCO stated that the purpose of deferred income tax was to prevent cross-subsidization between customers of today and tomorrow, by ensuring that the income tax expense recognized is based on accounting expenses recognized. The more significant the difference between income for accounting purposes versus income for tax due to timing differences, the more significant the issue of cross-subsidization becomes. ATCO indicated that deferral of only the Federal portion of the timing differences prevented cross-subsidization to some extent, but as timing differences provincially were not deferred, the full intent behind the deferral of income taxes was not achieved.

ATCO pointed out that, over the period of time that Northwestern was on the Normalized All Taxes Paid (NATP) method of income tax, it only recognized CCA equal to the net of the other timing add-backs and deductions. Generally, because the available CCA exceeded the CCA that had to be recognized, the tax pools with the higher write-off percentages were not depleted (the process was to claim from the lowest to the highest write-off tax pools until the required CCA level was attained). Due to the significant investment by the North in its production assets, which had a high write-off for tax purposes, the production tax pools of the North were generally not used over the period of time that Northwestern was on NATP. This resulted in a growing available balance in these tax pools, producing a significant difference between the CCA claimed and depreciation expense recognized, once the Company moved to the Federal deferred tax methodology in 1996. ATCO noted that this difference was deferred, and as a result the Federal deferred tax pool had grown since 1996.

ATCO stated that, in the years 2001 and 2002, the North disposed of a significant portion of its production assets. As a result, the Class 10 and 41 tax pools of the North were completely depleted in the year 2002. The impact of this was that the North had reached crossover Federally and would start to draw down its Federal deferred tax balance, commencing in the year 2002. ATCO refunded $7.2 million of deferred income taxes to North customers as a result of the Viking sale in the year 2002, which represented approximately 35% of the available Federal deferred income taxes. This deferred income tax amount translated to a refund of $11.6 million. As a result of this refund, ATCO pointed out, that there was a lower amount of deferred taxes available to be drawn down in the future. Furthermore, the majority of the investments currently made by ATCO had depreciation rates similar to the tax pool rates under which the investment was classified, which also minimized timing differences.

ATCO pointed out that the actual amount of the Federal deferred income tax available to be refunded would not be known until completion of the 2002 income tax filing, in June 2003. ATCO therefore recommended that the review of this amount occur at the time that the final amount is known, rather than increasing costs to customers by reviewing a forecast at the Application date, which would be updated at a later point. ATCO therefore only requested approval of the concept of refunding the Federal deferred income taxes at this time.

In addition to the change in income tax methodology for the North, ATCO also proposed that it would no longer defer income taxes related to pension and other post employment expense for the period of time that these expenses were recognized on a cash basis, due to the immateriality of the timing difference. ATCO noted that no issue was taken with respect to this matter either in evidence or in cross-examination.

ATCO also proposed a one-time adjustment related to deferred income taxes associated with the Gas Cost Over/Under-Recovery account, due to the income tax rate change, which occurred in the year 2001. ATCO noted that, over the course of the proceeding, adjustments had been made to the amount to be refunded. Specifically, in response to CG-AG-127, ATCO indicated that the refund to the North of $2,229,000 had to be removed as it was addressed as part of the North Core Agreement settlement, approved in Decision 2002-116.[61] Also, in response to CAL-AG-48(b) ATCO further amended the amounts to be refunded for each of the North and South. ATCO pointed out that one time adjustment for the North was increased by $1,273,000 and the adjustment for the South was increased by $4,607,000, with the net result that the one-time adjustment for the North was now $1,273,000, and the South adjustment was $6,817,000.

[61] Decision 2002-116 – ATCO Gas and Pipelines Ltd. (North), Application to Approve 2002 Rates, Amended North Core Agreement and Sale of Beaverhill Lake and Fort Saskatchewan Properties, dated December 24, 2002

ATCO was at a loss to understand the meaning of the term "ad hoc" used by Calgary with respect to deferred income taxes. ATCO noted that Calgary did not address the deferred income taxes in evidence, and that the Application clearly identified the items for which income tax is to be deferred.

ATCO noted that the CG agreed with the refund of the Federal deferred income taxes for the North, but believed that interest should be applied from January 1, 2003. ATCO noted that as these deferred taxes were included in no cost capital, the CG's suggestion was inappropriate, and customers would benefit twice from this suggestion and shareowners would be penalized.

Regarding the payment of interest to January 1, 2003 on the refund of deferred taxes relating to the change in income tax rates, ATCO viewed the proposal fair only if the Company was also afforded interest on the revenue shortfall from that date until such time as the shortfall is collected. ATCO also noted that due to the fact that North customers had already received a refund related to this as a result of the 2002 North Core negotiated settlement, the amount of the refund for the North had been reduced, as identified in ATCO's Argument.

Views of Calgary

Calgary continued to have concerns about the "ad hoc" use of deferred income taxes by ATCO, and recommended that, with the adoption of the taxes payable method for the North, the Board enunciate the short-term items for which ATCO would be allowed to use the future income tax method.

Views of the CG

The CG agreed with the concept of refund of the deferred Federal income taxes in the North by means of a one-time refund but submitted that the deferred tax balance should be subject to the payment of interest from January 1, 2003, based on the Board's current interest payment policy. The CG also concurred with ATCO's proposal to refund the impact of the tax rate changes on deferred taxes associated with deferred gas costs, subject also to payment of interest from January 1, 2003, based on the Board's current interest payment policy.

Views of the Board

The Board notes Calgary's concern with ATCO's "ad hoc" use of deferred income taxes, and that Calgary recommended the need for the Board to enunciate the short-term items that ATCO would be allowed to defer. In Decisions 2001-96 and 2001-97 (ATCO Pipelines South), the Board determined that the nature of deferrals included in the Applications was consistent with the criteria established by earlier Board rulings. The Board considers it appropriate to repeat the conclusion from those Decisions that "the development of guidelines would not provide any additional benefits".

The Board notes the proposal of the CG for application of interest on the refund of deferred taxes for the North and on deferrals associated with changes in deferred gas costs. The Board agrees with ATCO that as deferred taxes are included in No-Cost Capital, thereby reducing the Company's return, any application of interest on deferred taxes would therefore represent an additional benefit to customers. Accordingly, the Board does not accept the CG's recommendation for application of interest on deferred tax amounts.

6.5 Other Income Tax Issues

Views of ATCO

ATCO proposed a change with respect to the treatment of CCA associated with non-utility assets. Prior to 2003, ATCO did not made any adjustments to the utility CCA deduction related to non-utility assets. However, ATCO indicated that, since the Company is required to recognize the non-utility depreciation expense associated with these assets, it was appropriate that ATCO also be allowed to recognize the associated CCA deduction as a non-utility deduction. ATCO noted that no issue was taken with respect to this matter either in evidence or in cross-examination.

Noting that there had been no discussion on the record with respect to changes in the enacted income tax rates, ATCO indicated that Calgary was therefore introducing new evidence in Argument, which should not be relied upon by the Board without considering other updates to the forecast as a result of changed circumstances.

Views of Calgary

Calgary submitted that if there is a change in enacted income tax rates during the test periods, the impact of that change should be reflected in the compliance filing if enacted by that time, or that there should be a deferral account for changes in income tax rates.

Views of the Board

For the reasons discussed in Section 6.3 above, the Board agrees with Calgary that consistent with the direction in 2001-96, the Company's tax determination for the test years should be based on income tax rates announced or substantively enacted affecting the test years. The Board notes that, while ATCO has used the correct Federal income tax rates in determination of forecast income tax expense, the tax calculation has not given effect to the change in rate for Federal Resource Allowance proposed in the 2003 Federal Budget. The Board notes that the rate for Resource Allowance was set at 27% (2003) and 26% (2004), whereas ATCO used the rate of 28% for both test years.

The Board therefore, directs ATCO to recalculate income tax expense using the reduced rates for Resource Income of 27% (2003) and 26% (2004), based on a deductible percentage of 90% (2003) and 75% (2004) of the existing Resource Allowance.

The Board also notes that the rates of Provincial income tax proposed in the 2003 Provincial Budget were 12.5% (2003) and 11.5% (2004), whereas ATCO used the existing rate of 13% in calculating income tax expense. The Board considers that, although the amended rates have not yet been enacted, inclusion in the Provincial Budget gives the certainty envisaged in the CICA Handbook for application to corporations. Therefore, the Board directs ATCO in its Refiling to use the rates that have been announced by the governments notwithstanding that the announced rates have not yet been enacted.

Accordingly, recognizing that the rates are effective April 1, the Board directs ATCO to recalculate income tax expense to reflect the revised Provincial Income Tax rates of 12.62% (2003) and 11.75% (2004) on an annualized basis.

However, in addition to using the announced rates, the Board considers that an appropriately constructed deferral account would be fair for both customers and the Company to capture any changes from Federal and Provincial intentions over the test period. Accordingly, the Board directs ATCO to propose a deferral account in its Refiling that would account for any change in Federal Resource Allowance and Alberta tax rates.

7 FORECAST REVENUES

7.1 General

Views of ATCO

ATCO currently utilizes two temperature zones for weather normalizing, a North zone and a South zone. As a result, ATCO noted that the forecast of throughput was developed by temperature zone.

ATCO also noted that each zone currently had different rates and therefore when developing the forecast, ATCO used delivery rates effective April 1, 2002 as approved by Board Orders U2002 135[62] (AGS) and U2002-136[63] (AGN). Also shown as revenue in 2003 and 2004 was the impact of the 2001/2002 AGS Phase I decision. ATCO had assumed that interim rates would be implemented January 1, 2003 to recover the 2002 revenue shortfall as approved in Decision 2002-050.

ATCO indicated that the revenue forecast for its various rate groups was prepared consistent with forecast methodologies used in the AGS 2001/2002 GRA. ATCO also noted that although the Board accepted the methodologies used to develop the forecast for 2001 and 2002, the Board did not accept the component of the forecast that related to the impact of the high cost of gas. ATCO submitted that energy conservation was a major factor affecting Company sales. ATCO submitted that in Decision 2001-96, the Board had noted that the evidence that customers would use significantly less gas in the near term as a result of higher prices was speculative. Since the Board was not persuaded that there was a need, at that time, to adjust the consumption forecast to reflect the effect of higher gas prices, the Board directed AGS to recalculate consumption without including an adjustment for the effect of higher gas prices.

ATCO submitted that the actual sales per customer experienced by AGS in the past two years (shown in the table below) was 138.9 GJ’s and 136.2 GJ’s in 2000 and 2001, respectively (normalized to the same temperature base, 1980-1999). ATCO stated that, in retrospect, the actual decrease in sales per customer was significantly larger than either the Company forecast or the Board approved forecast. ATCO believed that the recent energy conservation survey undertaken by the Company continued to show that high gas prices or the perception of high gas prices would motivate customers to use less energy.

[62] Order U2002-135 – In the Matter of Changes to the Delivery Rates, Tariffs and Rate Riders of ATCO Gas and Pipelines – ATCO Gas South and ATCO Pipelines South, dated March 28, 2002

[63] Order U2002-136 – In the Matter of Changes to the Delivery Rates, Tariffs and Rate Riders of ATCO Gas and Pipelines – ATCO Gas North and ATCO Pipelines North, dated March 28, 2002

Table 19. Average Residential Sales per Customer (Table 5.1.1a)

	1999	2000	2001	2002
AGS GRA Application Sales per Customer Forecast	146.2*	142.0	140.0	137.5
Board Decision Sales per Customer Forecast	146.2	142.5	141.5	140.5
Actual Sales per Customer – South Zone	146.2	138.9	136.2	135.0**
Actual Sales per Customer – North Zone	145.0	146.0	141.0	139.5**

* Actual ** Forecast

The total revenue forecast (revised November 14, 2002) developed by ATCO was as follows:

Table 20. Utility Revenue Forecasts (Table 5.1.2a)

	Actual	Forecast		
	2001	2002	2003	2004
Residential (Sales & Transportation)	215,185	215,422	220,828	224,685
Commercial Sales	93,662	87,756	89,652	90,516
Commercial Transportation	2,489	4,917	5,177	5,177
Industrial Sales	3,569	2,989	2,829	2,829
Industrial Transportation	2,880	4,010	4,441	4,441
Irrigation	842	832	832	832
Sub-Total Rate Revenue	318,627	315,926	323,759	328,480
Late Payment	6,820	6,850	8,004	7,937
Storage Revenue	11,948	9,500	8,209	8,243
Other	26,688	25,147	14,476	14,594
Sub-Total Other Revenue	45,456	41,497	30,689	30,774
Sub-Total Rate and Other Revenue	364,083	357,423	354,448	359,254
Franchise Fees	107,792	95,003	103,601	103,889
Deferred Gas Costs	1,232,942	897,434	1,035,787	1,007,708
COPP Market Adjustment	---	10,913	15,639	15,333
COP Rider	---	(10,913)	(15,639)	(15,333)
Storage Market Adjustment	---	7,613	21,520	9,521
Storage Rider	---	(13,769)	(24,402)	(11,918)
Viking Negative Salvage/Deferred Tax Refund	---	(20,600)	---	---
Viking – Seismic	---	1,500	---	---
Refund of Deferred Income Taxes	---	---	(22,607)	---
One-Time Recovery of Hearing Costs	---	4,206	---	7,300
One-Time Recovery of Reserve Costs	---	---	---	338
COS Transferred to DGA	---	(819)	(2,041)	(1,901)
Cost of Service Adjustment	---	---	56,711	66,009
2001-2002 GRA Shortfall South	4,790	1,453	10,258	10,258
Total Utility Revenues	1,709,607	1,329,444	1,533,275	1,550,458

2001 Figures are weather adjusted using 20-year average 1980-1999.

ATCO submitted that the record related to the area of forecast revenue was quite extensive. In addition to the information in the Application, ATCO noted that it had responded to numerous detailed information requests. ATCO also noted that cross-examination with respect to forecast revenue was not extensive and limited for the most part to the forecasts for Rate 3 and Rate 13 customers.

ATCO noted that no intervener had filed evidence that proposed an alternate forecasting methodology to that presented by the Company. ATCO also noted that Calgary had filed evidence that provided the results of its analysis to test the ATCO forecast and argued that the Calgary evidence supported the reasonableness of the forecast. ATCO quoted the opening statement of Ms. Sharp:

> We typically submit evidence only when we are challenging the components. However, Calgary has been accused, occasionally, of asking for detailed information that does not show up in later evidence, and so we included this material, even though we have satisfied ourselves for now concerning the forecast.[64]

ATCO noted that the CG and AUMA/EDM both conducted some cross-examination related to weather normalization and that Calgary had identified the issue of weather normalization in its evidence but clarified under cross-examination that Calgary could not specify any concerns with ATCO's weather normalization. ATCO argued that the weather normalization methodology was consistent with previous Board directions on this issue.

Accordingly, ATCO submitted that forecast revenue was reasonable.

With respect to the revenue derived from published rate schedules, ATCO noted that none of the Interveners filed evidence proposing alternate forecasting methodologies. ATCO noted that Calgary and the CG had comments with respect to the methodologies used by the Company, and AUMA/EDM commented on the temperature data used for weather normalization.

ATCO noted that Calgary filed evidence that tested the results of the forecast for residential and commercial rate classes, and indicated that they were prepared to accept the residential and commercial forecast. ATCO noted that Calgary did not take issue with the forecast for the other rate classes.

ATCO noted that AUMA/EDM did not file evidence and did not take issue with the forecast, and that the CG did not file evidence but, in Argument, took issue with the forecast for each rate class with the exception of Irrigation. ATCO took issue with the CG's position.

ATCO submitted that the evidence before the Board in this proceeding is substantive and supports the forecast filed in the Application, and that the only meaningful evidence filed by the interveners was from Calgary. ATCO noted that Calgary's evidence supports the forecast for the residential and small commercial/apartment rates classes, which represent the majority of the revenue forecast. Accordingly, ATCO submitted that the Board should approve the revenue derived from published rates schedules as filed in the Application.

ATCO was disappointed with AUMA/EDM's position that the Company had under-forecast its revenues for the test years, without providing the basis or support. ATCO submitted that the Board should disregard this assertion.

Referring to AUMA/EDM's suggestion for use of more temperature stations to normalize gas sales, ATCO stated that, although theoretically the suggestion had merit, the practicality of doing this and related impact had to be considered. ATCO stated that issues to be considered included assignment of customers to a particular weather station, determination of the number of weather stations to use, obtaining historical weather data for new temperature stations, development of

[64] Tr. p. 2731, line 18

balance point/base load values for new temperature zones, etc. ATCO questioned the benefit of such a change, indicating that the majority of customers located in the Edmonton and Calgary area fall within the two weather stations currently used, and that this was particularly true in the South where close to 80% of the customers reside in the Calgary area. ATCO pointed out that the difference noted in the Calgary area between the airport and downtown was in the range of only 1.5% annual degree days. ATCO also indicated that the significant distance from Edmonton proper made use of the Edmonton Municipal Airport data appropriate. ATCO submitted that the Board should reject this suggestion, as the end result was likely more cost with little benefit.

With respect to the method used by AUMA/EDM to introduce this change, ATCO indicated that it was obvious that some research had been done to obtain the weather data for the period referenced. ATCO submitted that it would have been helpful if AUMA/EDM had filed evidence on this issue, which at the very least, could have identified the benefit from this change and the issues could have been addressed as part of this hearing process. ATCO submitted that what is before the Board is a suggestion based on very limited cross-examination and no evidence as to the reasons for the change and the benefits for making the change. ATCO stated that the Board should resist directing ATCO to implement such a change or even to provide a study into the merits of such a change based on such meager information. ATCO believed that AUMA/EDM has a responsibility to present a reasonable case to the Board before the Board directs any actions on the part of the Company.

ATCO noted that Calgary recommended that the Board direct the Company to undertake uncertainty analysis of core variables such as the number of customers and sales per customer and provide that analysis in its future applications.

Referring to the use of t-tests by Calgary to determine whether each model showed support for the recommended forecast, ATCO considered this test useful for determining whether the forecasts from a statistical model support a recommended value. ATCO stated however, that the models presented by the Company were not used to produce final forecast numbers, but instead to assist in the development of the final forecast. In this regard, ATCO explained that based on an examination of the different model results and experience to date, judgment was used to develop the forecast for each group of customers. In response to Calgary’s support for use of the combination of judgment and mechanics in creating forecasts, and statement that the judgment must be transparent, ATCO indicated that the rationale for its forecast was provided and use of judgment in forecasting was transparent. ATCO stated that each customer group forecast explanation included discussion on how judgment influenced the recommended forecasts.

ATCO considered that use of Calgary’s uncertainty analysis on a model not intended, on its own, to pinpoint a sales per customer number, might lead to flawed conclusions about the usefulness of that model. ATCO stated that calculating prediction intervals around a forecast to produce a probable range that would cover the “true” future value might provide little use in determining a recommended forecast since, due to the nature of prediction intervals, the resulting ranges could be very wide. As stated in the response to CAL-AG-76, ATCO placed confidence in the model forecasts based on the confidence the Company has in the model equation. ATCO stated that confidence in the regression model equation comes from examining various regression statistics, performing diagnostic tests and performing accuracy tests. ATCO indicated that these statistics would be provided in future applications.

With respect to the customer forecast, ATCO noted that a statistical model is not used for forecasting customer growth. ATCO stated therefore, that no statistical uncertainty analysis could be performed, and submitted that to date, the Company had found the current method of forecasting customer growth to be more accurate than by attempting to develop statistical models.

Views of AUMA/EDM

AUMA/EDM noted that ATCO used two temperature zones for weather normalizing, a North zone and a South zone, and ATCO confirmed that it used the Calgary International Airport temperature data for the South zone and Edmonton Municipal Airport temperature data for the North zone. AUMA/EDM also noted that ATCO's witness accepted, subject to check, that the temperature at the Edmonton Municipal Airport had been 550 degree-days or about 1.5 degrees warmer than the Edmonton International Airport over the period 1971 to 2000. ATCO's witness also accepted, subject to check, that the temperature at the Glenmore Dam in Calgary and the University of Calgary were 75 degree days and 57 degree days warmer than the Calgary International Airport over the period 1950 to 1981.

AUMA/EDM noted that ATCO's witness advised that ATCO had considered using more stations in the past. AUMA/EDM indicated that AltaGas Utilities Inc. used 11 different stations to normalize its sales.

AUMA/EDM considered that the temperature differences between the two weather stations to normalize sales and neighboring stations was sufficient to warrant the use of additional weather stations to normalize sales. AUMA/EDM argued that ATCO should be directed to utilize additional weather stations to normalize gas sales at the time of its next GRA.

Views of Calgary

Calgary expressed concern with the uncertainty in volumes, customers and sales per customer, which in turn, created uncertainty in revenues and earnings. Calgary believed it was apparent that ATCO did not do uncertainty analysis on its sales per customer forecast. Calgary recommended that the Board direct ATCO in future applications, to undertake uncertainty analysis of core variables such as the number of customers and sales per customer and to provide that analysis in its application.

Views of the Board

The Board notes AUMA/EDM's suggestion for use of more temperature stations to normalize gas sales, indicating that AltaGas Utilities Inc. used 11 different stations to normalize sales, compared to ATCO's use of only two. In particular, the Board notes that, in making this suggestion, AUMA/EDM cited temperature differences at particular locations in each of the two zones as reasons for the use of additional weather stations at each location.

The Board acknowledges that it should be expected that the differing weather patterns in Lethbridge, Grande Prairie, Red Deer, and Fort McMurray, compared to Calgary (International Airport) and Edmonton (Municipal Airport), might influence the outcome of sales forecasts and revenue normalization.

However, the Board acknowledges ATCO's submission that the suggestion before the Board is based on very limited cross-examination and evidence with respect to the reasons for the change and related benefits. The Board notes ATCO's position that, while the suggestion had merit, the cost of developing and using additional temperature zones would outweigh any potential benefits.

Based on the foregoing and acknowledgement of ATCO's statement that temperatures in Edmonton and Calgary affect the majority of customers, the Board does not consider the addition of new weather stations in the normalization process to be a priority item. However, in order to gain an appreciation of the significance of any difference, the Board directs ATCO, in its next GRA, to file weather information for the above four additional locations that have at least 20 years worth of temperature data, and to compare the degree-days (20-year average) for each area and demonstrate the significance or insignificance of using additional weather stations as compared to using only Calgary and Edmonton.

With respect to Calgary's suggestion that ATCO undertake an uncertainty analysis to establish confidence in sales forecasts, the Board notes that ATCO questioned the usefulness of such a model, and indicated that information provided in future applications would include regression statistics designed to provide confidence in the regression model equation.

The Board accepts ATCO's response to this issue, and considers that the provision of additional information including regression statistics at the next GRA will provide the opportunity for parties to re-evaluate the usefulness and merit in conducting uncertainty analysis to enhance the level of confidence in sales forecasts.

7.1.1 Sales Forecast Methodology

Views of ATCO

ATCO noted that in Decision 2001-96, the Board considered the sales forecasting methodology used by AGS reasonable and accepted the Company's forecast based on the regression methodology used. Therefore, ATCO stated that it would continue to use regression analysis as one of the Company's near-term forecasting tools. ATCO developed and utilized the following methodologies to assist in the development of its sales forecast.

1. Average Trend
2. Vintage Model
3. Multiple Regression Model
4. Individual Customer Analysis

ATCO noted that the Board directed AGS to provide a discussion and clear rationale to support the weighting methodology applied at the next GRA. ATCO submitted that it did not believe that development of a precise weighting methodology was appropriate. ATCO submitted that each methodology provides information that assists in the development of a forecast for each customer group. Based on an examination of the different model results and experience to date, judgment is utilized to develop the forecast for each group of customers. ATCO provided the rationale for the recommended forecast developed for the Application.

Vintage Model

Views of ATCO

ATCO stated that the purpose of the Vintage model is to allow the forecaster some insight into the impact of new home construction, conservation measures, and improvements in furnace efficiencies, on the sales per customer forecast. ATCO pointed out that this insight is used along with other forecasting models and, most importantly, judgment to determine an appropriate sales per customer forecast. ATCO indicated that the Vintage analysis displays, quite clearly, that the sales per customer changes from year-to-year and that there is a steady decrease in sales per customer over an extended period of time, and also allows some indication as to the approximate floor of the decrease in sales per customer.

ATCO stated that the Vintage Model is an approach that gives equal weight to a declining series of trends, and attempts to capture the impacts of recent efficiency improvements in the housing stock. ATCO stated that the real value of this approach is the insight gained and ultimately utilized in a final determination of the sales per customer forecast.

Views of Calgary

Calgary submitted that the vintage model technique was not appropriate and should not be used for two reasons. The first was that it did not make full use of the available data and second, there was an implied but untested hypothesis of structural change.

Average Trend Model

Views of ATCO

ATCO noted that the Average Trend Model is a less sophisticated approach then the other forecasting models, and similar to the Vintage Model. ATCO noted that, while the Vintage Model analyzes each individual customer and allocates those customers to a particular vintage, the Average Trend Model analyzes total consumption. ATCO pointed out that the forecasting approach is similar in that a declining series of trends is averaged to yield a sales per customer forecast.

Views of Calgary

Calgary submitted that this unique technique was inappropriate and repeated its comments and recommendation made with respect to the Vintage Model.

Calgary was supportive of ATCO's use of the combination of judgment and mechanics in creating forecasts. However, Calgary argued that the judgment must be transparent and the result should retain as much information as possible on the uncertainty in future sales per customer, by class. Calgary noted that the information was not currently provided by ATCO. Calgary recommended that the Board direct ATCO to routinely provide information that was supportive of all parties understanding the uncertainty in the sales forecast.

Multiple Regression Model

Views of ATCO

ATCO agreed with Calgary that misspecification (for example, excluded variables, incorrect form of variables) is a possible reason for the presence for autocorrelation in regression models.

ATCO pointed out that when introduced in the 2001/2002 AGS GRA, the Company indicated that the model "will continue to evolve and be refined on an ongoing basis." ATCO stated that, as a part of this refinement process the Company intends to explore additional explanatory variables that may alleviate the autocorrelation problem.

ATCO stated that, while it is difficult to determine precise causes for the recent decline in sales per customer, possible explanations could include large fluctuations in the cost of gas, which might motivate the consumer to improve home insulation, upgrade its furnace, and install set back thermostats. ATCO noted that many of these efficiency improvements would be of a permanent nature and so the Company should expect to see this decline through the forecast period.

Views of the Board

The Board notes that ATCO did not provide a weighting of its forecasting methodologies as directed in Decision 2001-96 on the basis that forecasts are prepared based on an examination of the results of each model, experience to date, and application of judgment to that data. The Board also notes that Calgary did not support use of the Vintage Model or Average Trend Model, believing that they did not make full use of the available data, and considered that there needs to be transparency in use of mechanics and judgment.

The Board agrees with Calgary that application of judgment, after assessing the output from various models, is effectively a form of weighting, albeit less formulaic. The Board considers it an open question whether a formula based approach to application of judgment would make the process more transparent and predictable.

Accordingly, the Board directs ATCO, at the next GRA, to expand its description of the rationale used in applying judgment for the various customer categories.

7.1.2 Customer Growth

Views of ATCO

ATCO indicated that the forecast was based on a review of data collected from agency staff and historical and projected population and housing start data gathered from a variety of sources including Canada Mortgage and Housing Corporation. ATCO noted that historically, 95% of the customer growth was in the residential sector and 5% was non-residential.

ATCO explained that growth was not forecast for transportation rate classes since, for the most part, they are customer transfers from sales service.

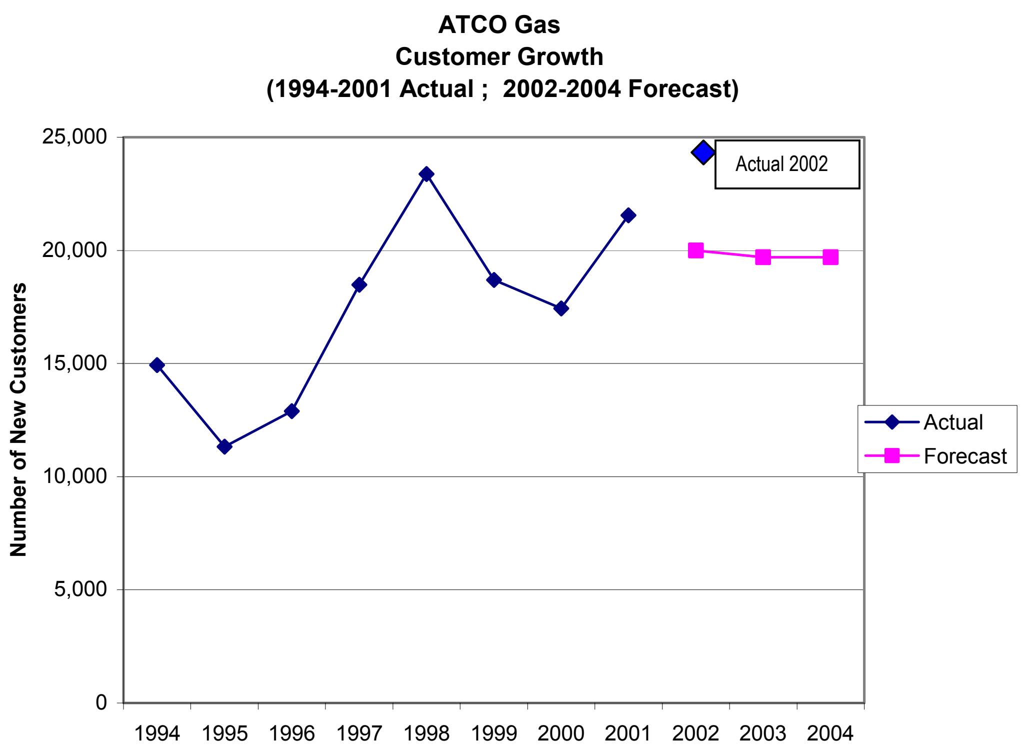
ATCO submitted the chart below to provide a historical and forecast view of the overall customer growth.

ATCO agreed with Calgary that the number of customers is an essential aspect of forecasting future volumes, but did not agree with Calgary's assertion that the Company's current method of forecasting customers is not transparent. ATCO submitted that to the contrary, ample evidence was provided in the Application and through subsequent information responses that clearly showed how the customer growth forecasts were derived. ATCO cited information in responses to CG-AG-101, CAL-AG-75 and in Section 5.1.1 of the Application to support this position.

ATCO referred to Decision 2001-96 with respect to the AGS 2001/2002 GRA, where the Board noted that none of the interveners expressed any concern with the forecast of customer growth, and considered the methodology adopted by the Company to be reasonable. ATCO noted that Calgary did not propose alternative forecasting methodologies, and submitted that the current methodology is still a reasonable approach to use to forecast customer growth.

ATCO considered the CG's argument with respect to forecast residential revenue a classic case of "having your cake and eating it too," by stating on the one hand, that 2002 actual information should be used to establish the customer forecast for the test years, but on the other hand, stating that the sales per customer forecast should be disregarded. ATCO stated that the Board should disregard such obvious "cherry picking."

Table 21. Customer Growth Chart



Views of Calgary

Calgary argued that ATCO's current method of forecasting customers was not transparent, and did not provide information on the likely range or probability of future number of customers.

Views of the CG

The CG argued that ATCO had significantly underestimated actual 2002 residential growth in its filing. Specifically the CG stated that in 2002, ATCO had under forecast Northern residential additions by 3,387 or 40% and Southern residential additions by 1,755 or 17%. The CG considered that since residential customers represented over 90% of ATCO customers, it was important to accurately forecast customer additions. The CG believed that the best available information with respect to opening balances for customer numbers should be used for the test years. Accordingly, the CG submitted that it would be more appropriate to use 2002 actual customers as the base for the 2003 and 2004 residential customer forecast and that ATCO should be directed to update its customer forecasts accordingly.

Views of the Board

The Board notes that the CG believed it appropriate to have ATCO alter its forecast growth for residential customers to be more in line with actual experience for 2002, where actual growth was significantly more than forecast.

While acknowledging the logic in the CG's argument, the Board questions the appropriateness of focusing on the results of a single year, in the absence of information on the trend of variances over a longer period. The Board is also concerned that the proposal does not take account of the fact that an increase in customers over forecast should result in an increase in the requirement for service lines and main extensions. The Board notes that this situation was apparent in 2002 when the increase in customer growth compared to forecast was accompanied by an increase in capital costs for service lines and mains. The Board recognizes that, where the customer forecast is exceeded, there will be a resulting increase in revenue, which in turn will be offset to some extent by an increase in capital expenditures compared to forecast.

The Board therefore does not accept the CG's position that ATCO should alter its growth forecast for residential customers, given the single-year focus, and that an increase in customer growth cannot be considered in isolation from related adjustments to capital expenditure forecasts, which have not been discussed in this proceeding. Accordingly, the Board approves ATCO's customer growth forecasts as filed.

7.1.3 Residential Sales

Views of ATCO

ATCO submitted that residential customers represented over 90% of total ATCO customers. This customer group includes single family and multi-family dwellings (having fewer than five units). 95% of these customers utilize between 50-250 GJ annually. The gas usage of these customers is very temperature sensitive. Major factors that affect average sales per customer for this customer group include the following:

- efficiency improvements in existing homes (shell and equipment improvements) brought on by the need to replace (e.g., furnace breaks down because of age);
- efficiency improvements in existing homes (shell and equipment improvements) brought on by financial need or environmental need to conserve energy, (e.g., high gas bills, lower emissions);
- new efficient housing construction, and
- characteristics of the occupants (e.g. energy conservation habits, whether anyone is at home during the daytime, renter vs. owner, number of people in household).

ACTO submitted the following two tables showing the residential forecast throughput for the North and South zones respectively:

Table 22. North Zone Residential Sales Forecast (Section 5.10, Table 5.4a)

	Actual	Forecast		
	2001	2002	2003	2004
Sales Per Customer	141.0	139.5	138.0	136.5
Change		-1.5	-1.5	-1.5
Throughput (TJ)	52,727	53,331	53,970	54,528

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 23. South Zone Residential Sales Forecast (Section 5.11, Table 5.4a)

	Actual	Forecast		
	2001	2002	2003	2004
Sales Per Customer	136.2	135.0	133.0	131.0
Change		-1.2	-2.0	-2.0
Throughput (TJ)	51,371	52,323	52,895	53,440

2001 figures are weather adjusted using the 20-year average (1980-1999).

With respect to the sales per customer forecast, ATCO suggested that the Board should disregard the attempt of the CG to introduce significant and detailed evidence in Argument. ATCO considered that the CG's entire discussion on energy conservation, rate of change, furnace efficiency and impacts of high gas prices should have been filed as evidence and would have allowed ATCO and the Board to test the validity of these claims. ATCO submitted that there was no evidence on the record in these proceedings to support the CG's assertions.

ATCO provided examples of unsubstantiated statements, which included conclusions that the rate of change in residential consumption must slow as the percentage of old housing stock decreases, as percentage of the total building stock, efficiency improvements from furnace changes are unlikely to be significant as in previous years, and that customers likely to adjust their occupancy characteristics had done so and no greater efficiency characteristics were likely.

ATCO took issue with these tactics at this point in the proceedings, and pointed out that only Calgary filed meaningful evidence and concluded that the sales forecast to be reasonable. ATCO also pointed out that the 2002 actual information should be regarded as a test of the reasonableness of the sales per customer forecast methodology, indicating that the forecast for the South zone was in essence exactly equal to actual and that in the North the forecast was above actual, which disproved what the CG claims. ATCO submitted that based on the evidence, the Board should approve the forecast as filed in the Application.

ATCO noted that Calgary was prepared to accept the forecast of residential sales.

Views of Calgary

Calgary accepted the current forecast of residential sales. However, Calgary recommended that the Board should direct ATCO to further improve its forecasting techniques and provide statistical analysis to support its forecast of customer numbers in future applications.

Views of the CG

The CG argued that the 2002 estimate was heavily influenced by twelve-month rolling data and that the recommendation for consumption was judgmental, based on three methods (Average Trend, Vintage Model and Multiple Regression Model).

The CG noted that ATCO maintained that its application should be examined as of the date it was prepared, on a prospective basis. The CG agreed with this approach believing that forecasts of average consumption should be based on analysis of trends rather than single year data.

The CG was concerned with the use of a forecast method that assumed the rate of change in prior years would be the same rate of change as that in future years, particularly where historical evidence did not suggest stable growth or declines. In particular, the CG argued that the rate of change in residential consumption must decrease as the percentage of old housing stock, built with older building standards, decreases as a percentage of the total building stock. The CG further argued that efficiency improvements from furnace changes were unlikely to be as significant as in previous years and the effect of going from a 50 to 60% efficient furnace to an 85% to 95% would be greater than the next increase in furnace efficiency.

The CG submitted that the largest driver of gas usage for residential consumption was heating and at best, a furnace could only provide the heat content of the natural gas. The CG argued that, while technology allowed the movement of furnace efficiency from 55% to 95%, the movement from 95% to 100% would not affect residential sales per customer as significantly as earlier efficiency changes and therefore, the rate of future change must necessarily decrease.

The CG submitted that for the most part, customers that were likely to adjust their occupancy characteristics had done so and no greater efficiency characteristics were likely. Further, those individuals concerned about environmental issues surrounding emissions or excessive energy use would likely have taken steps to reduce their consumption already.

The CG argued that high gas prices had already forced customers to take drastic steps to reduce their consumption of natural gas. The CG believed that an expectation that declines in consumption would continue at previous levels would only result in under forecasting of residential consumption with benefits to shareholders and unnecessary costs to consumers.

The CG noted that ATCO provided a residential forecast for AGN and AGS, in its response to an information request[65] from Calgary:

Table 24. Ten-Year Trend Line

Residential Forecast Based on Ten-Year Trend Line			
	2002	2003	2004
AGN Residential	141.6	140.2	138.8
AGS Residential	137.1	135.4	133.6

The CG believed that it was reasonable to use a residential sales forecast based on the Ten-Year Trend Line provided by ATCO and that it should be given significant weight when reviewing the residential sales forecast. The CG argued that the forecast was more conservative than the one prepared by ATCO as it slowed the rate of change for the test periods.

[65] CAL-AG-97

Views of the Board

With respect to the residential forecast based on a Ten-Year Trend Line analysis provided by ATCO in response to CAL-AG-97, the Board notes that the CG recommended that the analysis should be given significant weight in determination of the residential sales forecast. The Board notes that ATCO viewed this recommendation as "cherry-picking" on the basis that the CG recommended use of 2002 actual information to establish the customer forecasts, while indicating that the sales per customer estimate for 2002 should be disregarded given that it was heavily influenced by 12-month rolling data. In this regard, the Board acknowledges ATCO's position that actual sales per customer for 2002 were below forecast for the North, almost equal in the South and below the AGS 2001/2002 GRA forecast.

The Board considers that the 2002 results tend to support ATCO's reliance on twelve-month rolling data, and acknowledges ATCO's submission that the CG's proposal should have been presented in evidence to allow parties to test the validity of these claims. Accordingly, the Board does not accept the CG's proposal for more emphasis on the Ten-Year-Trend Line analysis, and expects that introduction of issues of this nature by interveners earlier in the process will facilitate more comprehensive review and discussion in future rate cases.

7.1.4 Commercial Sales

Views of ATCO

ATCO submitted that Commercial Sales included the following customer groups, small apartment, large apartment, small commercial and large commercial. Each of the customer groups had been forecast independently. Small apartment and small commercial included those customers with an annual consumption less than 8 TJ's (Rate 1), while large apartment and large commercial included customers with an annual consumption in excess of 8 TJ's (Rate 3). All forecast sales figures were restated on the temperature base (1982-2001) and the forecast for Commercial sales customers were done by zone.

The following tables were submitted by ATCO for each of the customer categories for both North and South zones:

Table 25. North Zone Small Apartment Sales Forecast (Section 5.10, Table 5.5a)

	Actual	Forecast		
	2001	2002	2003	2004
Sales Per Customer	1,563.9	1,565.0	1,565.0	1,565.0
Change		+1.9	0	0
Throughput (TJ)	6,437	6,488	6,549	6,599

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 26. North Zone Large Apartment Sales Forecast (Section 10, Table 5.5b)

	Actual	Forecast		
	2001	2002	2003	2004
Throughput (TJ)	2,373	2,146	2,112	2,112

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 27. South Zone Small Apartment Sales Forecast (Section 5.11, Table 5.5a)

	Actual	Forecast		
	2001	2002	2003	2004
Sales Per Customer	1,520.4	1,525.0	1,525.0	1,525.0
Change		+4.6	0	0
Throughput (TJ)	3,861	3,878	3,916	3,943

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 28. South Zone Large Apartment Sales Forecast (Section 5.11, Table 5.5b)

	Actual	Forecast		
	2001	2002	2003	2004
Throughput (TJ)	1,640	1,495	1,532	1,532

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 29. North Zone Small Commercial Sales Forecast (Section 5.10, Table 5.5c)

	Actual	Forecast		
	2001	2002	2003	2004
Sales Per Customer	757.2	745.0	742.5	740.0
Change		-12.2	-2.5	-2.5
Throughput (TJ)	28,393	28,459	28,822	29,159

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 30. North Zone Large Commercial Sales Forecast (Section 5.10, Table 5.5d)

	Actual	Forecast		
	2001	2002	2003	2004
Throughput (TJ)	15,400	13,783	13,666	13,666

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 31. South Zone Small Commercial Sales Forecast (Section 5.11, Table 5.5c)

	Actual	Forecast		
	2001	2002	2003	2004
Sales Per Customer	754.0	740.0	737.5	735.0
Change		-14.0	-2.5	-2.5
Throughput (TJ)	21,462	21,378	21,642	21,891

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 32. South Zone Large Commercial Sales Forecast (Section 5.11, Table 5.5d)

	Actual	Forecast		
	2001	2002	2003	2004
Throughput (TJ)	11,719	10,383	10,504	10,664

2001 figures are weather adjusted using the 20-year average (1980-1999).

ATCO had the same comments with respect to the suggestion of the CG regarding the Small Commercial/Apartment customer forecast, noting that the forecast 2002 year end customers for this rate class was out by only 13 (0.03%) for the North and 176 (0.61%) in the South. ATCO noted that the CG did accept the sales per customer forecast, and submitted that based on the evidence, the Board should approve the forecast as filed in the Application.

ATCO again took serious issue with the obvious introduction of detailed new evidence through Argument by the CG.

ATCO expressed concern that neither the Company nor the Board were afforded an opportunity to cross-examine witnesses on this evidence, and indicated that the CG could have sponsored this alternate forecast methodology and provided a witness to speak to it. ATCO considered the material on page 136 of the CG Argument in essence an alternate forecasting methodology that had not been afforded the testing by the Board or ATCO through information requests or cross-examination.

ATCO believed it would be inappropriate to direct the Company to re-file based on an untested methodology, which should have been filed at the appropriate time. ATCO considered that the Board should use the facts properly on the record to test the forecast.

ATCO believed that 2002 actual information was requested to test the reasonableness of the forecast methodology, and submitted that the forecasting methodology used by the Company to forecast revenues for this rate class produced accurate results. ATCO pointed out that this is demonstrated by the fact that the forecast revenues for Rate 3/13 were out by only $62,000, noting that the majority of the revenue derived from this rate class is based on demand not throughput. ATCO stated therefore that the magnitude of throughput that is under/over forecast is not as material as the forecast for the demand. ATCO submitted that based on the evidence, the Board should approve the forecast as filed in the Application.

ATCO noted that Calgary was prepared to accept the forecast of commercial sales.

Views of Calgary

Calgary noted that the forecast sales per customer appeared to be somewhat (mildly) low and noted that the odds were greater that actual would exceed forecast. As a result, without prejudice for future applications, and until further information was available, Calgary was prepared to accept the forecast of commercial sales.

Views of the CG

Small Commercial

The CG noted that the forecasting method used by ATCO for small commercial customers appeared to produce reasonable results when measured against actuals for 2002. Therefore, the CG recommended acceptance of ATCO's forecast of small commercial sales for the two test years. Consistent with the CG's recommendation on the use of 2002 actual customer base, the CG also recommended that the opening customer balance for small commercial be reduced to reflect the 2002 actual year-end customer number of 67,612 in place of the 67,801 for purposes of forecasting 2003 and 2004 customers and sales.

Large Commercial

The CG argued that since economic growth likely affected small commercial and large commercial customers alike, it was unlikely the large commercial growth in sales would be lower than small commercial growth during the test years.

The CG noted that although some of the reduction in consumption per customer might be attributed to smaller customers from Rate 1 moving to Rate 3, such movement alone did not explain the decrease in consumption per customer. For example the CG noted, if one assumed that the increase of 37 customers from 2001 to 2002 forecast for AGN was all attributable to small customers with consumption of 8000 GJ per year (i.e. the threshold for moving to Rate 3), removing the effect of these small customers moving to Rate 3 still left the 2002 forecast average consumption per customer lower than 2001 actual.

The CG argued that Exhibits 13-37 for AGN and 13-38 for AGS showed large commercial sales would be higher if historical trends were used to forecast the test year average customers, average consumption per customer and sales. The CG argued that there would be an increase in revenues for AGN of $281,000 and $238,000 in 2003 and 2004, respectively and for AGS of $355,000 and $444,000 in 2003 and 2004, respectively. The CG stated that an average rate revenue of $0.55 was used to calculate the revenue impact and reflected both the energy and demand components of Rates 3/13. The CG submitted that the revenue impact of any change in sales should include the demand and energy components since this would reflect the fact that, if load factor for the class was relatively stable, any increase in gas sales should be accompanied by a corresponding increase in demand units. In this respect, the CG argued that ATCO had understated the revenue impact of sales volume variation by reflecting only the energy components of applicable rates.[66]

The CG noted that the above analysis was only illustrative of the order of magnitude of under-forecasting of large commercial sales revenue. It was CG's submission, that ATCO's method of forecasting large commercial sales based on "an individual review of the consumption data for Rates 3 and 13 customers" was highly subjective, considering that the forecast must consider individual consumption for some 1500 customers. The CG pointed out that the 2002 actual results for large commercial sales varied materially from the forecast and produced a variance of 3.4% for AGN and 7.0% for AGS. The CG argued that the 2002 actual results showed that some form of trending would have produced a 2002 forecast closer to the actual. The CG calculated the variance using trending would have been -0.2% for AGN and 3.4% for AGS.

The CG submitted that ATCO should be directed to provide and include a revised forecast of large commercial sales and sales revenue for AGS and AGN based on trending of average customers and average consumption per customer and the complete analysis referred to ATCO's witness in its refiling. Specifically, this revised forecast should use the trending method discussed by the Company's witness to first forecast the 2002 sales for large commercial customers and develop a realistic forecast for 2003 and 2004 also based on trending methods comparable to those used for small commercial.

The CG further stated that similar to large commercial customers, large apartments were also essentially space heating customers. Accordingly, the CG recommended that the trend analysis

[66] Tr. p. 993; line 2

method discussed above for large commercial be used to forecast large apartment sales for 2002, 2003 and 2004.

Views of the Board

The Board notes the CG suggestion that ATCO should be directed to provide a revised forecast for large apartment and commercial customer growth based on a trending of average customers and average consumption per customer. The Board acknowledges ATCO's concern that the CG's suggested approach had not been introduced prior to written argument, and that parties were not afforded the opportunity to properly examine and test this new evidence.

The Board notes that 2002 actual sales per customer were close to forecast for these classes, which tends to support ATCO's position that the test year forecasts are reasonable. The Board therefore, does not accept the CG's proposal and expects that introduction of issues of this nature by interveners earlier in the process will facilitate more comprehensive review and discussion in future rate cases.

7.1.5 Industrial Sales

Views of ATCO

ATCO indicated that Industrial sales included Small Industrial Rate 1 customers that consumed less than 8 TJ's per year, and Large Industrial Rate 3 customers that use more than 8 TJ's per year. ATCO stated that these customers were not temperature sensitive and their energy requirements were primarily for production processes rather than space heating and therefore annual throughput was relatively steady.

Table 33. North Zone Small Industrial Sales Forecast (Section 5.10, Table 5.6a)

	Actual	Forecast		
	2001	2002	2003	2004
Throughput (TJ)	193	171	180	186

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 34. North Zone Large Industrial Sales Forecast (Section 5.10, Table 5.6b)

	Actual	Forecast		
	2001	2002	2003	2004
Throughput (TJ)	2,267	2,260	1,705	1,705

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 35. South Zone Small Industrial Sales Forecast (Section 5.11, Table 5.6a)

	Actual	Forecast		
	2001	2002	2003	2004
Throughput (TJ)	174	157	174	174

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 36. South Zone Large Industrial Sales Forecast (Section 5.11, Table 5.6b)

	Actual	Forecast		
	2001	2002	2003	2004
Throughput (TJ)	2,481	2,206	1,985	1,985

2001 figures are weather adjusted using the 20-year average (1980-1999).

ATCO Gas noted that the CG found the forecast revenue for industrial customers to be reasonable, and submitted that based on the evidence, the Board should approve the forecast as filed in the Application.

ATCO noted Calgary did not take issue with the Industrial Sales forecast.

Views of the CG

The CG agreed that individual forecasts for industrial customers were appropriate. However, the CG was concerned that ATCO's forecasting method appeared to ignore potential customer additions and growth.

The CG noted that ATCO's forecast of sales for large industrial customers for the test years appeared to be in line with prior year actuals. Accordingly, the CG considered that the forecast sales and revenues for industrial customers was reasonable.

Views of the Board

The Board finds the industrial sales forecasts reasonable, and accepts ATCO's forecasts as filed, noting that none of the interveners expressed any concern with the forecasts.

7.1.6 Irrigation Sales

Views of ATCO

ATCO provided the table below summarizing forecast average customers, peak customers and annual throughput for irrigation. Irrigation Rate 5 service is provided in the South zone only. ATCO submitted that irrigation throughput is not temperature dependant; therefore, the figures shown in the tables are not adjusted for weather.

Table 37. Irrigation Sales Forecast – Average and Peak Customers and Annual Throughput (Section 5.7, Table 5.7b)

	Forecast		
	2002	2003	2004
Average Customers	693	693	693
Peak Customers	1,617	1,617	1,617
Throughput (TJ)	787	787	787

2001 figures are weather adjusted using the 20-year average (1980-1999).

ATCO noted Calgary did not take issue with Irrigation Sales.

Views of the Board

The Board finds the irrigation sales forecasts reasonable, and accepts ATCO's forecasts as filed, noting that none of the interveners expressed any concern with the forecasts.

7.1.7 Distribution Transportation

Views of ATCO

ATCO stated that Distribution Transportation included both commercial and industrial Rate 13 customers. These customers utilize more than 8 TJ's annually. All customers in this group include customers that have been transferred from Rate 3 sales service to Rate 13 transportation service. The forecast was based on the historical records of the Rate 13 customers as of April 2002. Forecasts for these customers were developed by zone.

ATCO provided the following forecast for both North and South zones:

Table 38. North Zone Commercial Transportation Service Forecast (Section 5.10, Table 5.8a)

	Actual	Forecast		
	2001	2002	2003	2004
Y/E Customers	154	186	186	186
Throughput (TJ)	1,538	3,325	3,372	3,372
Annual Contract Demand (TJ)	114	251	234	234

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 39. North Zone Industrial Transportation Service Forecast (Section 5.10, Table 5.8b)

	Actual	Forecast		
	2001	2002	2003	2004
Y/E Customers	38	39	39	39
Throughput (TJ)	2,743	3,500	3,492	3,492
Annual Contract Demand (TJ)	143	173	180	180

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 40. South Zone Commercial Transportation Service Forecast (Section 5.11, Table 5.8a)

	Actual	Forecast		
	2001	2002	2003	2004
Y/E Customers	123	144	144	144
Throughput (TJ)	4,519	5,993	5,740	5,740
Annual Contract Demand (TJ)	212	342	348	348

2001 figures are weather adjusted using the 20-year average (1980-1999).

Table 41. South Zone Industrial Transportation Service Forecast (Section 5.11, Table 5.8b)

	Actual	Forecast		
	2001	2002	2003	2004
Y/E Customers	58	59	59	59
Throughput (TJ)	7,091	7,009	7,302	7,302
Annual Contract Demand (TJ)	326	359	360	360

2001 figures are weather adjusted using the 20-year average (1980-1999).

ATCO noted Calgary did not take issue with the Distribution Transportation forecast.

Views of the Board

The Board finds the Distribution Transportation service forecasts reasonable, and accepts ATCO's forecasts as filed, noting that none of the interveners expressed any concern with the forecasts.

7.2 Other Revenue

ATCO provided the following table to summarize all other revenue for both North and South for the test years.

Table 42. Other Revenue Forecast (Section 5.9, Table 5.9a)

	2003 Forecast			2004 Forecast		
	North	South	Total	North	South	Total
Affiliate						
ATCO Midstream Storage	-	8,209	8,209	-	8,243	8,243
ATCO Pipelines	4,334	1,511	5,845	4,413	1,545	5,958
Other Affiliates	2,203	1,687	3,890	2,246	1,718	3,964
Total Affiliate	6,537	11,407	17,944	6,659	11,506	18,165
Production Related	104	357	461	100	349	449
Penalty	4,230	3,774	8,004	4,136	3,801	7,937
Jobbing	502	618	1,120	517	637	1,154
Facility Repairs	405	377	782	417	388	805
Service Fees	476	357	833	540	387	927
Other	810	735	1,545	718	619	1,337
COS Transfer to DGA*	(1,139)	(902)	(2,041)	(1,046)	(855)	(1,901)
Total	11,925	16,723	28,648	12,041	16,832	28,873

*Note: COS Transferred to the DGA omitted in original filing.

ATCO noted that none of the interveners filed evidence to refute the Other Revenue forecast or took issue with the Other Revenue forecast in Argument (with the exception of the City of Calgary in Section 4.2.13 of its Argument). ATCO submitted that the Board should approve the Other Revenue forecast as filed in the Application.

Views of the Board

The Board notes that none of the interveners expressed any concern with the forecasts for Other Revenue and accepts ATCO's forecasts as filed.

8 OTHER MATTERS

8.1 Procedural Matters

Views of the Board

The Board notes that in argument and reply, ATCO, Calgary, AUMA/EDM, and the CG raised concerns relating to issues such as the consistency of Board rulings on procedural issues among different Board proceedings, the efficiency or inefficiency of the Information Request process, and the use of aids to cross-examination and Opening Statements in Board proceedings. Calgary also commented on these issues in the oral overview of its argument at the hearing on May 21,

2003. While the Board welcomes feedback regarding the efficiency of its processes, the Board was surprised to receive this feedback in the context of argument and reply on a particular proceeding.

A number of the concerns raised by parties related to the potential cost implications of the Information Request process, and the use of aids to cross-examination and Opening Statements. Ordinarily, the Board would expect parties to provide these comments in the context of the Board's costs process. In all proceedings, the Board sends a letter to interested parties inviting comments on costs claims submitted, and in this case that letter was dated August 12, 2003. For this proceeding, the Board has transferred comments regarding costs contained in argument and reply to the Board's costs file with respect to the GRA so that parties do not have to resubmit their comments in that context.

With respect to the feedback provided by parties on the issue of consistency of Board rulings on procedural issues, the Board notes that the circumstances of each particular case are unique and that in each case, the presiding panel must rule based on the facts before it. This was recognized by the Chairman in the current proceeding on March 11, 2003, when he stated, with respect to a ruling regarding the introduction of new evidence under the guise of an aid to cross-examination, "...we're not going to suggest that some simple aids aren't sometimes appropriate. Unfortunately, it's often a question of looking at the circumstances of each individual situation."[67] However, the Board will consider internally the comments made by parties and will consider whether it is appropriate to develop an internal collection of Board rulings.

9 SUMMARY OF BOARD DIRECTIONS

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

1. Based on the foregoing, the Board directs ATCO, in refiling its GRA to reflect the results of this Decision, to file the revenue requirement separately for North and South. The Board therefore expects that the outcome of this Phase I process will be the setting of separate revenue requirements for North and South, and that separate rates could be set for North and South in the subsequent 2003/2004 Phase II. The Board considers that before a single revenue requirement is implemented, ATCO must be able to demonstrate harmonization in accounting treatment in the North and South by resolving differences in treatment of issues such as no-cost capital, negative salvage, COP facilities and the Carbon reservoir. In addition, the Board considers that ATCO needs to propose a methodology in the rate design process to address any residual cross-subsidization issues between North and South. 12
2. However, despite the direction to determine separate revenue requirements for the North and South, the Board does not see the need for separate rate applications for North and South pending the establishment of a single revenue requirement. Accordingly, pending establishment and approval of a single revenue requirement in this or subsequent proceedings, the Board directs ATCO to file future applications for revisions to North and South rates in a single GRA. 12

[67] Tr. p. 259

33. Based on a risk-free rate of 6.0% and an equity risk premium of 3.0%, the bare-bones equity rate of return is 9.0%. Adding 50 basis points to account for a flotation cost allowance, the final equity rate of return increases to 9.5%. Accordingly, the Board approves a fair rate of return on common equity of 9.5% for ATCO for the test year 2003-2004 and directs ATCO to revise the test year forecasts to reflect the rate of 9.5%. 123

34. Accordingly, Board directs ATCO to maintain a common equity ratio of 37% for the test years, in line with the common equity ratio last approved in Decision 2001-96................. 138

35. The Board considers that these lower inflation factors are more consistent with the majority of evidence on the record and referred to specifically by AUMA/EDM, and agrees with the AUMA/EDM proposal for application of a 3.25% rate as a reasonable escalation factor to determine the labour forecasts for the test years. Accordingly, the Board directs ATCO to adjust its labour forecasts to reflect a 3.25% labour inflation rate...................................... 154

36. Accordingly, the Board directs ATCO to adjust its test year labour forecasts to reflect a vacancy rate of 6%. The Board expects ATCO to apply this rate to all areas after separating out capital related staffing and adjusting for the level of FTE's relative to projects, such as MRRP, that may be affected by this Decision. 160

37. The Board directs ATCO, in its Refiling, to revise the calculation of forecast O&M labour expense for the test years after application of the findings with respect to the inflation rate, vacancy rates and final FTE numbers as determined in this Section of the Decision. The Board also expects ATCO to revise the capital component of the labour forecasts to reflect the conclusions in this Section of the Decision, and in other Sections dealing specifically with staffing for new programs. 160

38. The Board also directs ATCO, in future GRAs, to present support for the determination of forecast FTEs setting out the relationship to customer growth, throughput and productivity or efficiency as a starting point, before reflecting any increase in response to new projects or other drivers. 161

39. Given the overwhelming opposition to ATCO's proposal for monthly meter reading, the Board questions the need to significantly increase costs to customers who apparently have little concern with the present level of service. The Board agrees with interveners that the need for reading meters on a monthly frequency has not been demonstrated at this time. Accordingly, the Board directs ATCO to revise each of the test year forecasts for the meter reading program to reflect the costs of reading meters every two months. 171

40. Given the historical experience, customer growth, the use of AMR, productivity gains and relevant inflationary factors, the Board directs ATCO, in the Refiling, to indicate with appropriate supporting evidence, the number of meter readers required in the North and South in light of the Board's conclusions with respect to meter reading frequency. 171

41. The Board therefore directs ATCO to decrease O&M test year forecasts to recognize direct and indirect labour costs, associated fringe benefits, supply costs related to the reduction in the number of meter readers, and to reduce all capital costs related to additional hand held meter reading equipment and vehicles to the level required to accommodate the appropriate level of staffing consistent with this Decision. 172

42. Accordingly, the Board directs ATCO to provide in future GRAs, details of all retirements from regulated operations since the preceding GRA, specifying years worked in regulated and non regulated divisions, the related chronology and the total number of years of employment used for pension purposes. 174

43. The Board directs ATCO to re-examine the treatment of the deferred pension balance in the next GRA and provide a detailed explanation and rationale for treatment of the pension plan surplus. 175
44. Accordingly, the Board directs ATCO to recover the one-time hearing expense in amount of \$3.4 million in the South and \$2.9 million in the North effective January 1, 2004. However, noting that the actual closing balance for 2002 was \$1.8 million less than forecast in the South, the Board directs ATCO to identify in the Refiling, any further adjustments that might be necessary to ensure equalization of North and South 2004 closing balances. 180
45. In view of the exclusion in the UCA, and the escalation in the level of legal fees charged to the reserve, and notwithstanding the findings in Decision E93004, the Board directs ATCO at the next GRA, to clarify its operating procedures with respect to the reserve with particular reference to legal fees, and provide an appropriate description of the legal fees charged against the reserve to ensure that expenses are prudently included. 184
46. Accordingly, the Board directs ATCO, in the Refiling, to revise the test year forecasts for Account 701 to \$3 million in each test year, appropriately allocated between North and South. 191
47. Accordingly, the Board directs ATCO, in its Refiling, to adjust the test year forecast for ATCO I-Tek Business Services to reflect the 11.1% reduction to rates approved in Decision 2002-069. 193
48. As indicated in Section 2.3.1 of this Decision, the Board does not accept ATCO's proposal for capitalization of administrative expense, and directs ATCO to adjust capital and O&M test year forecasts to reflect the re-instatement of the \$6.5 million to Administration and General Expense, adjusted for the reduction to labour increases as directed elsewhere in this Decision. 194
49. Based on this conclusion, the Board notes that the adjusted forecast for O&M expense (before adjustments to labour increases) in the test years will be \$57.518 million (2003), and \$58.233 million (2004), an increase of 19.4%-20.6% over 2002 actual expense of \$48.184 million. The Board notes that the O&M test year forecasts include a placeholder for Executive Compensation, and directs ATCO, in the Refiling, to confirm the amount of the placeholder for Executive Compensation, which will now be included in full in O&M expense. 194
50. Therefore, the Board directs ATCO, in its Refiling, to stipulate the ATCO Gas 4-hour peak demand that ATCO Pipelines will use for its system design and operational planning purposes and the ATCO Gas 24-hour billing demand that ATCO Pipelines will use for its cost allocation purposes. 196
51. Accordingly, the Board directs ATCO, in its Refiling, to adjust the test year forecast for ATCO I-Tek IT Services to reflect the 7.5% reduction to rates approved in Decision 2002-069. 200
52. Accordingly, the Board directs ATCO to reduce the test year forecast I-Tek volumes (CPU minutes) to 165,996 for 2003 and 169,647 for 2004. The Board expects that the volumes, as adjusted will be confirmed subsequent to the determination of service levels, which are to be addressed in a separate Master Service Agreement benchmarking module. The Board has determined these forecast amounts, using 2001 CPU minutes of 157,538 as a reference point, adjusted by customer growth forecasts of 3.0%, 2.3% and 2.2% from 2001 to 2004 respectively. 201

53. The Board understands that ATCO purports that, for revenue requirement purposes, an extension of the former lease using the former Board approved rates is reasonable. Therefore, the Board understands that ATCO has proposed continuation of the former approved rate of $13.58 psfpa in determining the test year forecasts in this Application. The Board is prepared to accept application of the rate of $13.58 psfpa in determining head office rent expense for the test years, and will expect ATCO to provide support for a market-based rate at the next GRA. Therefore, for clarification, the Board directs ATCO, in its Refiling, to confirm the head office rental rates and the calculation of the test year forecast amounts included for sublease costs in ATCO's submissions.. 203

54. Under these circumstances, the Board directs ATCO in its Refiling, to exclude forecast energy costs in the determination of the allocation of corporate charges and use the reduced amounts to allocate corporate costs for 2003 and 2004. 207

55. Accordingly, the Board directs ATCO to revise the fringe benefit forecasts for the test years to reflect any reductions in FTEs required as a result of Board findings with respect to staffing levels in other Sections of this Decision. 212

56. The Board agrees with Calgary that detailed depreciation data files and notes should be made available when rate applications are filed to provide additional time for data analysis and more complete evaluations. Therefore, the Board directs ATCO, in its next GRA, to make available upon request, the data files in electronic format and the accompanying field notes relevant to the data. 215

57. Also, as noted by AUMA/EDM, in BR-ATCO-149, ATCO provided the impact on the revenue requirement associated with the sale of Beaverhill Lake and Fort Saskatchewan producing properties. The Board directs ATCO, in the Refiling, to show the effects of the sales of these properties on the test years' revenue requirements in the amounts of $1.759 million for 2003 and $1.574 million for 2004 and reflect revisions to these amounts for the closing date of sale on January 1, 2003. 215

58. In addition, the Board directs ATCO to reflect the applicable amount of amortization related to the loss on sale of computer equipment to ATCO I-Tek as determined by the Board in Decisions 2002-069, 2002-097, and 2003-006. 215

59. The Board however, directs ATCO, in its Refiling, to revise the Schedules in Section 4.7 of the Application to reflect the effect of adjustments required as a result of findings in other Sections of this Decision. 218

60. The Board therefore directs ATCO, in the Refiling, to advise the Board on the process adopted to identify in the accounting records, those costs capitalized, but considered by the Company to be ordinarily deductible and being deducted for tax purposes in the year incurred. 231

61. However, the Board also recognizes the benefits that ATCO realizes from the synergies of corporate costs as an affiliate of CU and directs ATCO to demonstrate in its Refiling the extent to which LCT credit benefits are shared among all affiliates in the same manner that corporate costs are allocated. 233

62. The Board agrees with Calgary that, consistent with the direction in 2001-96, the Company's tax determination should be based on tax rates announced or substantively enacted affecting the test years. The Board notes that the rates of capital tax proposed in the 2003 Federal Budget were 0.225% for 2003 and 0.200% for 2004, whereas ATCO calculated LCT using the rate of 0.225% for both years. Based on the foregoing, the Board directs ATCO in its

10 ORDER

IT IS HEREBY ORDERED THAT:

(1) ATCO Gas shall comply with all Board directions in this Decision.

(2) ATCO Gas shall refile its 2003/2004 GRA (the Refiling), as required by this Decision, on or before December 1, 2003, incorporating the findings in this Decision.

(3) In the Refiling, ATCO Gas shall include all of the supporting schedules necessary for the Board to make its final determination respecting ATCO's 2003/2004 revenue requirement. The Refiling shall be at a level of detail sufficient to reconcile with the original filing, and to demonstrate compliance with the Board's findings.

(4) With respect to certain transactions with Affiliates, as specified elsewhere in this Decision, ATCO Gas shall include in the revenue requirement for the test years, the related expenditures and revenues as filed in the Application, and adjusted in this Decision, pending final determination of these amounts in separate benchmarking studies and related proceedings. ATCO will be required to adjust the amounts included as "placeholders" in the revenue requirement for the test years, after the Board has issued decisions on these separate benchmarking studies and related proceedings.

(5) ATCO Gas shall specifically identify in the Refiling, those items included in the revenue requirement as placeholders for the test years, and their related amounts.

Dated in Calgary, Alberta on October 1, 2003.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

B. T. McManus Q.C.
Presiding Member

(original signed by)

Gordon J. Miller
Member

(original signed by)

J. I. Douglas, FCA
Member

APPENDIX 1 – HEARING PARTICIPANTS

Principals and Representatives (Abbreviations used in Report)	Witnesses
ATCO Gas (ATCO or the Company) L. E. Smith J. E. Lowe	J. Beckett D. A. Wilson L. Bruce J. Janow O. Edmondson R. Trovato M. J. O'Brien K. C. McShane
Aboriginal Communities J. Graves A. O. Ackroyd	
Alberta Irrigation Projects Association (AIPA) J. H. Unryn	
Alberta Urban Municipalities Association (AUMA) J. A. Bryan	
Canadian Forest Products Ltd (Canfor) L. L. Manning	
Consumers Coalition of Alberta (CCA) J. A. Wachowich	
Consumers Group – Comprising: Aboriginal Communities Alberta Irrigation Projects Association Alberta Urban Municipalities Association Canadian Forest Products Ltd. Consumers Coalition of Alberta Federation of Alberta Gas Co-ops/Gas Alberta Public Institutional Consumers of Alberta	G. Newcombe L. Prefontaine
Federation of Alberta Gas Co-ops Ltd and Gas Alberta Ltd. (FGA) T. D. Marriott	
Public Institutional Consumers of Alberta (PICA) N. J. McKenzie R. Retnanandan	

Principals and Representatives (Abbreviations used in Report)	Witnesses
The City of Calgary (Calgary)	
R. B. Brander	H. W. Johnson
P. L. Quinton-Campbell	J. Stephens
	L. E. Kennedy
	H. J. Vander Veen
	L. Booth
	M. Berkowitz
	J. McCormick
	K. Sharp
The City of Edmonton (Edmonton)	
J. A. Bryan	
Alberta Energy and Utilities Board staff	
B. McNulty, Board Counsel	
J. Hocking, Board Counsel	
E. J. Gallagher, C.A.	
R. Armstrong, P.Eng.	
D. Popowich, P.Eng.	
R. Litt	

APPENDIX 2 – ABBREVIATIONS

Affiliate Decision means Decision 2002-069 Asset Transfer, Outsourcing Arrangements, and GRA Issues
AFUDC means Allowance for Funds Used During Construction
AGA means American Gas Association
AGN means ATCO Gas North
AGPL means ATCO Gas and Pipelines Ltd.
AGS means ATCO Gas South
AMR means Automated Meter Reading
APN means ATCO Pipelines North
Aquila means Aquila Networks Canada Ltd.
AR 546/63 means Alberta Regulation 546/63 – General Instructions to the Canadian Gas Association Uniform Classification of Accounts for Natural Gas Utilities Under the Jurisdiction of the Public Utilities Board of the Provincial of Alberta
ASL means Average Service Life
BCUC means British Columbia Utilities Commission
Board or EUB means the Alberta Energy and Utilities Board
CAPM means Capital Asset Pricing Model
CBRS means Canadian Bond Rating Service
CCA means Capital Cost Allowance
CICA means Canadian Institute of Chartered Accountants
CIS means Customer Information System
Code means Code of Conduct
COP means Company-Owned Production
CPI means Consumer Price Index
CPP means Canada Pension Plan
CPU means Central Processing Unit
CWIP means Construction Work in Progress
CWNG means Canadian Western Natural Gas Company Limited
DASD means Data Acquisition and Storage Device
DGIS means Distribution Gas Information System
Direct Energy means Direct Energy Marketing Limited
ES&G means Engineering, Supervision and General
ESOB means East Side Operating Base
FTEs means Full-Time Equivalents
GCRR means Gas Cost Recovery Rate
GJ means Gigajoule
GOC means Government of Canada
GOC Bonds means Long-Term Government of Canada Bonds
GRA means General Rate Application
GST means Goods and Services Tax
GTA means General Tariff Applications
IT means Information Technology
LCT means Large Corporation Tax
LDC means Local Distribution Company
Long Canada Bonds means Long-Term Government of Canada Bonds
Long Canadas means Long-Term Government of Canada Bonds
LUF means Lost and Unaccounted For

MRRP means Meter Relocation and Replacement Program
NATP means Normalized All Taxes Paid
NEB means National Energy Board
NGTL means NOVA Gas Transmission Ltd.
NPV means Net Present Value
NUL means Northwestern Utilities Limited
NWC means Necessary Working Capital
O&M means Operating and Maintenance
P FTE means Permanent Full-Time Equivalents
PP&E means Property, Plant and Equipment
psfpa means Per Square Foot Per Annum
Refiling means Compliance Filing to be submitted by ATCO Gas
ROE means Return on Equity
S&P means Standard & Poor's
S FTE means Seasonal Full-Time Equivalents
SCADA means Supervisory Control and Data Acquisition
T-Bills means Treasury Bills
UCA means Uniform Classification of Accounts as per AR 546/63
WCB means Workers Compensation Board

APPENDIX 3 – BOARD DECISIONS/ORDERS REFERENCED

Decision E82194	In the Matter of an Application to the PUB by APL, an owner of an electric utility, for an Order or Orders approving changes in existing rates, tolls or charges for electric light, power or energy supplied and service rendered to its customers within Alberta and those customers within the corporate limits of the City of Lloydminster, Saskatchewan dated August 18, 1982
Decision E87002	Northwestern Utilities Limited 1984/1985 General Rate Application dated February 6, 1987
Decision E88018	Northwestern Utilities Limited Application to Determine a Rate Base and Fix a Fair Return thereon for the Test Years 1987 and 1988 dated March 18, 1988
Decision E89091	TransAlta Utilities Corporation In the matter of a Filing by TransAlta Utilities Corporation, pursuant to a direction of the Public Utilities Board in Order C88027 dated November 14, 1988, for an Order or Orders fixing new rates, charges or schedules thereof for electric light, power or energy furnished by TransAlta Utilities Corporation to and for the public in Alberta during the years 1988, 1989 and 1990 dated December 15, 1989
Decision C90028	Village of Standard and Canadian Western Natural Gas Company Limited Application by the Council of the Village of Standard for Approval to Renew a Natural Gas Supply Contract with, to Confer a Special Franchise on and to Renew a Revenue Tax Agreement with CWNG dated September 12, 1990
Decision E91093	TransAlta Utilities Corporation 1991/1992 Phase I GRA dated December 16, 1991
Decision E93004	Canadian Western Natural Gas Company Limited 1992/1993 GRA Phase I dated February 8, 1993
Decision E94001	Northwestern Utilities Limited 1993/1994 GRA Phase I dated January 21, 1994

Decision U99070	Canadian Western Natural Gas Company Limited 1997 Return on Common Equity and Capital Structure; 1998 GRA – Procedural Directions and Partial Phase I Decision dated July 30, 1999
Decision U98060	Northwestern Utilities Limited Rates, Tolls, Charges and Terms and Conditions of Service for Core Customers for 1998 through to 2002 – Negotiated Settlement dated March 31, 1998
Decision U99102	Canadian Utilities Limited, Northwestern Utilities Limited and Canadian Western Natural Gas Company Limited Application for Renewal of the Reorganization of NUL and CWNG dated November 1, 1999
Decision 2000-9	ATCO Gas and Pipelines Ltd. (CWNG) 1997 Return on Common Equity and Capital Structure; 1998 GRA Phase I dated March 2, 2000
Decision 2000-82	ATCO Gas and Pipelines Ltd. (CWNG) Request to withdraw the 1999 GRA and assessment of the need for a 2000 GRA dated December 22, 2000
Decision 2001-75	GCRR Methodology and Gas Rate Unbundling Part A: Methodology and Unbundling Proceedings dated October 30, 2001
Decision 2001-96	ATCO Gas South 2001/2002 General Rate Application, Phase I dated December 12, 2001
Decision 2001-105	ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., and Northwestern Utilities Limited (ATCO Companies) Pension Filing – Negotiated Settlement dated December 31, 2001
Decision 2002-037	ATCO Gas and Pipelines Ltd. Disposition of Calgary Stores Block and Distribution of Net Proceeds – Part 2 dated March 21, 20002
Decision 2002-049	ATCO Pipelines South 2001/2002 General Rate Application Compliance Filing dated May 30, 2002

Decision 2002-069	ATCO Group Affiliate Transactions and Code of Conduct Proceeding Part A: Asset Transfer, Outsourcing Arrangements and GRA Issues dated July 26, 2002
Decision 2002-072	ATCO Gas, A Division of ATCO Gas and Pipelines Ltd. Transfer of Carbon Storage Facilities dated, July 30, 2002
Decision 2002-096	ATCO Pipelines South 2001/2002 General Rate Application, and Part A: Asset Transfer, Outsourcing Arrangements, and GRA Issues – Compliance Filing dated November 19, 2002
Decision 2002-097	ATCO Gas South 2001/2002 General Rate Application, Carbon Storage Transfer and Part A: Asset Transfer, Outsourcing Arrangements, and GRA Issues – Compliance Filing dated November 19, 2002
Decision 2002-115	ATCO Gas 2003/2004 General Rate Application – Interim Rate Application dated December 24, 2002
Decision 2002-116	ATCO Gas and Pipelines Ltd. (North) Application to Approve 2002 Rates, Amended North Core Agreement and Sale of Beaverhill Lake and Fort Saskatchewan Properties dated December 24, 2002
Decision 2003-006	ATCO Gas South 2001/2002 General Rate Application, and Part A: Asset Transfer, Outsourcing Arrangements and GRA Issues – Second Compliance Filing dated January 21, 2003
Decision 2003-040	ATCO Group Affiliate Transactions and Code of Conduct Proceeding, Part B: Code of Conduct dated May 22, 2003

Decision 2003-061	AltaLink Management Ltd. and TransAlta Utilities Corporation Transmission Tariff for May 1, 2002 – April 30, 2004 TransAlta Utilities Corporation Transmission Tariff for January 1, 2002 – April 30, 2002 dated August 3, 2003
Utility Cost Order 2002-69	ATCO Gas South 2001/2002 General Rate Application, Phase I dated October 11, 2002
Utility Cost Order 2002-70	ATCO Gas and Pipelines South Ltd. 2001/2002 General Rate Application, Phases I and II dated October 11, 2002
Order U2002-135	In the Matter of Changes to the Delivery Rates, Tariffs and Rate Riders of ATCO Gas and Pipelines – ATCO Gas South and ATCO Pipelines South dated March 28, 2002
Order U2002-136	In the Matter of Changes to the Delivery Rates, Tariffs and Rate Riders of ATCO Gas and Pipelines – ATCO Gas North and ATCO Pipelines North dated March 28, 2002