Decision **2012-091**

Alberta Utilities Commission

AltaGas Utilities Inc.

2010-2012 General Rate Application – Phase I

April 9, 2012

The Alberta Utilities Commission
Decision 2012-091: AltaGas Utilities Inc.
2010-2012 General Rate Application – Phase I
Application No. 1606694
Proceeding ID No. 904

April 9, 2012

Published by
The Alberta Utilities Commission
Fifth Avenue Place, Fourth Floor, 425 First Street S.W.
Calgary, Alberta
T2P 3L8

Telephone: 403-592-8845
Fax: 403-592-4406

Web site: www.auc.ab.ca

Contents

List of tables

The Alberta Utilities Commission

Calgary, Alberta

AltaGas Utilities Inc.
2010-2012 General Rate Application – Phase I

Decision 2012-091
Application No. 1606694
Proceeding ID No. 904

1 Introduction

1. On October 22, 2010, AltaGas Utilities Inc. (AUI, AltaGas or the company) filed a 2010-2012 General Rate Application – Phase I (GRA application) with the Alberta Utilities Commission (the AUC or the Commission). Specifically, AltaGas requested AUC approval of its forecast revenue requirement and rate base for the 2010, 2011 and 2012 test years, and an adjustment to the available 2010 capital cost allowance, following the split tax year resulting from the 2009 share transfer approved in Decision 2009-152,[1] such that the available 2010 capital cost allowance would be equivalent to the amount that would have been available absent the share transfer. In addition, AltaGas requested the establishment of certain deferral accounts and Commission approval to conduct a negotiated settlement process (NSP) with interested parties in relation to all aspects of the GRA application.

2. On November 1, 2010, the Commission issued a notice of application for this proceeding, through both the Commission's electronic distribution list and publication of an advertisement in 25 weekly newspapers in the AltaGas franchise area. Any party who wished to intervene in the proceeding was requested to submit a statement of intent to participate (SIP) to the Commission by November 26, 2010.

3. By letter dated November 24, 2010, the company responded to the AUC's October 14, 2010 notice concerning AUC Rule 026,[2] indicating that it would be deferring implementation of International Financial Reporting Standards (IFRS) until January 1, 2012. AltaGas stated that it anticipated it would need to file an update to its GRA application on or before December 17, 2010, to reflect the impact of the deferral of IFRS on its proposed 2010-2012 revenue requirements, as well as adjustments to correct a calculation error and reflect decreased costs in 2010, based on more current information.

4. On or before November 26, 2010, the Commission received SIPs from:

- the Consumers' Coalition of Alberta (CCA)
- the Office of the Utilities Consumer Advocate (UCA)
- ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.)
- BP Canada Energy Company
- FortisAlberta Inc.

[1] The AUC approved the transfer of all outstanding shares in the capital stock of AltaGas Utility Group Inc. to AltaGas Holdings #3 Inc., a wholly-owned subsidiary of AltaGas Income Trust in Decision 2009-152: AltaGas Utility Group Inc., Share Transfer and Amalgamation, Application No. 1605414, Proceeding ID. 295, October 1, 2009.

[2] AUC Rule 026: *Rule Regarding Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards* (Rule 026).

5. The UCA, in its November 26, 2010 SIP, and the CCA, in a letter dated November 29, 2010, indicated support for a negotiated process.

6. AltaGas requested Commission approval to negotiate the GRA application in its letter dated November 24, 2010. The company also informed the Commission that it would be filing a KPMG study on inter-affiliate shared services referenced in the GRA application (the KPMG study). In addition, AltaGas proposed to hold a technical meeting to highlight key aspects of the GRA application and address interested parties' preliminary questions and thereby improve the effectiveness and efficiency of the information request (IR) process.

7. In a letter dated December 7, 2010, the Commission denied AUI's request for permission to conduct a NSP, stating:

> As parties are aware, the Commission under normal circumstances supports negotiated settlement processes as having the potential to create regulatory efficiencies and other beneficial outcomes. However, in this case the Commission has identified two concerns it has with granting AUI's request:
>
> - AUI has proposed that 2012 be the year for going in rates for performance based regulation; and
> - the application includes significant forecast increases in rate base, revenue requirement and operating expenses throughout the test period.

8. The Commission accepted AltaGas's request to file an update to its GRA application, given that the number and nature of the updates described by AltaGas, including the filing of the KPMG study, constituted material revisions to the GRA application. The Commission also established a process schedule for the proceeding, which included a technical meeting and an oral hearing scheduled at that time for early June, 2011.

9. On December 20, 2010, AltaGas filed a letter with the Commission advising that it anticipated filing its 2010 actual results once they become available. As the actual results might have necessitated further updates to the GRA application, (e.g. changes to closing and opening plant balances and deferral account balances), the company proposed to defer filing of the GRA application update until February 25, 2011, after the release of the 2010 actual results. AltaGas submitted that deferring the update and interrogatory process would also eliminate unnecessary confusion, effort and IRs otherwise associated with two updates. The company advised that it would be filing the KPMG study before the end of 2010. AltaGas also requested that the Commission reconsider its ruling on the company's proposal for a NSP.[3]

10. By letter dated January 13, 2011, the Commission suspended the process schedule for the proceeding. The Commission accepted the company's proposal to update the GRA application

[3] In support of a NSP, AltaGas submitted that a NSP may also result in a thorough testing of the application; the recent 2008-2009 GRA was fully litigated; all active interveners have indicated support for a NSP; a NSP generally lends itself to more complete disclosure and discourse and there is a potentially greater likelihood of a "win-win" result for AltaGas and its customers; a NSP increases the potential for greater coordination and cooperation in future proceedings and may also better facilitate potential negotiation of any PBR mechanism; the identification of key cost drivers and the proposed filing of 2010 actuals should assist in ensuring full and appropriate testing of the 2010-2012 forecasts; and there is the potential for achieving significant regulatory efficiency particularly given the heavy 2010 AUC regulatory schedule.

by February 25, 2011 and directed it to file its update and the KPMG study on or before February 25, 2011. The Commission confirmed its earlier denial of AltaGas's request for a negotiated settlement process and reiterated that the application had to be tested to ensure that rates were just and reasonable and the public is served.

11. By letter dated February 16, 2011, the company advised that, due to unforeseen and unavoidable delays in accessing some required information, it now anticipated filing its GRA application update on March 11, 2011. Accordingly, on February 17, 2011, the Commission issued a letter advising parties that, given the January 13, 2011 suspension of the proceeding process schedule, AltaGas was excused from the Commission's previous direction to file its update and KPMG study on or before February 25, 2011.

12. On March 11, 2011, AltaGas filed an update to the GRA application (March update), stating that it reflected the company's most current information, including 2010 actual expenditures and year end balances. In the March update, AUI refers to 2010 numbers as both actual and forecast. For the purposes of this decision, the Commission considers all 2010 numbers to be the actual expenditures of the company for that test year. The March update also included the impacts of the deferral of IFRS to January, 2012, the KPMG study, and a new request for a deferral account for AltaGas' proposed demand side management (DSM) program. AltaGas requested that, due to the scope and impact of the changes and to avoid unnecessary confusion, the updated application replaced the previous application in its entirety. AltaGas also included a proposed schedule, stating that it might propose that a technical meeting be included in the schedule.

13. By letter dated March 17, 2011, the Commission requested parties' comments on the company's proposed schedule and encouraged any party that desired a technical meeting to communicate with AltaGas and other registered parties to gauge the need. The Commission also advised parties that it had added Exhibit 31to the record of this proceeding, a summary of information filed by AltaGas in its Rule 005: *Annual Reporting Requirements of Operational and Financial Results* (Rule 005) filings since 2003, to assist parties in the evaluation of the application. The Commission asked[4] AltaGas to confirm the numbers in the Rule 005 summary and to reconcile any differences between the application and the summary.

14. By letter dated March 25, 2011, the Commission established a schedule, reflecting several intervener-requested adjustments to AltaGas's March 11, 2011 proposal. Subsequently, a company-requested extension to its IR responses deadline was also accepted by the Commission and a revised schedule was established by letter dated May 31, 2011.

15. On April 19, 2011, the company filed supplementary depreciation information in support of its GRA application.

16. By letter dated June 20, 2011, the UCA filed a motion with the Commission requesting that AltaGas be directed to provide full and adequate responses to certain IRs. By letter dated June 21, 2011, the Commission established a process respecting the UCA's motion, establishing a process whereby AltaGas was invited to respond to the motion and the UCA was provided the opportunity to reply to the company's response. On June 24, 2011, AltaGas filed supplementary responses to the IRs identified in the UCA motion and on June 29, 2011, the UCA filed a letter

[4] Exhibit 40.01, AUC-AUI-2.

advising it now considered the record sufficiently complete for the purposes of preparing its evidence.

17. AUI filed a letter with the Commission on June 24, 2011, advising that its indirect parent company, AltaGas Limited (AL), had elected to adopt United States Generally Accepted Accounting Principles (U.S. GAAP) for its financial reporting purposes beginning January 1, 2012. As a result, AUI proposed to adopt U.S. GAAP, rather than IFRS, for its financial reporting purposes effective January 1, 2012. AltaGas submitted that it intended to reflect this change from IFRS to U.S. GAAP in a further update to its GRA application, to be filed no later than July 4, 2011. AUI proposed changes to the process schedule, including IRs on the further update to the GRA application.

18. By letter dated June 28, 2011, the Commission acknowledged the company's request to further update the GRA application and directed it to provide a blackline version and a summary of all of the changes to the GRA application, including all errors identified in its responses to IRs on the GRA application. The Commission made minor adjustments to the proposed schedule. On July 4, 2011, AltaGas filed an update to the GRA application (July update) to reflect the adoption of U.S. GAAP for regulatory purposes.

19. On September 15, 2011, the Commission received a motion from AltaGas requesting the striking of those portions of the UCA evidence and IRs dealing with proposed adjustments to the company's 2010 capital structure. The Commission responded to the motion, establishing a process for submissions on the matter. On September 30, 2011, the Commission denied the motion to strike the UCA evidence with respect to capital structure, but decided to have parties address the issue at the oral hearing scheduled for October 11, 2011.

20. On October 6, 2011, AltaGas filed an update to the pensions section of the GRA application, reflecting updated estimates from its actuary with respect to net periodic pension costs. The company also requested a pension expense deferral account.

21. The Commission held an oral hearing in Edmonton from October 11 to 19, 2011, before a division of the Commission consisting of Mark Kolesar (Panel Chair), Carolyn Dahl Rees (Vice-Chair) and Kay Holgate (Commission Member).

22. Subsequent to the oral hearing, the UCA's argument referred to an AL acquisition agreement with Pacific Northern Gas (PNG), expected to close on or about December 16, 2011. The UCA submitted that AltaGas's financial market services allocation formula should be revised for the 2012 test year if the transaction closed as expected. In reply argument, AltaGas argued against the UCA's proposal, submitting that the PNG acquisition would have no impact on the financial services allocation formula.

23. By letter dated December 22, 2011, the Commission determined that, in this case, the Commission required more information about the pending PNG acquisition and set out several questions to AltaGas and a process for queries from interested parties and responses from the company. The deadline for the company's responses to other parties' submissions was January 23, 2012. For the purposes of this decision, the Commission considers the record to have closed on January 23, 2012.

24. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding, including the

evidence and argument provided by each party. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

2 Background

25. In Decision 2009-176,[5] the Commission recognized that AltaGas is a wholly-owned subsidiary of AltaGas Utility Holdings Inc. (AUHI), which is a wholly-owned subsidiary of AltaGas Utility Group Inc. (AUGI). AUGI indirectly acquired AltaGas in a corporate reorganization undertaken by AltaGas Income Trust (AIT) in 2005,[6] and AIT and AIT's subsidiaries were deemed affiliates of the company. After the close of the record that resulted in Decision 2009-176, the Commission approved AUGI's share transfer and amalgamation of the company's indirect parent. In addition, effective July 1, 2010, AIT reorganized into AL, a dividend paying corporation, and AL is now the company's ultimate parent, making AL and its subsidiaries affiliates of the company.[7]

26. On January 8, 2010, AltaGas filed a compliance filing in response to Decision 2009-176 and on May 6, 2010, the Commission issued Decision 2010-197.[8]

27. On December 4, 2009, AltaGas applied to the AUC for approval to issue a 7.42 per cent debenture in the principal amount of $40 million due April 29, 2014 and a 6.94 per cent debenture in the principal amount of $20 million due June 29, 2016 to AUHI. Decision 2010-266[9] approved issuance of the 2009 debentures but deferred determination of the appropriate rate and term to the company's next GRA (the GRA application).

28. On January 22, 2010, AltaGas applied to the Commission for approval to issue 572,120 Class "A" common shares to AUHI for the maximum aggregate consideration of $17.2 million. This equity issue was approved by the AUC in Decision 2010-101.[10]

29. On May 21, 2010, the company filed an application for approval of interim terms and conditions of service (T&Cs). An amended set of T&Cs were filed on September 22, 2010, and subsequently approved by the AUC in Decision 2010-484.[11]

30. On May 21, 2010, AltaGas filed the 2008-2009 GRA Phase II application, based on the final approved results of the corresponding GRA Phase I application. A negotiated settlement

5 Decision 2009-176: AltaGas Utilities Inc., 2008-2009 General Rate Application Phase 1, Application No. 1579247, Proceeding ID. 88, October 29, 2009.
6 Decision 2010-197: AltaGas Utilities Inc., 2008-2009 General Rate Application, Phase I Compliance Filing, Application No. 1605779, Proceeding ID. 452, May 6, 2010.
7 Exhibit 30.01, March 11 update, page 5, paragraphs 14-16.
8 Decision 2010-197: AltaGas Utilities Inc. 2008-2009 General Rate Application Phase I compliance filing Application No. 1605779; Proceeding ID. 452, May 6, 2010.
9 Decision 2010-266: AltaGas Utilities Inc., Application to Issue 2009 Debentures: 7.42 Percent in the Principal Amount of $40,000,000 and 6.94 Percent in the Principal Amount of $20,000,000, Application No. 1605686, Proceeding ID. 418, June 9, 2010.
10 Decision 2010-101: AltaGas Utilities Inc., Issue of Common Shares to AltaGas Utility Holdings Inc., Application No. 1605820, Proceeding ID. 466, March 4, 2010.
11 Decision 2010-484: AltaGas Utilities Inc., Interim Terms and Conditions of Service, Application No. 1606231, Proceeding ID. 652, October 7, 2010.

process was conducted, resulting in the filing of a settlement agreement executed by AltaGas and all interveners. The settlement package was filed with the AUC on October 18, 2010, and included a provision extending the principles agreed upon in the settlement agreement to allow the establishment of final rates for the period 2010-2012. This will be accomplished through a Phase II compliance filing following receipt of a final decision on AltaGas's 2010-2012 GRA Phase I. Minor T&Cs amendments were included in the settlement agreement. On March 8, 2011, the Commission issued Decision 2011-073,[12] approving the negotiated settlement.

31. On September 2, 2010, AltaGas filed an application requesting an order approving the issue of an inter-company debenture from the company to AUHI in the principal amount of $30 million, with an issue date of October 4, 2010, and maturing on March 27, 2017. The expected annual coupon rate was 5.49 per cent and the expected issue cost was 0.21 per cent per annum. On September 20, 2010, AUC Decision 2010-448[13] approved the issuance of the debenture and deferred other related matters, including issuance cost and coupon rates, to the current GRA application.

32. On October 15, 2010, the company filed a 2010 interim rates application seeking approval for the continuation of the existing interim rates approved in Decision 2009-038.[14] The 2010 interim rates were approved by way of AUC Decision 2010-535.[15]

33. On December 3, 2010, AltaGas filed a 2011 interim rates application for approval of interim rates effective January 1, 2011. Decision 2010-621[16] approved an increase to the company's 2010 interim rates of 6.045 per cent, effective January 1, 2011.

34. On May 9, 2011, the company filed an application in compliance with Decision 2011-073. The compliance application also included a request to revise AltaGas's 2011 interim rates commensurate with the more current revenue requirement filed in its 2010-2012 GRA update dated March 11, 2011. On July 25, 2011, the Commission issued Decision 2011-311,[17] approving the compliance filing and the revised 2011 interim rates.

35. On August 18, 2011, the company filed an application with the Commission requesting approval of 2012 interim refundable rates. On January 12, 2012, the Commission issued Decision 2012-013[18] approving interim rates effective February 1, 2012.

12 Decision 2011-073: AltaGas Utilities Inc., 2008-2009 General Rate Application – Phase II, Negotiated Settlement, Application No. 1606230, Proceeding ID No. 651, March 8, 2011.

13 Decision 2010-448: AltaGas Utilities Inc., Application to Issue a Debenture in the Principal Amount of $30,000,000, Application No. 1606535, Proceeding ID. 818, September 20, 2010.

14 Decision 2009-038: AltaGas Utilities Inc., 2008 Interim Refundable Rates, Application No. 1604826, Proceeding ID. 170, March 30, 2009.

15 Decision 2010-535: AltaGas Utilities Inc., Interim 2010 Rates Application, Application No. 1606665, Proceeding ID. 889, November 18, 2010.

16 Decision 2010-621: AltaGas Utilities Inc., 2011 Interim Rates, Application No. 1606827, Proceeding ID. 971, December 24, 2010.

17 Decision 2011-311: AltaGas Utilities Inc., 2008-2009 General Rate Application Phase II Compliance and Updated 2011 Interim Rates, Application No. 1607310, Proceeding ID No. 1220, July 25, 2011.

18 Decision 2012-013: AltaGas Utilities Inc., 2012 Interim Rates, Application No. 1607602, Proceeding ID No. 1403, January 12, 2012.

3 Overview

3.1 Inflation

36. The following table sets out the inflation assumptions used by AltaGas in establishing its forecast revenue requirements:

Table 1. Inflation and other cost increases expressed as year-over-year percentage increase

Line				2010 forecast	2011 forecast	2012 forecast
					(%)	
1	General CPI			2.00	2.50	3.00
2	Salaries	Union		3.00	3.00	4.00
3		Salaried	Merit	3.00	3.00	5.00
4			Range Placement	1.50	1.00	1.00
5	Construction contractors			2.00	5.00	3.00
6	Construction material			2.00	2.50	3.00
7	General material			2.00	2.50	3.00
8	General contractors			2.00	2.50	3.00
9	Employee benefits			2.00	2.50	3.00

Source: Exhibit 30.01, Section 9.0, Table 68.

37. In determining forecast inflation rates, AltaGas explained that it took into consideration the forecast Consumer Price Index (CPI), Industrial Product Price Index (IPP) and Average Hourly Earning (AHE) forecasts, as well as the historical year over year trend for each. AltaGas also factored in information obtained directly from contractors and suppliers, and inflation rates applied for and approved for other utilities. Consideration was also given to the general trend in inflation rates. AltaGas provided the following updated inflation statistics in its March update.

Table 2. AltaGas inflation statistics

Line	Date of report	Forecast	2011	2012
1	January 2011	CPI	2.2	2.1
2		IPP	2.3	2.7
3		AHE	3.2	3.4
4	February 2011	CPI	2.3	2.1
5		IPP	2.8	3.3
6		AHE	3.0	3.7

Source: Exhibit 47.01, AUC-AUI-20(a), Table 2.0.

38. Noting the upward trend in the IPP and AHE, AltaGas concluded an adjustment to its original inflation forecasts was not warranted.[19] As the 2010 test year is based on actual results, AltaGas submitted that forecast inflation rates are not applicable to the 2010 forecast operating and maintenance (O&M) expenses.[20]

[19] Exhibit 143.01, AltaGas argument, page 81, paragraph 264.
[20] Exhibit 143.01, AltaGas argument, page 79, paragraph 262.

39. With respect to specific escalators, AltaGas explained that both union and non-union salaries were forecast to increase at 3.0 per cent, consistent with the rate agreed to in the current collective bargaining agreement for 2010 and 2011. AltaGas also noted that the Summer 2010 Conference Board of Canada report forecast increases in Alberta average weekly wages of 3.8 per cent for 2011 and 3.3 per cent for 2012. For 2012, AltaGas forecast union salary increases of 4.0 per cent based on the upward trend in the average hourly earnings forecast and the overall level of the Alberta average weekly wages forecast. Similarly, given the forecast pressure on the Alberta energy labour market in 2011 and 2012, AltaGas submitted that its forecasts for both union and salaried labour (3.0 per cent for 2011 and 5.0 per cent for 2012) are reasonable. AltaGas also noted that various human resource and compensation professionals have predicted average salary increases of 2.6 per cent in 2010 and 2.9 per cent in 2011.[21] Mercer (Canada) Ltd. (Mercer) predicted 3.0 per cent and 3.5 per cent, respectively.[22] AltaGas also submitted that its forecast salary escalations for 2011 and 2012 are consistent with salary escalations recently approved for Alberta utilities.[23]

40. With regard to general inflation, construction material, general material, general contractors and employee benefits, AltaGas noted that the IPP forecast is in excess of general CPI for 2011, suggesting greater pressure on industrial products and services pricing than on consumer goods. AltaGas submitted its forecast inflation for 2010-2012 is reasonable.

41. For construction contractors, forecasts were largely based on discussions with AltaGas contractors, as well as other potential contractors. Primary concerns from contractors related to increased fuel cost forecasts for the 2011 and 2012 period, as well as increasing pressure on the labour market, as oil and gas activity picks up. On an actual basis, AltaGas noted its 2011 contractor costs are significantly above the five per cent forecast, averaging in excess of 11 per cent relative to 2010.[24]

Commission findings

42. The Commission considers that AltaGas's forecast inflation rates identified in the tables above for the test years are consistent with the underlying inflation indices cited by AltaGas, with the exception of AltaGas's 2012 salary escalator and 2011 construction contractor escalator.

43. With respect to forecast increases in salaries, the Commission finds AltaGas's forecast salary escalator of three per cent to be reasonable in 2011 when compared against the supporting inflation indices but is not persuaded that different inflation rates should be applied to union and non-union personnel in 2012. The Commission considers that a four per cent increase in 2012 for both non-union and union personnel is reasonable and more consistent with underlying economic indices cited by AltaGas in its application. AltaGas is directed in the compliance filing to adjust its inflation rate forecast for salaried personnel to four per cent in 2012. Forecast range

---

21 Exhibit 30.01, Application, page 157-158, paragraph 232, referring to Application, Tab 8.0, Section 4.1 Salary & Wages Suppl. Documents, Hay Group Press Release, page 1-2.

22 Exhibit 30.01, application, page 157-158, paragraph 232, referring to Application, Tab 8.0, Section 4.1 Salary & Wages Suppl. Documents, Mercer Canadian Comp. Planning Survey, page 7.

23 Exhibit 30.01, application, page 158, paragraph 233, Table 16.0. ENMAX Energy Corp. 2009-11 RRO Non-Energy Application Decision 2010-483, October 7, 2010, page 15. Fortis Alberta Inc. 2010-11 PHI DTA Decision 2010-309, July 6, 2010, page 39. EPCOR Distribution & Transmission Inc. 2010-11 PHI DTA Decision 2010-505, October 28, 2010, page 35.

24 Exhibit 47.01, AUC-AG-20(a).

placement adjustment for salaried employees is addressed by the Commission in Section 6 of this decision.

44. The Commission finds the forecast escalators for construction contractors to be reasonable for the 2010 and 2012 test years. For 2011, AltaGas argued that its contractor expense forecast is reasonable when weighed against the actual 11 per cent increase experienced in 2011. The Commission is satisfied with AltaGas's explanation for its forecast contractor expense escalator for 2011 and finds its forecast for the test years is reasonable. AltaGas's constructor contractor inflation forecast is approved as filed.

45. Given that the remaining inflation factors and escalators adopted by AltaGas are consistent with the underlying inflation indices cited by AltaGas, the Commission finds them to be reasonable and approves their adoption for the purposes of calculating the revenue requirements for the test years.

3.2 Adoption of United States Generally Accepted Accounting Principles

46. On June 24, 2011, AltaGas submitted a letter[25] to the Commission in which AltaGas advised that AL had elected to adopt U.S. GAAP for its financial reporting purposes beginning on January 1, 2012. As a result, AltaGas would also adopt U.S. GAAP, rather than IFRS, for its financial reporting purposes effective January 1, 2012. On July 4, 2011, AltaGas submitted an update to its GRA application in the form of a U.S. GAAP supplementary filing.[26] AltaGas indicated that the primary difference between the July update and the March update relate to capitalization practices, pension expense and audit expense. For 2011, AltaGas will revise its capitalization practices to a refined methodology acceptable under both Canadian and U.S. GAAP[27] and will reduce its forecast audit expense. The change with respect to pension accounting will be effective January 1, 2012.

47. In response to AUC-AUI-133(a),[28] AltaGas indicated that to apply U.S. GAAP under the accounting principles required for financial statements filed with Canadian securities regulators, a company has to be registered with the United States Securities and Exchange Commission (SEC). AltaGas added that AL sought an exemption order from the Alberta Securities Commission to prepare its financial statements in accordance with U.S. GAAP without being registered with the SEC. On July 4, 2011, AL was granted an exemption order and has been approved to report financial results in accordance with U.S. GAAP for financial years commencing on January 1, 2012. The exemption will terminate on or after the earlier of January 1, 2015 and the date on which AL ceases to have activities subject to rate regulation.

Views of the parties

48. In its argument, AltaGas submitted that, given the similarities between Canadian GAAP and U.S. GAAP, the transition to U.S. GAAP is expected to result in far fewer adjustments and changes in accounting policy than would have been required had AltaGas proceeded with the adoption of IFRS. AltaGas added that, as there are relatively few areas of divergence between Canadian GAAP and U.S. GAAP that relate to AltaGas's operations, the forecast increases in

25 Exhibit 55.01, AltaGas letter regarding the change to U.S. GAAP.
26 Exhibit 61.02, July update.
27 Exhibit 66.01, AUC-AUI-141(a).
28 Exhibit 66.01.

audit fees under U.S. GAAP are $15,000 for 2011 and zero for 2012, as compared to forecast increases under IFRS of $125,000 in 2011 and $150,000 in 2012.[29]

49. The CCA concurred with AltaGas's adoption of U.S. GAAP for regulatory purposes. The UCA offered no comment on AltaGas's request to adopt U.S. GAAP for regulatory purposes.

Commission findings

50. Regardless of the accounting policies adopted for external reporting purposes, the Commission has the authority to set accounting policies for regulatory purposes. The Commission's views with respect to the two primary differences between the applications using IFRS and U.S. GAAP, related to capitalization policy and pension accounting are addressed in Section 3.3 and Section 6.2 of this decision.

51. The Commission must also consider the possibility of increased regulatory burden and consequently increased costs arising from the adoption of U.S. GAAP. The Commission considers additional regulatory burden could be incurred if:

- as AUI transitions to U.S. GAAP, further accounting differences are identified as between Canadian GAAP and U.S. GAAP
- the U.S. adopts IFRS in the future
- AltaGas's exemption from the Alberta Securities Commission is not extended beyond January 1, 2015

52. With respect to the potential for an increase in regulatory burden arising from the transition to U.S. GAAP, due to the identification of further accounting differences as between Canadian GAAP and U.S. GAAP, the Commission observes that accounting for rate regulated entities under U.S. GAAP is similar to Canadian GAAP. Also, AltaGas did not include any increased accounting or consulting costs for the transition to U.S. GAAP as part of the forecast revenue requirements for 2010, 2011 or 2012. The Commission agrees with AltaGas that U.S. GAAP is not sufficiently different from Canadian GAAP to result in a significant increase in regulatory burden.

53. With respect to the last two possible sources of increased regulatory burden arising from the transition to U.S. GAAP, the Commission considers these to be speculative and unlikely to occur within the test period. The Commission considers that any issues arising from these matters would be dealt with, in due course, by the Commission should the need arise.

54. Accordingly, the Commission approves AltaGas's request to adopt U.S. GAAP for regulatory accounting purposes as described in the July update.

3.3 Capitalization policy change

55. In the July update, AltaGas stated that it proposed to continue the capitalization practices in place for 2009 and previous years, with refinements to reflect changes arising from implementation of timesheets and enhanced time recording. AltaGas added that it currently has a timesheet and labour distribution system in place to charge costs for direct labour, benefits and

[29] Exhibit 143.01, AltaGas argument, paragraph 248.

vehicles to capital projects on the basis of time charged by employees. AltaGas provided a copy of its formal capitalization policy entitled Financial Control Management Practices: Capitalization Practice, or FCMP No. 2.3 as part of the July update.[30] AltaGas also capitalizes certain indirect and overhead costs. These indirect and overhead costs are described in its formal capitalization document.[31] The proposed changes to capitalization policy are acceptable under both Canadian and U.S. GAAP and will be adopted effective January 1, 2011.[32]

56. In response to CCA-AUI-51(a),[33] AltaGas included details of how the proposed capitalization practices regarding indirect and overhead costs differ from those currently approved by the Commission in connection with AltaGas's 2008-2009 GRA Phase I.

Views of the parties

57. The CCA argued that the net impact of the revisions to AltaGas's indirect and overhead costs capitalization policy is to increase the 2011 and 2012 revenue requirements. The CCA, referring to the attachment to the response to CCA-AUI-51(b),[34] indicated that the 2011 revenue requirement will increase by $1.816 million and the 2012 revenue requirement will increase by $2.113 million. The CCA submitted that these are material changes in the overall revenue requirements for these years and in fact represent 60 per cent of the 2011 revenue deficiency and 28.5 per cent of the 2012 revenue deficiency.

58. The CCA was concerned that in adopting U.S. GAAP, AltaGas took the opportunity to increase its revenue requirement by a material amount in the GRA application. The CCA had three areas of concern. The first concern was that, in all prior applications, AltaGas has steadfastly maintained that there was no need to change its capitalization policy, which has been in place since the 1980s. The CCA added that no prior AUC decision directed AltaGas to change its capitalization policy and hence the only trigger is the adoption of U.S. GAAP.

59. The CCA's second concern was with regard to AltaGas's rates for the proposed performance-based regulation (PBR) period. The CCA commented that AltaGas is on the cusp of adopting PBR. The CCA added that, even if there is merit in decreasing the amounts capitalized and increasing operating expenses, since the rates for 2012 are to be the "going-in" rates[35] this will mean that the rates for the 2012-2017 PBR period will be much higher under U.S. GAAP relative to either Canadian GAAP or IFRS.

60. The CCA's third concern was that, if the AUC approves the proposed capitalization policy of AltaGas, this will make the capitalization policy totally offside from the practices of other utilities regulated by the AUC as these other utilities are complying with IFRS and the AUC's Rule 026.

61. The CCA submitted that based on these concerns, it is not opposed to AltaGas continuing with the current capitalization practice approved by the AUC and that the Commission should deny AltaGas's proposed changes.

---

30 Exhibit 61.03, July update, capitalization practice attachment.
31 Exhibit 61.03, July update, capitalization practice attachment, pages 4-5.
32 Exhibit 66.01, AUC-AUI-141(a).
33 Exhibit 68.01.
34 Exhibit 68.03.
35 The 2012 rates that will give effect to the revenue requirement approved in this decision will form the basis for the going-in rates for the PBR period commencing in 2013.

62. AltaGas responded that, in its 2008-2009 GRA Phase I, it did not undertake a review of its capitalization policy. AltaGas added that at the time of the preparation of the 2008-2009 GRA Phase I, it had not implemented a detailed timesheet system to assist in more accurately assigning time to capital and non-capital related activities.

63. AltaGas stated that it was confused at the reference to IFRS made by the CCA because capitalization of overhead expenses is not allowed under IFRS. AltaGas added that it stands to reason that any entity not on IFRS would have higher overhead capitalization than those using IFRS. AltaGas indicated that the difference between its existing and proposed capitalization practices arises from improved data which has enabled AltaGas to better identify the time, activities and associated costs of its staff as being either capital or non-capital related. AltaGas submitted that continuing with the existing capitalization practice would fail to appropriately recognize and account for these staff related costs.

Commission findings

64. The Commission has the authority to direct AltaGas regarding its capitalization policies to be used in determining the capital costs of projects that will be included in AltaGas's rate base for regulatory revenue requirement purposes. The Commission is not limited by accounting standards when it approves capitalization policies but generally the Commission uses accounting standards as a reference tool in assessing the capitalization policies of the utilities.

65. The Commission recognizes that, even when all the utilities it regulates were operating under Canadian GAAP, there were differences among the capitalization policies approved by the Commission for the various utilities. Professional judgment with respect to accounting has been applied in the past and will continue to be applied under IFRS and U.S. GAAP. Consequently, the Commission expects that the capitalization policies of the utilities under its jurisdiction will continue to be different, even if all the other utilities operate under IFRS and the related guidance of AUC Rule 026. The Commission considers that comparability among the capitalization practices is not a major deciding factor in determining whether to approve the changes AltaGas has requested to its capitalization policies.

66. Despite the CCA's comment that the revenue requirements for 2011 and 2012 have increased because of the revisions AltaGas has made to its capitalization policy using U.S. GAAP, the overall revenue requirements for 2011 and 2012 have actually decreased from the figures included in the March update, in which the capitalization policy was prepared based on IFRS and AUC Rule 026.

67. The Commission has reviewed the proposed changes to the capitalization policy and considers that the use of a timesheet and labour distribution system, as noted in paragraph 55 of this decision, is a more accurate way to capture costs associated with capital than the 35 per cent allocation factor for indirect and overhead costs formerly used by AltaGas. The Commission observes that the amount of capitalized overhead has been reduced compared to the previously approved capitalization policy, as evidenced by the attachment to the response to CCA-AUI-51(b). Despite the fact that the immediate impact of less capitalized overhead is an increase in operating and maintenance expense, and thus increased revenue requirement and rates in the short term, the Commission considers that the better tracking of costs results in better capitalization policies.

68. The Commission therefore approves the capitalization policies that AltaGas has included in the July update.

4 Rate Base

69. This section sets out the Commission's findings with respect to the additions to rate base for the years 2008 and 2009 and the forecast capital costs for a number of projects and programs that are planned by AltaGas for implementation during the test years.

4.1 2010 opening rate base

70. In its March update, AltaGas updated its 2009 closing property, plant and equipment (PP&E) balance to $304.1 million. The table below sets out AltaGas's actual rate base for 2008 and 2009. The increase in net rate base for 2009 over 2008 was related to capital additions and retirements, changes in depreciation and other factors. The Commission will first examine capital additions to the opening rate base.

Table 3. Opening rate base[36]

	2008 actual	2009 actual
Rate base ($ million)	282.4	304.1
Per cent increase over prior year		7.7%

71. AltaGas provided its 2008 and 2009 actual capital expenditures and the approved forecasts, from the 2008-2009 GRA in tables 2.2 A and 2.2 B of the GRA application, and provided comparisons between the forecast and actual expenditures for these years in its responses to AUC-AUI-14 and AUC-AUI-17. The total actual expenditures of $22.2 million were $0.9 million or approximately four per cent less than forecast in 2008, and the total actual expenditures of $21.5 million were $4.3 million or approximately 17 per cent less than forecast in 2009. Comparisons of the 2008 and 2009 actual capital expenditures to the approved forecasts from the 2008-2009 GRA are provided below.

[36] Exhibit 30.01, March update, Tables 2.3 C, 2.3 D, 2.3 E.

Table 4. Comparison of forecast and actual capital expenditures for 2008[37]

	2008 approved costs	2008 actual costs	Variance actual to approved	Variance actual to approved
	($)	($)	($)	(%)
Office Equipment	294,900	329,400	34,500	12
Rural Sub'd Services	1,037,700	1,180,900	143,200	14
Town Mains	1,992,200	2,522,800	530,600	27
Rural Services	1,684,400	2,215,700	531,300	32
Rural Mains	-	60,400	60,400	100
Rural Sub'd Mains	703,100	1,692,700	989,600	141
Stations	49,600	312,500	262,900	530
Town Services	2,544,700	2,251,300	(293,400)	-12
eCIS+/TBC	3,553,000	2,979,600	(573,400)	-16
IS&T - Tangible	2,131,500	1,750,200	(381,300)	-18
Land	305,000	245,800	(59,200)	-19
Heavy Work Equipment	388,000	300,800	(87,200)	-22
Tools & Work Equipment	366,900	273,800	(93,100)	-25
Vehicles	1,337,500	889,200	(448,300)	-34
Looping	1,427,900	830,500	(597,400)	-42
Replacements	1,475,400	855,400	(620,000)	-42
Relocations	681,700	389,800	(291,900)	-43
Meters[38]	842,000	825,600	(16,400)	-2
Other[39]	178,500	176,700	(1,800)	-1
Gas Supply[40]	1,134,200	1,164,000	29,800	3
Structures[41]	919,200	933,100	13,900	2
Communications Equipment[42]	69,400	63,700	(5,700)	-8
	23,116,800	22,243,900	(872,900)	-4

37 Exhibit 47.01, AUC-AUI-14, Table 1.0.
38 Exhibit 30.01, March update, Schedule 2.2 A.
39 Exhibit 30.01, March update, Schedule 2.2 A.
40 Exhibit 30.01, March update, Schedule 2.2 A.
41 Exhibit 30.01, March update, Schedule 2.2 A.
42 Exhibit 30.01, March update, Schedule 2.2 A.

Table 5. Comparison of forecast and actual capital expenditures for 2009[43]

	2009 approved costs	2009 actual costs	Variance actual to approved	Variance actual to approved
	($)	($)	($)	(%)
Rural Services	1,848,700	2,790,300	941,600	51
Rural Mains	-	142,200	142,200	100
Rural Sub'd Services	1,119,600	1,119,200	(400)	0
Rural Sub'd Mains	773,800	1,291,000	517,200	67
Town Services	2,745,000	1,447,500	(1,297,500)	-47
Town Mains	2,168,000	648,600	(1,519,400)	-70
Meters	895,700	596,900	(298,800)	-33
AUC Adjustments - New Business	(18,300)	-	18,300	-100
Looping	459,000	968,900	509,900	111
Stations	464,600	432,000	(32,600)	-7
Replacements	1,989,200	1,393,900	(595,300)	-30
Other	368,600	225,000	(143,600)	-39
Relocations	313,000	217,100	(95,900)	-31
Gas Supply	2,745,800	1,935,300	(810,500)	-30
AUC Adjustments - System Betterment	(1,923,100)	-	1,923,100	-100
Land	100,000	128,200	28,200	28
Structures	2,024,100	569,900	(1,454,200)	-72
Office Equipment	114,800	85,600	(29,200)	-25
IS&T - Tangible	483,400	447,900	(35,500)	-7
IS&T - Intangible	1,568,200	709,700	(858,500)	-55
eCIS+/TBC	5,838,800	5,164,800	(674,000)	-12
Vehicles	1,168,000	945,500	(222,500)	-19
Heavy Work Equipment	242,900	63,300	(179,600)	-74
Tools & Work Equipment	336,700	162,900	(173,800)	-52
Communication Equipment	28,600	33,700	5,100	18
	25,855,100	21,519,400	(4,335,700)	-17

72. The most significant variances between the approved forecast and actual capital expenditures in 2008 related to a decrease of $620,000 in replacements, a decrease of $597,400 in looping, a decrease of $573,400 in eCIS+/TBC,[44] and a decrease of $448,300 in vehicles. AltaGas explained that the reduction in replacements was driven by third party demand, resulting in fewer watercourse crossings, roadway crossings, and service line replacements.[45] The postponement of the Beaumont High Pressure Loopline project to 2009 and the location of load growth resulted in less looping requirements than forecast.[46] The decrease in eCIS+/TBC resulted from the timing of the project and the decrease in vehicles was a result of a delay in the purchase of a number of vehicles.[47]

73. The decreases in 2008 were partially offset by an increase of $989,600 in rural subdivision mains, an increase of $531,300 in rural services, an increase of $530,600 in town mains, and an increase in stations of $262,900. AltaGas explained that the increases in mains

43 Exhibit 47.11, AUC-AUI-17, Attachment.
44 Electronic customer billing software used to meet Rule 004: *Alberta Tariff Billing Code Rules.*
45 Exhibit 30.01, March update, Section 2.2.2, paragraph 43.
46 Exhibit 47.01, AUC-AUI-13(b).
47 Exhibit 30.01, March update, Section 2.2.3, paragraph 54.

were due to an increased number of kilometers (km) installed as a result of demand from developers.[48] Increases in services were a result of a higher number of new sites and a slightly higher average cost per site.[49] Increases in stations were a result of the need to complete non-forecast work related to station alarms and station automated meter reading.[50]

74. The most significant variances as between the approved forecast and actual capital expenditures in 2009 related to a decrease of $1,519,400 in town mains, a decrease of $1,454,200 in structures, a decrease of $1,297,500 in town services, a decrease of $858,500 in information system and technology (IS&T) intangible, a decrease of $810,500 in gas supply, a decrease of $674,000 in eCIS+/TBC, and a decrease of $595,300 in replacements. AltaGas indicated that the decrease in mains was a result of fewer kilometers installed and a lower average cost per meter.[51] The decrease in structures was primarily due to a delay in the construction of the Leduc head office.[52] The decrease in services was a result of fewer services installed due to the economic slowdown.[53] The decrease in IS&T intangible was a result of a delay in the acquisition of asset management software.[54] The reduction in gas supply costs was due to lower unit costs than forecast for the Red Earth and Westlock gas supply project.[55] The decrease in eCIS+/TBC resulted primarily from a favourable foreign exchange rate.[56] Replacements were lower than the approved forecast due to a lower amount of pipe installed in the Superior PVC replacement project, the deferral of the Delia PVC replacement project to 2010, and a decrease in demand for watercourse and roadway crossing replacements.[57]

75. The decreases in actual as compared to forecast capital expenditures for 2009 were augmented by a reduction of $1,923,100 in system betterments from Decision 2009-176 relative to approved costs related to the inability of AltaGas to complete the volume of forecasted capital work.[58] This was offset by an increase of $941,600 in rural services, an increase of $517,200 in rural subdivision mains, and an increase of $509,900 in looping. The increase in rural services was a result of the addition of several large customers in rural areas contributing to an increase in the unit cost of construction.[59] Rural subdivision mains were higher than forecast because the majority of mains were installed in rural subdivisions.[60] To maintain system reliability and safety, a higher number of looping projects were identified and completed in 2009 than originally forecast.[61]

Commission findings

76. The Commission has reviewed the variance explanations provided by AltaGas and is satisfied that the actual capital expenditures for 2008 and 2009 are reasonable. The Commission has compared actual expenditures to approved forecasts, and is satisfied with AltaGas's variance

48 Exhibit 30.01, March update, Section 2.2.1, paragraph 35.
49 Exhibit 30.01, March update, Section 2.2.1, paragraph 34.
50 Exhibit 30.01, March update, Section 2.2.2, paragraph 45.
51 Exhibit 30.01, March update, Section 2.2.1, paragraph 35.
52 Exhibit 30.01, March update, Section 2.2.3, paragraph 55.
53 Exhibit 30.01, March update, Section 2.2.1, paragraph 36.
54 Exhibit 30.01, March update, Section 2.2.3, paragraph 55.
55 Exhibit 47.01, AUC-AUI-16(h).
56 Exhibit 30.01, March update, Section 2.2.3, paragraph 55.
57 Exhibit 47.01, AUC-AUI-16(e).
58 Decision 2009-176, Section 3.3.2, paragraphs 53-55.
59 Exhibit 30.01, March update, Section 2.2.1, paragraph 36.
60 Exhibit 30.01, March update, Section 2.2.1, paragraph 37.
61 Exhibit 47.01, AUC-AUI-16(d).

explanations. The Commission considers that the capital additions for the years 2008 and 2009 are reasonable and prudent and approves the opening rate base as filed.

4.2 Forecast capital expenditures

77. AltaGas's capital expenditures are forecast as identified in Table 6 below.[62] Commencing January 1, 2011, AltaGas changed its overhead capitalization practices, which may impact the year-over-year comparability of the figures.

78. The Commission notes that, as part of AltaGas's March update, AltaGas provided a revised summary of 2010 capital expenditures based on 2010 actuals.[63] The Commission also notes that, with very few exceptions, in the March update AltaGas did not revise the 2010 cost estimates included in most of the specific business cases. The Commission therefore considers that the 2010 business cases represent forecast rather than actual expenditures. As such, the Commission is unable to test the prudence of the 2010 expenditures on a business case by business case basis, unless there is clear information relating to the 2010 actual costs for a specific business case.

Table 6. Capital expenditures

	2008 actual	2009 actual	2010 forecast	2011 forecast	2012 forecast
	($000)				
New business					
Rural	2,276	2,933	2,330	2,027	2,125
Rural subdivision	2,874	2,410	1,597	1,377	1,421
Town	4,774	2,096	2,271	2,213	2,272
Industrial	-	-	828	-	-
Meters	826	597	831	781	796
System betterment	3,729	5,172	7,197	11,488	12,789
General plant	7,765	8,311	12,474	7,770	7,338
Costs of removal	920	706	644	746	598
Total	23,164	22,225	28,172	26,402	27,339

Business cases

79. The Commission reviewed the 43 business cases in the GRA application, 17 of which are examined in this section of the decision because the Commission had concerns with them or because interested parties raised issue with some of these business cases. These include business cases SB06, SB07, SB09, SB10, SB11, SB12 and SB13 related to the replacement of aging pipe, which are examined as a group in Section 4.2.2; business cases SB05 and SB08 related to replacement of pipe and meters, which are examined as a group in Section 4.2.3; business cases CR01, CR02 and CR03 which are examined in Section 4.2.4; and business cases SB01, SB02, SB14, GP12 and GP16 which are examined on a case-by-case basis in Section 4.2.5.

80. The remaining business cases are listed below. The Commission notes that interveners did not take exception to the following business cases, and the Commission has reviewed the

62 Exhibit 30.01, March update, schedules 2.2A - 2.2 E.
63 Exhibit 30.01, March update, Schedule 2.2C.

need for each project along with the cost/benefit analyses and discussions in these business cases. The Commission is of the view that the costs forecast in these business cases are reasonable. Accordingly, the costs associated with the following business cases are approved as filed for inclusion in the calculation of the revenue requirements for the test years:

System Betterment

- SB03 2010-2012 Unidentified Rural Looping
- SB04 2010-2012 Unidentified Relocations
- SB15 2010 PMS AMR
- SB16 2010-2011 PRS Upgrades
- SB17 2010-2012 Stations Refurbishment
- SB18 AMR Modem Replacement
- SB19 Almita Gas Supply
- SB20 Forest Estates Gas Supply
- SB21 Scenic Acres Gas Supply
- SB22 Suncor Replacement Gas Supply

General Plant

- GP01 2010-2012 Asset Management
- GP02 2011 Budgeting & Forecasting System
- GP03 2010 Fixed Asset Application
- GP04 2010 Land Database
- GP05 2010 Learning Management
- GP06 2010 Portable CNG Units
- GP07 2011 Purchase of Land Adjacent to HO
- GP08 2011-2012 Stettler Building-Shop
- GP09 2011 Itron Handheld Replacement
- GP10 2011 Leduc Facility Expansion
- GP11 2011 Microsoft Windows 7 Upgrade
- GP13 2011 Training-Outfitting Facility
- GP14 2012 Athabasca Building-Shop
- GP15 2012 HR Management System
- GP17 CIS Reporting for Compliance with AUC Rules 002 & 003

New Business

- NB01 Baytex

4.2.1 Other capital projects not identified in business cases

81. In addition to the business cases provided by AltaGas identifying specific projects, AltaGas included costs for projects that do not exceed the materiality threshold of $100,000 in its capital expenditure forecasts. AltaGas identified the following capital expenditures that were not included in the business cases as part of the GRA application:[64]

[64] Exhibit 47.12, AUC-AUI-18(b) Attachment.

Table 7. Other capital projects

	2010 forecast	2011 forecast	2012 forecast
	($)		
New business	7,028,700	6,398,700	6,614,000
System betterment	2,377,600	854,600	828,200
General plant	8,925,300	4,008,900	2,696,200
Total	18,331,600	11,262,200	10,138,400

4.2.1.1 New business

82. New business includes expenditures related to rural services, rural subdivision services and mains, town services and mains, and meters. The costs are made up of land, inspection, engineering and other company costs. AltaGas's forecast for 2010 was prepared using current material prices and current contractor rates, and the forecast for service sites installed and meters of mains installed was based on current information. The 2011 forecast includes a moderate increase in new service sites, and applies an increase in the unit rates of five per cent on contractor costs and 2.5 per cent on materials. The 2012 forecast includes a relatively constant growth in new service additions, and applies an increase in the unit rates of three per cent for contractor costs and materials.[65] There were no intervener comments on new business.

Commission findings

83. The Commission recognizes the difficulty in forecasting the expenditures in this area given the need to be responsive to customer growth. Directionally, the new business forecast is consistent with the inflation and growth forecasts provided by AltaGas in the GRA application. The Commission considers the forecast new business for 2010 of $7,028,700 to represent actual capital expenditures and therefore determines the costs to be reasonable and prudent. Additionally, the Commission approves the forecast capital expenditures for new business for 2011 and 2012 for inclusion in the calculation of the revenue requirements.

[65] Exhibit 30.01, March update, Section 2.2.1, paragraphs 38-41.

4.2.1.2 System betterment

84. System betterment expenditures that are not separately identified in business cases include the following:[66]

Table 8. System betterment expenditures

	2010 forecast	2011 forecast	2012 forecast
	($)		
Looping	172,200	79,400	75,900
Stations	841,300	302,000	158,100
Replacements	460,100	290,800	323,800
Other	505,200	182,400	270,400
Major projects:			
PVC replacement	151,400	-	-
Gas supply	247,400	-	-
Total	2,377,600	854,600	828,200

85. With the exception of the comments made by the UCA regarding the replacement component of system betterments, discussed in Section 4.2.3, there were no other intervener comments on the system betterment costs that were not included in business cases.

Commission findings

86. The Commission has considered the forecasts for system betterments that were not included in business cases. The Commission has reviewed the explanations provided by AltaGas and considers that the forecasts are reasonable. The Commission considers the system betterment costs for 2010 of $2,377,600 to represent actual capital expenditures and therefore determines the costs to be reasonable and prudent. Additionally, the Commission approves the forecast capital expenditures for system betterment for 2011 and 2012 for inclusion in the calculation of the revenue requirements.

66 Exhibit 47.12, AUC-AUI-18(b) Attachment.

4.2.1.3 General plant

87. General plant expenditures that are not separately identified in business cases include the following:[67]

Table 9. General plant expenditures

	2010 forecast	2011 forecast	2012 forecast
	($)		
Structures	5,391,700	1,104,200	-
Office equipment	583,500	511,200	143,000
IS&T - tangible	584,800	375,200	745,000
IS&T - intangible	693,200	386,600	204,700
Vehicles	828,700	1,172,100	1,210,000
Heavy work equipment	310,500	128,700	132,000
Tools & work equipment	349,700	203,800	220,000
Communication equipment	95,100	127,100	41,500
Other	88,100	-	-
Total	8,925,300	4,008,900	2,696,200

88. The major part of the structures and office equipment expenditures in 2010 and 2011 relates to the construction of the addition to the Leduc Head Office included in a 2009 business case that was provided in AltaGas's 2008-2009 GRA,[68] and subsequently deferred by AltaGas in an update to that application.[69] The 2010 IS&T intangible expenditures include the final costs associated with Rule 004: *Alberta Tariff Billing Code Rules* (Rule 004) included as a 2008 business case. The 2010 heavy work equipment expenditures include replacement of a fork lift, skid steer and trencher.[70] The remaining expenditures represent normal levels for replacement of computer equipment, furniture, vehicles and tools. There were no intervener comments on general plant.

Commission findings

89. The Commission has considered the forecasts for general plant that were not included in business cases, and the explanations of these expenditures provided by AltaGas.[71] The Commission finds that AltaGas provided adequate explanations of the costs and the Commission also understands that the most material dollars relate to projects that were supported by business cases in AltaGas's 2008-2009 GRA. The Commission considers the general plant costs for 2010 of $8,925,300 to represent actual capital expenditures and therefore determines the costs to be reasonable and prudent. Additionally the Commission considers that the forecast general plant costs for 2011 and 2012 are reasonable and approves them for inclusion in the calculation of the revenue requirements.

[67] Exhibit 47.12, AUC-AUI-18(b) Attachment.
[68] Proceeding ID No. 88, Exhibit 1, Business Case GP409.
[69] Proceeding ID No. 88, Exhibit 14.01, Section 3.3.3, page 43.
[70] Exhibit 47.01, AUC-AUI-18(b).
[71] Exhibit 47.01, AUC-AUI-18(b).

4.2.2 Mains replacement projects (SB06 - 2010-2012 Superior PVC Replacement, SB07 - 2010 Nacmine PE Replacement, SB09 - 2011 PE3306 Replacement Athabasca, SB10 - 2011-2012 Non-Certified PE Replacement, SB11 - 2012 Steel Tubing Mains, SB12 - PVC Replacement 2011-2012 and SB13 - Steel Main Replacement)

90. AltaGas submitted a number of business cases associated with replacing aging pipe due to safety and reliability concerns. The mains replacement projects have been split into different projects by AltaGas according to the type of pipe to be replaced and, in some circumstances, geographic regions. The risks associated with different types of pipe vary due to the physical characteristics of the pipe, creating the need for the separate projects.

91. In Business Case SB10, AltaGas is proposing to replace non-certified polyethylene (PE) pipe. AltaGas described the risks associated with non-certified PE pipe to be leakage due to the brittle nature of the pipe and how it reacts in areas of concentrated stress, such as areas where mechanical squeeze tools have been used, or where other external stresses like rock impingement, frost cycles and traveled surface stresses occur. In the 1970s, CSA standards were established to ensure the quality of PE pipe. PE mains and services originally manufactured and installed prior to 1973 are classified as non-certified or received an interim certified designation if manufactured between 1973 and 1975. AltaGas is proposing to replace the 300 km of PE pipe installed prior to 1975 that it operates, over a 10-year period, with 16 km to be replaced in 2011 at a cost of $544,300, and 36 km to be replaced in 2012 at a cost of $1,248,500.

92. In addition to Business Case SB10, AltaGas included Business Case SB07 to deal with the Nacmine system, which is comprised of PE pipe. AltaGas identified the same risks with this system as with other non-certified PE pipe installed prior to 1975. AltaGas is planning to replace 6.8 km at a cost of $674,600 in 2010.

93. AltaGas also included Business Case SB09 to deal with PE3306 pipe in the Athabasca region. PE3306 resin was used during the 1970s in the manufacture of polyethylene pipe. Over time, pipe manufactured with this particular resin displayed signs of premature aging identified by the inordinate number of leaks occurring in these systems. In the early 1980s, AltaGas undertook a replacement program for all known PE3306 pipe installed in its system throughout the province. While this program was successful in replacing the majority of the suspect pipe, small sections of previously unidentified PE3306 still exist, including the section recently found in the Athabasca region. AltaGas is planning to replace 5.7 km of PE3306 pipe in the Athabasca region in 2011, at a cost of $153,900.

94. In Business Case SB12, AltaGas is proposing to replace polyvinyl chloride (PVC) pipe that was installed in the late 1960s. AltaGas described this pipe as brittle and unpredictable to work with. Tie-ins are extremely difficult and hazardous due to the nature of the pipe, and the use of stopping equipment is also hazardous. In addition, many sections were installed without the use of tracer wire, making locating the pipe difficult in certain areas, and increasing the risk to the public or company employees working on or around the pipe. AltaGas is planning to replace 4.4 km of this pipe in 2010 at a cost of $98,100, 39.5 km in 2011 at a cost of $1,800,300, and 47 km in 2012 at a cost of $2,210,900.

95. In Business Case SB06, AltaGas set out its plans to deal with the Superior system in the Westlock area that is also comprised of PVC pipe. AltaGas identified the same risks with this

system as with other PVC pipe. AltaGas is planning to replace 20.7 km of this pipe in 2010, at a cost of $562,100.

96. In Business Case SB11, AltaGas is proposing to replace steel tubing mains and services. AltaGas stated that the risks associated with this type of pipe have arisen from the extensive use of mechanical compression fittings, and the use of welding practices that are now considered substandard. Steel tubing has yellow jacket polyethylene coating; however the 0.0035 inch wall thickness of the pipe is much thinner than typical steel pipe, which has a thickness of 0.109 inches. Consequently, any damage to the coating may result in more rapid corrosion leakage. In addition, the design of the system does not allow tapping or stopping equipment to be used, meaning there is no effective means of emergency control, connection for future services, or disconnection of existing services without the loss of supply to all customers on the relevant main line network. The cost of the replacement program for 2012 is expected to be $809,500, with an ongoing but undefined[72] replacement program to continue afterwards.

97. In Business Case SB13, AltaGas is proposing to replace steel pipe that was installed prior to 1957. AltaGas identified risks related to corrosion damage, weld failures and compression fitting failures with this type of pipe. This type of pipe was either installed without coating (also referred to as bare steel pipe) or with coating that provides minimal protection against corrosion. In addition, the pipe was not cathodically protected until at least 1956, and it is probable that some corrosion damage occurred between the time of installation and the time at which cathodic protection was applied. AltaGas has experienced a high frequency of corrosion leaks, weld failures and compression joint failures on pipe of this type and vintage over the past 20 years. AltaGas is planning to replace the 150 km of pipe of this type and vintage over a 10-year period, at a cost of $580,700 in 2010, a cost of $1,529,500 in 2011, and a cost of $2,205,300 in 2012.

98. For all of the above referenced business cases for aging pipe replacement, AltaGas considered the status quo alternative of operating the systems in their current condition. In each case, the status quo alternative was dismissed by the company, given the significance of the safety risks identified.

99. AltaGas considered the use of ground penetrating radar and the insertion of tracer wire as alternatives in circumstances where there are risks associated with not being able to locate PVC pipe. Ground penetrating radar was dismissed as an alternative by AltaGas because testing revealed unsatisfactory results. The insertion of tracer wire was also dismissed as an alternative by AltaGas because it can only be done on a temporary basis, and the temporary wire must be removed before resuming service to the location.

100. AltaGas also considered a more selective replacement program for steel mains, which would have involved identifying areas where corrosion damage exists, replacing compression fittings, and inspecting welds. AltaGas determined that it would not be practical to undertake such a program because it would be as costly as replacement, and it would be difficult to ensure that all problem areas had been identified.

Views of the parties

101. The UCA argued that AltaGas had not justified any of the proposed mains replacement programs and submitted that these business cases should be rejected. In the UCA's view, the

[72] Exhibit 50.01, UCA-AUI-14.

business cases identify various risks associated with each type of pipe in question, characterize these risks as unacceptable, and then conclude that the only viable alternative is to replace all of the facilities over a 10-year period. There is no demonstration in any of these cases that anything has changed, or that any of the identified risks are new or are increasing in any systematic way, or that the processes and procedures AltaGas has adopted for dealing with those risks over the past 40 years were inadequate. There was no quantitative or economic analysis of any other alternatives. Further, the status-quo alternative in each of these cases, namely carrying on with normal maintenance and natural replacement and retirement activity, was rejected without any substantive analysis.[73]

102. The UCA favoured an approach that relied on the natural retirement pattern of the system, with the continuation of existing processes and procedures, as opposed to the pre-retirement replacement program proposed by AltaGas.[74]

103. AltaGas objected to the UCA's characterization of the GRA application as a pre-retirement program. It argued that the "wait and see reactive approach" advocated by the UCA was unreasonable and out of step with the public safety expectations of customers and regulators. It added that workers, customers and the public would be subjected to unwarranted risk if AltaGas waited for failures to happen before replacing lines. AltaGas pointed out that it had identified a specific need to replace less than one per cent of the 20,000 km of pipe it operates, over three years, and less than five per cent over 10 years.[75]

104. The UCA clarified its position to state that it is not necessarily opposed to a structured replacement program, but its objections were more with the fact that AltaGas had not provided sufficient justification for the proposed replacement programs. The UCA argued that, if AltaGas wants to propose a new approach and that new approach imposes incremental costs on customers, it should be required to demonstrate that its existing practices are no longer sufficient. The UCA recommended that AltaGas be required to demonstrate the reasonableness of its completely new strategy, and suggested that it has not done so.[76]

105. In an effort to better understand the risks associated with the pipeline replacement programs, at the hearing, the Commission asked AltaGas to provide a risk matrix analysis on the various types of pipe. AltaGas provided the following response to the request:[77]

[73] Exhibit 71.01, UCA evidence, A12.
[74] Exhibit 71.01, UCA evidence, A16.
[75] Exhibit 143.01, AltaGas argument, page 10.
[76] Exhibit 150.01, UCA reply argument, paragraph 27, page 10.
[77] Exhibit 132.12, AltaGas response to undertaking, Transcript, Volume 6, page 1672, line 24.

Table 10. Pipeline risk assessment matrix

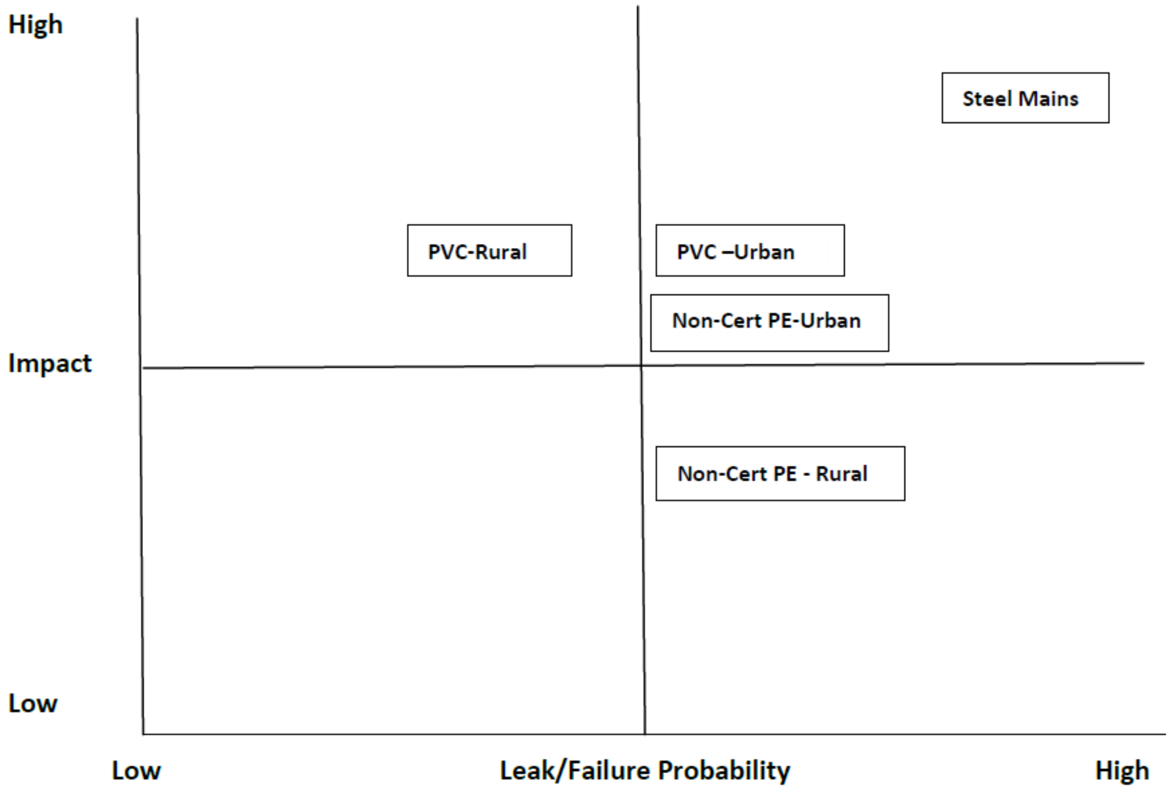

Table 11. Summary of pipeline replacement projects

Year	Steel mains	PVC urban	PVC rural	Non-Cert PE urban	Non-Cert PE rural
2010	5.9km; $0.7M -Leduc	None	25.1km; $1.0M -Superior	6.5km; $0.7M -Nacmine	None
2011	13.7km; $2.1M -Leduc, Fort Kent	13.8km; $0.8M -Leduc, Rosedale, Riviere Qui Barre, Neerlandia, Cardiff, Green Acres, Sunnyville	34.9km; $2.1M -Botha, Donalda, Leduc Rural	8.4km; $0.6M -Neerlandia, Cardiff, Rosedale, Sunnyville, Stettler	3.5km; $0.2M -Botha, Donalda, Leduc Rural
2012	22.4km; $4.0 M -Leduc, Athabasca	2.4km; $0.2M -Beaumont West	44.6km; $2.7M -Morinville Rural	33.3km; $1.6M -Erskine, Red Willow, Barrhead, Busby, Manola, Vega, Looma, Kavanagh, Carbondale, Sturgeon View, Green Acres	2.7km; $0.2M -Beaumont West

106. In reply argument, the UCA drew comparisons to Decision 2011-450[78] on the ATCO Gas 2011-2012 GRA. The UCA suggested that it would be appropriate for the Commission to apply some of the directions from Decision 2011-450 to this proceeding when it stated:

> …In Decision 2011-450 the Commission struck a balance between those competing considerations by directing ATCO Gas to replace its older vintage plastic mains over a 20 year period. If AUI and ATCO Gas are to be treated similarly on the core question of whether their older plastic mains need to be replaced, the UCA believes that it would be reasonable to also treat them and their customers similarly in relation to the cost burden that the planned replacements will impose on customers by scheduling the replacement program over a similar period.[79]
>
> …The UCA acknowledges that AUI's steel mains replacement proposal is different from ATCO Gas's proposal in Proceeding 969 in that AUI has limited its proposal to replacing only pre-1957 facilities over a ten-year period, whereas ATCO Gas proposed to replace all of its steel mains, including ones installed after 1957, over an approximately 100 year period. However, the reasoning stated by the Commission [in] denying ATCO Gas's proposal in Decision 2011-450 is equally applicable to AUI's proposal.[80]

Commission findings

107. In the Commission's view, the matrix helped to provide a more tangible analysis of the levels of risk associated with the different types of pipe that AltaGas proposed to replace, both in terms of the probability of an incident and the severity of incidents when they do occur. The Commission considers that AltaGas has justified the need for the proposed pipe replacement projects, and the Commission notes that AltaGas has recently experienced a catastrophic failure of pipe in the town of Athabasca, resulting in the sudden, uncontrolled release of gas in an urban environment.[81] The Commission is satisfied that the forecasts provided by AltaGas are reasonable for the following reasons. AltaGas has demonstrated that it is taking a methodical approach to replacing the areas of its system that it deems to represent the greatest risk to customers and to its employees, as evidenced by the fact that AltaGas is only proposing to replace one per cent of its system through these programs over the test period. The Commission relies on the risk analysis provided by AltaGas in Exhibit 132, demonstrating that that the risks associated with the types of pipe targeted for replacement are significant. The Commission finds that the UCA did not provide cogent evidence refuting the assessment of risk prepared by AltaGas in Exhibit 132.

108. With respect to the comparisons drawn by the UCA to Decision 2011-450 on the ATCO Gas 2011-2012 GRA, the Commission considers that the findings in that decision do not apply in this case given the differences in the program proposals between the ATCO Gas 2011-2012 GRA and AltaGas's GRA application.

109. With respect to the UCA's recommendation that a 20-year program for plastic pipe should be used, the Commission is not persuaded that a 20-year program is reasonable. There is

78 Decision 2011-450: ATCO Gas (a Division of ATCO Gas and Pipelines Ltd.), 2011-2012 General Rate Application Phase I, Application No. 1606822, Proceeding ID No. 969, December 5, 2011.
79 Exhibit 150.01, UCA reply argument, paragraph 17, page 7.
80 Exhibit 150.01, UCA reply argument, paragraph 18, page 7.
81 Exhibit 47.52, AUC-AUI-108(d) Attachment.

no evidence on the record that suggests a term of 20 years would effectively mitigate the risks that have been established in the circumstances faced by AltaGas.

110. Given the level of risks identified by AltaGas, and in the absence of any viable alternatives to mitigate the risks, the Commission determines that a methodical replacement of the pipe in question is the most reasonable approach at this time. Hence, the Commission approves the capital additions forecast in these business cases for the purposes of calculating the revenue requirements for the test years. This decision applies only to the test years 2010-2012. In future proceedings, if new evidence is provided that risks can be effectively mitigated through a program of longer duration, or through alternative means, the Commission may re-evaluate the terms of the proposed replacement programs.

4.2.3 System betterment - replacements

111. The replacements subcategory of system betterment expenditures includes costs to replace service lines, road crossings and creek crossings. The expenditures for business cases SB05 and SB08 are included in this subcategory of expenditures along with other smaller projects. Since the other smaller projects do not, individually, exceed $100,000, AltaGas did not provide business cases for them in the GRA application.[82]

112. The UCA submitted that AltaGas has had a history of overestimating its forecast replacement costs. The UCA suggested a 30 per cent reduction to forecast replacements based on historical forecasting inaccuracies. The UCA provided the following table to support its position:[83]

Table 12. Historical and forecast replacements expenditures

	($ thousands)	
2008 Forecast 1	1,602	
2008 Forecast 2	1,604	
2008 Approved	1,475	
2008 Actual	1,026	-31 per cent on approved
2009 Forecast 1	2,054	
2009 Forecast 2	1,999	
2009 Approved	1,989	
2009 Actual	1,394	-30 per cent on approved
2010 Forecast 1	605	
2010 Actual	460	-24 per cent on forecast 1
2011 Forecast 1	986	
2011 Updated Forecast	790	
2011 2nd Update	876	
2012 Forecast 1	803	
2012 Updated Forecast	604	
2012 2nd Update	665	

113. AltaGas explained that accurate forecasting of replacement projects initiated by municipalities, the provincial government or customers, which make up a significant portion of the forecast costs, is not possible. AltaGas also noted that the forecast costs for 2011 and 2012 are substantially lower than the actual costs in 2008 and 2009. In addition, AltaGas pointed to the need for Business Case SB08, to move inside meter sets to the outside, because it will improve

82 Exhibit 47.01, AUC-AUI-18.
83 Exhibit 71.01, UCA evidence, A.5, page 5.

safety for workers and customers, and reduce inconvenience and intrusion related to future meter servicing and reading.[84]

114. The UCA argued that AltaGas had conveniently ignored the actual expenditures for 2010 which were 47 per cent and 31 per cent less than the 2011 and 2012 forecasts. It submitted that these discrepancies supported its recommendation for a 30 per cent reduction.[85]

Commission findings

115. With respect to system betterment - replacement projects, the Commission notes that it is inherently difficult to forecast costs for programs driven by municipalities, the province and customers. The test period forecasts are lower than the actual costs incurred in 2008 and 2009. The Commission is not convinced by the UCA argument to reduce forecasts for 2011 and 2012, based on forecasting inaccuracies, because the forecasts are low when compared to historical actual costs. The Commission considers the system betterment - replacement costs for 2010 of $460,100 to represent actual capital expenditures and therefore determines the costs to be reasonable and prudent. Additionally, the Commission considers that the forecast system betterment – replacement costs for 2011 and 2012 are reasonable and approves them for inclusion in the calculation of the revenue requirements, including business cases SB05 and SB08.

4.2.4 Remediation projects (CR01 - 2011 Tennaco Watts, CR02 - 2012 South Clyde, CR03 - 2010 St. Paul Remediation)

116. AltaGas included a number of environmental remediation projects in the GRA application including the Tennaco Watts, South Clyde, and St. Paul business cases. None of these projects were opposed by interveners.

Commission findings

117. The Commissions considers that the remediation costs that are the subject of the above noted business cases should be approved only if the costs are reasonable and necessary for the provision of utility service. Given the record of the proceeding, the Commission is unable to make a determination as to whether these remediation costs are necessary for the provision of utility service. At issue is the question as to whether the facilities (in this case leases) for which the remediation projects are proposed are correctly a cost of AltaGas's utility service. Accordingly, the Commission directs AltaGas to file with the Commission, at the time of the compliance filing, its views as to why these costs are necessary for the provision of utility service, along with supporting evidence. The Commission will make its determination with respect to this matter in its decision on the compliance filing.

4.2.5 Projects and adjustments

4.2.5.1 Morinville gas supply (SB02)

118. AltaGas proposed to replace a significant portion of the existing gas supply provided by ATCO Midstream in the Morinville area due to concerns around increased tariff rates and reduced periods for notice of contract termination. The replacement gas supply is proposed to be provided through a tap into the ATCO Pipelines system to obtain service from a rate-regulated

[84] Exhibit 143.01, AltaGas argument, page 10.
[85] Exhibit 141.02, UCA argument, Section 2.2, paragraph 11.

supply. The forecast cost of the project is $1,035,800. The project payback period is estimated at approximately three years.

119. The UCA initially opposed the project on the basis that AltaGas has a history of over estimating gas supply additions, and raised concerns that the project would not be completed in 2012, as forecast. AltaGas provided an update on the progress of the project at the hearing, indicating that it had an agreement in principle with ATCO Pipelines, and the project is still expected to be completed on schedule.[86] Based on this information, the UCA withdrew its objection to this project because there was sufficient time to negotiate with landowners for rights-of-way and complete construction in 2012 as forecast.[87]

Commission findings

120. The business case identified the company's vulnerability to price changes and possible supply constraints in continuing to obtain gas supply from an unregulated provider. The option proposed will remove this vulnerability and has an estimated payback period of three years. Further, the project with ATCO Pipelines appears to be on schedule. For these reasons, the Commission considers the expenditures associated with this business case reasonable and approves the business case as filed for inclusion in the calculation of the revenue requirements for the test period.

4.2.5.2 Stettler gas supply (SB01)

121. AltaGas proposed to replace the existing gas supply provided by Penn West in the Stettler area due to concerns around a reduction in available supply pressure and deterioration in gas quality. The most feasible alternative to address the issues was determined to be obtaining supply from Apache Canada through the construction of a regulating, metering and odorizing station and 11km of distribution main at a cost of $456,000.

122. The UCA initially opposed the project on the basis that AltaGas has a history of over estimating gas supply additions, and raised concerns that the project would not be completed in 2012 as forecast. AltaGas provided an update on the progress of the project at the hearing, indicating that negotiations with Apache Canada were underway, and the project is still expected to be completed on schedule.[88] Based on this information, the UCA withdrew its objection to this project because there was sufficient time to negotiate with landowners for rights-of-way and complete construction in 2012 as forecast.[89]

Commission findings

123. The business case stated that the current supply is unreliable and inadequate for the company's needs. The Commission considers that the proposed solution addresses the issues identified and considers the forecast expenditures reasonable. Based on the updated information provided by AltaGas, the Commission approves the business case as filed for inclusion in the calculation of the revenue requirements for the test period.

[86] Transcript, Volume 5, pages 1299-1306.
[87] Exhibit 141.02, UCA argument, Section 2.4, paragraphs 16-17.
[88] Transcript, Volume 5, pages 1296-1299.
[89] Exhibit 141.02, UCA argument, Section 2.4, paragraphs 15 and 17.

4.2.5.3 Verdant Valley gas supply (SB14)

124. This project is required to resolve issues related to poor gas quality and reduced pressures from the current supplier, requiring a new source of gas supply. AltaGas stated that the alternative implemented for this project resulted in an actual cost of $360,840, which is less than the forecast cost of $422,700 for the alternative recommended in the business case.[90]

Commission findings

125. The business case stated that the current supply had poor quality and reduced pressure. The Commission considers that the solution as implemented addressed the issues identified and notes that no party objected to the need for the business case.

126. The Commission finds that the expenditure of $360,840 is reasonable and prudent and that it addressed the problems identified. This forecast is approved for inclusion in the calculation of revenue requirement. Because the solution as implemented by AltaGas resulted in lower costs than forecast in the business case, the Commission directs AltaGas to only include the actual cost of $360,840 in the calculation of revenue requirement in the compliance filing.

4.2.5.4 Document management system (GP12)

127. AltaGas applied for the approval of a new document management system. It submitted that all required documents and forms were stored on shared network drives. AltaGas described the existing system as a disorganized procedure for data management because everyone had the ability to create folders on the network drive, leading to a vast store of data with no systematic way of sorting or navigating through it. Consequently, the company experienced problems with version control, duplication and an inability to find desired documents. By implementing this project, AltaGas aimed to decrease replication of documents, improve security, define a cohesive workflow and enhance productivity by providing its employees with a well structured and organized document management system.

128. In its business case, AltaGas identified four alternatives to address its document management needs:

i) install and implement an "off the shelf" document management system

ii) design and install a customized document solution system

iii) update the current network drives and implement a cohesive classification system

iv) continue to use the network drives in their current state

129. Among other analyses, AltaGas undertook a comparative cost analysis and a relative ranking of the four alternatives based on their qualitative features, and determined that the first option was the preferred solution.

130. The estimated cost of alternative one is $589,600 based upon "reviewed quotes and previous projects conducted at AltaGas of a similar nature."[91] The document management software has been purchased and its implementation has already begun. At the hearing AltaGas

---

[90] Exhibit 47.01, AUC-AUI-109(c).
[91] Exhibit 8, Business cases, page 12.

indicated that the project is nearing completion and the actual costs are "in the 400,000-plus range,"[92] which is less than forecast.

Commission findings

131. The Commission observes that interveners have not raised concerns regarding this business case. The Commission considers that the company's attempts to resolve the issues without requiring a software solution were unsuccessful, and therefore accepts the need for the project. Given that the actual costs of the program are now forecast to be less than the original forecast provided in the business case, the Commission approves a forecast of $400,000 for inclusion in the calculation of revenue requirement.

4.2.5.5 Customer information server replacement (GP16)

132. AltaGas applied for the approval of a server replacement for its Financial Information System. By 2012, the server to be replaced will be nine years old and AltaGas submitted it is in need of replacement. Since 2008, additional users and demands for more information have caused an overload on the server and it no longer has the capacity to meet performance standards.

133. In the business case, AltaGas recommended that the eCIS server should be replaced with a new mid-size IBM server; and the JDE platform should be moved to the eCIS server. AltaGas advised during the hearing that it is now proposing to replace both its I-series servers with one I-series server. The new server is forecast to cost approximately $600,000, rather than the $990,000 forecast in the business case. According to AltaGas:

> It [the new server] provides the redundancy that we require plus overall the cost will be less. And we're able to replace the two units or -- with one unit for -- I think the estimate we had in here was something like $900,000. I think right now we're probably looking at more something in the order of $600,000.[93]

Commission findings

134. The Commission finds that the business case supports the need for a new server and observes that the interveners have not raised concern regarding this business case. Given that AltaGas identified a different approach to the project at the hearing, and consequently expects that the actual costs of the project will be less than the original forecast provided in the business case, the Commission approves a forecast of $600,000 for inclusion in the calculation of revenue requirement, which the Commission considers reasonable.

4.3 Business case threshold

135. AltaGas requested that the threshold on capital projects for which it needs to provide a business case be raised from $100,000 to $500,000. AltaGas submitted that, although its projects are not significantly different from projects applied for by other utilities, projects of lesser dollar value receive more regulatory scrutiny than other utilities. AltaGas provided the following table comparing the business case thresholds for various utilities regulated by the AUC:[94]

---

[92] Transcript, Volume 6, page 1520.
[93] Transcript, Volume 6, page 1524.
[94] Exhibit 47.01, AUC-AUI-11, Table 1.

Table 13. Business case thresholds

Other Utilities – Business Case Threshold		
Utility	**Threshold**	**Reference**
AltaGas Utilities Inc.	>$100,000	[Decision 2009-176]
ATCO Gas	>$500,000	[Appl. 1553052, s.2.3, p.7]
FortisAlberta Inc.	>$500,000	[Decision 2010-309, para. 432, p.82]
EPCOR Energy Alberta Inc.	>$250,000	[Appl. 1605758, ID 436 - 2010-2011 RRT Application; p.520]
EPCOR Distribution & Transmission Inc.	>$500,000	[Appl. 1605759, s.1.5.4, para. 230, p.76]
ENMAX Power Corporation	>$500,000	[Appl. 1550487, s.3.3.2, p.61]

Views of the parties

136. The UCA opposed the proposed increase to the business case threshold. The UCA argued that the current threshold for AltaGas appears reasonable based on the impact on customer rates. The UCA noted that neither the number of customers, nor the rate base or revenue requirements has increased five-fold since the last GRA, so the proposed increase is not warranted. The UCA identified that only about half of the business cases filed would remain if the threshold were increase to the $500,000 level proposed by AltaGas and, as a result, a proper assessment of capital expenditures could not occur.

Commission findings

137. The Commission must balance the regulatory burden involved in preparing and analyzing business cases with the need for a thorough testing of applications. While projects undertaken by AltaGas may be similar to projects undertaken by other utilities, the impact of a $500,000 increase in rate base has a different relative impact on the company's customers than it would on customers of a larger utility, given the relative size of AltaGas's rate base. The Commission notes that three of the business cases presented in the GRA application would have been omitted at a $250,000 threshold level. The Commission considers that an increase in the threshold to $250,000 provides an acceptable balance between the regulatory burden to AltaGas and the Commission's responsibility to set just and reasonable rates. Accordingly, the Commission approves a business case threshold of $250,000 for AltaGas.

4.4 Working capital

4.4.1 Lead lag study

138. AltaGas relied on the results of the lead lag study prepared for the 2008-2009 GRA in the GRA application. The company described the process it used to verify that these results would still apply to the current conditions. It explained that:

> AUI conducted a review of the factors with the potential to impact the appropriateness of the forecast expense lags. In particular, it examined the scope of each item, related service periods and/or payment terms.[95]

[95] Exhibit 143.01, AltaGas argument, paragraph 64, page 21.

Views of the parties

139. The CCA took exception to the fact that a new lead lag study was not performed for the GRA application. It cited concerns that the high level review performed by AltaGas could not provide the necessary assurance that the results of the previous study reflect current circumstances. The CCA was also concerned that, because the GRA application will be the last GRA prior to the PBR period, a significant period of time will have elapsed before a new study is undertaken. The CCA identified as a potential problem the difference that exists in the revenue lag when the company's value is compared to that of ATCO Gas. The CCA submitted that a placeholder should be used and a lead lag study undertaken with the amount to be trued up at the next PBR technical filing.[96]

140. AltaGas responded that it appeared nothing of significance had occurred to warrant a change to the revenue lag determined in the 2008-09 GRA study:

> … based on a review of factors having the potential to affect the revenue lag and of results using more current data sets, it appeared nothing of significance had occurred to warrant a change to the revenue lag determined in the 2008-09 GRA study. Therefore, as noted the value approved in the previous GRA continues to be appropriate and reasonable for this Application.[97]

Commission findings

141. The Commission accepts AltaGas's assertion that it performed a review of the factors that have the potential to affect the results of a lead lag study and found no indications to warrant a change in the results. The Commission is not persuaded that the benefits of performing a new study would justify the related costs. Therefore, the lead lag study analysis is accepted as filed.

4.4.2 Gas Utilities Act Code of Conduct Regulation audit

142. Currently AltaGas has a deferral account for *Gas Utilities Act*, R.S.A 2000, c. G-5, *Code of Conduct Regulation* AR 183/2003 audit fees. AltaGas forecast $65,700 for fees in its 2011 revenue requirement for its 2010 audit, but applied for an exemption.[98]

143. Subsequent to the filing of the GRA application, the Commission denied AltaGas's request for an exemption for the 2010 audit year in Decision 2011-193.[99] However, the Commission recommended that AUI explore the opportunity to reduce audit costs by undertaking a joint audit with its affiliate retailers and offered to waive the requirement for each of the companies to appoint an independent auditor.[100]

144. AltaGas indicated that it was able to achieve cost savings by having a joint audit conducted with affiliated retailers. AltaGas identified the 2010 actual costs as "approximately $16,725 in audit fees associated with that audit, which was a substantial savings."[101]

---

[96] Exhibit 142.01, CCA argument, paragraph 19, page 7.
[97] Exhibit 143.01, AltaGas argument, paragraph 61, page 20.
[98] Exhibit 30.01, March update, Section 2.6.3.7.
[99] Decision 2011-193: AltaGas Utilities Inc., Gas Utilities Act Code of Conduct Regulation, AR 183/2003, Audit Exemption, Application No. 1607029, Proceeding ID. No. 1089, May 3, 2011.
[100] Decision 2011-193, Section 6, paragraph 22.
[101] Transcript, Volume 5, page 1090.

Views of the parties

145. The CCA made recommendations with respect to the *Gas Utilities Act Code of Conduct Regulation* audit.[102] The CCA recommended that the audit expense in 2011 should be reduced from $65,700 to $16,725 to reflect cost savings from undertaking a joint audit with its affiliated retailers. The CCA also stated that the relatively small amount of *Gas Utilities Act Code of Conduct Regulation* audit costs does not warrant deferral account treatment.

146. In response, AltaGas stated:

> AUI also notes the CCA suggests this expenditure no longer warrants deferral account treatment. However, while AUI has received prior exemptions, there are no guarantees such exemptions will be granted by the Commission in future or on a regular basis. Further, with respect to cost sharing, there is no assurance such a shared audit approach will be approved for future audits. As well, the amount of audit costs largely depends on the scope of the audit and that scope is subject to the Commission's approval.[103]

Commission findings

147. The Commission considers the audit costs actually incurred in 2010, adjusted for inflation, to be reasonable and prudent for *Gas Utilities Act Code of Conduct Regulation* audit. The Commission approves $16,725 for *Gas Utilities Act Code of Conduct Regulation* audit costs in 2011 and $17,227 in 2012, as the Commission considers these costs to be reasonable. The Commission also considers that the forecast *Gas Utilities Act Code of Conduct Regulation* audit costs are not material enough to warrant continued deferral treatment, noting that "materiality of the forecast amount" is one of the criteria for evaluating deferral accounts, as established in Decision 2003-100.[104]

4.4.3 GST on gas cost recovery rate

148. AltaGas has changed the working capital treatment related to GST on delivery revenues in the GRA application with respect to the exclusion of GST related to the gas cost recovery rate (GCRR). AltaGas explained that, in determining the forecast GST on sales, an error occurred in calculating GST on the normalized delivery and GCRR revenues. The actual value correctly reflected the GST on delivery revenues, exclusive of the GCRR.[105]

Views of the parties

149. The CCA recommended in argument that, unless AltaGas can confirm its computation of the GCRR reflected a specific working capital reduction in relation to GST on GCRR sales, it should be directed, in the compliance filing, to continue the historical treatment approved by the AUC (i.e. to include GST on the GCRR component of sales revenues).[106] As the recommendation from the CCA was not made until argument, it was not subject to thorough review by all parties.

---

102 Exhibit 142.01, CCA argument, page 10, paragraphs 30-31.
103 Exhibit 151.01, AltaGas reply argument, paragraph 85, page 24.
104 Decision 2003-100: ATCO Pipelines, 2003/2004 General Rate Application – Phase I, Application No. 1292783, December 2, 2003, Section 7.2.1, page 115-116.
105 Exhibit 48.01, response to CCA-AUI-1(a)(ii).
106 Exhibit 142.01, CCA argument, paragraph 8, page 3.

150. AltaGas disagreed with the CCA's proposal to continue including GST on gas costs in distribution service cash working capital. Specifically, it argued that, as it is related to default supply, it did not belong in the distribution tariff.[107]

Commission findings

151. Based on the evidence, the Commission accepts the assertions made by AltaGas that the applied-for treatment is correct. The CCA did not indicate what potential problems may exist with AltaGas's new methodology, and why the historical treatment would be preferable. In the absence of the CCA providing a compelling reason to doubt the correctness of the new methodology, the Commission does not consider that it is necessary to continue with the historical treatment. Therefore, the Commission approves the change in the working capital treatment of the GST on GCRR revenues as filed by AltaGas.

4.4.4 GST on land and land rights and accrual adjustments on franchise taxes

152. Both AltaGas and the CCA[108] identified an error in the calculation of the GST capital expenditures portion of working capital with respect to GST on land and land rights. AltaGas acknowledged that land and land rights are not subject to GST and submitted that the base dollars used to calculate the GST capital expenditures portion of cash working capital should be adjusted to exclude those amounts.[109]

153. In addition, both AltaGas and the CCA identified an error in the calculation of the working capital requirements related to franchise taxes, whereby accrual adjustments had been included in the calculation but did not have any actual cash flows associated with them. AltaGas submitted that it was appropriate to adjust the base dollars used to calculate cash working capital in relation to franchise taxes to exclude accrual adjustments.[110] The CCA concurred and asked that the adjustment be reflected in the compliance filing.[111]

Commission findings

154. The Commission notes the errors identified, and accordingly directs AltaGas to correct the GST capital expenditures portion of working capital with respect to GST on land and land rights, and to correct the calculation of working capital to exclude franchise tax accruals in the compliance filing.

4.4.5 Income tax installments

155. The CCA provided a recommendation in argument that AltaGas should use the prior year income tax expense to calculate the working capital requirements of income tax installments. The CCA claims that "this method is more transparent than that used by AltaGas."[112]

156. AltaGas did not object to the CCA's recommendation and indicated that it was prepared to use the prior year's full rate income tax expense as a reasonable proxy for the prior year's income taxes paid and to make the necessary adjustment as part of the compliance filing.[113]

---

107 Exhibit 151.01, AltaGas reply argument, paragraph 78, page 22.
108 Exhibit 142.01, CCA argument, paragraph 26, page 9.
109 Exhibit 143.01, AltaGas argument, paragraph 66, page 21.
110 Exhibit 143.01, AltaGas argument, paragraph 66, page 21.
111 Exhibit 142.01, CCA argument, paragraph 21, page 7.
112 Exhibit 142.01, CCA argument, paragraph 24, page 8.

Commission findings

157. As the recommendation from the CCA was not made until argument, it was not subject to thorough review by all parties. The Commission is aware that calculating current year income tax installments based on the prior year income tax expense is a method acceptable to the Canada Revenue Agency (CRA). However, the Commission is also aware that another method that is acceptable to CRA is the use of a forecast of current year income tax expense in the event that a company expects to incur less income tax expense than in the prior year, in order to avoid making unnecessarily large installments. When forecast income tax expense is less than the prior year income tax expense, the latter method would reduce the working capital requirements of the company. It appears that AltaGas has utilized the latter approach in the GRA application, as evidenced by the income tax installments of zero included in the working capital requirements for 2010 and 2011.[114]

158. The Commission does not understand why the CCA recommended a methodology that acts to increase the tax installment component of working capital requirements of AltaGas beyond the minimum level permitted by CRA. Additionally, because the CCA's recommendation was not made until argument, parties were not able to properly test the recommendation. Based on the material on the record, and on the Commission's understanding of the installment methodologies permitted by CRA, the Commission does not accept the CCA's recommendation.

4.4.6 Other working capital

159. None of the interveners raised concerns with respect to the other areas of working capital that are comprised of:

- *Gas Utilities Act Code of Conduct Regulation* customer care testing costs
- AUC Rule 002[115]and Rule 003[116] survey costs
- AUC assessments
- UCA assessments

Commission findings

160. The Commission has reviewed the forecasts for these items and has determined that they are reasonable based on the costs in previous periods. The Commission therefore approves the forecasts as filed.

5 Capital structure

5.1 2010 deemed equity percentage

161. In the March update, AltaGas used the following figures for the return on equity and common equity percentage for the years 2010 to 2012.[117]

113 Exhibit 151.01, AltaGas reply argument, paragraph 83, page 23.
114 Exhibit 30.01, March update, Schedules 2.6.1E - 2.6.1.F.
115 AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors* (Rule 002).
116 AUC Rule 003: *Service Quality and Reliability Performance Monitoring and Reporting for Regulated Rate Providers and Default Supply Providers* (Rule 003).

Table 14. 2010-2012 return on equity and common equity percentage used by AltaGas

	2010 forecast	2011 forecast	2012 forecast
Rate of return on common equity	9.00%	9.00%	9.00%
Common equity percentage	43.00%	43.00%	43.00%

162. The figures shown in the table were not amended when AltaGas submitted its July update.

163. In the March update, AltaGas stated that the rate of return figure for 2010 and the common equity percentage figure for 2010 were included pursuant to Decision 2009-216.[118] AltaGas added that the forecast rate of return on common equity of 9.00 per cent for 2011 and 2012 is to be used as a placeholder, subject to a separate Commission process for setting the return on equity for those years. Similarly, the common equity percentage amount of 43.00 per cent for 2011 and 2012 is also subject to change to reflect any further process by the AUC for these years.

164. No party to the proceeding submitted any concerns with the placeholders that AltaGas used for 2011 and 2012 for the rate of return on common equity or the common equity percentage. The UCA did, however, make a recommendation that AltaGas's common equity percentage for 2010 be lowered to 35.00 per cent.

Views of the parties

165. The UCA stated that pursuant to the 2009 generic cost of capital (GCOC) decision[119] AltaGas would be entitled in 2010 to a 9.00 per cent rate of return based on a deemed common equity percentage of 43.00 per cent. The UCA stated that AltaGas's high percentage of common equity, relative to transmission companies, reflects the Commission's consideration that, on a prospective basis, AltaGas has slightly more business risk than transmission companies, and because AltaGas is a small company, it has more risk than larger companies. The UCA argued that a large part of this extra risk is associated with forecasting risk in relation to AltaGas's costs and revenues. In response to IR AUC-UCA-4(b), the UCA described forecasting risk as "… the risk that actual costs or volumes would differ from the approved forecast."[120] The UCA argued that, through the timing of the GRA application, AltaGas has in effect eliminated all of its forecasting risk for 2010.

166. The UCA submitted that for the year 2010 it is difficult to see what risk AltaGas incurred, since it effectively filed its GRA application for that year after it already knew what its costs, throughputs and revenues were, and it based its GRA application on those figures. The UCA advocated that, in these unusual circumstances, allowing AltaGas to retain the full benefit of its allowed common equity percentage for 2010, when the underlying basis for that common equity percentage did not exist in 2010, would over-compensate AltaGas's shareholders for the risks that they actually bore in 2010.

117 Exhibit 30.01, March update, paragraphs 141-142.
118 Decision 2009-216: 2009 Generic Cost of Capital, Application No. 1578571, Proceeding ID. 85, November 12, 2009.
119 Decision 2009-216.
120 Exhibit 77.02.

167. The UCA submitted that the benchmark electric transmission utility common equity percentage determined in the 2009 GCOC decision was 35.00 per cent.[121] The UCA recommended that AltaGas's rates should reflect this 35.00 per cent for the 2010 test year and that the resulting increase in the deemed debt percentage for 2010 should be treated at the appropriate short term debt rate.

168. AltaGas disagreed with the UCA's assertion that a large part of the higher business risk of AltaGas is due to forecast risk in relation to its costs and revenues. AltaGas also disagreed that the common equity percentage approved for it in Decision 2009-216 was, and is, only justified on a prospective basis. AltaGas stated that, in previous decisions, the Commission has clearly recognized AltaGas's higher business risks arising from the geographically dispersed nature of its service territory and its relatively small size, and AltaGas included excerpts from Decision 2004-052[122] and Decision 2009-216 to support this statement.[123] AltaGas submitted that these characteristics continue to exist and contribute to AltaGas's higher business risk, regardless of any change in AltaGas's forecasting risk.

169. AltaGas also filed rebuttal evidence on this issue prepared by Dr. Michael J. Vilbert, stating that rate of return levels that give investors a fair opportunity to earn the cost of capital are the lowest levels that compensate investors for the risks they bear. Dr. Vilbert added that an expected rate of return below the cost of capital shortchanges investors. Dr. Vilbert indicated that the cost of capital is an ex ante concept, meaning that investors care about expected returns and not realized returns. Dr. Vilbert argued that the UCA was looking at risk on a purely ex post or after the fact basis.

170. Dr. Vilbert suggested that any investor buying or selling shares in 2010 would have done so at the market prices reflecting the unchanged business risk of AltaGas because, in 2010, investors had no information that the timelines surrounding AltaGas's regulatory application submissions would develop as they have. There was no reduction in risk for investors in 2010 or any other year due to the update of the cost forecasts in March of 2011. Dr. Vilbert added that, to his knowledge the UCA's recommendation to reduce AltaGas's common equity percentage was not supported by any precedent.

171. The UCA stated that it understands that the cost of capital must be evaluated on an ex ante basis as described by Dr. Vilbert. However, the UCA argued that, in this case there never was a true ex ante forecast for ratemaking purposes for 2010 that might or might not match up with the actual results, since the forecast itself was effectively generated ex post, after the year 2010 was over. The UCA also stated that the equity investors in AltaGas are AltaGas Utility Group Inc. and indirectly, AL, both of which knew exactly what AltaGas was doing to obtain approval of rates for 2010. The UCA submitted that the only reasonable inference is that AltaGas and its equity investors knew or should have known, with increasing certainty over time, that the risk of a significant variance between forecast and actual results for 2010 was decreasing.

[121] Exhibit 71.01, UCA evidence, A22.

[122] Decision 2004-052: Generic Cost of Capital, AltaGas Utilities Inc., AltaLink Management Ltd, ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks), NOVA Gas Transmission Ltd., Application No. 1271597, July 2, 2004.

[123] Exhibit 81.01, AltaGas rebuttal evidence, paragraphs 40-42.

172. AltaGas, in its reply argument, countered that the specific ownership of a utility's equity holdings at any given point in time is not one of the considerations when the cost of capital for any utility is set. Rather, AltaGas stated, the utility cost of capital is based on the capital market perception of risk for that utility as a stand-alone entity. AltaGas submitted that, whether or not AltaGas Utility Group Inc. or AL had knowledge that AltaGas was using the actuals for 2010 as the basis for the 2010 forecast, the capital markets from which these entities source their capital had no means of knowing at the beginning of 2010 that AltaGas's forecast risk might be different in 2010.

Commission findings

173. In Decision 2009-216, the Commission awarded common equity percentages for the year 2009 for the utilities that it regulates, including AltaGas. Regarding adjustments to these common equity percentages, the Commission stated the following:

> 413. The equity ratios awarded in this Proceeding will remain in place until changed by the Commission. Individual utilities, or interveners, may apply for changes to equity ratios on the basis of significantly changed circumstances.[124]

174. The Commission accepts the evidence of Dr. Vilbert that assessing the common equity percentage of AltaGas should be from the viewpoint of an investor in equities of comparable risk prior to the test period, and that an ex post analysis of risk as proposed by the UCA is incorrect. Accordingly, the Commission considers it irrelevant that the actual investors are AltaGas Utility Holdings Inc. and indirectly AL. The Commission considers that the equity investors of AL bore the risk associated with their investment in AltaGas and should be afforded the equity returns expected by equity investors in equities of comparable risk, recognizing among other things the forecasting risk associated with AltaGas's 2010 revenue requirement. The Commission regulates on a forecast basis, and to reduce AltaGas's equity thickness after the fact would be tantamount to clawing back the return to which the Commission had determined equity investors were entitled to prior to the test period.

175. The Commission conducted its analysis in this decision from the perspective stated in Decision 2009-216, and considered whether AltaGas's circumstances for 2010 were significantly changed from the time of the decision. The Commission finds that there is no evidence on the record to indicate a significant change to AltaGas's circumstances for 2010 and, by implication, there is no evidence of a change in the risk of AltaGas for 2010. Accordingly, the Commission denies the UCA's request to reduce the common equity percentage of AltaGas for 2010 to 35.00 per cent. AltaGas's common equity percentage for 2010 remains at 43.00 per cent as determined in Decision 2009-216.

176. On December 8, 2011, the Commission issued Decision 2011-474,[125] 2011 GCOC, in which the Commission approved a return on equity of 8.75 per cent for 2011 and 2012.[126] In this same decision the Commission also approved a 43.00 per cent common equity percentage for

---

[124] Decision 2009-216, paragraph 413.
[125] Decision 2011-474: 2011 Generic Cost of Capital, Application No. 1606549, Proceeding ID No. 833, December 8, 2011.
[126] Decision 2011-474, paragraph 167.

AltaGas for the year 2011.[127] Regarding the common equity percentage for 2012, the Commission stated the following in Decision 2011-474:

> 295. The equity ratios awarded in this proceeding will remain in place until changed by the Commission. Individual utilities, or interveners, may apply for changes to equity ratios on the basis of significantly changed circumstances.

177. Consequently, the Commission approves 43.00 per cent as the common equity percentage for AltaGas for 2012 for purposes of determining the revenue requirement for 2012.

178. The Commission directs AltaGas to use rates of return on common equity of 9.00 per cent for 2010 and 8.75 for both 2011 and 2012 in the compliance filing. The Commission also directs AltaGas to use a common equity percentage of 43.00 per cent for 2011 and 2012 in the compliance filing.

5.2 Effective date for the two medium-term debentures issued by AltaGas in 2009

179. On December 4, 2009, AltaGas filed an application with the Commission requesting approval to issue two debentures with an effective date of October 8, 2009. One debenture was for $40 million with an interest rate of 7.42 per cent and a maturity date of April 29, 2014. The second debenture was for $20 million with an interest rate of 6.94 per cent and a maturity date of June 29, 2016. The Commission's findings with regard to this application are in Decision 2010-266.[128]

180. In Decision 2010-266, the Commission approved the issue of the two debentures but with an effective date of June 9, 2010, rather than October 8, 2009 as AltaGas had requested. The Commission did not approve the interest rates, the term of the debt or the issue costs, as the Commission considered that these matters would be better addressed in the broader context of AltaGas's next GRA. Consequently, in the March update, AltaGas stated that it expected the terms and costs of these 2009 debentures to be determined in this proceeding, subject to the outcome of the corresponding review and variance application or any possible appeal process.[129]

181. In the March update, AltaGas indicated that it had applied for a review and variance of Decision 2010-266 with respect to the effective date of the two debentures issued in 2009. AltaGas's position was that the AUC should vary Decision 2010-266 so that these debentures have an effective date of October 8, 2009. The embedded cost of debt schedule for 2010 in the March update included the balances of these two debentures in the opening balance for 2010.[130]

182. The Commission issued its decision on AltaGas's review and variance application of Decision 2010-266 on March 8, 2011. In Decision 2011-084,[131] the Commission stated the following:

---

127 Decision 2011-474, paragraph 294, Table 10.

128 Decision 2011-266: AltaGas Utilities Inc., Application to Issue 2009 Debentures: 7.42 Percent in the Principal Amount of $40,000,000 and 6.94 Percent in the Principal Amount of $20,000,000, Application No. 1605686, Proceeding ID. 418, June 9, 2010.

129 Exhibit 30.01, March update, paragraph 220.

130 Exhibit 30.01, March update, Schedule 3.2D, page 2 of 2 (PDF page 163 of 859).

131 Decision 2011-084: AltaGas Utilities Inc., Decision on Preliminary Question, Review and Variance of AUC Decision 2010-266, AltaGas Utilities Inc., Application to Issue 2009 Debentures, Application No. 1606441, Proceeding ID No. 769, March 8, 2011.

> 97. For the above reasons, the Commission is of the opinion that AUI's review request fails to raise a substantial doubt as to the correctness of Decision 2010-266 as required by Section 12(a)(i) of Rule 016. The Commission denies the review request.

183. In response to AUC-AUI-43(a), AltaGas submitted the following regarding Decision 2011-084:

> a) AUI can confirm Decision 2011-084 related to AUI's Review and Variance Application was issued on March 8, 2011. However, while the AUC did not accept the first three grounds advanced in AUI's application, the Decision left open the opportunity to raise, if necessary, the fourth ground of appeal, namely Decision 2010-266 deprives AUI of the opportunity to earn a fair return. Specifically, Decision 2011-084 states:
>
> > The Commission finds it premature to characterize either of these situations as depriving the utility of the opportunity to earn a fair return since AUI's 2010 revenue requirement (which includes the determination of AUI's "return on debt component of rate base") is currently being assessed by the Commission in AUI's 2010-2012 general rate application. That proceeding is the proper venue to ascertain the costs of AUI's debt for 2010: both the short term interest rate for the period of January through June 2010 and the deemed interest rate that the Commission will determine for the debentures for the test period. [p.20]
>
> Consequently, depending on the outcome of the current GRA application, the issue of whether the impact of Decision 2011-084, together with any impacts from this GRA decision, deprives AUI of a reasonable opportunity to earn a fair return, remains outstanding.[132]

Views of the parties

184. In its evidence, the UCA indicated that, on March 18, 2011, AltaGas filed a discontinuance of its application for Leave to Appeal Decision 2010-266 in the Court of Appeal of Alberta. The UCA submitted that Decisions 2010-266 and 2011-084 and this discontinuance all unequivocally support the fact that the 2009 debentures should not be effective until June 9, 2010. The UCA recommended that AltaGas remove the two debentures from the opening balance of the 2010 embedded cost of debt schedule and replace these amounts with short term debt at an interest rate of 1.20 per cent, which the UCA stated was the average rate for the AltaGas Income Trust bankers' acceptances as at December 31, 2009.[133]

185. In its rebuttal evidence, AltaGas stated that, although the AUC's decision was to establish the effective date of the 2009 debentures as June 9, 2010, the debentures were issued in 2009 and consequently the applicable rates are those associated with these two debentures. AltaGas added that the 1.20 per cent rate recommended by the UCA would violate AltaGas's statutory right to earn a fair return on its rate base under Section 37(1) of the *Gas Utilities Act*, R.S.A 2000 c. G-5. AltaGas also indicated that the 1.20 per cent rate is the rate reported in relation to the AL bankers' acceptances; not AltaGas Utilities Group Inc. or AltaGas. AltaGas submitted that there is no evidence on the record in this or any other proceeding to suggest that AltaGas or AltaGas

132 Exhibit 47.01, response to AUC-AUI-43(a).
133 Exhibit 71.01, UCA evidence, pages 19-20, A. 28.

Utility Group Inc. had access to the short term credit facility of AL or were able to secure such financing at this rate of 1.20 per cent.

Commission findings

186. The Commission considers that AltaGas has not submitted any evidence during the course of this proceeding that would result in the Commission changing the effective date of the two debentures issued in 2009. Despite the fact that the debentures were issued in 2009, the Commission's determination of an effective date of June 9, 2010, for the purposes of determining regulatory revenue requirements, is well within the Commission's authority as described in Section 26(2) of the *Gas Utilities Act*. The Commission may deem interest rates for these two debentures for the period between January 1, 2010 and June 9, 2010 other than the rates of 7.42 per cent and 6.94 per cent, for revenue requirement purposes, if the Commission finds that an alternative interest rate is warranted for determining just and reasonable rates. The interest rate for this period is addressed in Section 5.3.1 of this decision.

5.3 Debt rates

187. AltaGas has requested approval of the interest rates associated with a number of debentures. The Commission has prepared the following table which includes details about some of these debentures and the corresponding parent company debentures.

Table 15. Details of debenture issues

Date	Company	Amount issued	Term	Interest rate	Application submission date	AUC approved effective date
April 29, 2009	AltaGas Income Trust	$200 million	5 years	7.42%	N/A	N/A
June 29, 2009	AltaGas Income Trust	$100 million	7 years	6.94%	N/A	N/A
March 25, 2010	AltaGas Income Trust	$200 million	7 years	5.49%	N/A	N/A
November 26, 2010	AltaGas Ltd.	$175 million	7 years	4.60%	N/A	N/A
October 8, 2009	AltaGas Utilities Inc.	$40 million	5 years	7.42%	December 4, 2009	June 9, 2010
October 8, 2009	AltaGas Utilities Inc.	$20 million	7 years	6.94%	December 4, 2009	June 9, 2010
October 4, 2010	AltaGas Utilities Inc.	$30 million	7 years	5.49%	September 2, 2010	October 4, 2010

Notes: The October 8, 2009 debenture issues were approved in Decision 2010-266.
The October 4, 2010 debenture issue was approved in Decision 2010-448.

5.3.1 Debt rates – 2009 debentures

Views of the parties

188. The UCA expressed a concern about the interest rates associated with the two debentures from 2009. The UCA added that, while it considers that AltaGas should obtain its medium-term debentures from its indirect parent, AL, debt should be a reasonable proxy for current market conditions.

189. The UCA indicated that the effective date for the two debentures from 2009 was determined to be June 9, 2010. The UCA added that, although AL did not go to the market in June, 2010, it did go to the market on March 25, 2010 and issued $200 million of seven year notes at a coupon rate of 5.49 per cent. The UCA submitted that it would be reasonable to use the 5.49 per cent rate as a proxy for the cost rate for the two debentures from 2009.

190. AltaGas argued that the interest rates for the two debentures from 2009 are within the range of rates that would have been available to either AltaGas or AltaGas Utility Group Inc. from a placement in the private term debt market in either October or December, 2009. AltaGas stated that the rates proposed are reasonable as they reflect the best rates available to AltaGas at the time the two debentures were issued.

191. AltaGas submitted that, notwithstanding the Commission's decision that the effective date of the two debentures from 2009 was June 9, 2010, these debentures were indeed issued by AltaGas on October 8, 2009, and were on AltaGas's books as of the same date. AltaGas added that, with regard to the year 2010, AltaGas paid interest at the rates of 7.42 per cent and 6.94 per cent from January 1, 2010 to June 9, 2010 and that it should be allowed to recover the actual interest paid during this period. AltaGas stated that "any recovery of rates at less than 7.42 per cent and 6.94 per cent will constitute a direct hit to the company's bottom line"[134] and impact AltaGas's opportunity to earn a fair return.

Commission findings

192. Despite the finding in Decision 2010-266 that the effective date for the 2009 debentures is June 9, 2010, the Commission is not prepared to deem interest on these debentures at a short-term interest rate for the period of January 1, 2010 to June 9, 2010. The Commission considers that the debentures were issued and on the books of AltaGas as at October 8, 2009, and the period between October 8, 2009 and June 9, 2010 would be a significant period of time to carry short-term debt. In addition, the delay in the effective date of these debentures was not anticipated by AltaGas when it applied in December, 2009 for approval of these debentures.

193. The Commission considers that the relevant test associated with interest rates for debentures is an assessment of the prudence of the interest rates at the time that AltaGas received the proceeds, not when AL received the proceeds. There is no evidence on the record of this proceeding that details the exact interest rates at which AL would have been able to issue debt on October 8, 2009. Consequently, the Commission has examined debt issues made by comparable companies during this time period, as well as any information available regarding what interest rate ranges were in effect at this time, and deemed a prudent interest rate for the two debentures.

194. In Table 12.0 of the March update, AltaGas provided the following information regarding the range of estimated interest rates for October 8, 2009.

Table 16. Range of estimated coupon rates

Borrower in the market	Range of estimated annual coupon rates		Issuance market (In October 2009)
	5-year term debt	7-year term debt	
AltaGas Utilities Inc.	5.73% - 7.42%	6.19% - 7.03%	private
AltaGas Ltd.	5.73% - 6.10%	6.19% - 6.53%	public

195. As pointed out during the oral hearing, the information in Table 16 is a summary of information provided to AltaGas by Scotiabank, the Royal Bank and TD Securities as to what the indicative rates were at that time. Mr. Green, a witness for AltaGas, added that "… those are not actual contracted rates."[135] In examining the information in Tables 15 and 16, it is clear that the

[134] Exhibit 143.01, AltaGas argument, paragraph 110.
[135] Transcript, Volume 3, page 839, lines 23-25; page 840, lines 1-5.

interest rates for AL decreased between April 2009 and October 2009. The April 2009 AL issue was at an interest rate of 7.42 per cent while the range shown in Table 16 indicates that, for a five-year debenture in October 2009, the range of interest rates was 5.73 per cent to 6.10 per cent.

196. The Commission considered the information provided by AltaGas in response to an interrogatory in which the Commission requested that AltaGas provide evidence of debt issues made by companies with a similar credit rating to AL during the 2009 time period.[136] This information was prepared by BMO Capital Markets. It indicates that there were two debentures, each with a five-year term, issued in October 2009. The associated interest rates are 4.10 per cent and 5.65 per cent.

197. Given the above, the Commission deems the interest rate for the two debentures issued to AltaGas on October 8, 2009 to be the 5.49 per cent rate associated with the seven-year note issued by AL on March 25, 2010, because it is based on an actual debt issue made by AL and the 5.49 per cent interest rate is within the range of the interest rates achieved in the market, for BBB rated companies. While the interest rate associated with a five-year note on March 25, 2010 would more than likely have been lower than the 5.49 per cent interest rate actually negotiated by AL on the March 25, 2010 seven-year note, the Commission considers it reasonable to approve the rate of 5.49 per cent for both debentures from 2009, given the evidence on the range of interest rates.

198. **The Commission directs AltaGas, in the compliance filing, to use an interest rate of 5.49 per cent for the two debentures issued by AltaGas on October 8, 2009, and to reflect this interest rate as effective on January 1, 2010.**

199. The term of the two debentures has not yet been addressed. No party objected to the maturity dates on the two debentures. While the terms of the debentures are relatively short compared to the longer terms associated with other utilities,[137] the reason for the use of medium term notes was expressed by Mr. Green, a witness for AltaGas, as follows:

> For one, kind of the largest reason for that is we actually don't have access to debt that is longer than seven years. So seven years is the longest debt that we do have access through mirroring. So that's probably the largest reason on what we're referring to here.[138]

200. Based on AltaGas's inability to access debt of a term greater than seven years, and because the maturity dates are consistent with the corresponding issues of AL, the Commission approves the maturity date of April 29, 2014 for the $40 million debenture issued on October 8, 2009 and the maturity date of June 29, 2016 for the $20 million debenture issued on October 8, 2009 for the purposes of calculating revenue requirement.

---

136 The information was provided in Exhibit 47.23, AUC-AUI-45(e) Attachment.

137 In Decision 2012-010 regarding debenture issues for ATCO Gas and Pipelines Ltd. for example, as previously referred to in this Decision, the Commission approved one debenture with a 30-year maturity and another with a 50-year maturity. Decision 2012-010: ATCO Gas and Pipelines Ltd., Application to Issue Debentures to CU Inc., 4.543 Per Cent Debenture in the Principal Amount of $171,400,000, 4.593 Per Cent Debenture in the Principal Amount of $68,600,000, Application No. 1607871, Proceeding ID No. 1557, January 11, 2012.

138 Transcript, Volume 4, page 965, lines 12-18.

5.3.2 Debt rate – 2010 debenture

201. As indicated in Decision 2010-448, AltaGas applied on September 2, 2010 for approval to issue a $30 million debenture with an effective issue date of October 4, 2010 and a maturity date of March 27, 2017. In response to AUC-AUI-48(d),[139] AltaGas confirmed that the interest rate associated with this debenture was based on the interest rate associated with $200 million of medium term notes that AL had issued on March 25, 2010, and that the associated interest rate was 5.49 per cent. In Decision 2010-448 the Commission approved the issue date of October 4, 2010 and the principal amount of the debenture. The Commission considered that all other matters regarding the debenture, including the interest rate, term of the debt and issue costs, would be best decided within the context of AltaGas's next general rate application.[140]

Views of the parties

202. The UCA expressed a concern with using the proposed interest rate for a note that was issued more than six months prior to the effective date of October 4, 2010. The UCA indicated that, on November 23, 2010, AL issued a seven-year note at an interest rate of 4.60 per cent, 89 basis points lower than the 5.49 per cent rate that AltaGas applied for. The UCA submitted that, as a wholly-owned subsidiary of AL and presumably with the advice of AltaGas Utility Group Inc. on financial services, AltaGas should have been aware that rates had declined significantly since March, 2010. The UCA added that, more importantly, AltaGas should have been aware that AL was going to the market in November 2010 and that obtaining a debenture based on rates from March 2010, rather than a debenture based on expected rates from November 2010, would result in higher costs to AltaGas's customers. The UCA recommended that a reasonable proxy for the October 4, 2010 debenture interest rate would be 4.60 per cent.

203. AltaGas responded that it is not privy to the proposed timing of AL's debt issues and cannot predict with any certainty what the future interest rates of AL's medium-term notes will be. AltaGas added that the timing, tenor and size of medium-term note issuances are determined by AL's treasury department, which oversees the capital requirements of all of the businesses of AL, not just the utility operations. AltaGas stated that the decision to issue a medium-term note is often a time-sensitive matter of days, not weeks or months. AltaGas added that business units are often notified by AL's corporate treasury on any medium-term note issuance after the fact. AltaGas submitted that, in this case, the timing of the $30 million debenture in October 2010 was driven by the need to refinance a $30 million debenture that matured in October 2010. AltaGas consequently submitted that there is no basis for the UCA's recommendation to use the rate applicable to the November 23, 2010 medium-term note of AL in relation to AUI's October 4, 2010 debenture.

Commission findings

204. As mentioned above, the Commission considers that the relevant test associated with interest rates for debentures is an assessment of the prudence of the interest rates at the time that AltaGas received the proceeds, not when AL received the proceeds. There is no evidence on the record of this proceeding that details the exact interest rates at which AL would have been able to issue debt on October 4, 2010. Consequently, the Commission has examined debt issues made by comparable companies during this time period, as well as any information available regarding what interest rate ranges were in effect at this time, and deemed a prudent interest rate for the

139 Exhibit 47.01.
140 Paragraph 12 of Decision 2010-448.

October 4, 2010 issue. On November 26, 2010, AL issued a seven year note at 4.60 per cent. During the period between March 25, 2010, when AL issued the seven-year note at 5.49 per cent, and November 26, 2010, interest rates declined. The period between October 4, 2010 and November 26, 2010 is approximately eight weeks, and the period between March 25, 2010 and October 4, 2010 is approximately 28 weeks. The Commission considers the November 26, 2010 interest rate to be the best evidence on the record of interest rates on October 4, 2010 given its proximity to the date.

205. Given the above, the Commission deems the interest rate for the debenture issued to AltaGas on October 4, 2010 to be the 4.60 per cent rate associated with the seven-year note issued by AL on November 26, 2010, because it is based on an actual debt issue made by AL in reasonable proximity to October 4, 2010.

206. The Commission directs AltaGas, in the compliance filing, to use an interest rate of 4.60 per cent for the $30 million seven-year debenture issued by AltaGas on October 4, 2010.

207. Regarding the term of the debenture; given that AltaGas is unable to access debt of a term greater than seven years, and because the maturity date is consistent with the corresponding issue of AL, the Commission approves the maturity date of March 27, 2017 for the $30 million debenture issued on October 4, 2010 for the purposes of calculating revenue requirement.

5.3.3 Debt rate – 2012 debenture

208. In the March update, AltaGas included a forecast debt issue for 2012 of $28 million with a five-year term and a forecast interest rate of 4.77 per cent.[141] AltaGas based this forecast rate on a mid-2012 forecast for Canadian five year bond yields of 3.07 per cent and a credit spread of 1.70 per cent, as clarified in the response to AUC-AUI-43(a).[142]

209. In response to an undertaking, AltaGas submitted an update to the forecast for Canadian five year bond yields and the credit spread.[143] This update included a forecast of 2.00 per cent for Canadian five year bond yields and a credit spread of 2.40 per cent for a total forecast interest rate of 4.40 per cent.

210. In its reply argument, AltaGas submitted that 4.40 per cent is the appropriate interest rate to be used in determining AltaGas's revenue requirement. In its argument, the UCA stated that it was prepared to accept the updated figure of 4.40 per cent.

Commission findings

211. The Commission considers that the methodology used by AltaGas to forecast its interest rate associated with the 2012 debenture is acceptable and reflects the most recent forecasts on the record of the proceeding, which were provided during the oral hearing.

212. The Commission directs AltaGas, in the compliance filing, to use an interest rate of 4.40 per cent for the $28 million five-year debenture it is forecasting to issue in 2012.

[141] Exhibit 30.01, March update, paragraph 223. The 4.77 per cent is exclusive of a forecast annual issue cost percentage of 0.25 per cent.
[142] Exhibit 47.01.
[143] Exhibit 117.01, AltaGas response to undertaking, Transcript, Volume 3, page 916, line 7.

5.4 Debt issue costs

213. In the March update, AltaGas requested approval of the following debentures and their associated debt issue costs.

Table 17. Debentures and issue costs included in the application for approval

Issue date	Principal amount	Issue costs as an annual percentage
October 8, 2009	$40 million	0.15%
October 8, 2009	$20 million	0.23%
October 4, 2010	$30 million	0.21%
2012	$28 million	0.25%

214. The Commission commented on the information provided by AltaGas with respect to debt issue costs when it approved the issuance of the $30 million debenture for 2010 in Decision 2010-448 and included the following direction:

> 13. As one example, an area on which the Commission anticipates seeking more detailed information from AUI in the GRA is the allocation of issuance costs to AUI. To that end, the Commission directs AUI to provide more information on the allocation methodology used in allocating the issuance costs of the Debenture to AUI in its next GRA filing.

215. AltaGas provided its response to this direction in Section 3.2.2 of the March update. AltaGas stated that the issue costs associated with its 2010 debenture included in the 2010-2012 GRA reflect the fair market value of third party services and are separate from the financial market services provided by AltaGas Utility Group Inc. to AltaGas. AltaGas indicated that issue costs are the costs directly attributable to a specific debt issuance. AltaGas added that, with respect to underwriter's commissions, these vary with the size of the debenture issue and are allocated on a pro-rata basis. AltaGas stated that the other non-commission issue costs, such as the rating agency fees, legal fees, auditing fee and expenses associated with the preparation of the prospectus, are generally fixed and will not vary significantly with the size of the debt issuance. Consequently, AltaGas has not allocated these on a pro-rata basis but has included amounts that reflect the fair market value of these services.

Views of the parties

216. AltaGas argued that, even if the amount of the debt it receives is less than the size of the related medium term note issued by AL, the other non-commission costs would not vary significantly. AltaGas added that to arbitrarily apply a pro-rata adjustment factor to these non-commission costs would result in the other business units of AL unfairly subsidizing the real issue costs of AltaGas's debt requirement. AltaGas indicated that this distorts the fair market value of these third party costs, as these amounts will need to be incurred by the debt issuer, be it AL or AltaGas, to secure the required amount of debt financing.

217. The UCA submitted that it is not appropriate to view the issue costs on a stand-alone basis. The UCA stated that AltaGas receives financial market services from AltaGas Utility Group Inc. and AL, and pays for these services through inter-affiliate shared costs. The UCA argued that AltaGas should only pay for its pro-rata share of all the issue costs. The UCA indicated that AltaGas's proposed treatment regarding issue costs would result in a

disproportionate amount of the AL issue costs being recovered through AltaGas and therefore AL would benefit from reduced issue costs at the expense of AltaGas's customers. The UCA submitted that, in fairness to customers and in line with the long-standing precedent set by CU Inc. and the ATCO utilities, issue costs should be allocated among AL and its subsidiaries on a pro-rata basis. The UCA recommended that the following issue costs be used:

Table 18. Debentures and issue costs recommended by the UCA

Issue date	Principal amount	Issue costs as an annual percentage
October 8, 2009	$40 million	0.10%
October 8, 2009	$20 million	0.08%
October 4, 2010	$30 million	0.10%
2012	$28 million	0.10%

218. AltaGas responded that there was no evidence on the record of this proceeding to explain why the ATCO utilities and CU Inc. chose to pro-rate issue costs, nor is there any way to test the applicability of this arrangement to AltaGas's circumstances. AltaGas submitted that such untested evidence should not be given any weight. AltaGas referred to the situation between ENMAX Power Corporation and The City of Calgary and added that, even though ENMAX Power Corporation borrows from The City of Calgary indirectly through ENMAX Corporation; ENMAX Power Corporation is charged a 0.25 per cent administration charge on its debentures by The City of Calgary. AltaGas submitted that the standalone treatment is appropriate for AltaGas's debt issue costs, is not inconsistent with current AUC precedents, and is consistent with the standalone basis applied in determining the cost of capital.

Commission findings

219. The Commission considers that the debt issue costs should be allocated to AltaGas based on its pro-rata share of the total debenture. This methodology is fair and prevents possible cross-subsidization.

220. In Section 5.3.1 of this decision, the Commission found that the deemed interest rate for the 2009 debentures is 5.49 per cent, which is the interest rate associated with AL's seven-year debenture issued on March 25, 2010. To be consistent, the Commission considers that the debt issue costs associated with the March 25, 2010 issue should be used as the basis for allocating the debt issue costs for the 2009 debentures. The total issue costs of the March 25, 2010 issue were $1.122 million,[144] which represents 0.56 per cent of the total debt issue of $200 million. The Commission directs AltaGas, in the compliance filing, to allocate the debt issue costs on the 2009 debentures using 0.56 per cent as the basis for the calculations.

221. In Section 5.3.2 of this decision, the Commission found that the deemed interest rate for the 2010 debenture is 4.60 per cent, which is the interest rate associated with AL's seven-year debenture issued on November 26, 2010. To be consistent, the Commission considers that the debt issue costs associated with the November 26, 2010 issue should be used as the basis for allocating the debt issue costs for the 2010 debenture. There is no evidence in this proceeding which details the issue costs associated with the medium term notes issued by AL on November 26, 2010. The Commission directs AltaGas, in the compliance filing, to use an annual

[144] Exhibit 71.01, UCA evidence, page 21, A31.

issue cost percentage for the $30 million debenture issued by AltaGas on October 4, 2010, based on AltaGas's pro-rata share of the actual issue costs incurred by AL in connection with the medium term notes issued by AL on November 26, 2010. The Commission further directs AltaGas to submit an accounting of the total costs incurred by AL in connection with the medium term notes AL issued on November 26, 2010.

222. AltaGas included a forecast annual issue cost percentage of 0.25 per cent associated with the five-year debt issue it has forecast for 2012. The last issue cost percentage associated with a five year medium term note is the one associated with the $40 million debenture issued by AltaGas on October 8, 2009. The Commission considers that this same amount should be approved for the five-year debenture that AltaGas is proposing to issue in 2012. The Commission directs AltaGas, in the compliance filing, to use the annual debt issue percentage for the $40 million debenture issued on October 8, 2009 to forecast the debt issue costs for the $28 million debenture that AltaGas is proposing to issue in 2012.

223. Regarding the response provided by AltaGas to the Commission's direction in Decision 2010-448, the Commission has reviewed the material provided which contains information on the allocation methodology employed by AltaGas in allocating debt issue costs. The Commission finds that AltaGas has complied with the direction in Decision 2010-448.

6 Operating, maintenance and administration expenses

6.1 Operating and maintenance expenses (O&M)

224. In its July update, AltaGas forecast total O&M expenses of $32,628.800 in 2011 and $36,508,000 in 2012. AltaGas also provided 2010 actual O&M expenses of $27,914,800.

225. A detailed breakdown of AltaGas's forecast is provided in the table below:[145]

[145] Source: Exhibit 61.07, July update, Schedule 4.0B.

Table 19. O&M expenses for the 2010-2012 test years

Description	2009 actual	2010 forecast	2011 forecast	2012 forecast	2010 forecast vs. 2009 actual		2011 forecast vs. 2010 forecast		2012 forecast vs. 2011 forecast	
	$	$	$	$	$		$		$	
Salary	16,379,000	17,911,300	20,078,000	22,322,200	1,532,300	9.4%	2,166,700	12.1%	2,244,200	11.2%
Salary Capitalized & Overheads Deferred	(4,216,300)	(3,960,700)	(3,857,600)	(4,043,000)	255,600	-6.1%	103,100	-2.6%	(185,400)	4.8%
Salary Expense	12,162,700	13,950,600	16,220,400	18,279,200	1,787,900	14.7%	2,269,800	16.3%	2,058,800	12.7%
Employee Benefits	3,648,600	3,854,900	4,745,000	5,241,100	206,300	5.7%	890,100	23.1%	496,100	10.5%
Employee Benefits Capitalized & O/H Deferred	(924,800)	(1,042,500)	(974,400)	(1,021,800)	(117,700)	12.7%	68,100	-6.5%	(47,400)	4.9%
Employee Benefits Expense	2,723,800	2,812,400	3,770,600	4,219,300	88,600	3.3%	958,200	34.1%	448,700	11.9%
Vehicle & Heavy Work Equip.	1,116,200	1,041,600	1,149,500	1,200,400	(74,600)	-6.7%	107,900	10.4%	50,900	4.4%
Vehicle & Heavy Work Equip. Capitalized	(409,000)	(281,200)	(354,100)	(319,400)	127,800	-31.2%	(72,900)	25.9%	34,700	-9.8%
Vehicle and Heavy Work Equipment Expense	707,200	760,400	795,400	881,000	53,200	7.5%	35,000	4.6%	85,600	10.8%
Contractor Expense	1,138,300	1,102,900	1,169,000	2,137,300	(35,400)	-3.1%	66,100	6.0%	968,300	82.8%
Travel Expenses	481,500	577,600	595,600	624,000	96,100	20.0%	18,000	3.1%	28,400	4.8%
Telephone & Utilities	1,023,300	1,081,100	1,188,200	1,226,000	57,800	5.6%	107,100	9.9%	37,800	3.2%
Rent - Office & Warehouse	99,200	87,900	66,900	39,300	(11,300)	-11.4%	(21,000)	-23.9%	(27,600)	41.3%
Leases & Crossing Rentals	59,100	48,500	49,700	51,200	(10,600)	-17.9%	1,200	2.5%	1,500	3.0%
Maintenance Contracts	560,600	788,100	991,300	1,092,400	227,500	40.6%	203,200	25.8%	101,100	10.2%
Office Expenses	398,000	394,100	435,600	447,900	(3,900)	-1.0%	41,500	10.5%	12,300	2.8%
Customer Communications	14,600	27,800	30,900	31,800	13,200	90.4%	3,100	11.2%	900	2.9%
Training Fees & Dues	312,400	291,600	327,500	338,400	(20,800)	-6.7%	35,900	12.3%	10,900	3.3%

Table 19: O&M expenses for the 2010-2012 test years (continued)

Description	2009 actual	2010 forecast	2011 forecast	2012 forecast	2010 forecast vs. 2009 actual		2011 forecast vs. 2010 forecast		2012 forecast vs. 2011 forecast	
Bad Debt	164,900	126,100	174,200	170,400	(38,800)	-23.5%	48,100	38.1%	(3,800)	-2.2%
Insurance	597,100	502,800	579,600	619,800	(94,300)	-15.8%	76,800	15.3%	40,200	6.9%
Audit Fees	261,700	238,300	259,300	251,600	(23,400)	-8.9%	21,000	8.8%	(7,700)	-3.0%
Legal Fees	448,100	14,800	57,400	60,700	(433,300)	-96.7%	42,600	287.8%	3,300	5.7%
Consultant and Other Fees	881,500	796,400	1,255,100	1,353,000	(85,100)	-9.7%	458,700	57.6%	97,900	7.8%
Amortization of Regulatory Costs	1,018,300	598,900	694,300	638,800	(419,400)	-41.2%	95,400	15.9%	(55,500)	-8.0%
Amortization of Other Costs	313,700	-	-	-	(313,700)	-100.0%	-	NA	-	NA
Postage & Freight	516,200	566,500	574,700	604,200	50,300	9.7%	8,200	1.4%	29,500	5.1%
Material, Contractor & Other	2,469,300	2,493,500	2,780,400	2,813,500	24,200	1.0%	286,900	11.5%	33,100	1.2%
Inter-Affiliate, Shared Cost	2,095,600	2,307,500	2,375,500	2,467,000	211,900	10.1%	68,000	2.9%	91,500	3.9%
Inter-Affiliate, For Profit	185,100	171,400	61,500	63,300	(13,700)	-7.4%	(109,900)	-64.1%	1,800	2.9%
Credits	(185,400)	(219,200)	(288,200)	(332,100)	(33,800)	18.2%	(69,000)	31.5%	(43,900)	15.2%
Sub-Total Other OM&A Expenses	12,853,100	11,996,600	13,378,500	14,698,500	(856,500)	-6.7%	1,381,900	11.5%	1,320,000	9.9%
Capitalization	(1,787,200)	(1,605,200)	(1,536,100)	(1,570,000)	182,000	-10.2%	69,100	-4.3%	(33,900)	2.2%
Total OM&A Expenses	$ 26,659,600	$ 27,914,800	$ 32,628,800	$ 36,508,000	$ 1,255,200	4.7%	$ 4,714,000	16.9%	$ 3,879,200	11.9%

6.1.1 General

226. The table below sets out AltaGas's approved and actual O&M expenses for 2008 and 2009. The table shows that actual aggregate O&M expenses in 2008 and 2009 varied by less than two per cent for both years when compared to AltaGas's approved forecast O&M expenses.

Table 20. Comparison of actual O&M expenses to approved 2008-2009 O&M forecasts

O&M	2008 approved	2008 actual	2009 approved	2009 actual	Actual 2008 vs. approved		Actual 2009 vs. approved	
Total OM&A expenses	$23,322,700	$23,353,300	$26,159,693	$26,659,600	$30,600	0.1%	$499,907	1.9%

Source: Exhibit 61.07, U.S. GAAP Update, Schedule 4.0B.

Commission findings

227. The Commission considers that AltaGas's forecasting history appears reasonable when assessing the costs in aggregate. The Commission has reviewed AltaGas's explanation of specific expense items with material variances, and considers that these variances have been adequately explained. As such, the Commission considers that the 2009 actual results form a reasonable basis upon which to evaluate O&M expenses in the test period.

228. The Commission has reviewed AltaGas's O&M expense forecast for the 2010-2012 test years and considers that annual increases of five per cent or less, are reasonable given the inflation forecast approved in Section 3.1 and considering that forecast system growth for AltaGas, over the test years, averages 2.1 per cent per year (based on customer billings[146]) and the forecast average growth in mid year rate base is approximately 7.5 per cent.[147]

229. With this in mind, the Commission has reviewed AltaGas's forecast O&M expenses for the test years included in Table 19 above and finds that the O&M expenses listed below are reasonable given that, for the test years, they do not exceed five per cent on average or, where they exceed five per cent, the Commission accepts AltaGas's explanation of the factors underlying the forecast, and recognizes that the forecast increases are not material.

- travel
- telephone and utilities
- rent expenses lease
- crossing rentals
- office expenses
- customer communications
- training fees and dues
- audit fees
- legal fees
- postage and freight
- inter-affiliate for profit
- expenses credited
- capitalization

[146] Exhibit 47.01, AUC.AUI-53(d).
[147] Exhibit 61.06, July update, Schedule 2.7a.

230. The following O&M expense forecasts were addressed by interveners, or were identified by the Commission as requiring further scrutiny.

6.1.2 Bad debt

231. AltaGas forecast bad debt expense of $174,200 in 2011 and $170,400 in 2012, with actual bad debt expenses in 2010 totaling $126,100. This expense contains the non-gas costs related to uncollectable accounts. AltaGas explained that annual differences generally arise as a result of higher energy costs and changes in the economy, which impact consumers' ability to pay.[148] AltaGas explained that the 2010 bad debt expense decreased, as compared to 2009 actual, due in large part to declining total billings. The forecast for 2011 reflects a return to a more normal level of bad debt expense. The forecast for 2012 is consistent with the forecast for 2011.[149]

Commission findings

232. The Commission notes actual bad debt expense increased from $101,700 in 2008 to $164,900 in 2009, with bad debt expense in 2010 declining to $126,100. Interveners did not object to AltaGas's forecast bad debt expenses. The Commission understands that bad debt expense is subject to significant variability due to changes in energy costs and the economy. The Commission finds AltaGas's 2010 bad debt expense as filed to be reasonable, because it is within the range of actual bad debt experienced by AltaGas in the two previous years. With regard to AltaGas's forecast 2011-2012 bad debt expense, the Commission considers that AltaGas should rely on past experience and revise its forecast for 2011 and 2012 based on a three-year average of actual bad debt expense (2008-2010) to account for the variability in historical bad debt expense. AltaGas is directed to revise its bad debt expense accordingly in the compliance filing.

[148] Exhibit 30.01, March update, Section 4.13, page 194.
[149] Exhibit 30.01, March update, Section 4.13, page 194.

6.1.3 Salary and wages

233. AltaGas included several components as part of its salary and wages forecast. The forecast was comprised of the following:

Table 21. Salary expense detail

	2009 actual	2010 forecast	2011 forecast	2012 forecast
		($)		
Base Salary	14,810,000	16,412,900	17,373,000	19,798,400
Salary Increases	503,500	722,200	919,400	1,175,800
Salary Increase, Market Adjustment	-	9,200	390,000	-
Staff Increases, Annualized	1,099,500	590,900	856,600	619,400
Vacancies				
Existing Positions	(259,300)	(500,000)	(393,100)	(308,300)
New Positions	(767,400)	(295,500)	(428,300)	(309,700)
STIP	1,071,900	669,300	993,200	1,081,400
MTIP	-	217,100	217,200	216,600
Other	(79,200)	85,200	150,000	48,600
Total Salaries	16,379,000	17,911,300	20,078,000	22,322,200
Salaries Less Capitalized & Overheads Deferred	(4,216,300)	(3,960,700)	(3,857,600)	(4,043,000)
Salary Expense	12,162,700	13,950,600	16,220,400	18,279,200

Source: Exhibit 61.07.

6.1.3.1 Salary increases

234. AltaGas assumed salary inflation factors of 3.0 per cent in 2010, 3.0 per cent in 2011 and 4.0 per cent in 2012 for unionized employees, and 3.0 per cent in 2010, 3.0 per cent in 2011 and 5.0 per cent in 2012 for salaried employees.[150]

235. Additionally, AltaGas stated that on occasion it can modify disproportionately low salaries of employees as their experience and performance grows through range placement increases. These adjustments are forecast at 1.5 per cent of the salaried employee forecast in 2010 and 1.0 per cent in 2011 and 2012.[151]

Commission findings

236. As stated in Section 3.1, the Commission accepts AltaGas's salary inflation factors with the exception of the 2012 inflation increase for salaried employees, which is limited to 4.0 per cent.

237. The Commission has reviewed all of the salary components including base salaries, salary increases, and range placement adjustments. The Commission has also reviewed the additional compensation mechanisms including market competitiveness adjustments, short term incentive plan and mid-term incentive plan. The additional compensation mechanisms are discussed in more detail below. The Commission accepts that the mechanisms proposed are

[150] Exhibit 30.01, March update, Section 9.0, Table 68.
[151] Exhibit 30.01, March update, page 162.

reasonable and necessary to enable AltaGas to provide a competitive compensation package to its employees, and also considers that, after giving effect to the adjustment for the 2012 inflation rate for salaried employees the aggregate forecast year-over-year compensation increases provided to employees are reasonable.

6.1.3.2 Market competitiveness adjustment

238. AltaGas aims for the mid-market, or 50th percentile, for employee compensation. This amount is determined using publically available salary and benefits surveys. However, certain positions garner additional compensation to attract and retain staff in key positions. A one time increase of approximately $400,000 was made to the salary forecast, or approximately 2.2 per cent, paid primarily in 2011. AltaGas submitted that the salary adjustment was prudent and necessary and should be included in its revenue requirement.[152]

239. The UCA opposed the salary adjustment, arguing that "… as a matter of general forecasting practice it is unsafe to permit utilities to embed in their forecasts ad hoc adjustments that are not driven by prior period actual experience and objective factors like inflation ..."[153] However, the UCA conceded "in this case, largely because of the protracted schedule for this proceeding and AltaGas's strategy of filing its final 'forecasts' well into the second of three test years, actual events have overtaken the forecasts in a way that could result in unfairness to AltaGas if it were denied recovery of incremental salary amounts that it has already paid or committed to pay and that the UCA is unable to say are imprudent or unreasonable."[154]

Commission findings

240. The Commission agrees with the UCA's assertion that it would be unfair to deny recovery of the adjustments, given that AltaGas has already paid or committed to pay the adjustments to employees, particularly in light of AltaGas' statement that the adjustment was required to maintain and attract employees. The Commission notes that AltaGas's forecast market competitive adjustment for the test years brings salaries and overall compensation to the mid-market (or the 50th percentile) level. In the current circumstances the Commission accepts AltaGas' statement that the adjustment was required to maintain and attract employees and approves the forecast as file.

6.1.3.3 Short-term incentive plan (STIP)

241. AltaGas forecast STIP expenses in 2011 and 2012 of $993,200 and $1,081,400 respectively, with the 2010 actual STIP expenses totaling $669,300. AltaGas's forecast for all variable pay programs and short term incentive plans is based on an assumption that all business unit team and individual objectives will be achieved.[155] Consistent with the Commission's direction in Decision 2007-094,[156] AltaGas has established a deferral account to capture the differences between total STIP paid out and approved amounts. The differences resulted in a reduction of $219,200 to the 2010 actual results.[157]

---

152 Exhibit 143.01, AltaGas argument, pages 49-50.
153 Exhibit 141.02, UCA argument, Section 4.2, paragraph 139.
154 Exhibit 141.02, UCA argument, Section 4.2, paragraph 139.
155 Exhibit 30.01, March update, page 174.
156 Decision 2007-094: AltaGas Utilities Inc. 2007 General Rate Application Phase I Application No. 1494406, December 11, 2007, page 35.
157 Exhibit 30.01, March update, page 178.

Commission findings

242. The Commission finds that AltaGas's STIP for the test years is reasonable and that AltaGas is correctly capturing the differences between total STIP paid out and approved amounts through its STIP deferral account, as directed by the Commission in Decision 2007-094. Interveners did not object to AltaGas's STIP. The Commission approves the company's forecast STIP for its 2010-2012 test years.

6.1.3.4 Medium-term incentive plan (MTIP)

243. Approximately 96 AltaGas salaried employees were granted MTIP units in 2009, representing approximately one per cent of the total salary budget.[158] AltaGas forecast MTIP expenses of $217,100 in 2010, $217,200 in 2011, and $216,600 in 2012.

244. The UCA argued that MTIP could potentially be tied to profitability, citing section 4 of the plan:[159]

> Phantom Units <u>may be awarded</u> to directors, officers and employees of the Corporation (AL) and its affiliates. <u>The Committee</u> (Human Resources and Compensation Committee of the Corporation) <u>shall have the sole discretion</u> to select the individual participants (the Participants) from among such class of eligible persons to whom Phanton Units <u>may be granted and to determine the number of Phantom Units to be granted to each Participant</u>. (emphasis added)

245. The UCA argued for denial of AltaGas's MTIP request, given the broad discretion granted to the Human Resources Committee to potentially circumvent the Commission's practice of not awarding STIP or Long Term Incentive Plan (LTIP) tied to earnings or profitability.[160]

246. AltaGas submitted that MTIP is necessary to attract, motivate and retain staff, but distinguishable from the type of plans identified by the UCA by forgoing performance targets, because it is conditional only on AL's ability to make a dividend payment. AltaGas described the distinction as follows:

> The MTIP agreement with employees indicates the only 'performance' requirement is AL must issue a dividend in the applicable year. Consequently, rather than specifying any net income target, such as in the case of utilities requesting LTIP, the AUI MTIP 'performance' metric simply serves to ensure AL is able to curtail any payout in the unlikely event it is not able to issue a dividend at some point during the year.[161]

Commission findings

247. The Commission has reviewed the forecasts and explanation of the company's proposed MTIP. The Commission is satisfied that the AltaGas MTIP is linked to profitability only to the extent that a dividend can be paid. Hence, the Commission does not find the UCA's concerns to be warranted because the interests of rate-payers and shareholders are not in conflict. There is no requirement that the profit of the company exceed the amounts reflected in calculating the approved rate of return. The Commission agrees with AltaGas that MTIP can be an effective tool

[158] Exhibit 30.01, March update, page 179.
[159] Exhibit 141.02, UCA argument, Section 4.4, paragraph 148.
[160] Exhibit 141.02, UCA argument, Section 4.4, paragraphs 148-150.
[161] Exhibit 81.01, AltaGas rebuttal evidence, Section 4.4, paragraph 87.

that mitigates recruiting costs and staff turnover, and therefore approves the MTIP forecast as applied for.

6.1.3.5 Staff additions

248. AltaGas forecast it will add eight new permanent positions in 2010, ten in 2011 and nine in 2012 to operate a sustainable system and provide required levels of customer service, worker and public safety, environmental stewardship and compliance.[162] A detailed breakdown of the company's forecast full time equivalents (FTEs) additions and the primary drivers proffered for each position is set out below:[163]

2010 Forecast of Permanent Position Additions

Positions Forecast (8)	**Primary Driver(s)**
Design Engineer	Growth, Safety, Sustainability
Project Supervisors (2)	Growth, Safety, Sustainability
Technician, Distribution Operations	Growth, Safety
GIS/CAD Operator	Growth, Safety, Sustainability
Employee Development Specialist	Growth, Safety
Fleet Specialist Safety,	Environment
Customer Care Representative	Growth

2011 Forecast of Permanent Position Additions

Positions Forecast (10)	**Primary Driver(s)**
Engineering Technologist	Growth, Safety, Sustainability
Construction Inspector (3)	Growth, Safety, Sustainability
Design Engineer	Growth, Safety, Sustainability
Technician, Special Projects Crew	Growth, Safety, Sustainability
Director, Corporate Services	Safety, Environment, Competency
Facilities Caretaker	Growth
Supervisor, IFRS	Growth
Manager, Regulatory & Environmental Compliance	Growth, Environment, Sustainability

2012 Forecast of Permanent Position Additions

Positions Forecast (9)	**Primary Driver(s)**
Regional Clerk (2)	Growth, Safety, Sustainability
Technician, Distribution Operations (2)	Growth, Safety
Corporate Services Coordinator	Safety, Environment, Competency
Clerk, Customer Information System	Growth
Clerk, General Accounting IFRS,	Growth
Database Analyst Growth,	Sustainability
Regulatory Specialist	Growth, Sustainability, Compliance

249. AltaGas indicated that an additional accounting position for IFRS implementation is no longer required because AltaGas plans to adopt U.S. GAAP instead of IFRS. Instead of the IFRS

[162] Exhibit 30.01, March update, page 162.
[163] Exhibit 30.01, March update, pages 165-166.

position, AltaGas plans to add an IT support position in its place.[164] The additional IT support position was not included in the GRA application.

Views of the parties

250. Based on its analysis of forecast new positions,[165] the UCA estimated that seven of the permanent position additions in the three test years were capital related. The UCA recommended that the number of capital-related FTE's be reduced in accordance with the reductions in major projects, as determined by the Commission in its final decision.

251. AltaGas argued that, due to the geographically dispersed nature of its business, it is not practical or physically possible to reduce portions of FTEs on the basis of disallowed system betterment costs.

252. AltaGas submitted that, in the event the AUC disallows or reduces any amounts forecast for system betterment costs, such reductions should not serve as the basis for further reductions of new or existing FTEs.[166]

253. The UCA argued that there may not be a direct correlation between the recommended reductions in system betterment costs and new capital-related FTEs, and that AltaGas has not met its burden of proof to show otherwise. Therefore, a reduction in the number of capital-related FTEs in design staff, supervisors, technicians and construction inspectors is justified.[167]

Commission findings

254. Other than the general reductions to FTEs proposed by the UCA related to system betterment costs, interveners did not object to any of the specific additional positions proposed by AltaGas. The Commission has reviewed all of the staff additions requested by AltaGas and considers them to be reasonable with the exception of the proposal to replace the Supervisor IFRS position originally intended to be added in 2011, with an IT support position. The Commission does not approve the addition of an IT support position because the need for this position was not substantiated. The Commission therefore directs AltaGas to remove the costs of the Supervisor IFRS position from the forecast, without the addition of an IT support position.

255. The Commission does not consider that any of the disallowances made in other sections of this decision are sufficient to require a reduction in new or existing FTEs. The Commission therefore approves the remaining positions as filed for the test years.

6.1.3.6 Vacancy rates

256. AltaGas forecast frictional vacancies of 8.3 FTEs in 2010, 5.1 in 2011, and 4.1 in 2012.[168]

Views of the parties

257. In its argument, the UCA recommended the frictional vacancy rate be based on the actual frictional vacancies over the last three years, consistent with the Commission's approved practice

[164] Transcript, Volume 6, page 1510.
[165] Exhibit 50.01, UCA-AUI-35(h).
[166] Exhibit 143.01, AltaGas argument, page 48.
[167] Exhibit 150.02, UCA reply argument, Section 4.2.1, paragraph 89.
[168] Exhibit 30.01, March update, page 166, Table 24.0.

in Decision 2009-176 and previous decisions.[169] The UCA recommended that the use of the 2.93 per cent average vacancy rate is warranted and reasonable, resulting in an increase in vacancies of 1.9 FTEs in 2011 and 2.9 FTEs in 2012, corresponding to salary reductions of $168,655 in 2011 and $273,818 in 2012.[170]

258. AltaGas responded to the UCA's recommendation on frictional vacancies by indicating that it anticipates it will hire all new FTE additions as forecast. Consequently, AltaGas submitted no adjustment to its forecast is required.[171]

Commission findings

259. The Commission accepts the UCA submission, which is consistent with Decision 2009-176,[172] that historical average frictional vacancy rates are a reasonable predictor of FTE vacancy rates for the test period. Therefore, the Commission directs AltaGas, in the compliance filing, to incorporate a 2.93 per cent frictional rate in its revenue requirement in 2011 and 2012 respectively.

260. The actual vacancy rate for 2010 was approximately four per cent, which exceeds the 2.93 per cent frictional vacancy rate approved above. The Commission recognizes that the 2010 forecast represents the actual experience of AltaGas, and therefore the 2010 vacancy forecast is approved as filed.

6.1.4 Employee benefits

261. Employee benefits include all statutory (i.e. CPP, EI and WCB) benefits, pension and other benefits (i.e. health and dental), as well as moving expenses, education reimbursements and uniforms.[173] AltaGas explained that:

- The 2010 Forecast costs, before adjustments for capitalization and deferred overheads, are higher than the 2009 actual results due to increases in statutory premiums, staff additions and salary increases.
- The forecast for 2011 is higher than 2010 due to staff and salary increases impacting statutory plans, premium increases in AltaGas's plans and pension cost increases.
- The forecast for 2012 is higher than 2011 due to staff and salary increases impacting statutory plans, premium increases in AltaGas's plans and pension cost increases arising from changes in pension accounting.[174]

169 Decision 2009-176, Section 4.2.2, paragraph 140.
170 Exhibit 71.01, UCA evidence, A.45, page 30.
171 Exhibit 143.01, UCA argument, Section 4.2.2, paragraphs 162-163.
172 Decision 2009-176, Section 4.2.2, paragraph 140.
173 Exhibit 30.01, March update, page 180.
174 Exhibit 30.01, March update, page 181.

Table 22. Employee benefits actual and forecast expenses

Employee Benefits	2009 actual	2010 forecast	2011 forecast	2012 forecast	2010 forecast vs. 2009 actual		2011 forecast vs. 2010 forecast		2012 forecast vs. 2011 forecast	
	($)	($)	($)	($)	($)	(%)	($)	(%)	($)	(%)
Statutory	695,000	790,900	973,100	1,052,100	95,900	14	182,200	23	79,000	8
Company Pension Plans	1,557,100	1,552,100	2,017,000	2,290,700	(5,000)	0	464,900	30	273,700	14
Other Company Plans	1,109,200	1,257,000	1,397,900	1,534,300	147,800	13	140,900	11	136,400	10
Third Party Administration of Plans	155,000	62,300	157,800	161,300	(92,700)	(60)	95,500	153	3,500	2
Other - Moving, Uniforms, Education	132,300	192,600	199,200	202,700	60,300	46	6,600	3	3,500	2
	3,648,600	3,854,900	4,745,000	5,241,100	206,300	6	890,100	23	496,100	10
Capitalized	(924,800)	(1,042,500)	(974,400)	(1,021,800)	(117,700)	13	68,100	-7	(47,400)	5
Total Employee Benefits Expense	**2,723,800**	**2,812,400**	**3,770,600**	**4,219,300**	**88,600**	**3**	**958,200**	**34**	**448,700**	**12**

Source: Exhibit 61.07, July update, Schedule 4.0B – Employee Benefits.

6.1.4.1 Statutory benefits

262. The CCA performed a review of all statutory benefits and provided recommendations on each individual component.[175] The CCA indicated that the CPP expense of $479,000 in 2010, $537,400 in 2011 and $575,800 appear reasonable.[176]

263. The CCA recommended a reduction on EI expense for 2011 and 2012. The CCA stated that the EI rate of 2.08 per cent was constant for the years 2008-2010 but no evidence was filed by AUI to support the escalation of the 2011 rate to 2.14 per cent in 2011 and 2.20 per cent in 2012. The CCA recommended that the AUC approve the average escalation rate experienced over the period 2008-2010 of 2.50 per cent which results in a reduction in EI expense of $7,500 in 2011 and $17,200 in 2012.[177]

264. The CCA also recommended a reduction to WCB expense. The CCA stated that, while the actual increase in the WCB maximum per employee was six per cent in 2009, the increase was 175 per cent in 2010 due to a 'significant increase in our premium in 2010."[178] It added that AltaGas acknowledged it now has actual rates and the increase of eight per cent in each of 2011 and 2012 is lower than forecast.[179] As AltaGas did not quantify the actual increases, the CCA recommended an increase of no more than the inflation rate of 2.50 per cent in 2011 and 3.0 per cent in 2012, as forecast by AltaGas.[180]

175 Exhibit 142.01, CCA argument, pages 13-16.
176 Exhibit 142.01, CCA argument, page 14, paragraph 44.
177 Exhibit 142.01, CCA argument, page 14, paragraphs 45-46.
178 Transcript, Volume 1, page 113, lines 16-19.
179 Transcript, Volume 1, page 114, lines 6-8.
180 Exhibit 30.01, March update, paragraph 541.

265. The CCA recommended that the total statutory forecast for 2011 and 2012 be reduced by $12,800 in 2011 and $30,800 in 2012 in respect of statutory benefits.[181]

Commission findings

266. The Commission notes that AltaGas did not respond to the CCA's recommendation with respect to statutory benefits. Due to an absence of evidence and consistent with prior year escalations in EI and WCB, the Commission accepts as reasonable the CCA's recommendation that the total statutory benefits forecast for 2011 and 2012 be reduced by $12,800 in 2011 and $30,800 in 2012. AltaGas is directed to revise its statutory benefits forecast in the compliance filing.

6.1.5 Vehicles and heavy work equipment

267. The vehicle and heavy work equipment account includes the cost of operating and maintaining AltaGas's fleet of vehicles. The actual vehicle and heavy work equipment expenses and the amounts capitalized for 2009 are set out in the table below, along with the forecast expenses and capitalized amounts for the test years. The values for 2010 are the actual amounts incurred by AltaGas. The forecast for 2011 reflects an increase in the number of vehicles in the fleet and various cost increases. The forecast for 2012 reflects an additional increase in the number of vehicles in the fleet, plus a 3.0 per cent general inflationary increase.[182]

Table 23. Vehicle and heavy work equipment actual and forecast expenses

	2009 actual	2010 forecast	2011 forecast	2012 forecast
Total Vehicle and Heavy Work Equipment	$1,116,200	$1,041,600	$1,149,500	$1,200,400
Capitalized and Overheads Deferred	(409,000)	(281,200)	(354,100)	(319,400)
Total Vehicle and Heavy Work Equipment Expense	$ 707,200	$ 760,400	$ 795,400	$ 881,000
Number of Service Vehicles In Fleet	93	94	102	104
Fleet-Only Costs	$ 877,200	$ 911,600	$ 953,500	$ 1,012,000
Cost per Service Vehicle In Fleet	$ 9,432	$ 9,398	$ 9,348	$ 9,731

Source: Exhibit 61.07, July update, Schedule 4.0B – Vehicle and Heavy Work Equipment.

268. The CCA recommended a reduction to the vehicle and heavy work equipment forecasts in 2011 and 2012. The CCA noted historical inaccuracies in AltaGas's forecast fuel cost.[183] The CCA proposed that fuel costs for 2011 and 2012 be calculated by applying general inflation and accounting for changes to the fleet size.[184] The impact of the CCA recommendation was a reduction of $29,000 in 2011 and $11,000 in 2012.[185]

269. AltaGas responded that the CCA had overlooked the impact of the 2010 vehicle additions and increased tonnage of the vehicles, which would have an upward impact on fuel expenses.[186]

181 Exhibit 142.01, CCA argument, page 16, paragraph 50.
182 Exhibit 30.01, March update, pages 181-182.
183 Exhibit 142.01, CCA argument, page 37, paragraph 117.
184 Exhibit 142.01, CCA argument, page 39, paragraph 123.
185 Exhibit 142.01, CCA argument, page 39, paragraph 124.
186 Exhibit 151.01, AltaGas reply argument, pages 80-81.

Commission findings

270. The Commission considers that AltaGas has adequately explained that additional vehicles, in particular larger trucks and trailers, contributed to additional forecast fuel costs. The Commission also notes that the forecast costs per service vehicle only increases moderately during the test years. Accordingly, the Commission approves AltaGas's 2010-2012 vehicle and heavy work equipment forecasts as filed.

6.1.6 Contractor expenses

271. AltaGas described contractor expense as including "the operating costs incurred for meter reading, janitorial services and other small contractor services."[187] The approved and actual 2008 and 2009 contractor expenses as well as the forecasts for the test years are included in the following table:

Table 24. Contractor expenses

	2008 approved	2008 actual	2009 approved	2009 actual	2010 forecast	2011 forecast	2012 forecast
Contract Meter Reading	$ 680,600	$ 707,400	$ 739,800	$ 785,600	$ 824,300	$ 860,600	$ 1,811,600
Janitorial & Building Maintenance	179,300	164,300	190,300	186,200	116,800	130,500	134,500
Contractor Standby	168,800	180,400	162,900	166,500	161,800	177,900	191,200
Total Contractor Expense	$1,028,700	$1,052,100	$1,093,000	$1,138,300	$1,102,900	$1,169,000	$2,137,300
Number of Meter Reads Annually	6	6	6	6	6	6	12
Year End Service Sites	68,181	68,278	70,181	69,370	70,933	72,529	74,161
Average Service Sites	66,727	67,054	68,727	68,447	69,980	71,556	73,160
Service Sites Billed	799,524	805,850	823,520	822,565	838,548	857,477	876,724

Source: Exhibit 61.07, July update, Schedule 4.0B – Contractor Expense.

272. AltaGas explained that the relatively small decrease in the 2010 forecast compared to the 2009 actual results was primarily due to a reduction in janitorial costs, and the increase in the 2011 forecast over the 2010 forecast was primarily due to the increase in contract meter reading costs resulting from an increase in the number of customers and an increase in the per meter read charge.[188] The increase in the 2012 forecast over the 2011 forecast was primarily a result of the move to monthly meter reading for all service sites.

273. When asked to demonstrate that contract meter readers were more economical than company meter readers or the adoption of AMR technology with drive-by radio frequency collection systems, AltaGas "concluded from a cursory assessment" that the cost of monthly meter reading was approximately $1 million per year compared to the approximately $1.5 million per year associated with installing AMR technology before consideration of annual operating costs of AMR.[189]

274. The UCA objected to the increase in contractor costs resulting from the move to monthly meter reading. It argued that AltaGas has not provided any support for the asserted benefits of

---

[187] Exhibit 30.01, March update, Section 4.4, page 182.
[188] Exhibit 30.01, March update, Section 4.4, page 183.
[189] Exhibit 50.01, UCA-AUI-40(b).

monthly meter reading, nor a business case to support the $906,000 increase in 2012, which the UCA argued should include an assessment of an "ATCO Gas-type" AMR system to determine the best long-term solution."[190]

275. The UCA submitted that AltaGas would only be forced to implement monthly meter reading if Rule 002 specified a date to commence monthly meter reading. Rule 002 currently requires the gas distributor to "progress towards a goal of having every site billed on actual meter readings."[191] In the UCA's view, consideration of and working towards an AMR system would appear to qualify under the current Rule 002.[192]

276. AltaGas responded that the proposed monthly meter reads in 2012 are necessary and prudent. Given the dispersed nature of a significant portion of AltaGas's service territory, it is doubtful whether AMR technology will be able to produce the same level of benefit to customers, over the long term, as reported by ATCO when it proposed its transition to AMR. Accordingly, AltaGas has not examined AMR implementation on a broad scale at this time. Given the uncertainties associated with the costs and benefits of AMR implementation, AltaGas submitted that its proposal to move to monthly meter reading in 2012, using additional contract labour, should be approved as filed.[193]

Commission findings

277. Section 4.1 of Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*, states that:

> The reporting of both monthly and exception metrics by the owner in Rule 002 quarterly reports and Rule 002 annual reports will provide the Commission with information about the owner's progress towards the goal of having every site bill every month based on accurate, actual meter readings. In addition, the metrics provide visibility to the Commission of the owner's performance in relation to the requirements of Rule 004: *Alberta Tariff Billing Code*.[194]

278. The Commission considers that AltaGas has established a monthly meter reading program forecast for 2012 that is consistent with Rule 002. The Commission concurs with the UCA that a cost-benefit analysis (business case) on monthly meter reading compared against AMR would have been the preferred approach to evaluate the reasonableness of the two options. Absent a detailed business case, the evidence on the record only provides a cursory assessment of AMR. Nonetheless, the Commission finds that the potential benefits of monthly meter reading and compliance with Rule 002 support approval of these costs. AltaGas's contractor monthly meter reading forecast for 2012 is approved as filed.

279. The Commission is satisfied that the remainder of AltaGas's forecast contractor expenses were adequately justified by AltaGas and are reasonable. AltaGas's contractor expenses for the test years are therefore approved as filed.

[190] Exhibit 141.02, UCA argument, Section 5.5, paragraph 154.
[191] Rule 002, effective July 1, 2010, Section 3.1.
[192] Exhibit 71.01, UCA evidence page 35.
[193] Exhibit 143.01, AltaGas argument, pages 52-56.
[194] AUC Rule 002, Section 4.1.

6.1.7 Maintenance contracts

280. Maintenance contracts expense includes the costs incurred by AltaGas for fees paid to software and hardware vendors pursuant to agreements entitling AltaGas to software upgrades, fixes or specified response times.[195] The approved and actual 2008 and 2009 maintenance contracts expenses as well as the forecast costs for the test years are included in the following table:

Table 25. Maintenance contracts

	2008 approved	2008 actual	2009 approved	2009 actual	2010 forecast	2011 forecast	2012 forecast
	($)						
Customer Information System	158,200	150,800	158,000	254,300	276,600	313,200	325,800
Financial Systems	105,600	74,500	108,500	65,900	162,300	250,100	254,400
Operational Systems	95,000	135,400	99,200	152,000	259,600	306,800	328,700
Administrative Systems	-	-	-	-	-	30,000	90,000
Network and Security	36,900	30,600	38,000	54,800	68,100	69,200	70,800
Other Systems	44,000	17,900	45,200	33,600	21,500	22,000	22,700
Total Maintenance Contracts	439,700	409,200	448,900	560,600	788,100	991,300	1,092,400

Source: Exhibit 61.07, July update, Schedule 4.0B – Maintenance Contracts.

281. AltaGas explained year-over-year variances as follows:[196]

> The [2010] forecast is $227,500 higher [than 2009 actual] due to the addition of new software and hardware, most notably AUC Rule 004 Alberta Tariff Bill Code, asset management and financial asset reporting software.
>
> …
>
> The [2011] forecast is $203,200 higher [than 2010 forecast] resulting from the addition of new software. In 2010, AUI introduced a performance appraisal system, a fixed asset system, a timesheet system, a modification to the billing system and the first stages of an asset management system. Therefore, increases were required in 2011 to reflect the additional maintenance contracts.
>
> …
>
> The [2012] forecast is $101,100 higher [than 2011 forecast] primarily due to the addition of new software related to human resources, modifications to other systems and a new "I" Series computer.

282. The CCA took issue with increases in the costs for maintenance contracts, and questioned whether some of the costs should be capitalized. The CCA argued that AltaGas should be directed to include, in the compliance filing, a detailed assessment of why the costs included in maintenance contracts are all "period costs" and should not be capitalized, as well as an assessment of the nature and extent to which these costs are on-going or one-time costs. The

195 Exhibit 30.01, March update, page 189.
196 Exhibit 30.01, March update, pages 189-190.

CCA also recommended that AltaGas provide a continuity schedule of additional information for maintenance contract costs related to each software system.[197]

283. AltaGas stated in response to UCA-AUI-43(a) that maintenance contracts are paid annually and are expected to continue on an ongoing basis. While AltaGas will negotiate with vendors for multiple year agreements to reduce costs and spread them over the life of the contract, in some instances, vendors will require lump sum payments for such arrangements. AltaGas reviews these contracts annually to ensure it only pays for services it uses.[198]

Commission findings

284. The Commission understands that the CCA did not take issue with any of the actual maintenance contract costs or the variance explanations provided by AltaGas, and only raised concerns over the accounting treatment with respect to whether the costs should be capitalized. The Commission is satisfied with AltaGas's explanation of how it determined that the costs are period costs, and the Commission agrees that they do not qualify to be capitalized. The Commission is satisfied with AltaGas's explanation of its forecast maintenance contract expenses. AltaGas's forecast maintenance contract expenses for the test years are approved as filed.

6.1.8 Insurance

285. Insurance expenses includes the cost of all insurance, including vehicle, office and various liability policies. The approved and actual 2008 and 2009 insurance expenses as well as the forecast costs for the test years are included in the following table:

Table 26. Insurance expenses actual and forecast

	2008 approved	2008 actual	2009 approved	2009 actual	2010 forecast	2011 forecast	2012 forecast
Expenses				($)			
Auto Liability	83,100	83,000	84,100	81,800	86,500	84,900	93,300
Office Contents	61,000	61,000	62,300	61,100	61,200	62,300	64,100
Contractor Equipment	6,000	6,000	5,600	5,400	6,300	9,700	9,800
Commercial General	25,000	25,000	25,500	25,000	31,300	50,200	51,700
Property	80,000	79,900	81,700	81,000	94,500	137,900	162,000
Crime	6,600	6,600	6,500	6,400	6,500	10,800	11,200
Director & Officer	22,300	22,200	22,000	23,100	14,600	-	
Umbrella Liability	200,100	200,000	204,200	200,200	201,900	223,800	227,700
Total Before Adjustments	484,100	483,700	491,900	484,000	502,800	579,600	619,800
Add: Approved Regulatory Adjustment	111,300	111,300	113,100	113,100			
Total Insurance Expense	595,400	595,000	605,000	597,100	502,800	579,600	619,800

Source: Exhibit 61.07, July update, Schedule 4.0B – Insurance Expense & Premiums.

197 Exhibit 142.01, CCA argument, paragraphs 133-134.
198 Exhibit 151.01, AltaGas reply argument, paragraph 261.

286. AltaGas explained its forecast of annual insurance expenses as follows:

> "The forecast for 2010 is $94,300 less than the 2009 Actual (normalized). In Decision 2009-176, the Commission approved an adjustment to 2009 of $113,100. This adjustment is not continued in 2010. No change in coverage is anticipated.
>
> …
>
> The forecast for 2011 increases 15.3% from 2010 forecast due to anticipated increases in premiums for insuring the above ground facilities against catastrophic events, the head office building addition and fleet additions forecast for 2011.
>
> …
>
> The forecast for 2012 is 5.9% greater than the 2011 Forecast, reflecting the full impact of the increased 2011 premiums for insuring the above ground facilities against catastrophic events, the head office building addition and fleet additions in 2012."[199]

287. The CCA argued that AltaGas had not sufficiently justified the increases in insurance expense attributable to market increases. As a result, the CCA recommended a reduction of $13,000 in both 2011 and 2012.[200]

288. In response to the CCA's submission, AltaGas submitted that it had explained the increases with regard to insurance expenses in response to CCA-AUI-8(b) as follows:[201]

> Premiums for 2011/2012 and for 2012/2013 are forecast to increase by the general escalation factors of 2.5% in 2011 and 3.0% in 2012. Automobile insurance coverage is forecast to increase an additional 8.5% in 2011 and 2% in 2012 due to the forecast increase in the number of vehicles insured. In 2011, the premiums for office buildings and contents are forecast to increase approximately $30,000 with the expansion of the head office building.
>
> The forecast for the 2011 insurance expense is based on the premiums paid for the 2010/2011 coverage period and the forecast premiums for the 2011/2012 coverage period. The forecast for the 2012 insurance expense is based on the forecast premiums for the 2011/2012 coverage period and the forecast premiums for the 2012/2013 coverage period recalculated to reflect the calendar year period, January – December.

Commission findings

289. The Commission is satisfied that AltaGas adequately explained the forecast increase in insurance expenses for the test years in the above noted IR response and the Commission finds the forecast insurance expenses to be reasonable. AltaGas's forecast insurance expenses for the test years are approved as filed.

6.1.9 Consultant and other fees

290. The consultants and other fees include the costs associated with consultants and fees associated with services, such as bank charges, credit cards and meter sealing. The approved and

[199] Exhibit 30.01, March update, pages 195-196.
[200] Exhibit 142.01, CCA argument, page 44, paragraph 140.
[201] Exhibit 151.01, AltaGas reply argument, page 77.

actual 2008 and 2009 consultant and other fees expenses as well as the forecast costs for the test years are included in the following table:

Table 27. Consultant and other fees – detail

	2008 approved	2009 actual	2009 approved	2009 actual	2010 forecast	2011 forecast	2012 forecast
				($)			
Consultants							
Information Systems and Technology Consultants	135,800	254,700	141,900	156,700	149,400	245,500	252,900
Management and Systems Cons.	137,000	207,800	410,000	340,300	197,400	262,100	217,600
Human Resource Consultants	73,000	124,400	27,000	25,000	69,700	224,000	228,600
Records Management	-	-	- -	-	-	6,100	6,300
Health, Safety and Training Cons.	116,000	80,000	71,000	45,800	87,000	130,600	134,500
Other Fees							
Customer Surveys	35,000	13,700	35,000	38,200	-	-	-
Bank Charges and Fees	109,600	101,400	111,600	113,700	100,200	102,700	105,800
Credit Card Fees	-	-	-	-	-	101,200	217,500
Staff Recruitment Costs	-	90,500	-	126,400	112,700	115,000	120,000
Meter Sealing Fees	40,000	33,400	40,500	34,400	55,700	66,900	68,900
Other	-	-	-	1,000	24,300	1,000	900
Total Consultants and Other Fees	646,400	905,900	837,000	881,500	796,400	1,255,100	1,353,000

Source: Exhibit 61.07, July update, Schedule 4.0B – Consultants and Other Fees.

291. AltaGas explained that the 2010 forecast includes a decrease in costs, as compared to 2009, due to the deferral of human resource based studies and a decrease in IS&T consultants. The 2011 forecast includes an increase, as compared to the 2010 forecast, due to safety and human resource training not completed in 2010 and the impact of the introduction of credit cards for bill payments. For 2012, AltaGas forecast a provision for normal increases and the annualized impact of credit cards.[202]

292. At the hearing, AltaGas provided an update with respect to credit card fees, indicating it expected to incur no costs in 2011 and $108,000 in 2012 because the implementation of the credit card payment system had been delayed to approximately mid-2012.[203]

293. The CCA questioned the escalation of consultant and other fees, particularly with respect to the most significant forecast increase in costs for IT consultants, HR consultants and credit card fees; noting that the increases in 2011 and 2012 are in excess of the general inflation factors proposed by AltaGas. The CCA claimed that AltaGas's explanations for the increases were "somewhat vague, raising questions as to the real need for and prudence of the forecast costs."[204]

294. The CCA recommended a cost reduction for credit card fees on the basis that implementation of the credit card payment system was deferred, as acknowledged by AltaGas at the hearing.[205] In addition, the CCA proposed that AltaGas's 2011-2012 forecast consultant costs

202 Exhibit 30.01, March update, page 199.
203 Transcript, Volume 5, pages 1202-1203.
204 Exhibit 142.01, CCA argument, page 47, paragraph 145.
205 Exhibit 142.01, CCA argument, Section 9, paragraph 145.

should be reduced to be more consistent with the average of these costs in the three prior years.[206] The CCA proposed reductions to AltaGas's forecast consultant costs of $153,900 in 2011 and $344,700 in 2012.

295. AltaGas accepted that an adjustment for the delay in implementing the credit card payment system was appropriate, but argued that the other reductions proposed by the CCA were not warranted. AltaGas argued that the averaging approach recommended by the CCA should be rejected as it would fail to allow development, implementation and maintenance of the specific IT and HR related activities budgeted for the test years.[207] AltaGas submitted that its forecast expenses for consultant and other fees are reasonable and necessary to complete the IT and HR programs required in the test years.[208] Accordingly, subject to the adjustment to credit card fees, AltaGas submitted that its forecasts for consultant and other fees be approved as filed.

Commission findings

296. The Commission considers that the forecasts for credit card fees should be reduced to reflect the revised timing of the implementation of the credit card payment system. The Commission therefore directs AltaGas to revise these costs to zero in 2011 and $108,000 in 2012 in the compliance filing.

297. The Commission has considered the recommendation from the CCA to make the forecast for the remaining consultant and other fees for 2011 and 2012 equivalent to the three-year average. The Commission accepts AltaGas's explanation that additional support will be required to maintain the new information systems being implemented by AltaGas and that there is a requirement for additional safety and human resource training. The Commission finds that AltaGas has justified the increases in excess of the three year average, and therefore approves the forecasts as filed.

6.1.10 Amortization of regulatory costs

298. Regulatory fees include the costs associated with various regulatory proceedings and processes. The approved and actual 2008 and 2009 regulatory fees as well as the forecast costs for the test years are included in the following table:

206 Exhibit 109, CCA aid to cross on consultants.
207 Exhibit 151.01, AltaGas reply argument, pages 75-76.
208 Exhibit 143.01, AltaGas argument, paragraph 196.

Table 28. Amortization of regulatory costs

	2008 approved	2008 actual	2009 approved	2009 actual	2010 forecast	2011 forecast	2012 forecast
				($)			
Regulatory Hearing Costs	698,500	698,500	698,500	698,500	188,900	261,300	261,300
AUC Assessments	316,900	316,900	316,900	316,900	246,800	235,500	235,500
UCA Funding	2,900	2,900	2,900	2,900	137,000	117,600	117,600
GUA Code of Conduct Regulation Audit	-	-	-	-	-	35,000	-
GUA Code of Conduct Regulation Customer Care Testing	-	-	-	-	1,800	1,800	1,900
AUC Rules 002 & 003 Surveys	-	-	-	-	24,400	43,100	22,500
Total Regulatory Amortization	1,018,300	1,018,300	1,018,300	1,018,300	598,900	694,300	638,800

Source: Exhibit 61.07, July update, Schedule 4.0B – Amortization of Regulatory Costs.

299. The UCA recommended a reduction in hearing costs of $61,000 in each of 2011 and 2012 as a result of a change in scope for the GCOC proceeding and the 2010-2012 Phase II compliance filing.[209] In its rebuttal evidence, AltaGas submitted that it used the best information available, including data from previous proceedings, to forecast its regulatory hearing costs for the test years.[210] The UCA submitted in argument that this was precisely the thinking that led to an over-collection of $884,500 in 2008 and 2009. The UCA proposed adjustments to AltaGas's forecast for the specific changes in proceeding scope it identified. The UCA submitted that its proposed adjustments are reasonable and should reduce the possibility of another large over-collection. The UCA submitted that, although there is a deferral account for regulatory fees, the best estimates of hearing costs should be utilized to mitigate future adjustments through the Y-factor under incentive regulation.[211]

300. In reply argument, AltaGas accepted that the UCA's suggestions are reasonable, and provided revised estimates for the adjustments.[212] AltaGas noted that the GCOC cost claim, excluding intervener costs, amounted to $158,900 or approximately $107,800 less than forecast in the application, and agreed to adjust its forecast to reflect this outcome. With respect to forecast 2010-2012 GRA Phase II compliance filing costs, AltaGas submitted that the UCA's estimate of $10,000 in intervener costs is not unreasonable. However, AltaGas stated that it was uncertain how much work may be required by AltaGas's Phase II consultants to apply the final 2010-2012 rates to the negotiated rate structure and whether external legal counsel may be engaged for this process. Nonetheless, AltaGas submitted it was reasonable to reduce the estimated professional fees to $25,000. These estimates reflect a reduction in professional fees of $56,000 and a reduction in intervener costs of $20,000. Consequently, AltaGas submitted an overall reduction in forecast regulatory hearing costs of $183,800 to be recognized as a reduction in regulatory fees expenses of $91,900 in each of 2011 and 2012 was reasonable.

209 Exhibit 71.01, UCA evidence, A.52, page 35.
210 Exhibit 81.01, AltaGas rebuttal evidence, paragraph 95.
211 Exhibit 150.02, UCA argument, page 37, paragraph 96.
212 Exhibit 151.01, AltaGas reply argument, Section 4.3.4, page 76.

Commission findings

301. Both AltaGas and the UCA agree that a reduction to regulatory fees is warranted. The Commission finds that the adjustments proposed by AltaGas to be reasonable, and directs AltaGas to reflect these adjustments, in the compliance filing.

6.1.11 Material, contractor and other

Table 29. Material, contractor and other details

	2008 actual	2009 approved	2009 actual	2010 forecast	2011 forecast	2012 forecast
			($)			
Operations & Maintenance Field Activities						
Leak Surveys	99,600	210,600	369,600	229,000	312,200	321,500
Odourizing Distribution System	206,500	145,000	287,700	182,400	300,700	309,700
Cathodic Protection Line Surveys	103,400	35,000	43,000	60,700	149,900	149,100
Compressor Rental	48,800	63,900	49,100	54,200	51,400	52,900
Gas Outage Response	65,800	-	-	-	-	-
Environmental Waste Disposal	51,700	42,600	32,600	21,500	49,100	50,600
Anode Replacement Program	-	85,200	51,000	-	26,100	26,800
Meter Recalls	137,300	167,200	129,400	126,100	145,400	149,800
Brushing Pipeline Right of Ways	-	10,700	12,100	37,600	66,100	58,700
Other Pipeline Operating Activities	93,700	68,500	105,100	120,800	140,800	144,900
Leak Repairs	443,500	461,500	392,500	394,400	390,800	406,700
High Pressure Line Lowering	1,000	16,000	12,700	10,000	14,400	14,900
Station Operating and Maintenance	171,300	101,700	271,200	305,500	294,700	302,900
Meter Testing and Repair	136,800	152,000	166,100	245,000	173,700	178,900
General District Office Operations	26,200	74,000	69,000	75,400	91,600	94,400
Small Tool Replacements and Repairs	137,300	117,200	186,100	171,700	194,600	200,400
Total Operations & Maintenance Field Activities	1,722,900	1,751,100	2,177,200	2,034,300	2,401,500	2,462,200
Other Activities						
Safety and Training	67,200	66,100	70,800	93,400	88,100	90,700
Bill Printing	98,700	74,300	88,500	81,600	96,700	101,600
Building Maintenance	57,200	81,600	132,800	110,100	157,100	121,000
Data for Upgrade to Land Database	-	-	-	36,100	37,000	38,000
Feasibility Studies expensed	-	-	-	138,000	-	-
Total Other Activities	223,100	222,000	292,100	459,200	378,900	351,300
Total Material, Contractor & Other	1,946,000	1,973,100	2,469,300	2,493,500	2,780,400	2,813,500

Source: Exhibit 61.07, July update, Schedule 4.0B – Material, Contractor and Other.

302. The 2010 forecast reflects a 1.0 per cent increase in these costs over 2009. The forecast for 2011 reflects price increases on normal activities and an increase in cathodic protection and leak survey activities. The forecast for 2012 reflects price increases on normal activity levels.[213]

[213] Exhibit 30.01, March update, page 203.

AltaGas explained the 2011 forecast reflects the completion of the 2010 and 2011 work, and allows for system growth and an aging system.[214] [215]

303. The UCA took issue with the forecasts for these expenses, particularly with respect to leak surveys, cathodic protection, line surveys, and brushing pipeline rights of way and recommended that these expenses in 2011 and 2012 be rebased on 2010 actuals and then escalated by general inflation factors of 2.5 per cent and 3.0 per cent respectively.[216] The UCA explained that these expense activities are subject to discretionary spending and deferrals.[217] In evidence, the UCA explained the rationale for its recommendation as follows:

> As shown in the table AUI originally forecast a significant increase for 2010 over average actual costs for 2008-2009, followed by general inflationary increases in 2011 and 2012. However, when AUI updated its forecast in March 2011, the actual costs for each of the three categories came in at 40%, 25% and 58% lower than the forecast that had been filed on October 22, 2010 or some 2 ½ months before the end of the year which is of considerable concern to the UCA. AUI provided some explanation for the increases in 2011 and 2012, including the carryover of some leak and cathodic surveys into 2011, the use of contractors to supplement AUI personnel starting in 2010, increased emphasis on survey work and the move to a more systematic seven year brushing cycle.[218]
> (footnotes removed)

304. The CCA noted significant year-over-year fluctuations in certain expenditures, and supported a more normalized approach to determining the 2011 and 2012 forecasts. The CCA recommended using a five-year historical average (based on 2006-2010 actual results) which would allow for an escalation factor of 2.5 per cent in 2011 and 3 per cent in 2012 for leak surveys,[219] odourization,[220] cathodic protection and line surveys.[221] The CCA recommended using the recent experience of costs, for the years 2008-2010, escalated for forecast inflation, as the basis for determining the 2011 and 2012 forecasts for other pipeline operating activities.[222] The CCA also recommended that the 2011 and 2012 brushing costs should be limited to the 2010 actual costs, escalated for inflation.[223]

305. The CCA questioned AltaGas's utilization of contractors to replace internal resources that AltaGas lost in the 2008-2009 timeframe for other pipeline operating activities. The CCA argued that it is not clear why these resources could not be replaced. As such, the CCA recommended that the 2011 and 2012 forecasts be based on recent costs, for the years 2008-2010, escalated for forecast inflation.[224]

306. AltaGas identified that, if certain leak survey expenditures are not carried out due to external constraints, it is only a matter of time before they will need to be completed to maintain

[214] Transcript, Volume 6, page 1223, line 11.
[215] Exhibit 143.01, AltaGas argument, page 57, paragraph 193.
[216] Exhibit 71.01, UCA evidence, A.53, at page 37.
[217] Exhibit 141.02, UCA argument, Section 4.7, paragraph 164.
[218] Exhibit 141.02, UCA argument, Section 4.7, paragraph 164.
[219] Exhibit 142.01, CCA argument, page 50.
[220] Exhibit 142.01, CCA argument, page 52.
[221] Exhibit 142.01, CCA argument, page 56.
[222] Exhibit 142.01, CCA argument, page 58.
[223] Exhibit 142.01, CCA argument, page 57.
[224] Exhibit 142.01, CCA argument, page 58.

system integrity. Consequently, AltaGas argued that basing the forecast on a single year, as suggested by the UCA, is inappropriate and not supportable.

307. With regard to the CCA's proposals, AltaGas argued that it failed to take into account growth in the system over the proposed period. AltaGas also recognized that there have been fluctuations in the past in leak survey expense. AltaGas submitted that its forecasts continue to be reasonable and reflective of actual and expected costs over the test period. If the AUC determines that a more normalized approach is reasonable, AltaGas submitted that a three-year running average of leak survey expenses, with adjustments for inflation, may be a reasonable alternative for forecasting this item.[225]

308. In response to the CCA's recommendation on odourization expenses, AltaGas submitted that its forecasts of odourant expense in 2011 and 2012 are reasonable and reflect expected usage in a normal year consistent with 2008 and 2009 actual expenditures. AltaGas also recognized that there have been fluctuations in the past in odourant expense as reflected in the 2010 recorded expense. However, AltaGas indicated that, should the AUC determine that a more normalized approach is appropriate, a three-year running average of odourant expense with adjustments for inflation may be a reasonable alternative for forecasting this item.[226]

309. AltaGas disagreed with the CCA's recommendations on cathodic protection and line surveys. AltaGas explained that, until 2010, it employed in-house staff to perform annual cathodic protection and line surveys. However, the inability to attract qualified personnel to these internal positions resulted in difficulty in completing adequate surveys as scheduled. Consequently, in 2010, AltaGas began contracting these services. AltaGas identified that the inability to secure a contractor until part way into 2010 caused the actual expense for that year to be understated relative to what would be expected in a typical year; whereas the 2011 and 2012 forecasts are reflective of what AltaGas expects normal expenditures to be.[227]

310. AltaGas disagreed with the CCA's recommendation on other pipeline operating activities. AltaGas submitted that, while the evidence indicates the substitution of internal resources by contractors contributed to cost increases, there is no evidence to suggest the proposed combination of contract and internal resources is not a prudent arrangement, given resource availability and the required skill sets. AltaGas also stated that the CCA ignored the fact that one of the factors contributing to the increase in the other pipeline operating activities related to the increasing number of communication installations.[228]

311. With regard to brushing pipeline rights of way, AltaGas explained that, in 2010, it had undertaken the development of a plan to better manage vegetation control. AltaGas argued that spending on right-of-way brushing cannot be considered discretionary as it ensures system integrity and the provision of safe and reliable service. AltaGas submitted that its forecast of brushing expenses for the test period represents a prudent level of expenditure consistent with the planned program and should be approved as filed.[229]

---

225 Exhibit 143.01, AltaGas argument, Section 4.3.2.2, pages 67-68.
226 Exhibit 151.01, AltaGas reply argument, page 69.
227 Exhibit 151.01, AltaGas reply argument, page 70.
228 Exhibit 151.01, AltaGas reply argument, page 72.
229 Exhibit 151.01, AltaGas reply argument, pages 70-71.

Commission findings

312. The Commission has reviewed the explanations for the variability in the expenses provided by AltaGas, and considers that AltaGas has justified the year over year fluctuations. Further, the aggregate material, contractor and other expenses forecast is not inconsistent with the Commission recognized five per cent annual reasonability increase threshold. Therefore, the Commission is not convinced that the normalized approaches proposed by the CCA and the UCA are warranted, and approves the forecasts as filed.

6.2 Company pension plans

6.2.1 Overview

313. The following table sets out the total forecast and actual pension plan expenses for 2008 through 2009, as well as the forecast pension expenses for the test years, for both the AltaGas pension plan and the AltaGas inter-affiliate pension plans. The AltaGas inter-affiliate pension plans include pension expense and supplementary executive retirement plans.

Table 30. AltaGas pension plans

	2008 forecast	2008 actual	2009 forecast	2009 actual	2010 forecast	2011 forecast	2012 forecast
	($)						
Total AltaGas pension plans[230]	1,097,000	1,098,800	1,540,400	1,557,100	1,552,100	2,017,000	2,624,600[231]
Inter-affiliate pension plans[232]	222,424	222,424	235,444	235,444	100,522	103,603	109,519

314. On October 5, 2011, the company's actuary, Mercer (Canada) Limited (Mercer), provided AltaGas with updated 2012 pension estimates. The 2012 pension funding requirements increased by $536,000 and pension expenses increased by $334,000. After the tax effects of $134,000 are removed, these updated estimates equate to a $200,000 increase in the 2012 revenue requirement. The update reflects a decline in the discount rate from 6.75 per cent to 5.58 per cent, changes in actuarial assumptions to compute solvency liabilities (interest rates, mortality rates), and changes in the asset mix from 60/40 equity/fixed income to 50/50 equity/fixed income.[233]

315. AltaGas submitted that its defined benefits (DB) pension plan and other post-employment benefits (OPEB) are essential components of its overall compensation package and are required to assist it in attracting and keeping the staff it requires for safe and effective operation of its distribution system. AltaGas therefore requested the proposed pension and OPEB expenses be approved as filed, along with its proposed deferral account treatment for recovery of future differences between actual pension expenses and the pension expenses included in the approved revenue requirement.[234]

230 Exhibit 61.07, July update, Schedule 4.0B Attachment - OM&A Expenses Detail & Variances, Employee Benefits.
231 Exhibit 91.01, October 6, 2011 pensions update – Mercer.
232 Exhibit 48.23, CCA-AUI-41(a) attachment.
233 Exhibit 91.01, October 6, 2011 pensions update – Mercer.
234 Exhibit 143.01, AltaGas argument, page 52.

316. The CCA agreed in principle with the adoption of U.S. GAAP for rate-making purposes and generally with the resulting impacts to AltaGas's pension costs. However, the CCA had a number of concerns related to AltaGas's forecast pension expense.

Commission findings

317. The Commission notes that a number of concerns were raised by the CCA regarding AltaGas's pension plan practices which are addressed in the sections below. For the reasons set out, the Commission does not accept the CCA's recommendations, with respect to pension practices. The Commission approves AltaGas's forecast pension expenses as filed, with the exception of third party administration costs, as determined in Section 6.2.8.

6.2.2 Accrual versus cash (funding method) and transitional adjustment to U.S. GAAP and related deferral account

318. AltaGas stated it was continuing to use the accrual method of recovering pension expenses associated with its DB plan and that, under the accrual method, the amount of pension expense included in the revenue requirement is equal to the forecast pension expense calculated for financial reporting purposes.[235]

319. AltaGas is transitioning to U.S. GAAP in 2012. Due to the differences in pension accounting guidance under U.S. GAAP and Canadian GAAP (Part V of the CICA Handbook)[236] there will be a change to the calculation of pension expense, which AltaGas proposes to recognize for regulatory purposes.

320. AltaGas proposed amortizing pension losses of $1,166,500, the amount of its net transitional adjustment to convert its pension accounting from Canadian to U.S. GAAP. AltaGas requested this amortization over a period of 10 years starting in 2012, enabling it to recover these amounts in rates in a manner similar to the corridor method currently employed in pension accounting where gains and losses are recognized over time.[237]

Views of the parties

321. The CCA recommended that the AUC direct AltaGas to reflect the cash method of accounting for pension expense commencing January 1, 2012. The net result would be a significant net decrease to the pension cost component of revenue requirement, including the October 5, 2011 Mercer update. The CCA provided the following reasons for its proposal:

- The cash method will bring AltaGas in line with most of the utilities regulated by the AUC.
- The cash method will bring about internal consistency with the cash method treatment previously approved for OPEB within AltaGas.
- The determinations of the cash or funding amounts, while based on the results of an actuarial valuation, provide stability and predictability because the amounts are generally not subject to change each year (other than for special funding requirements to meet solvency requirements).

---

235 Exhibit 61.02, July update, paragraph 23.
236 Exhibit 143.01, AltaGas argument, paragraph 173.
237 Exhibit 61.02, July update, paragraph 30.

- Converting to the cash basis obviates the need for customers to pay an additional $1,166,500 of prior period costs.
- The $1,166,500 adjustment to retained earnings is retroactive for ratemaking purposes, given that the $1,166,500 is related to a cost in prior years (i.e. January 1, 2007 to December 31, 2011). U.S. GAAP allows the recognition of regulatory assets and liabilities. As such, there is no reason why the net charge to retained earnings of $1,166,500 should not be recorded as a regulatory asset in AltaGas's financial statements. The AUC has been clear that accounting principles which may be appropriate for external reporting purposes do not automatically ”trump” well-established practices approved by the AUC for rate making purposes.[238]

322. In its responses to information requests, AltaGas disagreed with the CCA that the cash method provides more stability and predictability than the accrual method because, it attributed the dramatic year-over-year swings to changes in returns, which were in turn caused by shifts in the economy.[239]

323. AltaGas acknowledged, in reply argument, that most, if not all, other AUC-regulated utilities use the cash method of accounting for pension expense for regulatory purposes. It also agreed that the cash method is much easier to understand and provides stability and predictability, when the actuarial studies coincide with the GRA. However, AltaGas submitted that the CCA failed to provide sufficient justification to warrant changing the company’s pension accounting method from an accrual to a cash basis, other than for consistency with other utilities.[240]

324. AltaGas agreed with the CCA that, if the cash method of accounting for pension plans were adopted, the proposed deferral account for the cumulative adjustment to retained earnings of $1,166,500 related to the retrospective application of U.S. GAAP ASC 715 from January 1, 2007, to January 1, 2012, would no longer be required. If the cash method of accounting for pension costs were adopted, AltaGas also proposed that the amount included for pension costs in the revenue requirement be updated in the compliance filing to reflect the Mercer actuarial valuation of AltaGas’s pension plans for funding purposes as of September 30, 2011. AltaGas estimated that, based on the October 5, 2011 update, this would result in a $360,300 increase in the forecast revenue requirement.[241]

Commission findings

325. Having approved the change to U.S. GAAP, and given the materiality of the $1,166,500 pension loss amount resulting from the transition to U.S. GAAP, the Commission also approves the amortization of the pension loss amount.

326. The Commission recognizes AltaGas is the only AUC-regulated utility that uses the accrual basis to account for pension expense. However, this is not determinative of the matter. The Commission must consider the specific impacts of the proposed change. The Commission accepts AltaGas’s statements that year-over-year swings are caused by changes in return, which are in turn caused by changes in the economy, rather than being a consequence of the accounting

[238] Exhibit 142.01, CCA argument, pages 19-22.
[239] Exhibit 48.01, CCA-AUI-42(a).
[240] Exhibit 151.01, AltaGas reply argument, pages 56-58 and 60.
[241] Exhibit 151.02 AltaGas reply argument, cash versus accrual impact spreadsheet.

method. The Commission also notes that, with the $1,166,500 pension loss amortization, the net transitional adjustment for AltaGas to convert its pension accounting from Canadian to U.S. GAAP will not result in a significant change from the current method of recognition of gains and losses over time. Therefore, the Commission approves AltaGas's request to continue using the accrual method to account for its pension expense. The Commission notes that matters respecting the disposition of deferral accounts under the PBR regime will be determined in Proceeding ID No. 566.

6.2.3 Differences between actual pension expense and pension expense included in the approved revenue requirement

327. Due to the unpredictable and significant fluctuations in the discount and liability proxy rate used in pension forecasts, AltaGas proposed to establish a pension expense deferral account to capture future differences between actual pension expense and the forecast pension expense included in the approved revenue requirement, with any deferred amounts to be recovered in rates in the subsequent test period. AltaGas stated that the proposed deferral account would protect customers and AltaGas from the potentially significant and unpredictable impacts arising from market conditions which are outside AltaGas's control.[242]

328. AltaGas stated that, while a deferral account would not be required for the cumulative adjustment under the cash method, under both the cash and accrual method it continues to propose a pension deferral account be put in place commencing January 1, 2012, for any special payments it may be required to make for any unfunded liabilities associated with its DB pension plans. If the cash method of accounting for pension plans is adopted, there would be similar circumstances warranting the use of deferral account treatment, as noted in Decision 2010-189.[243] [244]

329. If the Commission determines the pension deferral account is not appropriate for 2012, AltaGas requested its 2012 forecast revenue requirement be increased by $200,000 to reflect the net impact of the revised pension cost estimates. The table below illustrates the effect on AltaGas's revenue requirement, as calculated using data from the October 5, 2011 Mercer report.

Table 31. Estimated effect on 2012 revenue requirement – updated October 5, 2011[245]

	Amount ($)
Increase in pension expense	334,000
Less: tax effect of funding increase	134,000
Effect on revenue requirement	200,000

Views of the parties

330. No parties commented on this proposal.

242 Exhibit 91.01, October 6, 2011 pensions update – Mercer.
243 Decision 2010-189: ATCO Utilities, Pension Common Matters, Application No.1605254, Proceeding ID. 226, April 30, 2010, paragraphs 90-94.
244 Exhibit 151.01, AltaGas reply argument, page 58.
245 Exhibit 91.01, October 6, 2011 pensions update – Mercer, Paragraph 4, Table 2.

Commission findings

331. The Commission acknowledges the potentially significant changes in returns which are due in part to market conditions which are outside of the company's control. However, AltaGas has not provided the evidence required with respect to materiality and predictability regarding the need to create a deferral account to capture the experience gains and losses. Therefore, the proposed deferral account is denied. However, the Commission approves the company's requested $200,000 increase in the 2012 forecast revenue requirement to reflect updated pension cost estimates. AltaGas is directed to include in the compliance filing the net $200,000 increase in its 2012 revenue requirement, as estimated by Mercer.

6.2.4 Other post-employment benefits (OPEB)

332. The forecast cost of OPEB, such as life insurance and health care provided to certain AltaGas employees, has previously been included in its revenue requirement on a cash basis. The company has proposed to continue with the cash method of forecasting OPEB expenses in its revenue requirements.[246]

Views of the parties

333. The CCA made reference to the requirements under both Canadian and U.S. GAAP that OPEB be recognized on an accrual basis, but did not pursue this as an issue during the proceeding.[247]

Commission findings

334. Given that there has been no evidence arguing for the elimination of the cash method for forecasting OPEB, the Commission approves the continued use of the cash method for forecasting of OPEB expenses.

6.2.5 Other CCA recommended changes to AltaGas's pension plan

335. The CCA recommended changes to AltaGas's pension plan practices. These recommendations are discussed in this section.

6.2.5.1 Transition by parent to defined contribution (DC) pension plan for all new employees

336. AltaGas confirmed that all of its permanent employees are part of its DB pension plan.[248]

Views of the parties

337. The CCA advised that the AltaGas Ltd. 2010 annual report stated that, on July 1, 2005, AltaGas Ltd. had implemented a defined contribution (DC) pension plan for substantially all new employees. The CCA recommended that the company be directed to address the merits of introducing the DC plan to those employees not already enrolled in the DB plan (i.e. to all new employees) and that the company should address this matter in its first annual technical and rates filing. The CCA recognized that there are issues of retention and competitiveness which should be considered before any decision is taken to adopt a pension change similar to that made by AltaGas Ltd., but noted that such a practice would be consistent with the practices approved by

[246] Exhibit 61.02, July update, page 12.
[247] Exhibit 142.01, CCA argument, page 17.
[248] Exhibit 48.01, CCA-AUI-42(g).

the Commission for other utilities such as the ATCO Group of Companies and FortisAlberta Inc.[249]

338. The CCA submitted that, unlike a DB plan, the determination of pension expense under a DC plan is not mired in uncertainty as it is simply a mechanical formula which applies a certain percentage to the employee's pensionable salary. As such, the expense determination brings about a level of certainty and stability in pension expense determination.[250]

339. AltaGas responded that its DB pension plan is one of the essential components of its overall compensation package and is vital to its efforts to attract and retain the appropriate staff complement required for the safe and effective operation of the AltaGas distribution system. Altering one component of a comprehensive compensation package would fail to adequately assess the impact or potential impacts on other elements of the package, as a whole, or the company's ability to attract new staff in a reasonable and timely manner. AltaGas also observed that both EPCOR's and ENMAX's regulated utility divisions continue to maintain DB pension plans that are open to new employees.[251]

Commission findings

340. The CCA has not presented any compelling evidence that introducing a DC plan for new employees would result in a net advantage to either the company or its customers. The CCA has not persuaded the Commission to direct AltaGas to alter this individual component of its overall compensation practices.

6.2.5.2 Transparency of DB plan amendments

341. AltaGas stated that the salaried plan had not been amended since the last valuation and extrapolation for accounting purposes performed on December 31, 2009. However, the bargaining unit plan was amended in 2010 to increase the benefit accrual from 180 per cent to 200 per cent for service on and after January 1, 2010. These changes were reflected in the 2010 net periodic pension cost and December 31, 2010 accrued benefit obligation for this plan.[252]

Views of the parties

342. The CCA stated that, as a result of a collective bargaining process, amendments to the bargaining unit pension expense, as of January 1, 2010 resulted in pension expense increases of $45,000 in 2010, $64,000 in 2011 and $75,000 in 2012. Rather than reflecting these increases as salary or operating expense, they were included as part of the increase in pension expense, but with no evidence to justify this increase, other than the statement it was part of the collective bargaining process.[253]

343. The CCA submitted that one must question how "driven" management discussions are with its bargaining unit employees, if management expects that customers will backstop all costs associated with all plan amendments. The CCA proposed that the AUC should direct AltaGas, in future rate applications or as part of its annual PBR technical and rates filing, to provide full

249 Exhibit 142.01, CCA argument, pages 24-26.
250 Exhibit 142.01, CCA argument, pages 25-26.
251 Exhibit 151.01, AltaGas reply argument, pages 59-60, from Transcript, Volume 6, page 1408, line 21.
252 Exhibit 48.24, CCA-AUI-43(b) Attachment page 15 of 36.
253 Exhibit 142.01, CCA argument, page 27.

transparency in all cost increases sought in the test years through pension plan amendments so that parties can adequately examine the impacts of such amendments.[254]

344. AltaGas replied that the CCA's recommendations on this matter should be rejected because AltaGas has been fully transparent with regards to the pension plan amendments proposed during the test period. AltaGas argued that it was unfair and inaccurate to "cherry pick" one amendment to the collective agreement without considering all the changes. Also, it was unreasonable to expect that future amendments to the collective bargaining agreement would have to await regulatory approval before AltaGas ratified the agreement as this would result in unnecessary delays and inefficiency.[255]

Commission findings

345. The Commission is not clear about what the CCA is asking the Commission to do and makes no finding.

6.2.5.3 Proposed change in pension plan asset mix

346. Subsequent to the filing of the March update, AltaGas determined it would revise the proposed pension plan asset allocation from 60 per cent equity and 40 per cent fixed income to 50 per cent equity and 50 per cent fixed income.

Views of the parties

347. The CCA stated that a large part of the increase in 2012 pension expense was not related to the proposed adoption of U.S. GAAP, but to the proposed change in asset mix. The CCA submitted that AltaGas has not provided evidence of whether other entities with a DB pension plan are similarly adopting a more conservative asset portfolio, nor has it advanced a compelling justification for re-setting its investment mix in its pension plan assets as proposed.

348. To the extent this change in mix will result in additional costs to customers, and since the benefits are not clearly quantified, the CCA argued that the proposed change be denied. The CCA added that any change in the investment mix should be filed for approval in the context of the company's 2013-2017 PBR Application.[256]

349. AltaGas responded that it strongly disagreed with the CCA's position because the AltaGas Retirement Saving Committee was responsible for making reasonable and prudent investment decisions and for management of the various risks associated with the company's pension plans.[257]

Commission findings

350. The CCA has not provided any evidence demonstrating that the change in asset mix to a more conservative mix was imprudent. The Commission rejects the CCA's recommendation.

254 Exhibit 142.01, CCA argument, page 27.
255 Exhibit 151.01, AltaGas reply argument, page 60.
256 Exhibit 142.01, CCA argument, pages 27-29.
257 Exhibit 151.01, AltaGas reply argument, pages 60-61.

6.2.5.4 Employee's contributions to pension plan

351. AltaGas confirmed that none of its employees pay any contribution to the pension plan. The pension plan is fully funded by the company.[258]

Views of the parties

352. The CCA submitted that, given the significant benefit employees receive from the DB plan, it was surprising that AltaGas did not require its employees to contribute some portion of the cost of their pensions. The CCA argued that it was unfair that customers backstopped 100 per cent of the pension expense in light of the "significant and ever-increasing costs of the pension plan as evidenced in this GRA."[259] The CCA pointed to the FortisAlberta 2012-2013 General Tariff Application (GTA) in which it was stated that each DB member contributes 2.2 per cent of earnings up to the year's maximum pensionable earnings (YMPE), plus 4.0 per cent of earnings in excess of the YMPE. The company pays the remaining cost of the plan.[260] Also, AltaGas added that the ATCO Group of Companies, an entity with which AltaGas may compete for employees, requires a contribution from its employees.[261]

353. The CCA proposed that AltaGas should be directed to provide as part of the compliance filing, the results of a survey, or information garnered from its actuary, of employee pension contribution rates from a sample of other entities which also provide DB pension plans and propose an employee contribution rate to be used. This rate should be taken into account by the actuary in the determination of employer pension expense and funding requirements from January 1, 2012.[262]

354. AltaGas replied that comparisons regarding the specifics of its pension plan and those of other companies cannot be drawn without consideration of all the terms of each plan, and the total pension benefits ultimately payable to the plan members. To illustrate its point, it added that the company's pension plan does not include an annual cost of living adjustment, unlike the ATCO pension plans. It argued that there are significant material differences among pension plans and that each utility should continue to have its entire compensation package examined within the context of its own organization.[263]

355. AltaGas filed an undertaking regarding the comparability of its total compensation:

> According to Mercer's analysis, performed completely independent of AUI and its GRA, the value of AUI's pension, in terms of Employer-Provided Value, ranges from 8.6% to 10.2% of base pay, compared to the Peer Group average of 8.7% to 9.1%. When Total Value is considered, the value of AUI's plan remains the same while the Peer Average increases to a range of 11.5% to 11.9%, due to the impact of employee contributions in a number of the Peer Group plans.[264]

356. Based on the above quoted analysis, AltaGas submitted that employee contributions to pension plans do not typically change the long-term total amount of compensation provided to

258 Transcript, Volume 5, page 1135, lines 5-9 and Transcript, Volume 5, page 1137, lines 3-7.
259 Exhibit 142.01, CCA argument, pages 29-30.
260 Exhibit 152.01, CCA reply argument, page 6.
261 Exhibit 142.01, CCA argument, pages 29-30.
262 Exhibit 142.01, CCA argument, page 30.
263 Exhibit 151.01, AltaGas reply argument, page 62.
264 Exhibit 132.23, AltaGas response to undertaking with respect to Transcript, Volume 6, page 1616, line 20.

employees but instead simply alter the timing of payout by deducting amounts from employees' current wages to contribute towards higher retirement benefits that will be paid out in the future. Moreover, the employer-provided value of AltaGas's plan is, to a considerable extent, in the same range as most other companies.[265]

Commission findings

357. The Commission accepts AltaGas's argument that pension plans cannot be compared on the basis of individual components. The Commission declines to direct AltaGas to provide information in the compliance filing as to employee contribution rates from other entities providing defined benefit pension plans, as requested by the CCA.

6.2.6 Treatment of pension costs from affiliates for tax purposes

358. Total pension expense incurred by AltaGas includes pension expense allocated through inter-affiliate charges. AltaGas's forecast of inter-affiliate pension expense charges was provided in response to CCA-AUI-41(a) and is shown in Table 30 above. The affiliate pension costs allocated to AltaGas are $100,552 in 2010, $103,603 in 2011 and $109,519 in 2012.[266]

Views of the parties

359. The CCA submitted that these amounts are not recognized as add-backs to determine income taxes, while all other pension expense is so added. It appears that AltaGas did not reduce taxable income for temporary tax differences arising from funding amounts related to inter-affiliate charges. The CCA recommended that, for income tax purposes, AltaGas should add back the pension expense and deduct pension funding amounts related to amounts it gets allocated through inter-affiliate charges in the same manner as it treated its own pension expense and funding amounts.[267]

360. AltaGas responded that the CCA's assertion regarding the proper tax treatment for the inter-affiliate pension charges is incorrect. It explained that it already receives a 100 per cent deduction for inter-affiliate charges on its income tax return as these costs are classified as management fees and are a fully deductible business expense for tax purposes. Therefore, no further adjustment to the tax treatment of inter-affiliate costs is necessary.[268]

Commission findings

361. The Commission accepts AltaGas's explanation in this matter that it is able to deduct 100 per cent of inter-affiliate charges, achieving the same result with less complexity.

6.2.7 Other company plans

362. AltaGas's other company plans include supplemental health and dental, heath spending account, life insurance, dependent life insurance, accidental death and dismemberment insurance, long term disability insurance and an employee savings plan.[269]

---

265 Exhibit 151.01, AltaGas reply argument, pages 62-63.
266 Exhibit 48.23, CCA-AUI-41(a).
267 Exhibit 142.01, CCA argument, pages 31-32.
268 Exhibit 151.01, AltaGas reply argument, page 63.
269 Exhibit 48.01, CCA-AUI-5(b).

Views of the parties

363. The CCA expressed concerns about significant forecasting errors in 2008 and 2009, resulting in customers paying $334,700 more, based on AUC-approved revenue requirements, than the actual costs incurred. The CCA submitted, however, that the evidence appears to confirm the increasing rates forecast by AltaGas for health and dental plans and it did not object to the company's forecasts as filed.[270]

Commission findings

364. The Commission has reviewed the pattern of costs from 2008 to 2010 and the forecast costs for 2011 and 2012 and notes a general upward trend in a linear pattern. The Commission accordingly finds the AltaGas forecast for these expenses to be reasonable. The Commission approves AltaGas's forecasts as filed.

6.2.8 Third party administration of plans

365. Third party benefits administration costs are costs related to pension plan administration, extended health and dental plan, health spending plan and vision plan administration, other company benefit plans, including life insurance and long term disability plans, and company savings plan administration contracted out to third party providers. AltaGas provided the following breakdown of this account:

Table 32. Third party administration costs[271]

	2008 actual	2009 actual	2010 actual	2011 actual	2012 actual
	($)				
Pension plan and benefits plan administration	139,900	128,900	41,000	130,600	133,200
Benefits administration fee	17,400	9,700	2,800	10,100	10,400
Savings plan administration and fees	9,600	16,400	18,500	17,100	17,700
	166,900	155,000	62,300	157,800	161,300

366. The CCA submitted that there were significant differences between the approved forecast and the actual costs for 2008 ($86,900 versus $166,900) and 2009 ($99,600 versus $155,000).[272]

367. AltaGas explained that the reduction in the level of the 2010 actual expense relative to 2008 and 2009 reflected certain anomalies due to over-accruals. As well, the 2009 benefits review, with respect to life and long-term disability, locked in rates for a period of three years (2009-2011) so that there was no need to incur the benefits review expense in 2010. The next such review should be in 2012.[273]

368. The CCA submitted that, due to significant differences between actual and forecast costs for 2008-2009, and issues with over or under accruals of certain costs, the 2011-2012 forecasts should reflect a more normalized average, based on the actual costs incurred for the last three years (2008-2010). As such, the CCA recommended that the 2011-2012 forecast should be reduced by $26,500 in 2011 and $26,000 in 2012, as the following table illustrates:

270 Exhibit 142.01, CCA argument, pages 34-35.
271 Exhibit 48.01, CCA-AUI-5(e).
272 Exhibit 105, CCA aid to cross.
273 Transcript, Volume 5, page 1170, lines 23-24.

Table 33. Third party administration plans[274]

	2008	2009	2010	2011	2012
	($)				
AltaGas's forecast	166,900	155,000	62,300	157,800	161,300
3-year average 2008-2010			128,067		
Add: 2.5 per cent inflation - 2011[275]				131,268	
Add: 3.0 per cent inflation - 2012[276]					135,206
Reduction in third party administration costs				-26,532	-26,094

369. AltaGas submitted that its forecasts continue to be reasonable and reflective of actual and expected costs over the test period, but should the AUC determine a more normalized approach is appropriate, the CCA's proposed three-year average is not unreasonable, with an adjustment for inflation.[277]

Commission findings

370. The Commission considers that the issues raised by the CCA with respect to AltaGas's forecast costs for third party administration are valid. AltaGas did not provide any explanation to refute the CCA's critique or provide any specific evidence to explain the basis for its 2011 and 2012 forecasts. Therefore, in the compliance filing, AltaGas is directed to incorporate the CCA's recommended reductions to the third party administration plans forecast, as provided in the table above. AltaGas is also directed to adjust these amounts of $26,532 for 2011 and $26,094 for 2012 for inflation, as suggested by the CCA.

7 Inter-affiliate costs

7.1 Overview

371. For 2010 to 2012, AltaGas receives services from AUGI under an administrative services agreement (ASA) between AltaGas and AUGI. Pursuant to the ASA, AltaGas forecast inter-affiliate costs (also referred to as shared services) of $2,307,500 in 2010, $2,375,500 in 2011, and $2,467,000 in 2012, which represents increases of 10.1 per cent, 2.9 per cent, and 3.9 per cent respectively.[278] AUGI's forecast inter-affiliate shared services expenses (including AL's forecast expenses) are allocated to AltaGas on an expense-recovery basis. AltaGas's inter-affiliate services are categorized as either operational services or financial market services.

274 Exhibit 142.01, CCA argument, pages 36-37.
275 Exhibit 30.01, March update, paragraph 541, inflation table.
276 Exhibit 30.01, March update, paragraph 541, inflation table.
277 Exhibit 151.01, AltaGas reply argument, page 64.
278 Exhibit 61.07, July update, Schedule 4.0B Revised O&M & A Detail- Inter-Affiliate Shared Services.

Table 34. 2008-2012 inter-affiliate shared services costs

Inter-Affiliate Shared Services	2008 approved	2008 actual	2009 approved	2009 actual	2010 forecast	2011 forecast	2012 forecast
	($)						
Operational Services	883,400	883,400	1,004,100	1,004,100	975,400	1,007,800	1,050,200
Financial Market Services	1,505,900	1,505,900	1,897,900	1,897,900	1,499,200	1,541,100	1,598,200
Less: Non-regulatory	(93,000)	(93,000)	(98,600)	(98,600)	(167,100)	(173,400)	(181,400)
Total Inter-Affiliate Shared Services before disallowed costs	2,296,300	2,296,300	2,803,400	2,803,400	2,307,500	2,375,500	2,467,000
Less: Disallowed	(559,500)	(558,300)	(707,800)	(707,800)	-	-	-
Total Inter-Affiliate, Shared Services	1,736,800	1,738,000	2,095,600	2,095,600	2,307,500	2,375,500	2,467,000

372. For purposes of the GRA application, AltaGas has deducted STIP and Supplemental Employee Retirement Plan (SERP) components that were shareholder-focused from its forecast inter-affiliate costs, consistent with the disallowance of AUGI STIP and SERP in Decision 2009-176.[279] The deducted STIP and SERP forecast costs are $167,125 in 2010, $173,354 in 2011, and $181,398 in 2012.[280]

373. In Decision 2009-176 and in Decision 2007-094,[281] the Commission disallowed certain costs as indicated in the table above. The costs disallowed in Decision 2009-176 were calculated based on a reduction of the percentage of costs allocated from AUGI to AltaGas to 56.78 per cent of AUGI's forecast expenses. As a result, AltaGas's inter-affiliate expenses in 2008 and 2009 were reduced by approximately 25 per cent in each year.

374. Operational services are provided to AltaGas by AUGI for the purpose of assisting AltaGas in carrying on its business activities. Operational services provided to AltaGas by AUGI employees in each test year include:

- financial reporting and control operational service
- tax operational service
- human resources operational service
- treasury operational service
- regulatory operational service
- insurance operational service
- executive and strategy operational service
- internal audit operational service
- AltaGas directors' fees operational service[282]

279 Decision 2009-176: AltaGas Utilities Inc., 2008-2009 General Rate Application Phase I, Application No. 1579247, Proceeding ID. 88, October 29, 2009.

280 Exhibit 30.01, March update, Table 34.0 Disallowed Portions of AUGI STIP & SERP page 214.

281 Decision 2009-176: AltaGas Utilities Inc., 2008-2009 General Rate Application Phase I, Application No. 1579247, Proceeding ID. 88, October 29, 2009. Decision 2007-094: AltaGas Utilities Inc. 2007 General Rate Application Phase I, Application No. 1494406, December 11, 2007.

282 Exhibit 30.01, March update, pages 206-209.

375. AltaGas submitted a report prepared by KPMG in support of its forecast inter-affiliate costs. AUI engaged KPMG to conduct an independent review of the costs directly charged or allocated to AltaGas.[283]

376. KPMG stated that the 2010-2012 AUGI forecast expenses and AltaGas forecast expenses are reasonable and are allocated to AltaGas without mark-up, on an expense-recovery basis. KPMG concluded that the AUGI forecast expenses and AltaGas forecast expenses reflect open market prices. KPMG found that the shared services provided to AltaGas by AUGI are required by AltaGas and are not duplicative. KPMG also found the model used to allocate shared services costs to AltaGas to be mathematically accurate, logical and internally consistent. It is KPMG's opinion that the AUGI expense allocators utilized in the 2010-2012 Model are consistent with the AUGI expense allocators utilized in the 2009 Model and allocate AUGI forecast expenses to AltaGas in a manner that is consistent with the 2009 Model.[284]

377. AltaGas explained that its Inter-Affiliate Code of Conduct, as approved by the AUC, does not identify fair market value as being the maximum amount that may be paid by AltaGas for shared services. AltaGas's's Inter-Affiliate Code of Conduct stipulates the company must act prudently in determining whether the charges from the affiliate recover the complete costs of providing the service (and, implicitly, *only* the complete costs of providing the service).[285] There is no maximum value to the costs that can be allocated.

378. AltaGas argued that, based on the opinion expressed in the KPMG report, the shared services provided to AltaGas by AUGI are required by AltaGas and are not duplicative. KPMG stated in its report:

> In our opinion, the Shared Services provided to AUI by AUGI are required. In addition, we understand that AUI does not have the internal resources to perform the Shared Services itself. Based on the scope of review and limitations, key assumptions and comments contained herein, we are of the opinion that the Shared Services provided by AUGI to AUI are not duplicative.[286]

379. The scope of the KPMG review appears to have evolved. The Commission notes the following point in the addendum to the KPMG engagement letter included in the scope of services:

> Assessment of the reasonableness of the forecast operational and financial service costs charged to AUI by AUGI and the allocation of the AltaGas Ltd. third-party financial service costs to AUI through AUI.[287]

380. However, the KPMG report in the executive summary describes the purpose of the engagement as:

> Assess the reasonableness of the AUGI forecasted expenses ("AUGI Forecast Expenses") for 2010 to 2012 that are allocated by the 2010-2012 Model.[288]

283 Exhibit 143.01, AUI argument, paragraph 123.
284 Exhibit 30.01, March update, paragraphs 440-442.
285 Exhibit 143.01, AUI Argument, paragraph 122.
286 Exhibit 30.01, March update, Tab 12.0 KPMG Review of AUI Inter-Affiliate, Shared Services Costs, page 5 of 36.
287 Exhibit 47.37, page 6 of 7.

381. In response to questioning by the panel chair, Mr. Williams confirmed that they began by looking at the services provided by AUGI, discussed the services with AUGI and then asked AltaGas to confirm the nature of the services. KPMG did not identify objective criteria to identify when a service was required but revised their questions as they worked. When questioned why they did not start from the "bottom up" by saying "What's required for the provision of a utility service at AUI, and where are they getting those costs from?" Mr. Williams said that the decision was a practical consideration.[289]

382. AUI submitted in its application, that:

> In the opinion of KPMG, the 2010-2012 AUGI Forecast Expenses and AltaGas Forecast Expenses are reasonable and are allocated to AUI without mark-up, on an expense-recovery basis. Furthermore, KPMG concluded that the AUGI Forecast Expenses and AltaGas Forecast Expenses reflect open market prices.[290]

383. In testimony, Mr. Williams provided the basis for the KPMG opinion:

> So the basis of our opinion is that, (a) the costs are true costs, that the costs are being – are flowing down at cost, and that the allocation of those costs is based on a reasonable allocator, and the methodology is consistent, and that the allocations are done in an appropriate and accurate manner.[291]

384. The UCA questioned whether KPMG relied too heavily on information provided by AUGI and AltaGas without the benefit of an audit. The UCA raised specific concerns with respect to the inclusion of unspecified professional services in the 2011 and 2012 test years, the compensation of AUGI's Chief Executive Officer, the inclusion of costs related to a vacant AUGI position and the composite allocator used to allocate financial market service costs to AltaGas. AltaGas submitted, on the basis of the KPMG study, that it has met the obligation of prudence in determining the fees paid by AltaGas for the shared services because they include only the complete costs of providing the services.

Commission findings

385. Having considered the scope of the review undertaken by KPMG and the key assumptions in the report, the Commission finds that the KPMG report failed to adequately demonstrate that the inter-affiliate services provided to AltaGas are necessary for the provision of utility service or that the cost of the services allocated to AltaGas is reasonable. The Commission finds that KPMG ignored the disallowance of costs in Decision 2009-176 in its report, reviewed costs from the perspective of AUGI and AL, rather than from AltaGas's perspective, and did not adequately support the cost allocators utilized. The Commission discusses some specific aspects of the KPMG report in the following sections of this decision.

[288] Exhibit 30.01, March update, Tab 12.0 KPMG Review of AUI Inter-Affiliate, Shared Services Costs, page 4 of 36.
[289] Transcript, Volume 1, page 343, line 12 to page 348, line 9.
[290] Exhibit 30.01, March update, paragraph 440.
[291] Transcript, Volume 1, page 320, lines 3-9.

7.2 Commission analysis

386. The Commission has considered the following specific matters with respect to allocation of shared services to AltaGas.

7.2.1 Comparison of AUI's inter-affiliate expenses to ATCO Gas

387. The UCA noted that inter-affiliate shared services costs have increased substantially since 2006, the last year before AUGI costs were included in AltaGas's inter-affiliate shared services costs.[292] In 2006 and 2007, actual inter-affiliate shared services costs were $518,204 and $1,151,000 respectively.[293]

388. In evidence, the UCA compared the inter-affiliate shared services costs per average customer per year to the ATCO corporate costs allocated to ATCO Gas for the period 2010-2012 and found that the AltaGas inter-affiliate shared services costs per average customer per year were four times greater than those of ATCO Gas. The UCA questioned KPMG's opinion that the costs are reasonable, are required and are not duplicative and recommended a detailed examination as to whether the services are required, whether they are being provided in the most efficient manner and whether they are being provided at a reasonable cost.

389. In rebuttal evidence, AltaGas submitted that it has one fifteenth the number of customers of ATCO Gas and requires the same types of corporate services. AltaGas argued that, if anything, the analysis suggests that the costs are reasonable.[294]

Commission findings

390. The Commission considers, in the circumstances, that it is very difficult to compare utility metrics given the different characteristics of AltaGas and ATCO Gas, such as differences in the number of customers and the size and nature of the respective service territories. Consequently, in this particular case the Commission considers that the metric of inter-affiliate shared services cost per customer offers little insight as to the reasonableness of AltaGas's inter-affiliate expenses.

7.2.2 Non-recurring corporate conversion and tax project consulting expenses

391. The UCA expressed concerns with respect to the following opinion of KPMG:

> In our opinion, the 2010-2012 AUGI Forecast Expenses and AltaGas Forecast Expenses which we were able to assess are reasonable. The only expenses which we are unable to assess for reasonableness are the 2010 AltaGas non-recurring corporate conversion and tax project consulting expenses [included in 2010-2012 Third Party Financial Market Services Expenses] and unspecified 2011 and 2012 corporate and tax project consulting expenses. Accordingly, we provide no opinion on the reasonableness of those particular expenses.[295]

392. Although KPMG explained that it was unable to assess or provide an opinion as to the reasonableness of the unspecified 2011 and 2012 professional services related to corporate

[292] Exhibit 71.01, UCA evidence, page 22, A33.
[293] Exhibit 71.01, UCA evidence, page 22, A33.
[294] Exhibit 81.01, AltaGas rebuttal evidence, paragraph 74.
[295] Exhibit 30.01, March update, Tab 12.0 KPMG Review of AUI Inter-Affiliate, Shared Services Costs, pages 4 to 5 of 36.

matters, KPMG stated that AUGI's management is of the view that it is reasonable to make such an allowance since, in the normal course of business, unforeseen circumstances requiring professional services typically arise.[296] In response to UCA-AUI-54(b), AltaGas provided a breakdown of these costs allocated to AltaGas:

Table 35. Non-recurring corporate conversion and tax project consulting costs

	2010	2011	2012
Total corporate conversion and other corporate and tax project expenses	1,000,000	1,025,000	1,055,750
AUGI allocator	15.50%	15.50%	15.50%
AUI allocator	61.38%	61.38%	61.38%
Expenses allocated to AUI	95,128	97,506	100,431

Expenses allocated to AUI figures may not compute exactly due to rounding.

Commission findings

393. The Commission accepts AltaGas's non-recurring corporate conversion and tax project consulting costs in 2010 as these costs were largely driven by the 2010 change in the AL corporate structure. The restructuring provides access to public debt and capital markets. The Commission therefore approves AltaGas's 2010 forecast as filed.

394. The Commission does not, however, approve the forecast for unspecified 2011 and 2012 corporate and tax project consulting expenses allocated to AltaGas. The company has failed to provide a sufficient justification for these costs. The Commission directs AltaGas to reflect this finding in its compliance filing to this decision by reducing the corporate services cost allocation by $97,506 in 2011 and $100,431 in 2012.

7.2.3 Compensation of the CEO of AUGI

395. The UCA expressed concerns regarding the CEO's total compensation included in AUGI's costs and allocated to AltaGas, noting that a similar concern arose in the 2008-2009 GRA.[297] The UCA argued, based on the size of AUGI, that the CEO's compensation should be compared to the 25th percentile rather than the 50th percentile or median used by Mercer and KPMG. The UCA recommended that AUGI's CEO total compensation should be in the range of $400,000 to $600,000 based on other companies closer to the 25th percentile.[298] The UCA recommended that the AUGI costs to be allocated to the utility subsidiaries should be reduced accordingly.

396. The Mercer study, referred to in the KPMG report, considered only total direct compensation and did not take into consideration other compensation benefits such as MTIP, SERP, health and payroll benefits, and training. KPMG's witness, Mr. Williams, revised KPMG's report, stating that AUGI's CEO direct compensation was above the median of all three peer groups.[299] No information was provided on the record regarding the reasonability of AUGI's CEO total compensation and the resulting impact on AltaGas shared services costs. KPMG expressed an opinion that the costs for other compensation benefits were reasonable on an aggregate AUGI employee basis.[300] However, the basis for this opinion appears to be a

296 Exhibit 30.01, March update, Tab 12.0, KPMG Report, pages 22-23.
297 Exhibit 71.01, UCA evidence, A37.
298 Exhibit 71.01, UCA evidence, Question 37 and Exhibit 141.02, paragraphs 117-120 and Exhibit 93.01.
299 Transcript, Volume 1, page 83, lines 1-7.
300 Exhibit 30.01, March update, Tab 12.0, KPMG Report, page 26.

comparison to historical costs and forecasts. No third party comparisons were provided in the KPMG report.

397. KPMG stated that the direct compensation component of AUGI's CEO was above the median of the three peer groups used as comparators. However, there is no evidence with respect to the CEO's total compensation.

Commission findings

398. The KPMG witness confirmed that AUGI's CEO direct compensation is above the median of the three peer groups used for comparison in the Mercer Report.[301] However, the Commission recognizes that total direct compensation does not take into consideration other compensation benefits (such as MTIP, SERP, health and payroll benefits, and training). No analysis of reasonableness was provided by KPMG on these other compensation benefits specific to AUGI's CEO, nor did the Mercer study provide a comparison of AUGI's total compensation against any peer group. Accordingly, the Commission finds that the analysis undertaken by KPMG is not helpful in determining whether the allocation of total compensation of AUGI's CEO to AltaGas is reasonable.

399. The best evidence before the Commission in this proceeding is the total direct compensation comparison with three peer groups in the Mercer report that shows AUGI's CEO total direct compensation is above the median of all three peer groups.[302] As such, the Commission directs AltaGas to adjust the compensation amount of AUGI's CEO to reflect the average amount of the median total direct compensation of the three peer groups before calculating the amount to be allocated to AltaGas in the test years. The Commission calculates the average of the median total direct compensation of the three peer groups to be $564,000.[303]

7.2.4 AUGI vacant position

400. During the hearing, the UCA noted that Mr. Green of AUGI acknowledged that AUGI had forecast a complement of 10 new positions, but stated that the vacant Manager of Corporate Reporting and Control position was not filled and will not be filled in the immediate future.[304] The annual allocated cost included in the AltaGas forecast for this vacant position, for each of the test years, is $134,258.[305] The UCA submitted that the AUGI costs to be allocated to the utility subsidiaries should be reduced by that amount in each of the test years.[306]

401. AltaGas submitted that the fact the vacant position may or may not be filled as forecast should not affect the overall forecast. Forecasts are, by their nature, subject to the types of staff additions and deletions that occur in the normal course of running any business.[307]

[301] Transcript 1, page 83, lines 1-7.
[302] Exhibit 47.01AUC.AUI-70(L) and update to table as per Transcript 1, page 85, lines 3-9.
[303] Exhibit 47.01, AUC-AUI-20(L), page 12 of 14.
[304] Transcript, Volume 1, pages 0173 – 0175.
[305] Transcript, Volume 1, page 0177, lines 15-18. Exhibit 30.01, Application, Section 4.22A Attachment – Dedication of Labour Time and Fully Burdened Costs by AUGI position.
[306] Exhibit 141.02, UCA argument, paragraph 134.
[307] Exhibit151.01, AltaGas reply argument, paragraph 179.

Commission findings

402. As AUGI has no plans to fill the vacant Manager of Corporate Reporting and Control position, the Commission agrees with the UCA that the AUGI costs to be allocated to the utility subsidiaries should be reduced by the costs related to this position for the 2010-2012 test years. AltaGas is directed to remove $134,258 for the vacant Manager of Corporate Reporting and Control position from the company's inter-affiliate costs, for each of the test years, in the compliance filing to this decision.

7.3 Allocators

403. In assessing whether the shared services costs have been correctly allocated to AltaGas, the Commission does not consider that there is a single correct allocation methodology, but that the process must be reasonable and appropriate in the circumstances.

404. Four allocators are identified in the KPMG report: a headcount allocator, an hours of service allocator, a composite allocator, and a work effort allocator. KPMG described all allocators as objective and stated that all but the composite allocator are reasonable.

405. The Commission has examined the composite allocator, which was questioned by the UCA, and the work effort allocator, with respect to which KPMG expressed a qualification.

7.3.1 Composite allocator

406. AUGI allocated 61.38 per cent of AUGI's financial market services costs to AltaGas based on a composite allocator that equally weights revenues, total assets and capital asset additions. Although the allocator was based on 2008 financial information, the numbers for Heritage Gas were adjusted to reflect AUGI's increased ownership to 100 per cent in 2009.[308]

407. The KPMG report stated that the composite allocator was adopted by AUGI based on a general direction of the board[309] and that KPMG had not assessed the reasonableness of the allocator but noted that the composite allocators for both AL and AUGI are based on an objective measure.

408. The UCA recommended that the composite allocator be based on 2010 audited financial results, should not include the cost of natural gas in the calculation of revenues, and should include the Heritage Gas revenue deferral account in the revenue component of the allocator. As a result, the UCA recommended that only 56.8 per cent of AUGI's Financial Market Services be allocated to AltaGas.[310]

409. With regard to the use of 2010 financial results, AltaGas submitted that the current ASA is effective for the period January 1, 2010 to December 31, 2012. As the 2010 audited financial results were not known at the commencement of the ASA, it would not be appropriate to allocate the costs on a basis different than what is stipulated and agreed to in the shared services contract.

410. The UCA submitted, in reply argument, that the appropriateness of the composite allocator in this proceeding is a matter that the Commission should address without being bound

[308] Exhibit 30.01, March update, paragraph 407.
[309] Exhibit 30.01, March update, Tab 12.0, KPMG Report, footnote 7 refers to Decision 2007-094, page 55.
[310] Exhibit 71.01, UCA evidence, page 27, A40.

in any manner by the fact that AltaGas entered into an agreement with a non-arms length subsidiary.[311]

411. AltaGas submitted that the UCA's suggestion to exclude the cost of gas from the allocator should be rejected. As indicated in AltaGas's rebuttal evidence, the composite allocator is used to allocate financial market service costs. As the commodity costs for the three entities have a significant bearing on the amount of capital required by AltaGas, Heritage Gas and Inuvik Gas, the company submitted that it would be inappropriate to remove this essential cost element from the allocation mechanism.[312] Doing so would not adequately reflect the size of the working capital requirements of each affiliate.[313]

412. AltaGas explained that the revenue deferral account for Heritage Gas Ltd. is already included in the revenues ($9.712 million) and the asset balance is included as part of the total assets ($26.880 million).[314] Therefore, AltaGas submitted that the composite allocator already takes into account the potential impact of the Heritage Gas Ltd. revenue deferral account.

Commission findings

413. The Commission is satisfied with AltaGas's explanation that the Heritage Gas Ltd. revenue deferral account is already included in the revenues and assets of Heritage Gas Ltd. The Commission is also satisfied with AltaGas's rationale for including the cost of gas in the revenue component of the composite allocator, in these circumstances. AltaGas has stated that the cost of gas has a significant impact on the capital required and there is no evidence on the record to challenge this assertion.

414. In this proceeding, the 2010 actual audited financial results are available. Given the October 8, 2009 change in structure, which established AL as AltaGas's indirect parent, the Commission considers that 2010 audited financial results are reflective of the operations and asset structure in place during the test years.

415. The Commission finds that it is reasonable to use 2010 audited financial results to calculate both AL's composite allocator and AUGI's composite allocator. AltaGas is directed to use 2010 audited financial results for the purpose of calculating these allocators. With respect o the AUGI composite allocator, the Commission accepts that using 2010 audited financial statements results in a composite allocator of 54.45 per cent.[315] Accordingly, AltaGas is directed to use an AUGI composite allocator of 54.45 per cent in the compliance filing.

416. Although the Commission accepts the composite allocator for the purposes of this decision, the Commission makes no determination as to the validity of the components of the composite allocator, the relative weight to be given to each, or the measurement of the individual components.

7.3.2 Work effort allocator

417. The AUGI work effort allocator is used to allocate personnel and related overhead expenses for operational services (direct) and for financial market services (indirect).

311 Exhibit 150.02, UCA reply argument, paragraph 84.
312 Unlike ATCO Gas, AltaGas provides both default gas supply and distribution services.
313 Exhibit 81.04, AUI rebuttal evidence, paragraph 75.
314 Exhibit 143.02, AUI argument, paragraph 146.
315 Exhibit 47.01, response to AUC-AUI-69(a).

418. Consistent with direction provided by the Commission in Decision 2007-094 and reiterated in Decision 2009-176, KPMG relied on time sheets to calculate the work effort allocator. However, the time information recorded by AUGI is for the seven-month period from January 1, 2010 to July 31, 2010.[316] As observed by KPMG for specific projects and tasks, the related work effort is not necessarily expended evenly throughout the year and, as a result, the year to date work effort may not necessarily be indicative of the work effort on an annualized basis.[317] KPMG assessed the reasonableness of the 2010 work effort relative to the year to date work effort by considering the impact of specific anticipated projects or tasks for the five-month period from August 1, 2010 to December 31, 2010 and found the forecast work effort to be reasonable. KPMG relied on AUGI management's view that the work effort is not expected to materially change from one year to the next, due to the generally repetitive cyclical and long-term nature of the projects in which AUGI personnel are typically involved.

419. In response to a question from the Commission as to whether KPMG had looked at the business plans or assumptions made in the forecasts, Mr. Williams stated that:

> A MR. WILLIAMS: Well, we would have --
> I'd have to go back through my files. I don't
> recall looking at a business plan per se. But
> definitely we would have had extensive
> discussions on the assumptions that were built
> into the forecast in terms of time. And it
> really relates back to the tasks and the
> activities that the people are involved with.[318]

Commission findings

420. The Commission agrees with KPMG's observation that, for specific projects and tasks, the related work effort is not necessarily expended evenly throughout the year and as a result the year to date work effort may not necessarily be indicative of the work effort on an annualized basis. The forecast period is a three year period. The Commission considers that KPMG should have reviewed AUGI's forecast business plans, projects and tasks for the test years and assessed whether the work effort allocator proposed by AltaGas is reasonable for the test years. The Commission is not persuaded that the evidence on the record adequately supports the use of the work effort allocator for the years 2011 and 2012.

421. Accordingly, the Commission directs AltaGas to reduce to the allocated amount of AUGI costs arising from the application of the work effort allocator by 10 per cent in each of 2011 and 2012, owing to uncertainty in the level of projects and tasks affecting the calculation of the work effort allocator, and the lack of support provided for it in respect of these test years.

422. AltaGas's remaining allocators are approved, as filed, for the purposes of calculating the revenue requirements for the test years.

7.4 Reasonableness of inter-affiliate costs

423. AltaGas's Inter-Affiliate Code of Conduct is designed to mitigate the potential misalignment of interests between shareholders and customers of AltaGas. Under AltaGas's

---

[316] Exhibit 30.01, March update, Tab 12, KPMG Review, page 16, footnote 10.
[317] Exhibit 30.01, March update, Tab 12, KPMG Review, page 30.
[318] Transcript, Volume 1, page 315, line 17 to page 316, line 1.

Inter-affiliate Code of Conduct, shared services are to be priced on a cost recovery basis (Section 2.1 (v)). AltaGas's Inter-Affiliate Code of Conduct defines cost recovery basis as meaning "the complete costs of providing the service, determined in a manner acceptable to the utility, acting prudently" (Section 2.1 (l)).[319]

424. AltaGas explained that its Inter-Affiliate Code of Conduct, as approved by the AUC, does not identify fair market value as being the maximum amount that may be paid by AltaGas for shared services:

> In fact, AUI's Inter-Affiliate Code of Conduct does not provide for *any* maximum on the amount that may be paid by AUI for shared services. Rather, it stipulates AUI must act prudently in determining whether the charges from the affiliate recover the complete costs of providing the service (and, implicitly, *only* the complete costs of providing the service).[320]

425. KPMG stated in its report:

> Our review did not identify any mark-up (e.g. profit component) on the AltaGas Forecast Expenses or on AUGI Forecast Expenses. In other words, the AUGI Forecast Expenses (including AltaGas Forecast Expenses) are allocated to AUI on an expense-recovery basis.[321]

426. Mr. Williams, on behalf of KPMG, stated "We are not giving a fair value opinion here. That is not what we were asked to do, nor are we giving one."[322]

427. The UCA submitted that the fact that AltaGas pays AUGI's costs without markup is not a true measure of the prudency of those costs. The prudency of the inter-affiliate costs can only be based on benchmarking or fair market value opinions, neither of which were provided by KPMG.[323]

Commission findings

428. The Commission notes that AltaGas and KPMG did not submit evidence with respect to fair market value and provided no evidence as to whether it would be less expensive for AUI to provide the services itself. Although the Commission considers that it may not always be practical, at every GRA, to file evidence or a report that evaluates whether or not it may be less expensive for AltaGas to provide these shared services itself or through a third party, a periodic review would assist the Commission in determining whether the existing shared services agreement is a prudent arrangement. The Commission also considers that Section 3.3.4 of AltaGas's Inter-affiliate Code of Conduct contemplates a periodic review of the prudence of its shared services arrangements. The Commission directs AltaGas to undertake such a review at the time its next filing where inter-affiliate costs are to be considered.

---

[319] Order U2004-416: AltaGas Utilities Inc., Inter-Affiliate Code of Conduct Filing, Application No. 1365034, December 1, 2004.
[320] Exhibit 143.01, AUI Argument, paragraph 122.
[321] Exhibit 30.01, March update, Tab 12.0, KPMG Report, page 5 of 36.
[322] Transcript, Volume 1, page 325, lines 09-13.
[323] Exhibit 150.02, UCA reply argument, paragraph 77.

7.5 Subsequent event - Pacific Northern Gas

429. Subsequent to the close of the hearing, AL entered into an agreement with Pacific Northern Gas (PNG) to indirectly acquire all of the issued and outstanding shares of PNG. The UCA submitted, in reply argument, that the AUGI Financial Market Services allocation formula (composite allocator) should be revised for the 2012 test year if the transaction closed as expected. The acquisition closed on December 20, 2011.[324]

430. In a letter dated December 22, 2011, the Commission established a process for supplemental submissions with regard to AL's acquisition of PNG in order to determine whether the acquisition may have an impact on any inter-affiliate cost allocations to AltaGas during the test period.

431. In its supplemental submission, the UCA submitted that it would be reasonable for the Commission to address the PNG issue in the same way it addressed the same problem in Proceeding ID No. 969,[325] by approving some reasonable 2012 corporate allocation to AltaGas as a placeholder and finalizing the result in a later proceeding when the facts can be clarified and the issue can be conveniently dealt with by the Commission. The UCA also requested that any such process be based on PNG's total assets, revenues and capital expenditures as of 2010 as opposed to 2009.[326]

432. The CCA also recommended that AltaGas be directed to reflect all changes in its costs and revenues as a result of the acquisition by AltaGas Ltd of PNG in the compliance filing. The CCA suggested that one possible way to deal with this module is to review the matter in the context of the compliance filing.[327]

433. AltaGas contended that there was no basis to revise the allocation calculation due to the PNG acquisition for purposes of this proceeding for the following reasons:

- The transaction will not have closed as of the close of record of this proceeding.
- PNG obtains its debt financing directly from third parties and will not immediately rely on either AL or AUGI for services related to debt market access.
- PNG is being acquired by AL and will not be a subsidiary of AUGI.
- PNG has not requested any operational or financial market services from AUGI.[328]

Commission findings

434. With respect to the acquisition of PNG, AltaGas explained that, while PNG will rely on AL for equity financing and may or may not utilize AltaGas Ltd. financing at some future date as its existing third party sourced debt matures, PNG currently has sufficient resources to provide any other operational and financial market services it may require.[329] The Commission is satisfied with AltaGas's explanation that, given the corporate structure, PNG will not be a subsidiary of AUGI and AUGI does not anticipate providing any inter-affiliate services (either operational or financial market) to PNG during the 2010-2012 test period. The Commission finds that there is

324 Exhibit 154.01, IR response to AUC-AUI-159(a).
325 Proceeding ID No. 969 is the ATCO Gas 2011-2012 General Rate Application Phase I proceeding.
326 Exhibit 159.01, UCA supplemental submission regarding PNG, pages 3-4.
327 Exhibit 160.01, CCA supplemental submission regarding PNG, pages 2-3.
328 Exhibit 151.01, AUI reply argument, paragraph 150.
329 Exhibit 161.01, AUI supplemental submission with respect to PNG acquisition, pages 5- 6.

no evidence on the record that warrants a change in AL's composite allocator associated with the equity and debt financing requirements of PNG. Additionally, the Commission finds that establishing a placeholder for 2012 is not warranted because there is no evidence that the composite allocator for 2012 will be affected the PNG acquisition.

7.6 Criteria for assessing reasonableness of inter-affiliate charges

435. AltaGas's Inter-Affiliate Code of Conduct is designed to mitigate the potential misalignment of interests between shareholders and customers of AltaGas.[330] As per AltaGas's Inter-affiliate Code of Conduct, shared services are to be priced on a cost recovery basis (Section 2.1 (v)).[331] As noted above, AltaGas has interpreted its code to mean that there is no maximum value for shared services costs. However, the Commission must assess the reasonableness of costs and considers fair market value may be utilized as a measure in this assessment.

436. Over time, the Commission has developed, and now generally relies upon, the following three criteria to assess the reasonableness of inter-affiliate costs:

a. Are the services necessary for the provision of utility service?

b. Are the costs allocated correctly?

c. Would it be less expensive for the utility to provide the services itself or to seek a different third party provider on a stand alone basis?[332]

437. The Commission notes that the Inter-Affiliate Code of Conduct is currently under review and any revisions to it that may result from the review are unknown at this time. However, it is likely that the above criteria will continue to be used in some fashion in future reviews of the reasonableness of inter-affiliate costs. The Commission considers that future studies of inter-affiliate charges, such as the KPMG Report, should address the three criteria above, at minimum.

8 Depreciation

438. AUI applied for depreciation expenses in its revenue requirement of $12,191,651 in 2010, $12,598,267 in 2011 and $13,465,672 in 2012.[333] AltaGas also applied to modify the commencement date for calculating depreciation for new assets.

439. To support its depreciation expense forecast, AltaGas filed company-sponsored evidence[334] on depreciation and a depreciation study prepared by Gannett Fleming.

440. The Gannett Fleming depreciation study relied on the company's asset mortality history, interviews with management and operations staff, review of approved service life estimates from a selected group of peers, and the past Canadian-based experience of Gannet Fleming. In

---

330 U2004-416, AUI Inter-Affiliate Code of Conduct (Released December 1, 2004), Section 1.1 Purpose and Objectives of the Code.
331 Ibid., Section 2.1, Definitions, page 4.
332 Based on Decision 2010-505, paragraph 100.
333 Exhibit 61.06, July update, Schedule 1.0A.
334 Exhibit 49.01, AltaGas depreciation study by Gannett Fleming.

response to an information request, Gannett Fleming also provided information as to the relative weighting given to historical experience of the company, peer industry experience, Gannett Fleming professional judgment, expected innovation in technology and discussions with company staff in arriving at its average service life estimates for each account.

441. AltaGas proposed adoption of the recommendations of the depreciation study.

442. The following table compares depreciation expense for 2008 and 2009 to the forecast amounts for 2010 to 2012, and the relative percentage increases.

Table 36. Comparison of depreciation expense in total

	2008 actual	2009 actual	2010 forecast	2011 forecast	2012 forecast
			($ millions)		
Depreciation expense (Exhibit 61.06, Schedule 1.0A)	$10.1	$10.6	$12.2	$12.6	$13.5
Increase year over year - dollars		$0.5	$1.6	$0.4	$0.9
Increase year over year – percentage		5.0%	15.1%	3.3%	7.1%
Increase from 2008 actual - dollars			$2.1	$2.5	$3.4
Increase from 2008 actual - percentage			20.8%	24.8%	33.7%
Increase from 2009 actual - dollars			$1.6	$2.0	$2.9
Increase from 2009 actual - percentage			15.1%	18.9%	27.4%

443. The UCA commented on the depreciation study in general and proposed changes to the depreciation parameters and related forecast depreciation amounts for the four largest accounts (the four accounts), being 465 (transmission mains), 467 (transmission measuring and regulating equipment), 473 (distribution services), and 475 (distribution mains). The UCA submitted that the Gannett Fleming depreciation study did not adequately support and justify the requested life and net salvage values.[335] In particular, the UCA argued that the narrative in support of the recommendations for the four accounts was only two pages long, while 22½ pages of narrative was provided for general depreciation, including survivor curves, and the retirement rate method of analysis.

444. The UCA criticized the methodology used by Gannett Fleming and submitted that the information provided was insufficient for the specific life proposals. Further, the UCA noted that the specific narrative provided relied on generalized and unsupported statements.

445. AltaGas noted that the UCA's recommendations would have a significant negative impact on its cash flow and credit metrics.[336]

446. The following table compares the current depreciation parameters, the proposed parameters submitted by AltaGas and the UCA, and the percentage of assets represented in each of the four accounts. The dollar impact by year of the proposed changes is provided in Table 38.

[335] Exhibit 141.02, UCA argument, paragraph 167.
[336] Exhibit 132.04, AltaGas response to undertaking, Transcript, Volume 2, page 591, line 22.

Table 37. Comparison of depreciation parameters for four specific accounts

Account	Account Title	% of assets in account at December 31, 2009	Current Parameters Note 1	AUI Proposal	UCA Proposal
465	Transmission Mains	11.9%	60 L3	57 L3	60 L3
467	Transmission Measuring and Regulating Equipment	5.4%	33 S2.5	43 R3	47 S2
473	Distribution Services	27.0%	44 R4	48 R4	52 R4
475	Distribution Mains	33.5%	55 R2	55 R2	70 R1.5

Note 1: Source – Exhibit 2 from Proceeding ID No. 88; Tab 21- depreciation technical update, page 11 of 49.

Table 38. Difference in forecast depreciation using AltaGas parameters and the UCA's parameters

Year	Account	Account title	Depreciation forecast - AltaGas	Depreciation forecast - UCA	Difference
			($ millions)		
2010	465	Transmission Mains	0.773	0.649	0.124
2010	467	Transmission Measuring and Regulating Equipment	0.658	0.503	0.155
2010	473	Distribution Services	3.382	2.035	1.347
2010	475	Distribution Mains	2.514	1.650	0.864
2010	**Total**		**7.327**	**4.837**	**2.490**
2011	465	Transmission Mains	0.803	0.674	0.129
2011	467	Transmission Measuring and Regulating Equipment	0.729	0.557	0.172
2011	473	Distribution Services	3.616	2.181	1.435
2011	475	Distribution Mains	2.581	1.665	0.916
2011	**Total**		**7.729**	**5.077**	**2.652**
2012	465	Transmission Mains	0.830	0.697	0.133
2012	467	Transmission Measuring and Regulating Equipment	0.788	0.602	0.186
2012	473	Distribution Services	3.820	2.304	1.516
2012	475	Distribution Mains	2.795	1.804	0.991
2012	**Total**		**8.233**	**5.407**	**2.826**

447. The Commission will examine the changes proposed by the UCA to the four accounts, in separate sections below, and will examine the proposed changes in forecast depreciation for average service lives in other accounts in summary, following consideration of the four accounts.

8.1 Account specific changes

8.1.1 Account 465 – transmission mains

448. AltaGas forecast depreciation expenses of $772,933 in 2010,[337] $800,717 in 2011[338] and $825,473 in 2012[339] for Account 465 based on Mr. Kennedy's depreciation study which proposed a change to the Iowa curve for this account to 57-L3. The currently approved depreciation for this account assumed an Iowa curve of 60-L3.

337 Exhibit 60.01, AltaGas IR responses, Schedule 5.1F, line 13.
338 Exhibit 60.01, AltaGas IR responses, Schedule 5.1G, line 13.
339 Exhibit 60.01, Schedule 5.1H, line 13.

449. In the depreciation study,[340] Gannet Fleming observed that the original survivor curves, as plotted, indicate retirement ratios that begin to increase from approximately age 25 through age 58, and noted that company operations and management staff indicated that they did not expect a significant change to the average service life characteristics from an operational perspective. Gannet Fleming recommended the 57-L3 Iowa curve based on the fit to historic data, the indications from management, and on the professional judgment of Gannet Fleming.

Views of the parties

450. The UCA submitted that Mr. Kennedy did not provide an adequate basis to reduce the average service life[341] and recommended that the current 60-year life estimate be retained. The UCA's expert, Mr. Pous, submitted that a visual examination suggests that Iowa curve 60-L3 also provides a good fit.[342]

451. Mr. Pous further submitted that:[343]

- The evidence from Gannet Fleming's discussion with the company's management and operations personnel could also mean that a 63 or 65 average service life is reasonable.
- Mr. Kennedy's decision to reduce the life is not explained by reasonable expectations of the future, which suggest a longer life due to better wrapped coatings, more regular inspections, etc.
- An analysis of Mr. Kennedy's peer group suggests that it is inappropriate to reduce the average service life.
- Neither AltaGas nor Mr. Kennedy identified why 60 or 63 years would not be a reasonable life selection.

452. In argument, the UCA disputed Mr. Kennedy's computed mortality methodology, noting that he undertook a simulated plant records (SPR) calculation which yielded an 85-year life, but ignored the life indication while accepting the dispersion pattern indicated by the SPR analysis.[344]

453. The UCA further submitted that, even using the 57-year average service life, given the factors considered and the approximate weighting Mr. Kennedy provided, consideration of peer group value, innovations in technology and discussions with company staff, one would arrive at a conclusion that no change from the existing 60-year average service life, or alternatively, an increase would be warranted.[345] The UCA pointed out that applying Mr. Kennedy's own weightings from Exhibit 75.02 yielded a result of 60 years, which is in excess of AltaGas's recommendation for a 57-year life. The UCA submitted that the Commission should accept Mr. Pous' recommendation to retain the existing 60-L3 life-curve combination.

454. AltaGas submitted in rebuttal evidence that a visual examination of the curves demonstrates that Mr. Kennedy's proposal is superior.[346] Further, AltaGas submitted that Mr. Pous' assertions with respect to the impact of technology on service lives had no evidentiary

340 Exhibit 30.01, March update, page II-23 and II-24 (pages 735 and 736 of 859).
341 Exhibit 71.03, direct testimony of Mr. Pous, page 9, Q/A 18.
342 Exhibit 71.03, direct testimony of Mr. Pous, page 10, Account 465 Chart.
343 Exhibit 71.03, direct testimony of Mr. Pous, page 9, Q/A 19.
344 Exhibit 141.02, UCA argument, paragraph 180.
345 Exhibit 141.02, UCA argument, paragraph 182.
346 Exhibit 81.01, AltaGas rebuttal evidence, Q/A11.

support and that the only clear evidence is the superior fit to the observed life table of Mr. Kennedy's curve.[347]

455. AltaGas submitted that, while Mr. Pous may not agree with the results of the computed mortality method, no evidence was provided to suggest that the computed mortality method does not provide accurate average service life estimates.[348] AltaGas noted that the AUC has accepted the computed mortality method in the past as a reasonable approach.[349]

Commission findings

456. The Commission agrees with Mr. Kennedy that the 57-L3 Iowa curve provides for a better visual fit with the observed life data than Mr. Pous' proposed 60-L3 Iowa curve. However, when the other factors identified as being relevant in Mr. Kennedy's analysis are taken into account, the Commission finds that there is insufficient corroborating evidence to support the adoption of the curve proposed by Mr. Kennedy. Mr. Kennedy indicated that the weighting to be given to the historical experience (the data) for this account should be 60 per cent. Other factors such as innovation and peer experience make up the other 40 per cent of the weighting. The calculation provided by the UCA of the average service life resulting from Mr. Kennedy's own weightings yielded an average service life of 60 years. Mr. Kennedy also stated, in his depreciation study, that management and operations staff did not expect a significant change to the average service life characteristics for transmission mains, from an operational perspective.[350]

457. Given the above, the Commission is not convinced that the life expectancy of the assets in Account 465 should be altered from 60 years to 57 years. Accordingly, AltaGas is directed to retain the life assumptions for Account 465, as approved in Decision 2009-176, in the compliance filing.

8.1.2 Account 467 – transmission measuring and regulating equipment

458. AltaGas forecast depreciation expenses of $658,377 for 2010,[351] $724,882 for 2011,[352] and $777,742,[353] for 2012 based on the depreciation study by Gannet Fleming, in which Mr. Kennedy proposed a 43-R3 curve for this account. The current Iowa curve is 33-S2.5, as approved in Decision 2009-176. The change proposed by AltaGas would extend the average service life of the assets in this account from 33 to 43 years. Neither the company nor Mr. Kennedy provided any rationale in the GRA application for the proposed change in the Iowa curve for Account 467.

459. In response to an information request, Mr. Kennedy indicated that, for Account 467, he had placed a 75 per cent weighting on historical experience of the company, 20 per cent on peer industry experience, zero per cent on Gannett Fleming professional judgment, zero per cent on expected innovations in technology and five per cent on discussions with company staff.[354]

347 Exhibit 81.01, AltaGas rebuttal evidence, Q/A11.
348 Exhibit 143.01, AltaGas argument, paragraph 212.
349 Decision 2005-127.
350 Exhibit 30.01, March update, Tab 13 (depreciation study), PDF pages 735-736.
351 Exhibit 60.06, AltaGas IR responses, Schedule 5.1F, line 16.
352 Exhibit 60.06, AltaGas IR responses, Schedule 5.1G, line 16.
353 Exhibit 60.06, AltaGas IR responses, Schedule 5.1H, line 16.
354 Exhibit 75.02, AUC-AUI-157(a) Attachment.

Views of the parties

460. The UCA proposed that the average service life for the assets in Account 467 be extended, however the UCA proposed to extend the life to 47 years rather than the 43 years proposed by Mr. Kennedy. The UCA noted that neither AltaGas, in the GRA application, nor Mr. Kennedy, in the depreciation study, provided any narrative to support the life proposal for Account 467.[355]

461. In argument, the UCA submitted that Mr. Pous' fit to his proposed curve is superior, relying on a better visual fit of the "meaningful portion of data", and the curve is consistent with Mr. Kennedy's SPR analysis. Therefore, the UCA argued that the Commission should adopt Mr. Pous' proposed 47-S2 curve. The UCA also submitted that Mr. Kennedy's proposal to extend the average service life estimate to only 43 years is based on an assumption of moderation that is inconsistent with other parts of his testimony and should, therefore, not be accepted.[356]

462. In rebuttal evidence, Mr. Kennedy noted that Mr. Pous proposed a further life extension to Account 467 which appeared to be based on a perceived better Iowa curve fit. Mr. Kennedy had proposed a life extension from 30 years to 43 years, an increase of over 43 per cent, and noted the proposal of Mr. Pous to extend the average service life from 30 years to 47 years represents an increase in excess of 56 per cent. Mr. Kennedy stated "the increase as proposed by Mr. Kennedy is already outside of the range of magnitude Mr. Kennedy would normally recommend in one proceeding … the increase of over 43% provides for a good fit to the historic retirement data, while conforming to a concept of moderation."[357]

Commission findings

463. The Commission considers that the Iowa curve proposed by Mr. Pous provides a better visual fit to the survivor data. However, the Commission is concerned that the UCA proposal represents too significant an increase from the existing average service life, given the record of the proceeding. In this regard, the Commission notes that the average service life proposed by the UCA is well in excess of the average service lives of both the companies in the Gannet Fleming peer group, which have average service lives of 40 and 25 years. Given the magnitude of change for this account proposed by the UCA, even recognizing the better visual fit to Mr. Pous' proposed curve, the Commission is reluctant to accept the 47-S2 Iowa curve. The Commission is of the view that it would be reasonable, in this instance where both experts recommend an increase in average service life, to choose the midpoint of the average service lives proposed by the two experts. The Commission is of the view that the current S2.5 curve shape should be retained.

464. Accordingly, AltaGas is directed in the compliance filing to use an Iowa curve of 45-S2.5 to calculate forecast depreciation for Account 467.

8.1.3 Account 473 – distribution services

465. For Account 473, AltaGas forecast depreciation expenses of $3,382,024 for 2010,[358] $3,606,433 for 2011,[359] and $3,789,940 for 2012,[360] based on its depreciation study, which

[355] Exhibit 71.03, direct testimony of Mr. Pous, page 11, Q/A 22.
[356] Exhibit 141.02, UCA argument, paragraphs 186 and 189.
[357] Exhibit 81.05, AltaGas rebuttal evidence, response to question 12, page 7 (PDF 8/14).
[358] Exhibit 60.06, AltaGas IR responses, Schedule 5.1F, line 21.
[359] Exhibit 60.06, AltaGas IR responses, Schedule 5.1G, line 21.

proposed the adoption of a 48-R4 Iowa curve. The current Iowa curve for account 473 is 44-R4, as approved in Decision 2009-176. Mr. Kennedy supported his proposal for Account 473[361] by noting the increasing retirement ratios from age 20 to age 48, and interviews with company management and operations staff which forecast no change to the service life characteristics from an operational perspective. Mr. Kennedy indicated he had used a 60 per cent weighting of historical experience; 20 per cent weighting of peer industry experience; zero per cent weighting of the professional experience of Gannett Fleming; 15 per cent weighting of expected innovations in technology and a five per cent weighting of discussions with company staff. Gannett Fleming's peer group revealed the following Iowa curves: 55-R3; 55-R2.5; 50-R3; 50-R2.5 and 40-R2.

Views of the parties

466. The UCA proposed that the average service life for the assets in Account 473 be extended to 52 years, based on the analysis of Mr. Pous. The UCA submitted that the quality of the underlying historical data is problematic to the extent that the SPR analysis that Gannett Fleming conducted defaulted to a "stop fitting" position.[362] The UCA further submitted that the information provided by AltaGas personnel is "questionable as it relates to this account."[363] The UCA submitted that, given the quality of both the historical data and input from management, a greater level of significance should be given to the type of assets in the account and indications from the industry with respect to life expectancy.[364] The UCA noted that newer plastic pipe has the potential life expectancy of 100 years from a strictly physical standpoint, but would be expected to have a shorter life due to dig-ins, relocations and other forces of retirement.[365] From an industry perspective, Mr. Pous noted that the peer group had one 40-year average service life estimate and four between 50 and 55 years.

467. Mr. Pous argued that, given the inability to obtain a curve fit from the SPR analysis and the fact that Mr. Kennedy chose a dispersion pattern different than his peer group, concern must be raised as to why only 15 per cent weighting was assigned to innovations in technology, which should increase life expectancy.

468. The UCA submitted that Mr. Pous provided a valid and verifiable life analysis for this account and the Commission should adopt Mr. Pous' recommended 52-R4 curve.

469. AltaGas responded that the truncation of the SPR analysis was due to the amount of retirement dollars, not due to the quality of data, as Mr. Pous suggested, and that the level of plant exposed remains high. AltaGas submitted that it is the quantity of data not the quality of data that is lacking.[366] AltaGas further submitted that assertions from Mr. Pous regarding the life of the pipe remain unsubstantiated and unconfirmed.[367]

360 Exhibit 60.06, AltaGas IR responses, Schedule 5.1H, line 21.
361 Exhibit 49.01, depreciation study, page II-24.
362 Exhibit 71.03, direct testimony of Mr. Pous, pages 15-16, Q/A 29.
363 Exhibit 71.03, direct testimony of Mr. Pous, pages 15-16, Q/A 29.
364 Exhibit 71.03, direct testimony of Mr. Pous, pages 15-16, Q/A 29.
365 Exhibit 141.02, UCA argument, paragraph 193.
366 Exhibit 81.01, AltaGas rebuttal evidence, Q/A13.
367 Exhibit 81.01, AltaGas rebuttal evidence, Q/A13.

Commission findings

470. Both experts recommended an increase in the average service life for the assets in Account 437 beyond the 44 years currently approved in Decision 2009-176. The Commission also notes that both experts expressed concerns with the data in Account 473.

471. The peer group of companies identified by Mr. Kennedy has a range of average service lives from 40 to 55 years, with a mean of 50 years. Four of the five peer companies have average service lives of 50 years or greater. Only one company has an average service life of 40 years.

472. Although Mr. Kennedy indicated the weighting given to various factors, the supporting analysis of how they result in the proposed average service life was not provided.

473. The primary difference between the two experts appears to be their view with respect to the impact of new technology. On this point, the Commission did not find the evidence of either expert to be clearly persuasive, and has determined that it will adopt a midpoint of the average service lives proposed by the two experts.

474. The Commission also notes that the UCA raised a concern in argument with respect to the dispersion to be associated with this account. It is only in argument that it is clear that the UCA first proposed an S-4 curve. The current dispersion curve of R-4 is the same one that the UCA had proposed in its evidence and that Mr. Kennedy proposed. Accordingly, the Commission is of the view that the R-4 curve should remain, in the absence of any evidence to the contrary.

475. Accordingly AltaGas is directed in the compliance filing to use a 50-R4 Iowa curve for the purposes of calculating depreciation for Account 473.

8.1.4 Account 475 – distribution mains

476. AltaGas forecast depreciation expenses of $2,514,398 for 2010,[368] $2,571,350 for 2011,[369] and $2,763,867 for 2012,[370] based on the 55-R2 Iowa curve approved in Decision 2009-176, which Mr. Kennedy proposed to retain. Mr. Kennedy supported his proposal based on historical retirements, additions and other plant transactions analyzed by the retirement rate method.[371] Mr. Kennedy also relied on interviews with company operations and maintenance personnel that indicated no expected change in retirement characteristics.[372] Mr. Kennedy submitted that the currently approved Iowa curve for this account continues to provide a good fit to the historic retirement patterns and no change is warranted at this time.

477. In response to AUC.AUI-157(a), Mr. Kennedy indicated that he placed 50 per cent weighting on historical experience; 15 per cent on peer industry experience; 10 per cent on Gannett Fleming professional judgment; 15 per cent on expected innovation in technology and 10 per cent on discussion with company staff. The average service life of the peer group is in the range from 60 to 65 years.

---

368 Exhibit 60.06, AltaGas IR responses, Schedule 5.1F, line 24.
369 Exhibit 60.06, AltaGas IR responses, Schedule 5.1G, line 24.
370 Exhibit 60.06, AltaGas IR responses, Schedule 5.1H, line 24.
371 Exhibit 49.01, depreciation study, page II-25.
372 Exhibit 49.01, depreciation study, page II-25.

View of the parties

478. Based on normalization of early retirements, the UCA proposed that a 70-R1.5 curve be adopted for Account 475. The UCA submitted that Mr. Kennedy's analysis relies on synthetically aged data, and that neither AltaGas nor Mr. Kennedy knows specifically what is reflected in the 8.5-year age bracket.[373] The UCA submitted that its proposed 70-R1 curve is almost a precise fit through age 20 and represents a far superior fit than the currently approved 55-R2 Iowa curve. With the exception of a period from 25.5 to 30 years, the UCA submitted that its proposed curve provides a better or equivalent fit as compared to the currently approved curve.[374]

479. In argument, the UCA commented that the amount of observable life data only reaches 80 per cent surviving at 42 years of age and provides limited information to derive a forecast life indication.[375] Further, the UCA commented that, in his depreciation study, Mr.Kennedy did not indicate that he considered peer group industry information or innovations in technology.[376]

480. The UCA submitted that Mr. Pous' proposal of 70-R1 or 70-R1.5 is a better fit to the observed life table.[377] Further, the UCA submitted that its proposal of 70-R1 is reasonable because it is:

- only five years longer than the result of Mr. Kennedy's peer group analysis
- virtually identical to Mr. Kennedy's recommendation for transmission mains
- shorter than the 72 and 75 year values Gannet Fleming have recommended for other utilities

481. In reply, AltaGas submitted that Mr. Pous' assertions on longer life are not supported by the evidence.[378] AltaGas submitted that adopting Mr. Pous' recommendation would mean that some pipe would have a maximum life of 141 years, which is not supported by any evidence.[379] AltaGas submitted that Mr. Pous' presentation of his graphs to only 70 per cent surviving eliminates the extremely long maximum life indication. AltaGas submitted that Mr. Pous' recommendations are at the extreme end of approved curves in Canada, and that even large diameter long haul pipelines (Enbridge, TransCanada, Kinder Morgan and ATCO Pipelines) do not have approved life estimates of the length recommended by Mr. Pous.[380]

482. AltaGas submitted that, while Mr. Pous relied on new generation pipe having a longer life than earlier generations, no party provided any evidence upon which to base this theory. AltaGas argued that, while there may be lab testing to investigate pipe characteristics, lab tests cannot replicate in-field conditions, such as vibrations by railways and road crossings or frost heaving.[381]

---

[373] Exhibit 71.03, direct testimony of Mr. Pous, page 17, Q/A 34.
[374] Exhibit 71.03, direct testimony of Mr. Pous, page 17, Q/A 34.
[375] Exhibit 141.02, UCA argument, paragraph 199.
[376] Exhibit 141.02, UCA argument, paragraph 201.
[377] Exhibit 71.02, UCA evidence, pages 17-19.
[378] Exhibit 81.01, AltaGas rebuttal evidence, Q/A 14.
[379] Exhibit 81.01, AltaGas rebuttal evidence, Q/A 14.
[380] Exhibit 81.01, AltaGas rebuttal evidence, Q/A 14.
[381] Transcript, Volume 2, pages 552-553, Exhibit 143, AltaGas argument, paragraph 214.

Commission findings

483. Both parties observed limitations relating to the data in Account 475. The Commission notes that the original life table ends at age 41.5, with 80.22 per cent surviving. However, the placement band is 1945 to 2009 and the calculated annual and accrued depreciation schedule begins at 1951. Since depreciation is being calculated on assets that are 60 years old, it is unusual to have an original life table ending at age 41.5. The Commission accepts the views of both experts that there are problems with the available data.

484. The Commission notes that three of the peer group companies have average services lives of 60 years and the fourth an average service life of 65 years. As Mr. Kennedy said he placed a 15 per cent weighting on the peer group, the Commission is surprised that Mr. Kennedy did not propose any extension to the average service life.

485. The Commission considers that the 70-year curves proposed by Mr. Pous are a better visual fit to the data than Mr. Kennedy's 55-R2 curve. However, the increase in average service life would be significant and is unsupported, given the data available. Both experts referred to other factors including technological innovation, peer groups, professional judgment and discussions with AltaGas staff. In the Commission's view, the information on the record with respect to the average service lives of the peer group of companies, and some of the information on technological change, provide directional guidance for an increase in average service life.

486. Even though the visual fit of Mr. Pous' proposed Iowa curves with 70-year average service lives may appear superior, adopting a 70-year average service life for this account, as proposed by Mr. Pous, would have a sizeable impact which, in the Commission's view, is not adequately supported by the current data on survivability. Given the inherent uncertainty in estimating physical lives of plant and service, the limited data available and the uncertainty regarding the extent to which factors other than physical life will impact average service life, the Commission favours a more gradual increase in the estimated average service life for this account. Accordingly, the Commission finds that the use of an average service life, between the currently approved average service life and the average service life of 70 years as proposed by the UCA, would result in a reasonable estimate of depreciation expense for mains in the test period. The mid-point of the range of average service lives for the peer group is 62.5, which is also the mean of the average service lives proposed by the two experts.

487. The Commission also finds that there has not been sufficient evidence to warrant a change in the dispersion pattern at this time, and is of the view that the R2 dispersion pattern approved in Decision 2009-176 and proposed by Mr. Kennedy should continue to be used.

488. Accordingly, AltaGas is directed, in the compliance filing to use an Iowa curve of 62.5-R2 to calculate depreciation for Account 475.

8.2 Changes in proposed depreciation parameters for other accounts

489. In addition to the four specific accounts indicated in Table 37 that were disputed by the UCA, AltaGas has proposed changes to the depreciation parameters for other accounts, as indicated in the following table.

Table 39. Proposed depreciation parameters for other accounts

Account	Account title	Current parameters (Note 1)	AUI proposal (Note 2)
463	Transmission Measuring and Regulating Structures	45 R4	55 R3
472	Distribution Structures and Improvements	46 R3	55 R3
474	Distribution House Regulators	41 R3	48 R2
477	Distribution Measuring and Regulating Equipment	40 R4	50 R3
478	Distribution Meters	34 R2.5	30 R2.5
485	Distribution Heavy Work Equipment	16 L0.5	14 L1
483.1	General Plant – Furniture and Office Equipment	20 SQ	15 SQ

Note 1: Source – Exhibit 2 from Proceeding ID No. 88; Tab 21- depreciation technical update, page 11 of 49.
Note 2: Source – Exhibit 49.01, depreciation study, page III-4.

Commission findings

490. No party objected to the change in survivor curves for the accounts included in the above table. The Commission has reviewed the evidence provided by AltaGas with respect to the accounts in Table 39 and finds the parameters for these accounts, as filed, to be reasonable. Accordingly, these parameters are approved for the purpose of calculating the revenue requirements for the test years.

8.3 Changes in methodology

8.3.1 Calculation of depreciation for new assets

491. In the GRA application, AltaGas proposed to modify the commencement date for calculating depreciation for new assets from January 1 of the year following the completion of construction or acquisition of the asset to its in-service date. Under this convention, AUI will recognize one-half of one-year of depreciation in the year of completion or acquisition. This change was proposed because of the upcoming transition to IFRS. AltaGas proposed adopting this practice, referred to as the mid-year convention, for regulatory accounting purposes to eliminate differences between financial and regulatory reporting as allowed under AUC Rule 026. AltaGas advised that the proposed change would increase forecast depreciation expense in 2010 by $346,000 and decrease the forecast amortization of CIAC by $28,200. AltaGas argued that the proposed practice is consistent with the depreciation methods approved for other AUC-regulated utilities.

492. Subsequent to the filing of the GRA application, AltaGas advised the Commission that it was proposing to adopt U.S. GAAP for regulatory reporting. AltaGas made no comment on the proposed mid-year convention for the depreciation of new assets under U.S. GAAP.

493. No comments were received from interveners in regard to this change in practice.

Commission findings

494. AltaGas has not indicated whether it proposes to adopt the mid-year convention for depreciation expense for new assets, if a change to U.S. GAAP is approved. The proposed method has been accepted for other utilities and the impact is approximately three per cent of depreciation for 2010.

495. The change was proposed to maintain consistency between financial and regulatory reporting. Accordingly, if under U.S. GAAP AltaGas intends to use the mid-year convention for the purposes of financial reporting, the Commission approves the use of the applied-for mid-year convention for the purpose of regulatory reporting as well. AltaGas is directed to confirm its intentions with respect to this change in practice in the compliance filing.

8.4 Net salvage

496. Net salvage rates were included as part of the depreciation study performed by Gannett Fleming. AltaGas applied for changes to its net salvage rates for certain accounts, as presented in the following table:

Table 40. Proposed net salvage rate changes[382]

Account	Account title	Current rate (%)	Forecast rate (%)
461.00	Transmission Plant - Land Rights	0	0
463.00	Transmission Plant - Measuring & Regulating Station Structures	0	0
465.00	Transmission Plant - Mains	-5	-10
465.00	Transmission Plant - Mains - Barrhead/Westlock	-5	-10
467.00	Transmission Plant - Measuring & Regulating Station Equipment	-35	-50
471.00	Distribution Plant - Land Rights	0	0
472.00	Distribution Plant Measuring & Regulating Station Structures	0	0
473.00	Distribution Plant - Services	-30	-75
474.00	Distribution Plant - Regulators & Meter Sets	5	0
474.01	Distribution Plant - Customer AMR	0	0
475.00	Distribution Plant - Mains	-5	-10
475.05	Distribution Plant - Mains - 5 Year	-5	0
477.00	Distribution Plant - Measuring & Regulating Station Equipment	-5	-15
478.00	Distribution Plant - Meters	10	0
482.00	General Plant - Structures & Improvements	0	0
483.10	General Plant - Furniture & Equipment	0	0
484.00	General Plant - Transportation Equipment	25	25
485.00	General Plant - Heavy Work Equipment	20	20
486.00	General Plant - Tools & Work Equipment	0	0
488.20	General Plant - Communication Equipment - Owned	0	0

497. Gannett Fleming described its methodology for estimating net salvage percentages as follows:

> The estimates of net salvage were based primarily on a review of the last 5 years of net salvage data, the expectations of the company, and on the professional judgment of Gannett Fleming. The management of the company provided Gannett Fleming with a summary of the past 5 years of net salvage data. Gannett Fleming compared this data to the indications from the company management, and to the currently approved net salvage percentages. The preliminary net salvage estimates were then compared to other natural gas distribution and transmission utilities in order to development the final recommendations.[383]

[382] Exhibit 50.30, UCA-AUI-61(b) Attachment.
[383] Exhibit 49.01, depreciation study, page II-26.

498. In some circumstances, Mr. Kennedy reviewed the mathematical results of his study and concluded that the results were too extreme, and he therefore utilized a moderated approach in arriving at the recommended rates. AltaGas summarized the moderated approach utilized for Account 473 as follows:

> With regard to Account 473 – Distribution Services there was significant evidence and cross-examination related to the net salvage percentage for this account. While there was no debate regarding the fact the recent historical experience indicates a multiple of two to three times the original cost of the assets being retired, there was considerable discussion about its implications for future net salvage rates. In this regard, Mr. Kennedy recommends a moderated approach to deal with the significant indications of increases to the required percentages. Specifically, his approach recognizes recent trends are greater than those typically experienced by Canadian peers; may be short term indications, given the recent programs to replace early generation plastic pipe, and changes in accounting practices may moderate the increase to some extent.[384]

Views of the parties

499. Mr. Pous, on behalf of the UCA, submitted that the net salvage estimates of Gannett Fleming for two accounts resulted in significant increases from the existing rates, and that the increases were not sufficiently justified. For accounts 467 and 473, Mr. Pous recommended retention of the existing negative net salvage rates as indicated in the table below, which he estimated would result in a standalone reduction to forecast depreciation expense for plant as at December 31, 2009 of $109,381 and $1,298,151 for the two accounts respectively.

Table 41. UCA proposed net salvage adjustments[385]

Account	Account title	AUI proposal	UCA proposal
467	Transmission Plant - Measuring & Regulating Station Equipment	-50%	-35%
473	Distribution Plant - Services	-75%	-30%

500. Mr. Pous submitted that a lack of sufficient data produced extreme results in the analysis of net salvage. With respect to Account 467 he explained:

> The evidence is that AUI has retired only $720 of plant during the past 5 years. However, due to unexplained historical action, AUI has contaminated the soil around at least one of its facilities. The cost to remediate AUI’s contamination of soil is approximately $700,000. Since this historical relationship would produce a 1000% negative net salvage, Mr. Kennedy decided to propose what he views as an alternative reasonable value.[386]
>
> …
>
> Given that the historical database is meaningless, even as recognized by Mr. Kennedy, Mr. Pous could have proposed a reduction in negative net salvage corresponding to the negative 5% level the peer group exhibited. Rather than recommend a significantly less negative level, Mr. Pous elected to remain conservative and retained the existing negative 35% ...[387]

384 Exhibit 143.01.AltaGas argument, page 63.
385 Exhibit 71.03, UCA evidence, A43, page 23.
386 Exhibit 141.02, UCA argument, page 85.
387 Exhibit 141.02, UCA argument, page 86.

501. Mr. Pous further argued:

> Even if one assumes the site contamination activity is typical, which AUI has not demonstrated, the historical sample of activity is less than 0.004% of the plant balance, or statistically insignificant.[388]

502. Mr. Pous also submitted that there were similar issues related to a lack of sufficient data with respect to the analysis of net salvage for Account 473, and he explained:

> Another problem with Mr. Kennedy's reliance on the historical database is that the database is too small. First, Mr. Kennedy admits that the initial five-year database is the minimum level. However, he removes two of the five years of data because he views those two years as extraordinary, without providing the basis for his actions…[389]
>
> In summary, the UCA submits that AUI and Mr. Kennedy have failed to support the negative 75% net salvage proposal. The historical database cannot be relied upon for the various reasons noted, and obvious[ly] was heavily discounted by Mr. Kennedy. The peer group analysis does not support Mr. Kennedy's proposal. Even Mr. Kennedy's reasonableness check identified during cross-examination actually disproves [and] fails to support Mr. Kennedy's proposal. AUI's new policy of allocating 5% of total cost of retirement/replacement work orders further diminishes the credibility of its proposal and may prove that Mr. Pous's proposal is also excessively negative. Finally, AUI's policy of abandonment when possible should result in low levels of negative salvage. All these factors result in the same conclusion – that AUI has not met its standard of proof in support of its proposal. The UCA requests that the Commission [decide] to adopt Mr. Pous's conservative proposal to retain the existing negative 30% net salvage.[390]

503. In response to the concerns raised by Mr. Pous with respect to limited data sets, AltaGas supplied analysis supported by additional years of data. Based on the revised analysis, AltaGas argued that the applied-for net salvage rates are still appropriate, as indicated in the following comments:

> Even in circumstances where the cost of removal associated with site clean-up is removed from this more extensive database, the fifteen year cost of removals would total $303,104, resulting in a net salvage of -187% ($161,836/$303,104). Therefore, the historic record clearly indicates the -50% recommended by Mr. Kennedy [for account 467] is conservative as compared to historic experience.[391]
>
> As previously noted, with regard to the UCA's concern the five year historic database is too limited [for account 473] AUI notes an additional ten year period of net salvage data has also been provided. Moreover, the additional years of data indicate even higher costs of removal. In particular, review of the undertaking response related to this account shows the fifteen year average cost of removal requirements have been in excess of -450%.[392]

388 Exhibit 150.02, UCA reply argument, paragraph 111, page 46.
389 Exhibit 141.02, UCA argument, page 87.
390 Exhibit 141.02, UCA argument, page 89.
391 Exhibit 151.01, AltaGas reply argument, paragraph 300, page 91.
392 Exhibit 151.01, AltaGas reply argument, paragraph 312, page 94.

Commission findings

504. The Commission agrees with the UCA and the evidence of Mr. Pous, and considers that AltaGas has failed to provide sufficient justification for the proposed changes to the net salvage rates for accounts 467 and 473. The Commission accepts Mr. Pous' arguments that a lack of sufficient data has led to an analysis that cannot be considered statistically significant. This was highlighted by the fact that Mr. Kennedy did not accept the mathematical results produced by his own study for Account 473, and he concluded that a moderated approach was required to bring the suggested rate closer to the historical rate. In addition, there is a significant difference between the rates of -50 per cent and -75 per cent recommended by Mr. Kennedy for accounts 467 and 473, respectively, and the results of -187 per cent and -450 per cent from the revised analysis based on the expanded data sets. This appears to indicate that the basis for the recommended rates is weighted heavily on professional judgment.

505. Given the magnitude of the increases requested by AltaGas, and the fact the results of the mathematical analysis do not support the recommended rates, the Commission does not find that there is sufficient evidence to adopt the net negative salvage values proposed by the company. In the absence of sufficient evidence, the Commission denies the requested increases in net salvage rates for accounts 467 and 473 for the test period and directs AltaGas to include the results of this finding in the compliance filing.

506. With respect to accounts other than 467 and 473 for which changes to net salvage rates were proposed, the Commission observes that interveners did not object to any of the other rates. The Commission has reviewed these net salvage rates and considers them to be reasonable. The proposed changes to the net salvage rates in these accounts are much less significant and will not have a significant impact on revenue requirement. Accordingly, the Commission approves the other net salvage rates as filed.

9 Income taxes

507. In the March update, Section 6[393] included information on the income tax component of the revenue requirements. AltaGas indicated that, consistent with its current accounting practice for income tax, it would defer all future income tax and not include it as part of the forecast revenue requirements. AltaGas added that it is claiming all available deductions allowed under the income tax laws, including the maximum capital cost allowance, to minimize income tax in each of the forecast test years. AltaGas indicated that all costs deducted for tax purposes are consistent with past practice.

508. AltaGas stated that the income tax forecasts included in the March update reflect all enacted and proposed income tax measures announced in the federal and Alberta provincial budgets, up to and including the 2010 federal budget tabled on March 4, 2010, and the 2010 Alberta budget presented on February 9, 2010. AltaGas indicated that there were no new corporate income tax reductions announced in the 2010 budgets. AltaGas added that previously enacted income tax rates for the 2010 to 2012 test years are as follows:

[393] Section 6.0 starts at paragraph 477 of Exhibit 30.01.

Table 42. Forecast corporate income tax rates used by AltaGas

	2010 forecast	2011 forecast	2012 forecast
		(%)	
Federal corporate income tax rate	18.00	16.50	15.00
Alberta corporate income tax rate	10.00	10.00	10.00
Combined corporate income tax rate	28.00	26.50	25.00

509. AltaGas stated that no accelerated capital cost allowance measures were announced in the 2010 budgets that would impact AltaGas. AltaGas added, however, that the 2009 budgets provided a temporary 100 per cent capital cost allowance rate, with no half year rule, for eligible computer equipment acquired after January 27, 2009, and before February 1, 2011. AltaGas indicated that forecast computer equipment acquisitions expected to be eligible for accelerated capital cost allowance are included in Class 52.

510. In its July update,[394] AltaGas updated the income tax forecast for 2010 to reflect an error in one of the add backs for the year 2010. This adjustment increased the tax loss for 2010 by approximately $70,000.[395] The income tax changes, included in the July update, reflected the changes in pre-tax income and certain add backs and deductions arising from AltaGas's decision to adopt U.S. GAAP for regulatory purposes. These changes are detailed in Table 1.0 of the July update.[396] AltaGas did not include any income tax methodology changes in its July update.

511. Three issues regarding income tax were raised during the course of the proceeding. AltaGas raised an issue regarding potential recovery of capital cost allowance from the year 2009. The CCA raised an issue regarding the accelerated capital cost allowance for eligible computer equipment as well as an issue in connection with removal costs.

9.1 Capital cost allowance and the 2009 split taxation year

512. AltaGas indicated that the share transfer approved in Decision 2009-152 resulted in a change of control for AltaGas and triggered a deemed year-end for income tax purposes. AltaGas added that the deemed income tax year-end occurred on October 7, 2009 and, as a result, AltaGas was required to file two income tax returns for 2009. The first income tax return covered the period January 1 to October 7, 2009 and the second covered the period October 8 to December 31, 2009.

513. AltaGas stated that, in preparing its 2008-2009 GRA Phase I, it did not contemplate the share transfer and the resulting deemed income tax year-end and, as a result, no impact for additional income tax was included in the 2009 forecast. AltaGas indicated that the one area where the deemed income tax year-end had a material effect was in the determination of the capital cost allowance claimed in each of the two tax returns for 2009. AltaGas submitted that the sum of the capital cost allowance available under the two income tax returns was less than the amount otherwise available, had the deemed income tax year-end not occurred. AltaGas added that this difference stemmed from the timing of the additions to the undepreciated capital cost allowance pool.

[394] Exhibit 61.02, July update.
[395] Exhibit 61.02, July update, paragraph 69.
[396] Exhibit 61.02, July update, Table 1.0, page 4 of 27.

514. AltaGas attempted to address this situation in its 2008-2009 GRA Phase I compliance filing by reducing its forecast capital cost allowance for 2009 by $1,918,919. In the compliance filing, AltaGas requested Commission approval to reflect this $1,918,919 adjustment in its 2010 revenue requirement rather than its 2009 revenue requirement. In Decision 2010-197,[397] on AltaGas's 2008-2009 GRA Phase I compliance filing, the Commission addressed this request as follows:

> 26. With respect to AUI's proposal to reduce capital cost allowance in 2010, the Commission considers that AUI's Compliance Filing pertains to AUI's revenue requirement for the 2008-2009 test years. As such, the Commission finds that making a determination on AUI's proposal to reduce any amount of capital cost allowance for the 2010 test year is premature and beyond the scope of this proceeding.
>
> 27. Further, the Commission considers that it lacks the necessary information relating to the two taxation years for which AUI will be filing actual income tax returns in 2009. This information would need to be reviewed in relation to the capital cost allowance calculations set out in Table 10 of the Compliance Filing. The Commission notes that the information set out in Table 10, which arose as a result of the Share Transfer, was unavailable at the time the record for AUI's 2008-2009 GRA closed.
>
> 28. Consequently, with the exception of Table 10, the Commission approves AUI's Compliance Filing, as revised in its April 7, 2010 filing. This includes the non-capital loss carry-back from 2009 to 2008 (Schedule 2.7) that resulted from applying the maximum amount of capital cost allowance forecast for the 2009 test year in accordance with Direction 32 in Decision 2009-176. AUI may resubmit its proposal for a reduction in 2010 capital cost allowance otherwise required to be claimed under the flow-through method at its next GRA. (footnote removed)

515. AltaGas added that, accordingly, it was seeking approval as part of this 2010-2012 GRA Phase I to reduce its capital cost allowance claim for the 2010 year by the $1,918,919 difference resulting from the 2009 split taxation year. In response to questioning during the oral hearing, Mr. Mantei, a witness for AltaGas, confirmed that the resulting impact on the 2010 revenue requirement for this difference would be approximately $750,000.[398]

Views of the parties

516. AltaGas argued that the evidence clearly showed that the adjustment to the 2010 opening balance does not cause harm to customers as the customers received the benefit in the previous year. AltaGas stated that failing to make the adjustment would result in unjust enrichment of customers and unwarranted losses to AltaGas. AltaGas therefore submitted that its proposed adjustment is fair, equitable and reasonable and should be approved.

517. The CCA disagreed with AltaGas's position. It stated that AltaGas did not have an income tax deferral account in place for 2008 and 2009 and AltaGas actually rejected submissions by interveners in AltaGas's 2008-2009 GRA Phase I proceeding for the establishment of an income tax deferral account. The CCA submitted that, in the absence of an income tax deferral account, there was simply no basis to have customers pay any income tax costs which varied from the 2009 approved forecast. The CCA added that these variances

[397] Decision 2010-197: AltaGas Utilities Inc., 2008-2009 General Rate Application Phase I Compliance Filing, Application No. 1605779, Proceeding ID. 452, May 6, 2010.

[398] Transcript, Volume 6, page 1585, lines 14-25; Volume 7, page 1586, lines 1-3.

between forecast capital cost allowance and actual capital cost allowance are no different than any other forecast variance and, as such, the related risk belongs to shareholders.

518. The CCA indicated that the share transfer agreement was not requested by customers and customers did not get any direct benefit from such an arrangement. The CCA added that any redress for lost capital cost allowance must be sought from the parties who requested the share transfer agreement.

519. AltaGas responded that, even if one could consider any aspect of the adjustment to be retroactive, the adjustment to the 2010 opening capital cost allowance balance is still appropriate to avoid unnecessary harm to AltaGas. AltaGas indicated that the issue of retroactive rate making and the “no-harm principle” was specifically addressed by the Commission in Decision 2009-215,[399] the ATCO Income Tax Matters decision:

> 63. … Notwithstanding, the Commission has also considered whether the “no harm” test applies in this case or could be used to circumvent the principle against retroactive ratemaking, the principle of prospectivity and the principle of regulatory certainty. The Commission considers that the application of the “no harm” test both by itself and its predecessor, the Board, has been limited to proceedings involving the disposition of a utility’s asset outside of the normal course of business, share acquisitions and financings.

520. AltaGas stated that, in this instance, the evidence clearly shows that the adjustment of the 2010 undepreciated capital cost balance arises from the 2009 share transfer which occurred in late 2009. Rater than creating harm, the proposed adjustment effectively keeps customers and AltaGas in the same position they would have been had the share transfer’s impact not occurred.

Commission findings

521. The relevant considerations associated with this issue are forecasting risk, as advocated by the CCA, and the “no harm” principle brought forward by AltaGas. With respect to forecasting risk, the Commission regulates on a prospective basis. In prospective rate making, the utility submits its best forecast of the items comprising its revenue requirement for a test year and, when applicable, this forecast includes income taxes. Included in the forecast income tax expense for a test year is the forecast for capital cost allowance. This forecast of capital cost allowance is a function of the forecast capital additions as well as the forecast capital cost allowance rates. Forecasting risk associated with capital cost allowance generally arises when the actual capital additions are different than the forecast or if the actual capital cost allowance rates are different than the forecast rates. In the absence of a deferral account, any difference between the actual amount of capital cost allowance and the forecast amount rests with the utility’s shareholder.

522. In this case, another element (the taxation year) is a part of forecasting risk. A deemed taxation year occurred in 2009 that had not been forecast by AltaGas. The Commission considers that, although it is unusual, this deemed taxation year is an element of forecasting risk. The Commission sometimes allows utilities to guard against unusual forecasting risks by approving deferral account treatment. In this case, AltaGas did not request such a deferral account for any areas regarding income tax expense for the years 2008 and 2009, despite the proposal by interveners that such a deferral account be granted. Consequently, the Commission considers that

399 Decision 2009-215: ATCO Electric Ltd., 2009-2010 General Tariff Application – Regulatory Treatment of Income Tax Refund, Application No. 1578371, Proceeding ID. 86, November 12, 2009.

AltaGas has to bear the forecasting risk associated with income tax, including the occurrence of any unusual events such as a deemed taxation year. In the Commission's view, this finding is consistent with the Commissions finding in paragraph 174 that the equity investors of AL bore the risk associated with their investment in AltaGas and should be afforded the equity returns expected by equity investors in equities of comparable risk, recognizing among other things the forecasting risk associated with AltaGas's 2010 revenue requirement.

523. Regarding the "no harm" principle, the Commission considers that this principle is intended to establish "no harm" to customers, not to utilities. This was made clear in Decision 2009-152 regarding the share transfer application.

> 20. The "no harm" test is intended to balance the potential positive and negative impacts of the proposed Share Transfer and Amalgamation on customers to ensure that they are at least no worse off after those transactions are completed.

524. The Commission considers that AltaGas, or AltaGas's parent company, would have been in a position to assess whether any harm would result to AltaGas due to the share transfer. AltaGas did not raise any such issue of harm during the share transfer application, as verified by Mr. Tuele, a witness for AltaGas during the oral hearing. During questioning by counsel for the CCA, when asked if AltaGas had raised the tax consequences of the deemed tax year end during the share transfer application proceeding, Mr. Tuele testified that: "Mr. Mantei and I both think that we -- we didn't."[400] Mr. Mantei, another witness for AltaGas, added: "Well, I think the very simple answer is that I suspect it was probably missed in the discussions that were held around the share transfer application."[401]

525. The Commission considers that AltaGas's customers should not be held accountable for AltaGas's inability to identify and address all issues related to the share transfer in the share transfer application. It is the responsibility of the management of AltaGas to identify any items that impact the company. The Commission considers that AltaGas cannot raise issues at a later date because it omitted to do so earlier, as it is not in keeping with prospective rate making. The Commission therefore rejects AltaGas's request to reduce its capital cost allowance claim for the 2010 year by the $1,918,919, the difference resulting from the 2009 split taxation year.

526. The Commission directs AltaGas, as part of the compliance filing pursuant to this decision, to remove the reduction of $1,918,919 it made to its forecast 2010 capital cost allowance claim included on Schedule 6.0 B in the July update.

9.2 Accelerated capital cost allowance for eligible computer equipment

527. As mentioned above, AltaGas stated that the 2009 budgets provided a temporary 100 per cent capital cost allowance rate, with no half year rule, for eligible computer equipment acquired after January 27, 2009, and before February 1, 2011. AltaGas indicated that forecast computer equipment acquisitions expected to be eligible for accelerated capital cost allowance are included in Class 52.

[400] Transcript, Volume 5, page 1273, lines 8-9.
[401] Transcript, Volume 5, page 1273, lines 22-25.

Views of the parties

528. The CCA raised the issue of whether all acquisitions eligible for Class 52 treatment had been identified. Specifically, the CCA questioned whether assets identified as Class 10 would have qualified as Class 52 in 2010 and whether assets identified as Class 50 would have qualified as Class 52 in 2011.

529. The CCA stated that in 2010, the Class 52 additions only amount to $212,403 whereas other capital cost allowance rate classes, such as Class 10, had additions of $1,053,212. The CCA argued that the evidence is not clear, but it appears that AltaGas should have recorded some of the additions included in Class 10 as Class 52. The CCA submitted that AltaGas should be directed to address this issue.

530. The CCA stated that while the accelerated write off under Class 52 was available until the end of January, 2011, AltaGas has recorded no asset additions under Class 52 in 2011. The CCA also argued that AltaGas's suggestion that its decision to acquire assets is made irrespective of any potential income tax gains was imprudent, if those decisions resulted in an increase in customer costs. The CCA recommended that the Commission deem 1/12th of the Class 50 additions AltaGas has forecast for 2011 as being Class 52 additions. The CCA added that AltaGas has forecast $355,200 of Class 50 additions for 2011 so 1/12th of this amount equals $29,600.

531. AltaGas responded that, while a prudent utility operator should consider income tax implications as a factor in the procurement management process, this is not the only factor to be considered. AltaGas added that other factors, such as the timing of purchase requirements, carrying costs, cash flow availability, product availability, safety concerns, transportation, logistics and storage must be considered. AltaGas argued that the only potential tax savings that could be gained by allocating computer equipment additions to Class 52 instead of Class 50 is the time value of money benefits associated with deducting the costs using an accelerated capital cost allowance rate. AltaGas added that in total the same amount of capital cost allowance is available for deduction whether it is claimed in one year or over the course of several years.

532. AltaGas stated that the Class 10 additions of $1,053,212 forecast for 2010 and the $1,251,250 in Class 10 additions forecast for 2011 relate exclusively to automotive equipment and do not qualify as eligible computer equipment for inclusion in Class 52.

Commission findings

533. The Commission does not accept the CCA's recommendation that AltaGas deem certain Class 50 assets as being eligible for inclusion in Class 52. No assets were forecast to be acquired during the period of eligibility in 2011 and AltaGas has provided an explanation of the factors considered in its acquisition decisions.

534. Regarding the CCA's suggestion that AltaGas should have included some of the Class 10 additions for 2010 and 2011 in Class 52, the Commission accepts AltaGas's submission that, as clearly demonstrated in Exhibit 48.21 (the attachment to the response to CCA-AUI-40(a)), the only forecast additions to Class 10 in 2010 and 2011 are comprised of additions classified as transportation equipment and heavy work equipment. There is nothing classified as computer equipment that is forecast to be added to Class 10. Consequently, the Commission considers that no computer equipment is included in Class 10. Therefore, the Commission rejects the

recommendation by the CCA that AltaGas record some of the additions in Class 10 in Class 52 instead.

9.3 Removal costs

535. In its argument, the CCA raised a concern that not all forecast removal costs were being deducted by AltaGas in calculating the forecast income tax amounts for 2010 through 2012.

Views of the parties

536. In its reply argument, AltaGas submitted that the 2010-2012 forecasts for income taxes already reflect all removal costs as tax deductions and therefore no updates or corrections are necessary for these years. AltaGas added that it will correct the 2009 actual schedules in the compliance filing to reflect the appropriate amount of removal costs for 2009.

Commission findings

537. The Commission notes that AltaGas, in its response to CCA-AUI-37(a), included the following information:

> Line 16 – Capitalized Project Work: Capitalized Project Work consists mainly of removal costs recorded against accumulated depreciation for regulatory book purposes. For tax purposes these costs are deducted in the year they are incurred. Prior to 2008, AUI only deducted removal costs related to the reclamation of well sites. Consequently, the only removal costs included in 2008 Approved relate to reclamation of well sites. Starting with 2008 Actual, AUI began deducting all removal costs. For 2008 Actual, there are some items included in the Capitalized Project Work line item that should have been shown on a separate line. These include $140,604 of software licenses capitalized for book purposes and $18,100 of STIP that was treated as a deferred charge for book purposes.

538. The Commission has reviewed Schedule 6.0 A (Income Taxes for 2008 and 2009) that was filed with AltaGas's July update[402] and agrees with the CCA that there is no amount included under the "2009 Actual" column for removal costs, or capitalized project work, as it is labeled on the schedule. The Commission understands that there are forecast deduction amounts included for 2010, 2011 and 2012 for removal costs as evidenced at the line item entitled "Capitalized Project Work" on Schedule 6.0 B that was filed with the July update.[403] The forecast deduction amounts included on this schedule for removal costs are as follows: $643,920 for 2010; $746,600 for 2011 and $597,900 for 2012. Based on this evidence, the Commission finds that AltaGas has included all eligible forecast removal costs on its income tax schedules.

10 Utility revenue

10.1 Overview

539. Rate 1/11 (Small General Service) is typically taken by urban and rural residential customers and small business customers consuming up to 6,400 GJ/year. Rate 2/12 (Optional Large General Service) is typically taken by larger customers, mainly businesses, using more than 6,400 GJ/year. Rate 3/13 (Optional Demand General Service) is typically taken by AltaGas's largest customers who require significant demand capacity and use more than

[402] Exhibit 61.06, July update, revised application schedules.
[403] Exhibit 61.06, July update, revised application schedules.

13,300 GJ/year (assuming 100 GJ demand). Rate 4/14 (Optional Irrigation Pumping Service) is a seasonal service available only to customers using natural gas as a fuel for pumping irrigation water between April 1 and October 31.[404]

10.2 Customer growth

540. AltaGas provided its growth forecast for the test period 2010-2012, and stated that the 2010 numbers are generally based on actuals. The table below also includes the forecasts for the test years as well as the 2008 and 2009 actual and forecast (approved) customer growth numbers.

Table 43. 2008-2012 customer growth[405]

	2008 forecast	2008 actual	2009 forecast	2009 actual	2010 forecast	2011 forecast	2012 forecast
Year-end customers:							
Residential (Rate 1/11)	48,698	48,918	50,298	49,815	50,964	52,190	53,450
Commercial (Rate 1/11)	6,465	6,561	6,615	6,594	6,661	6,781	6,903
Rural (Rate 1/11)	12,802	12,602	13,052	12,763	12,977	13,227	13,477
Large General Service (Rate 2/12)	167	150	167	145	137	137	137
Demand (Rate 3/13)	49	47	49	51	52	52	53
Irrigation (Rate 4/14)	213	243	213	185	212	236	236
	68,394	68,521	70,394	69,553	71,003	72,623	74,256

541. The 2008 and 2009 variance between forecast and actual year-end total customers is 0.2 per cent and -1.2 per cent respectively.

542. For Rate 1/11, the 2011 and 2012 forecasts are based on the company's forecast new service line additions for the respective years, and AUI is expecting modest growth in the number of customers. AltaGas stated that these forecasts utilize the same approach as approved in previous GRAs.[406]

543. For Rate 2/12, the company has forecast a net reduction in customers for 2010, reflecting customers switching to Rate 1/11 and Rate 3/13, with no projected change in Rate 2/12 customers for 2011 and 2012.[407]

544. For Rate 3/13, as in previously approved forecasts, the forecast of the number of customers is developed at the individual customer level.[408] AltaGas has forecast a net increase of one customer for 2010, no change in 2011 and one customer in 2012.[409]

545. For Rate 4/14, the 2011 and 2012 forecasts are calculated using a five-year historic average of Rate 4/14 customers and load, based on 2005 to 2009, inclusive. AltaGas proposed

404 Exhibit 1, application, Section 7.0, page 292.
405 Exhibit 30.01, March update, schedules 7.1A and 7.1B.
406 Exhibit 143.01, AltaGas argument, page 67.
407 Exhibit 30.01, March update, page 322.
408 Exhibit 143.01, AltaGas argument, page 70.
409 Exhibit 30.01, March update, page 323.

that the increases are appropriate as the 2010 forecast is based on current data and, in 2011 the company anticipates that some irrigation customers will switch from Rate 1/11 to Rate 4/14.[410]

10.2.1 Rate 3/13 forecast

Views of the parties

546. The CCA stated that AltaGas is forecasting a net addition of one customer in 2010 and nil customer additions in 2011 and 2012, while the last five years of history shows average net additions of 2.2 customers per year. The CCA argued that the Commission should use a five-year historical average as the basis upon which to assess the forecast for this class. In the view of the CCA, it is difficult to assess what net additions in Rate 3/13 are related to system growth, transfers from other rate classes or attrition, since AltaGas does not track or forecast customer additions as between attrition and growth. As this rate class has a higher consumption per customer than any other rate class, the CCA submitted that AltaGas should be directed to undertake such tracking.[411] In the view of the CCA, the nil forecast for 2011 and 2012 does not appear reasonable and AltaGas should be directed to increase the forecast net addition by 2.0 in each test year.

547. AltaGas responded that the CCA's claim that it had forecast zero Rate 3/13 customer additions in 2012 was incorrect, pointing out that it had forecast one customer addition in 2012. In addition, the CCA used incorrect customer addition numbers for 2006 through 2009[412] to support its recommended increase of 2 customers per year. AltaGas argued that the year-end numbers provided in its response to AUC-AUI-2(a) were a more accurate reflection of actual year-end customer data and the changes over time. The average of these more accurate numbers is -0.5 per year.[413]

Commission findings

548. The Commission considers the AltaGas method of forecasting at the individual customer level for large customers acceptable and is not persuaded that using a five-year historical average as the basis upon which to forecast customer additions for this class would produce a more accurate forecast. Given the year-end numbers provided in response to AUC-AUI-2(a), the Commission finds AltaGas's forecast for this rate class to be reasonable. The Commission approves AltaGas's Rate 3/13 customer forecasts for 2010-2012 as applied-for.

549. With respect to the CCA's proposal to track Rate 3/13 customer changes, the Commission is not persuaded that the type of customer tracking the CCA suggests will produce a more accurate forecast and there is no evidence on the record of the proceeding as to whether it will be practical to implement. Accordingly, the CCA's proposal is denied.

10.2.2 Rate 4/14 forecast

Views of the parties

550. The CCA took issue with the AltaGas forecast of no change in customers for 2012. It noted that the 2011 and 2012 forecasts are calculated using a five-year historic average of

410 Exhibit 30.01, March update, page 324.
411 Exhibit 142.01, CCA argument.
412 The CCA used the AltaGas response in CCA-AUI-16(a).
413 Exhibit 151.01, AltaGas reply argument.

Rate 4/14 customers and load (based on 2005 to 2009, inclusive).[414] The CCA argued that there was no evidence to suggest that there will be any more or less availability of water in 2012 or that commodity prices will be any different in 2012 than in 2010 and 2011. The CCA submitted that the nil forecast for 2012 does not appear reasonable and recommended an addition of about 25 customers, which is the average of 2010 and 2011 net additions, rounded down to the nearest whole number.[415]

551. AltaGas replied that the number of irrigation customers tends to fluctuate from year to year, as illustrated by the data provided in its response to AUC.AUI-2(a) (reproduced below). It argued that its forecast for irrigation customers at year-end 2011 and 2012 is reasonable and matches relatively closely the levels experienced in 2008. AUI pointed out that there was a significant decline in customers over the past five years.[416]

Table 44. Irrigation customers

Year	Actual year-end customers	Net change
2005	265	
2006	258	-7
2007	209	-49
2008	243	34
2009	185	-58
2010	212	27
Average		-10.6

Commission findings

552. The Commission notes that AltaGas used the same forecast methodology approved in the previous AUI decision.[417] The Commission is not persuaded that the CCA's proposal to add 25 customers to the 2012 forecast is reasonable. In addition, the Commission finds the company's forecast to be reasonable in light of the historical information it provided. Accordingly, the Commission approves AltaGas's irrigation customer forecast, as applied-for.

10.3 Distribution throughput

553. AltaGas provided its throughput forecast for the test period 2010-2012, as set out in the table below. This table also includes the forecast and actual throughput for 2008 and 2009. AltaGas submitted that the 2010 numbers are generally based on actuals.

[414] Exhibit 142.01, CCA argument.
[415] Exhibit 142.01, CCA argument.
[416] Exhibit 151.01, AltaGas reply argument.
[417] Decision 2009-176.

Table 45. 2008-2012 throughput and Rate 3/13 demand forecasts[418]

	2008 forecast	2008 actual	2009 forecast	2009 actual	2010 forecast	2011 forecast	2012 forecast
Throughput (GJ):							
Residential (Rate 1/11)	5,910,023	5,833,121	6,082,625	5,877,071	5,949,290	5,979,092	6,017,994
Commercial (Rate 1/11)	4,043,737	4,313,407	4,152,855	4,382,596	4,550,834	4,635,670	4,786,840
Rural (Rate 1/11)	2,230,667	2,188,876	2,245,593	2,291,516	2,322,213	2,363,290	2,412,952
Large General Service (Rate 2/12)	1,228,015	1,174,513	1,197,868	1,213,974	1,244,595	1,261,804	1,309,997
Demand (Rate 3/13)	2,867,945	2,297,948	2,862,570	2,102,435	2,236,439	2,474,507	2,463,374
Irrigation (Rate 4/14)	89,982	66,610	89,982	81,879	25,985	79,717	79,717
	16,370,369	15,874,475	16,631,493	15,949,471	16,329,356	16,794,080	17,070,874
Annual billing demand (GJ):							
Demand (Rate 3/13)	191,444	188,356	189,444	214,980	199,881	204,496	206,645

554. The 2008 and 2009 variance between total forecast and total actual throughput is -3.0 per cent and -4.1 per cent, respectively. The 2008 and 2009 variance between forecast and actual Rate 3/13 annual billing demand is -1.6 per cent and 13.5 per cent respectively.

555. With the exception of Irrigation Rate Class 4/14,[419] the company's approach for determining forecast customer usage and total throughput is the same approach approved by the Commission and its predecessor for AltaGas's 2007 GRA[420] and 2008-2009 GRA.[421] For the residential, commercial and rural segments of Rates 1/11 and Rate 2/12, usage is based on a trending analysis performed on five-year historical normalized data for usage per customer.[422] The historical normalized average usage per customer data is based on actual billing history and regional heating degree day data. The normal heating degree days include a 20-year history covering 1991-2010. In its forecast, AltaGas based the 2010 forecast on actual normalized results, and based the 2011 and 2012 forecasts on a simple linear regression model incorporating the 5-year normalized historical data from 2006-2010. To complete the process, AltaGas used customer forecasts, heating degree day data and historical average load data (base and heat sensitive) to develop distribution throughput forecasts by district, by month and by customer class.[423]

556. The residential category of Rate 1/11 usage continues to decline, consistent with observed historical normalized results. The company submitted that this trend is also supported by evidence from ATCO Gas' recent 2011-2012 GRA Phase I,[424] where similar reductions between 2006 and 2010 were projected.[425] Based on the trending analysis performed by AltaGas, distribution throughput forecasts for the residential customer segment under Rate 1/11 reflect

418 Exhibit 30.01, March update, schedules 7.1A and 7.1B.
419 Exhibit 143.01, AltaGas argument.
420 Decision 2007-094: AltaGas Utilities Inc., 2007 General Rate Application Phase I, Application No. 1494406, December 11, 2007.
421 Decision 2009-176.
422 Exhibit 1, application, pages 325-326.
423 Exhibit 1, application, page 326.
424 Decision 2011-450: ATCO Gas (a Division of ATCO Gas and Pipelines Ltd.), 2011-2012 General Rate Application Phase I, Application No. 1606822, Proceeding ID No. 969, December 5, 2011.
425 Exhibit 143.01, AltaGas argument.

continuing reductions in consumption, likely attributable to energy conservation by customers and higher efficiency appliances.[426]

557. Rural customer class usage under Rate 1/11 reflects relatively level consumption in all three test years. Increased usage during the forecast test period is expected for the commercial customer class under Rate 1/11 and for Rate 2/12.[427]

558. Rate 3/13 has the fewest number of customers of all rate classes but serves the highest consuming customers. AltaGas forecasts Rate 3/13 billing demand and throughput by individual customer, using actual historical data and, if available, customer specific information obtained through interactions with customers in this rate class. The increase in the 2011 forecast throughput and billing demand reflects the full year impact of growth in 2010 and net growth in 2011. The company is not anticipating any significant change in 2012.[428] AltaGas submitted that this method of forecasting for the Rate 3/13 class is appropriate because consumption per customer is considerably larger than the other rate classes and tends to be unique to the circumstances of each customer.[429]

559. For Rate 4/14, the 2011 and 2012 forecasts were calculated using a five-year historical average of Rate 4/14 load (based on 2005 to 2009, inclusive).[430] Generally, the most recent five-year history (2006-2010) would be used to calculate the average. However, because 2010 was an unusually low consumption year, AltaGas considered it appropriate to use the average based on the years 2005 to 2009; justifying this exception as being consistent with the objective of establishing forecasts reflecting normal conditions, resulting in reasonable revenue forecasts for the test period.[431] The company proposed that the forecast for the test period is appropriate because the 2010 forecast is based on current data, and in 2011 AUI anticipated a return of some irrigation customers from Rate 1/11 to Rate 4/14.[432]

10.3.1 Average consumption per Rate 1/11 customer and difference between AltaGas's trending analyses and forecasts

560. Two specific issues were raised by the CCA – the forecast average consumption per customer for Rate 1/11 and the difference between AltaGas's trending analyses and forecasts.

Average consumption per Rate 1/11 customer

561. The CCA asked AltaGas[433] to comment on the differences between the average usage per Rate 1/11 customer it had forecast and the ATCO Gas forecast for residential customers.[434]

562. In its response to the CCA, the company suggested some of the differences may be due to the fact that, while AltaGas's Rate 1/11 customers consume about 6,400 GJ per year, ATCO Gas's Rate 1 includes customers consuming up to 8,000 GJ per year. As well,

426 Exhibit 1, application, page 291.
427 Exhibit 30.01, March update, page 291.
428 Exhibit 1, application, section 7.0, page 327.
429 Exhibit 143.01, AltaGas argument, page 70.
430 Exhibit 30.01, March update, page 324.
431 Exhibit 143.01, AltaGas argument, page 70.
432 Exhibit 30.01, March update, page 324.
433 Exhibit 48.01, CCA-AUI-18 (a).
434 Exhibit 142.01, CCA argument, page 64.

AltaGas's Rate 1/11 includes a rural class, whereas ATCO Gas's does not, and AltaGas's rural class customers have a higher average usage than customers in AltaGas's residential class.

563. The CCA provided the numbers in the table below[435] and submitted that the AltaGas forecast was lower than that of ATCO Gas by about 1.8 per cent in 2010, 2.1 per cent in 2011 and 2.7 per cent in 2012.[436]

Table 46. Comparison of average residential usage per customer

	2010	2011	2012
AltaGas (GJ)[437]	118.8	116.6	114.6
ATCO Gas North (GJ)[438]	121.0	119.1	117.7
Difference (GJ)	-2.2	-2.5	-3.1
Difference (%)	-1.8	-2.1	-2.7

564. The CCA stated that no real evidence had been provided to support the increasing difference in the average usage per customer as between ATCO Gas and AltaGas. The CCA recommended the AUC direct AltaGas to increase its forecast 2012 residential average usage to about 115.4 GJ per customer, reflecting a difference of about 2.0 per cent, which is the average difference in residential usage as between AltaGas and ATCO Gas for the years 2010 and 2011.[439]

565. AltaGas submitted that the CCA's recommendation is not based on any evidence and should be disregarded. The existence or absence of evidence to support an increasing difference between the average usage per customer of ATCO Gas' low-use class and AltaGas's residential class is irrelevant. AltaGas pointed to its evidence, which included a detailed explanation of AltaGas's previously approved normalization method and a historical normalized usage trending analysis provided in support of the forecast usage for all categories of Rate Class 1/11 and Rate Class 2/12.[440]

Differences between AltaGas's trending analyses and forecasts

566. AltaGas identified minor errors in the historical data used to determine residential, commercial, rural and large general service normalized usage per customer for 2010-2012. The company provided corrected values. The original and corrected numbers are set out in the table below. AltaGas submitted that the changes are relatively immaterial and the original uncorrected usage forecasts are reasonable for determining AltaGas's forecast sales revenue, but that it was willing to update its forecast in the compliance filing, if required, to reflect the corrected values.[441]

435 Exhibit 48.01, CCA-AUI-18 (a).
436 Exhibit 142.01, CCA argument, page 63.
437 Exhibit 1, application, Table 59.
438 ATCO Gas 2011-2012 GRA, Application No. 1606822, Proceeding ID No. 969, Table 7.1.1 -13, Tab 7.3, Attachments 1 and 2, Tabs 8-1-3 and 8-2-3.
439 Exhibit 142.01, CCA argument, page 64.
440 Exhibit 151.01, AltaGas reply argument, pages 100-101.
441 Exhibit 48.01, response to CCA-AUI-18(c).

Table 47. Usage per customer forecasts (GJ/year)

Customer class	Year	Corrected forecast[442]	Original forecast[443]
Residential	2010	118.80	118.82
	2011	116.58	116.60
	2012	114.58	114.40
Rural	2010	181.44	181.43
	2011	181.30	181.29
	2012	181.63	181.62
Commercial	2010	688.80	688.76
	2011	695.02	694.99
	2012	704.93	704.89
Large general service	2010	9,062.76	9,057.09
	2011	9,214.79	9,210.25
	2012	9,567.70	9,562.02

567. The CCA observed that, in most cases, the trending analysis using the corrected usage values showed slightly higher volumes of usage per customer than the trending analysis filed by AltaGas in its GRA application. The CCA requested that AltaGas be directed to include, in the compliance filing, the corrected average usage per customer data consistent with the results of the trending analysis provided in response to CCA-AUI-18(c).[444]

Commission findings

568. The Commission has reviewed the approved forecast and actual throughput variances filed by AltaGas for each of the rate classes and notes that the company used forecasting methodologies consistent with those used in the past[445] and approved in Decision 2009-176.[446]

569. The Commission is not persuaded by the CCA's recommendation that the Commission should consider the ATCO Gas average usage per customer and directs AltaGas to adjust its residential customer segment forecast accordingly. The Commission accepts the company's explanation respecting the differences between its forecast and that of ATCO Gas. The Commission also recognizes the differences in the make-up of the customer classes of the two utilities. Therefore, the Commission approves the company's filed forecast for average consumption per customer for Rate 1/11.

570. The updated historical data provided by AltaGas for the residential, commercial, rural and large general service customer segments is very close to the original historical data filed and the Commission considers the errors to be immaterial. The Commission therefore approves the customer throughput forecast for each of the rate classes, as applied-for.

571. The Commission has also reviewed the annual billing demand forecasts for each of the test years. Given that the company has used the same forecasting methods previously approved

[442] Exhibit 48.01, response to CCA.AUI-18(b)(c), attachment.
[443] Exhibit 1, application, Table 59.
[444] Exhibit 142.01, CCA argument, page 65.
[445] Includes a review of Rule 005 summary numbers, recognizing pre-2007 forecasting methodologies were somewhat different.
[446] Decision 2009-176: AltaGas Utilities Inc. 2008-2009 General Rate Application Phase 1, Application No. 1579247, October 29, 2009.

by the Commission in Decision 2009-176 and, given that the forecast is influenced by a relatively few number of customers with relatively large demand, the Commission finds the billing demand forecasts for the test years to be reasonable and approves them as filed.

10.4 Distribution revenues

572. AltaGas provided its distribution revenue forecast for the test period 2010-2012. The 2010 numbers are generally based on actuals. The table below also includes the forecast and actual 2008 and 2009 distribution revenue numbers.

Table 48. Distribution revenue forecast[447]

	2008 forecast	2008 actual	2009 forecast	2009 actual	2010 forecast	2011 forecast	2012 forecast
Distribution revenues				($)			
Residential (Rate 1/11)	18,720,373	18,744,424	22,313,467	23,598,774	25,592,546	27,560,814	28,016,573
Commercial (Rate 1/11)	6,521,894	6,934,745	7,665,750	8,567,662	9,519,699	10,246,587	10,483,945
Rural (Rate 1/11)	5,800,236	5,726,010	6,779,810	7,220,442	7,853,998	8,473,983	8,641,173
Irrigation (Rate 4/14)	164,041	140,455	197,189	189,579	110,330	218,221	218,221
Large General Service (Rate 2/12)	1,481,254	1,374,264	1,681,232	1,705,560	1,823,865	1,948,427	1,995,994
Demand (Rate 3/13)	1,416,553	1,372,488	1,629,814	1,733,749	1,936,685	2,103,897	2,121,910
Revenue deficiency[448]	3,664,258	3,664,258	590,669	590,669			
2008 revenue collected in 2009[449]				(2,857,908)			
2010 deficiency adjustment[450]					(1,425,710)		
	37,768,609	37,956,644	40,857,931	40,748,527	45,411,413	50,551,929	51,477,816

573. AltaGas provided a forecast of $45.4, $50.6 and $51.5 million in distribution service revenues for 2010, 2011 and 2012, respectively. Approximately 92 per cent of the company's forecast distribution revenue was derived from Rate 1/11. Optional Rate Classes 2/12, 3/13 and 4/14 make up the balance of the forecast distribution service revenues.[451]

574. Forecast distribution revenue was based on a relatively constant increase in Rate 1/11 customers through the test period. Customers in Rate 2/12 and Rate 3/13 were forecast to remain relatively stable in 2011 and 2012. Customers in Rate 4/14 were forecast to increase at closer to historic levels.[452]The 2008 and 2009 variances between forecast and actual distribution revenues are 0.5 per cent and 0.3 per cent, respectively.

575. In determining its forecast, AltaGas applied existing rates to forecast billing determinants for the test period. AltaGas's distribution service revenues for 2010 were based on existing rates approved on an interim refundable basis in Decision 2009-038, effective for consumption on and after May 1, 2009, and Decision 2010-535, effective for consumption on and after December 1,

447 Exhibit 30.01, March update, schedules 7.1A and 7.1B.
448 Decision 2010-197: AltaGas Utilities Inc. 2008-2009 General Rate Application Phase I compliance filing, Application No. 1605779, Proceeding ID No. 452, May 6, 2010.
449 Decision 2009-038: AltaGas Utilities Inc. 2008 interim refundable rates, Application No. 1604826, Proceeding ID No. 170, March 30, 2009.
450 Unrecovered revenue deficiencies attributed to prior test years, Decision 2009-107 - AltaGas Utilities Inc., 2007 Deficiency Rider F – Reconciliation, Application No. 1605190, Proceeding ID No. 215, July 21, 2009.
451 Exhibit 30.01, March update, page 291.
452 Exhibit 30.01, March update, page 291.

2010. AltaGas also adjusted the 2010 distribution service revenues by $1.4 million to remove from total revenues the recovery in 2010 of residual 2007, 2008 and 2009 deficiencies outstanding and not collected in previous years.[453]

576. The company's 2011 and 2012 distribution service revenues were based on the 2011 interim rates approved in Decision 2010-621.[454] Subsequent to that filing, the Commission approved revised 2011 interim rates in Decision 2011-311,[455] effective August 1, 2011 and AltaGas applied to the Commission for 2012 interim rates. The 2012 interim rates were approved in Decision 2012-013.[456] AltaGas proposed that the impact of both decisions 2011-311 and 2012-013 be reflected in any subsequent compliance filing related to this proceeding.[457]

10.4.1 Incremental distribution revenues for Rate 1/11

577. The CCA asked AltaGas to provide the incremental distribution revenue per customer for Rate 1/11.[458] In response, AltaGas provided a table setting out the incremental units billed and revenues from the forecast customer additions. As a result of cross-examination, AltaGas filed a revised calculation, stating it is more accurate because it added the incremental revenue associated with the net addition of customers in 2010, 2011 and 2012.[459] The revised numbers (and percentage changes as calculated by the CCA[460]) are shown below:

Table 49. Quantification of incremental revenues from net additions

Rate 1/11 Incremental Dist'n Revenue/GJ ($/GJ):	2010 forecast normalized	2011 forecast normalized	2012 forecast normalized
Residential	4.30	4.61	4.67
Commercial	2.10	2.22	2.21
Rural	3.38	3.59	3.58
Total	9.78	10.42	10.46
Incremental Dist'n Revenue/GJ (% Change):			
Residential		7.2	1.3
Commercial		5.7	-0.5
Rural		5.8	-0.3
Total		6.5	0.4

578. The CCA calculated that, while the Rate 1/11 rate classes in 2011 show a growth in the incremental distribution revenue per GJ averaging 6.54 per cent, the average growth in 2012 is only 0.385 per cent. The CCA submitted that no reasonable explanation was provided by AltaGas for this decrease in growth rate from 2011 to 2012 and, as 2012 rates will form the basis

453 Exhibit 143.01, AltaGas argument.
454 Decision 2010-621: AltaGas Utilities Inc., 2011 Interim Rates, Application No. 1606827, Proceeding ID. 971, December 24, 2010.
455 Decision 2011-311: AltaGas Utilities Inc., 2008-2009 General Rate Application Phase II Compliance and Updated 2011 Interim Rates, Application No. 1607310, Proceeding ID No. 1220, July 25, 2011.
456 Decision 2012-013: AltaGas Utilities Inc., 2012 Interim Rates, Application No. 1607602, Proceeding ID No. 1403, January 12, 2012.
457 Exhibit 143.01, AltaGas argument.
458 Exhibit 48.01, CCA-AUI-14(e).
459 Exhibit 132.33, undertaking, Transcript, Volume 5, page 1248, line 11; Exhibit 132.08, undertaking, Transcript, Volume 5, page 1248, line 11.
460 Exhibit 142.01, CCA argument.

for the going-in rates for the 2013-2017 PBR period, it is critical that 2012 reflect a more realistic expectation of growth in the incremental distribution $/GJ. The CCA recommended AltaGas be directed to include, in the compliance filing, an increase in the incremental distribution revenue per Rate 1/11 customer in 2012 that is at least equivalent to that for 2011.[461]

579. AltaGas submitted that the main factor influencing the differences in incremental revenues per net addition customer is the change in existing rates applied in 2010 relative to 2011 and 2012 and, therefore, the CCA's proposal should be disregarded. AltaGas also stated that the CCA's concern about incremental revenues and base rates, as they relate to the 2013-2017 PBR period, is irrelevant in the context of the GRA application and premature since final rates for 2012 have not yet been established. Moreover, AltaGas's proposed PBR mechanism includes final rates based on actual, rather than forecast, billing determinants.[462]

Commission findings

580. The Commission has reviewed the approved forecast for distribution revenues and the actual revenues for 2008 and 2009. The Commission considers that AltaGas's distribution revenue forecast has historically been at a generally acceptable level.[463]

581. AltaGas proposed to recognize the impact of decisions 2011-311 and 2012-013, and the resulting revised 2011 interim rates and the 2012 interim rates in the compliance filing. The Commission is of the view that AltaGas must update its distribution revenue forecast to reflect the amount resulting from interim rates approved in decisions 2011-311 and 2012-013 in the compliance filing, and directs AltaGas to do so.

582. The Commission does not accept the CCA's recommendation to increase the incremental distribution revenue per GJ per net addition Rate 1/11 customer in 2012 to reflect a growth rate at least equivalent to that for 2011. The Commission accepts AUI's explanation that the main factor influencing the differences in incremental revenues is the increase in rates from 2010 to 2011, while rates from 2011 to 2012 did not increase. The Commission notes, for example that the base fixed charge for residential Rate 1/11 increased from $0.794 in 2010 to $0.842 in 2011 and 2012 representing a six per cent increase.[464]

583. The Commission has reviewed the forecast distribution revenues and, with the updates based on decisions 2011-311 and 2012-013 directed above, finds them to be reasonable. Accordingly, the Commission approves the forecast distribution revenues, as filed, subject to the direction set out in paragraph 581.

10.5 Other revenues forecast

584. AltaGas receives other (non-distribution) revenues from the provision of several services to customers. Other revenue consists of penalty revenue, service work, closed rate transportation, interest on Energy Resources Conservation Board (ERCB) deposits, special meter readings and other miscellaneous revenues.

---

461 Exhibit 142.01, CCA argument.
462 Exhibit 151.01, AltaGas reply argument.
463 Includes a review of Rule 005 summary numbers, recognizing pre-2007 forecasting methodologies were somewhat different.
464 Exhibit 132.33, undertaking, Transcript, Volume 5, page1248, line 11.

585. AltaGas provided its other revenue forecasts for the test period 2010-2012, set out in the table below. The table also includes the actual and forecast for 2008 and 2009.

Table 50. Other revenues forecast[465]

Other revenues	2008 forecast	2008 actual	2009 forecast	2009 actual	2010 forecast	2011 forecast	2012 forecast
				($)			
Penalty revenue	105,100	117,502	118,600	146,501	167,700	173,700	168,900
Service work	136,800	147,704	136,800	71,396	135,100	124,700	128,400
Closed rate transportation	587,001	589,190	588,187	552,870	536,576	436,895	394,580
Interest on ERCB deposit	9,900	9,100	10,100	1,766	2,400	1,200	1,200
Special meter readings	429,600	424,380	442,800	425,248	411,700	430,300	434,600
Other miscellaneous revenue	60,000	81,524	60,000	56,306	47,500	81,900	73,900
	1,328,401	1,369,400	1,356,487	1,254,087	1,300,976	1,248,695	1,201,580

586. The 2008 and 2009 variances between forecast and actual other revenues are 3.1 per cent and 7.5 per cent, respectively.

10.5.1 Penalty revenues

587. Penalty revenues consist of charges applied to customer bills for late payments pursuant to AltaGas's T&C's.

588. AltaGas stated that the 2010 forecast is based on actual results. The 2011 and 2012 forecasts are based on three year historic average ratios of penalty revenues to gross revenues. Gross revenues are equal to the sum of distribution revenues, gas cost recovery rate revenues and third party transportation rate revenues. Penalty revenues specific to distribution service are subsequently determined by applying the forecast ratio of distribution revenues to gross revenues.

10.5.2 Service work

589. Service work relates to work associated with customer requested replacements and relocations, as well as billing for third party damages to AltaGas plant assets, and is net of the cost of providing the service.

590. The forecast for 2010 reflects actual revenues. The 2011 and 2012 forecasts are based on the three year historical average for 2007 through 2009 and inflated using the inflation escalators requested in the Application.

10.5.3 Closed rate transportation

591. Closed rate transportation consists of revenue from Producer Transportation Rates 10a, 10b and 10c and Special Contract Rate 30. These rates are associated with closed customer specific contracts that are not available to any other customers.

592. The decline in revenues over the test period reflects the termination of one account under Rate 10a in 2011, which is fully realized by 2012.

465 Exhibit 1, application, Schedule 7.4.A.

10.5.4 Interest on ERCB deposit

593. This is interest revenue on the deposit held by the ERCB.

594. The forecast for interest revenue on the ERCB deposit was based on the current deposit balance and interest currently credited to the AltaGas deposit account for 2011 and 2012. The 2010 forecast was updated to actual interest received in 2010.

10.5.5 Special meter reading

595. The special meter readings account includes revenue from charges to customers for special meter reads, connection fees, reconnect fees, service reactivation, reinstallation of meters and regulators, and customer requested removal and testing of meters.

596. The original 2010 forecast was based on the three-year historical average for 2007 through 2009. The year 2010 was updated based on actual data and the 2011 and 2012 forecasts were based on the original 2010 forecast, increased for inflation.

10.5.6 Other miscellaneous revenue

597. Other miscellaneous revenue consists of revenues and fees received by AltaGas for any other activities not accounted for as revenue from service work or other special meter reads.

598. The 2010 forecast is based on actual results. The 2011 and 2012 forecasts are based on the three-year historical average from 2007 to 2009 adjusted for revenues not expected to recur. The non-recurring revenues relate primarily to administrative fees paid to AltaGas under the natural gas rebate program which was discontinued in 2009.[466]

Views of the parties

599. Neither the CCA nor the UCA commented on the other revenue forecasts.

Commission findings

600. The Commission has reviewed the approved forecast for other revenues and the actual revenue for 2008 and 2009. The Commission notes that the forecasts for 2010-2012 are based on forecasting methodologies consistent with those used in the past[467] and approved in Decision 2009-176. The Commission considers that the company's other revenue forecast has historically been at a generally acceptable level. As a result, the Commission approves each of the other revenue forecasts as filed for the test years, subject to the following direction.

601. The Commission directs AltaGas to make any necessary adjustments to the service work and special meter read forecasts for 2011 and 2012 to give effect to the inflation rates approved in this decision, and to include the adjusted forecast amounts in the compliance filing.

---

[466] Exhibit 1, application, pages 329 to 332; Exhibit 143.01, AltaGas argument, pages 72 to 74; response to AUC-AUI-82, and response to CCA-AUI-21(i).

[467] Includes a review of Rule 005 summary numbers, recognizing pre-2007 forecasting methodologies were somewhat different.

11 AUC Rule 005 reports

602. In the March update, the cover letter stated:

> Enclosed for filing is AltaGas Utilities Inc.'s updated 2010-2012 GRA – Phase I Application. AUI submits the enclosed application, business cases and schedules all reflect AUI's most current information, including actual 2010 year end balances and deferral of IFRS to January 2012. Based on the updated information, the revenue requirement requested for 2010 is $48.9M, $57.5M for 2011 and $66.2 M for 2012.
>
> In addition to 2010 actual results and associated variance explanations, the updated application includes KPMG's analysis of AUI's Inter-Affiliate Shared Services costs and a request for a deferral account in relation to AUI's proposed Demand Side Management (DSM) program. Due to the scope and impact of the changes and to avoid unnecessary confusion, AUI requests the enclosed application replace the existing application in its entirety.

603. During the oral hearing,[468] AltaGas's main witness panel was questioned about differences between the 2010 actual figures for return on rate base and income taxes included in the March update and the corresponding figures for return on rate base and income taxes reported for 2010 in the AltaGas 2010 Annual Report of Financial and Operational Results submitted in accordance with the Commission's Rule 005.[469] The differences were explained by the fact that the 2010 actual figures included in the application were weather normalized, while the 2010 actual figures included in the 2010 Annual Report of Financial and Operational Results were not weather normalized.[470]

Commission findings

604. The Commission finds that AltaGas's practice of adjusting the 2010 actual billing determinants for weather normalization for purposes of the GRA application is acceptable. The Commission considers that the use of weather normalized data is a long standing regulatory practice in forecasting billing determinants for natural gas distribution utilities and the Commission approves the use of the weather normalized data as the basis for the AltaGas 2010 revenue requirement.

12 Separate default rate tariff reporting

605. In addition to being a natural gas distributor, AltaGas is also a default gas supply provider. The costs in the GRA application include the costs of providing the default gas supply service.[471] The rates for providing this service are set pursuant to a Phase II GRA. Given the Commission's current rate regulation initiative proceeding regarding the adoption of PBR for AltaGas's natural gas distribution function, the Commission was interested in whether AltaGas could separate out the costs included in the GRA application that relate to providing the default gas supply service. The purpose of separating out these costs is to make sure that AltaGas's

---

468 The questioning on this area is included in Transcript, Volume 6, page 1419, line 17 to page 1427, line 2.

469 AltaGas's 2010 Annual Report of Financial and Operational Results were submitted on the record of this proceeding and are included as Exhibit 47.08.

470 Transcript, Volume 6, page 1423, line 3 to page 1424, line 16, and page 1425, lines 16-24.

471 As confirmed by Mr. Mantei, a witness for AltaGas, during questioning from Commission counsel at Transcript, Volume 6, page 1427, lines 14-21.

going-in distribution rates for any PBR plan do not include any costs that are related to the retail operation of the default gas supply service.

606. During the interrogatory process, the Commission asked AltaGas to indicate whether it could separate, by year, the forecast costs included in the GRA application that are for the default rate tariff function and, if this is not possible, to explain why. In response, AltaGas stated:

> AUI is a natural gas utility and performs the distribution and the default gas supply provider function within its franchised areas. AUI is the only natural gas utility in Alberta providing both functions to the end users on its system. Currently, 96.5% of the end users on the system receive both distribution and default gas supply services from AUI.
>
> As a default gas supply provider, AUI sought and received approval of a Default Supply Provider Administration Fee. This fee was established as part of the AUI 2005-2006 GRA Phase II proceeding (Application No. 1491262) in Decision 2007-079. In developing the fee, AUI undertook to determine an estimate of what the long run avoided costs would be in the event all end use customers were served by third party retailers. This avoided cost approach was taken as the costs associated with administering the Default Rate Tariff (DRT) as part of the total costs of the utility (AUI). AUI does not have a stand alone entity or division responsible for providing the DRT administration function. The staff and the assets employed to provide the DRT function also perform distribution functions and attempting to separate them on any basis other than the currently approved avoided cost method would be arbitrary and not yield any meaningful results. Accordingly, AUI is unable to provide separate costs related to the DRT function.[472]

Commission findings

607. During the oral hearing,[473] the company's main witness panel responded to questions about the possible separation of the costs associated with the provision of default gas supply services. The witness panel was referred to Schedules 7.1C, 7.1D, and 7.1E of the March update,[474] and the default supply administration fees included in the GRA application of $0.074 per customer per day for 2010, and $0.078 per customer per day for each of 2011 and 2012 and asked how these administration fees were calculated. The Commission is not satisfied that AltaGas responded to these questions adequately.

608. Accordingly, the Commission requires the information regarding how the default supply administration fees included in the GRA application for 2010, 2011 and 2012 were determined. The Commission notes that AltaGas included a calculation in Schedule 6.8 – Functionalized Customer Accounting – Long Run Avoided Costs as part of its 2008-2009 GRA Phase II filing.[475] The Commission directs AltaGas, in the compliance filing, to prepare and submit a schedule similar in format to Schedule 6.8 of Exhibit 3 of Proceeding ID No. 651, for each of 2010, 2011 and 2012. The Commission also directs AltaGas to show how the resulting daily default supply administration fees included in Schedules 7.1C, 7.1D and 7.1E are calculated from the information shown on the schedules similar in format to Schedule 6.8 for each of 2010, 2011 and 2012 directed above.

[472] Exhibit 47.01, response to AUC-AUI-3.
[473] The questioning on this area is included in Transcript, Volume 6, page 1427, line 3 to page 1437, line 1.
[474] Exhibit 30.03, March update, schedules.
[475] Proceeding ID No. 651, Exhibit 3.

13 Other deferral accounts

13.1 Natural gas settlement system code deferral account

609. On August 30, 2010, by way of Bulletin 2010-22,[476] the AUC initiated a consultative process with industry participants to develop a rule for natural gas load settlement. AUC Rule 028: *Natural Gas Settlement System Code* (Rule 028) was approved on March 29, 2011, and became effective April 4, 2011. It was subsequently revised and effective on January 1, 2012. During the consultation on the development of Rule 028, AltaGas indicated that it planned to seek specific exemptions once the rule came into effect because it was not currently in a position to comply with certain provisions. In Bulletin 2011-11,[477] which informed the gas utilities of the adoption of the rule, the Commission provided to AltaGas a temporary delay in the enforcement of certain sections of the *Natural Gas Settlement System Code* to allow AltaGas time to file an exemption request.

610. In the GRA application, AltaGas submitted that, at this stage of the process, it was too early to determine the amount of work required of AltaGas to comply with the *Natural Gas Settlement System Code* but, to date, it had incurred significant capital expenditures to comply with other AUC Rules – for example Rule 004: *Alberta Billing Tariff Code Rules* (Rule 004) and Rule 010: *Rules on Standards for Requesting and Exchanging Site-Specific Historic Usage Information for Retail Electricity and Natural Gas Markets* (Rule 010). AltaGas's 2010-2012 forecasts do not include any provision for costs to change its current settlement processes to comply with the *Natural Gas Settlement System Code*. AltaGas submitted that, if it could reasonably determine the costs of implementing the *Natural Gas Settlement System Code* during the course of this proceeding and if the costs were material, it would provide an update to the GRA application to reflect the impact. No such estimate was received by the close of record. AltaGas also submitted that, if costs were not known prior to the conclusion of this proceeding, but subsequently it determined such costs to be material, it was requesting approval of a deferral account.[478]

611. In response to an IR, AltaGas advised that, as Rule 028 was only recently developed, it was still in the very preliminary stages of determining what would be required to become compliant with the daily settlement aspect of the *Natural Gas Settlement System Code* and was unable to provide any detailed information at that time.[479]

612. On May 13, 2011, AltaGas filed an application requesting a two-year exemption from compliance with certain sections of Rule 028 and a permanent exemption from Section 11. In Decision 2011-346[480] the Commission approved an exemption for six months to allow AltaGas to complete research and analysis to evaluate all options for implementing a settlement information system that is compliant with the *Natural Gas Settlement System Code*. AltaGas was also

---

[476] Bulletin 2010-22, Consultation Process for Establishing a Natural Gas Settlement System Code, August 30, 2012.

[477] Bulletin 2011-11, Rule 028 (Version 1.0): *Natural Gas Settlement System Code Rule*, April 1, 2011.

[478] Exhibit 30.01, March update, page 52, paragraphs 60-61.

[479] Exhibit 48, response to AUC-AUI-23(a).

[480] Decision 2011-346: AltaGas Utilities Inc., Natural Gas Settlement System Code Rules Exemption Application, Application No. 1607324, Proceeding ID No. 1236, August 23, 2011.

directed to make further application to the AUC by the end of the six-month exemption period (February 28, 2012) requesting a further exemption and outlining its proposed solution.[481]

613. AltaGas's rationale for requesting a deferral account for NGSSC costs was explored during the hearing:

> Q. And so the request -- what I understood was the request for a deferral account deals with the uncertainty of the costs associated with that.
>
> A. MR. MANTEI: That is correct. We, at this point in time, do not have a cost estimate of what it's going to be to put that system in place. The expectation is that it will be, I would say, not in the full order of what TBC [Tariff Billing Code] would have cost us, but it's certainly going to be in the, you know, several millions of dollars.
>
> So we've asked for a deferral account to basically allow us to trap the costs and be able to recognize those costs and recover them through rates in -- sometime in the near future.[482]

Based on the above testimony, AltaGas submitted that deferral account treatment for *Natural Gas Settlement System Code* costs is appropriate because the costs cannot be reasonably forecast, they are material and are not within the control of AltaGas management.[483]

614. No other parties commented on this issue during the proceeding.

615. On February 28, 2012, AltaGas applied for a further exemption from Rule 028 until March 15, 2013.[484] In this application, in response to the Commission's direction in Decision 2011-346, AltaGas outlined its proposed solution for implementing a settlement information system along with two alternatives, and included the forecast costs of each of the three options.

Commission findings

616. The Commission is of the view that AltaGas has not provided enough justification for the Commission to approve a deferral account for these *Natural Gas Settlement System Code* costs. While Mr. Mantei testified as to the materiality of the costs, the Commission is not convinced that the costs are beyond the company's control or cannot be reasonably forecast. Therefore the requested deferral account is denied.

617. In the February 28, 2012 exemption application, AltaGas provided details of its proposed solution for implementing a settlement information system along with two alternatives and forecast costs. The Commission directs AltaGas to include this information in the compliance filing and any and all additional updated information the company has, so that the Commission can consider whether to approve the forecast costs to be incurred in 2012 (and any actual costs incurred in 2010 and 2011) in relation to AUI's implementation of a settlement information system that is compliant with Rule 028.

---

481 Decision 2011-346: Natural Gas Settlement System Code Rules Exemption Application, Application No. 1607324, Proceeding ID. 1236, August 23, 2011.

482 Transcript, Volume 6, page 1552, line 12.

483 Exhibit 143.01, AltaGas argument, page 81, paragraphs 259-260.

484 Application No. 1608205, Proceeding ID No. 1746, request for further exemption from the requirements of AUC Rule 028, pursuant to AUC Decision 2011-346.

13.2 Demand side management program and deferral account

618. AltaGas proposed to implement a DSM program and applied for a deferral account to capture the design and development work on the program. AltaGas plans to perform the design work in 2011 and 2012, with an expected implementation date of the DSM program of January 1, 2013. AUI described the program as:

> Working in coordination with consultants specialized in the area of DSM; the design phase will include consultations with customers and other utilities to identify and address key areas of concern related to customer usage, energy efficiency and overall reduction of greenhouse gases (GHG) and to facilitate potential coordination and synergies between utilities' programs. AUI also anticipates coordinating with Climate Change Central (CCC), as well as other climate change programs to ensure the optimal impact of AUI"s DSM program over time.[485]

619. AUI has requested deferral treatment of the design and development costs on the following basis:

> As this is a new initiative, the scope and structure has yet to be fully determined and consultation with consultants, customers and other industry participants will be vital to its design. Because the costs of this important initiative are expected to be material and cannot be reasonably forecast at this time, AUI is requesting establishment of a deferral account in relation to the costs for design, development and implementation of the program.[486]

Views of the parties

620. The UCA was not opposed to a DSM program from a public interest perspective, if there was a coordinated approach amongst utilities, Alberta Climate Change Central and the Alberta government which was not the case in this instance.[487] However, the UCA opposed approval of the proposed DSM program because AltaGas had no idea of the costs of such a program or what the program was going to be. Furthermore, it argued that AltaGas acknowledged that it did not have a legal mandate under regulation or law,[488] nor even a responsibility to its customers to implement such a program and AltaGas was not interested in assuming any of the risks associated with the proposed DSM program. The UCA summarized, in its evidence, the reasons it opposed the DSM proposal in the ATCO Gas 2011-2012 GRA Phase 1, which was more advanced than the AltaGas proposal.[489] The UCA further argued that it would be premature to approve the deferral account when AltaGas had not prepared a business case for the project describing the nature of the program, including a cost-benefit analysis.[490]

621. AltaGas responded to the UCA's criticism about the lack of business case as follows:

> AUI submits there is a difference between the costs and benefits of a DSM program and the costs required to do the preliminary work needed to design and develop effective DSM programs. The costs for which AUI is requesting approval of a deferral account is for the latter category of costs. The costs and benefits of a DSM program will of course

[485] Exhibit 30.01, March update, Section 2.6.3.14, paragraph 128.
[486] Exhibit 30.01, March update, Section 2.6.3.14, paragraph 131.
[487] Exhibit 141.02, UCA argument, page 21.
[488] Transcript, Volume 6, page 1607.
[489] Exhibit 71.01, UCA evidence, A19.
[490] Exhibit 71.01.UCA evidence, A20.

> be supported by business cases when they are brought before the AUC for approval, prior to implementation.[491]

622. The CCA was supportive of AltaGas pursuing DSM initiatives, and of the deferral account requested by AltaGas. The CCA stated:

> In our view, therefore, there is limited gain from a rejection of the proposed deferral account; on the other hand, the upside of granting a deferral account is that the utility will be forced to contemplate and assess DSM initiatives, within the developing DSM area and in light of the AUC comments in Decision 2011-450. To this end, in order that AUI's senior management considers DSM as a priority, and address concerns raised by interveners in this proceeding in a timely manner, the CCA recommended in Argument that AUI be directed to provide an annual report of all DSM initiatives undertaken; to be useful, such reports should provide detailed cost benefit analyses in support of these initiatives, as well as all actions undertaken to work with other utilities and external third parties.[492]

Commission findings

623. Before the Commission makes a determination on the requested deferral account for AltaGas's proposed DSM program, the Commission must consider whether the proposed program as described by AltaGas should be pursued. The Commission notes that the information provided by AltaGas with respect to the proposed DSM program is limited because the company is still in the design and development stage of the program; however, the underlying intent of the program is to address "customer usage, energy efficiency and overall reduction of greenhouse gases (GHG)."[493] In Decision 2011-450,[494] the Commission considered a more advanced DSM program that had a similar basis to AltaGas's. The Commission notes that as of the date of the hearing AltaGas had not taken any steps in relation to the development and design of the proposed DSM program.[495]

624. The Commission considers important the AUI acknowledgement that there was no basis in law which supports a DSM program. Also, the parties to this proceeding were aware of the issue of whether there was statutory authority for DSM programs in the ATCO Gas 2011-2012 GRA proceeding. The Commission determined the following in Decision 2011-450 on the issue of statutory authority for a DSM program:

> 662. The evidence on the record with respect to DSM focused on whether the proposed programs fell within the legislative scope of a gas distributor and issues of general public policy and societal considerations including energy conservation, climate change, renewable energy, the development of government policy, customer preferences, the coordination of DSM efforts, the efficient delivery of DSM programs, practices in other jurisdictions, and the availability of certain services in the competitive market.
> …

491 Exhibit 151.01, AltaGas reply argument, page 108, paragraph 353.
492 Exhibit 152.01, CCA reply argument, page 4, paragraph 7.
493 Exhibit 30.01, March update, Section 2.6.3.14, paragraph 128.
494 Decision 2011-450: ATCO Gas 2011-2012 GRA Phase I.
495 Transcript, Volume 5 at page 1095.

668. Parties agreed that the legislative authority to approve the inclusion of DSM costs in revenue requirement depends on the definitions in the Act and Section 4(1)(b) of the *Roles, Relationships and Responsibilities Regulation*.

669. The term "gas distribution services" refers to services the gas distributor is required to provide under the act, Section 4(1) of the *Roles, Relationships and Responsibilities Regulation*, under other regulations, or by direction of the Commission.
670. The Commission considers that there are two essential components of Section 4(1)(b). First there is a requirement of a gas distributor to make decisions about "building, upgrading, and improving the gas distribution system." Secondly, those decisions must be made for the "purpose of providing safe, reliable and economic delivery of gas to customers in the service area served by the gas distribution system." Both of these components of Section 4(1)(b) must be interpreted to determine whether the proposed DSM projects are a necessary function for a gas distributor.

…

671. AG and CCA have argued for a broad interpretation of Section 4(1)(b), while the other interveners have suggested a more narrow interpretation. …

…

675. The Commission finds that Section 4(1)(b) is intended to relate to the physical aspects of the facilities and the improvement or upgrading of service quality. System improvements and upgrades are not without constraints. Decisions made about building, upgrading and improving the gas distribution system, must be made "for the purpose of providing safe, reliable and economic delivery of gas." The Commission considers that the words "safe and reliable" relate to the facilities used to provide gas distribution service and the quality of that service. Decisions made on building, upgrading and improving the gas distribution system must be made to ensure or improve the safety of the delivery of gas distribution service, the reliability of gas distribution service and the economic delivery of gas distribution service.

676. The term "economic delivery" must be construed in the context of the *Gas Utilities Act* and the *Roles, Relationships and Responsibilities Regulation* taken as a whole. The legislation provides for the regulation of gas utility rates and services. The Commission must determine just and reasonable rates for the provision of gas distribution service by the owner of a gas utility. The Commission finds that in this context "economic delivery" means the delivery of gas distribution service at an economically efficient cost to ratepayers, so as to ensure rates remain just and reasonable.

…

679. The Commission finds that the reduction in consumption is not intended to be captured in Section 4(1)(b). The Commission does not agree that the wording of Section 4(1)(b) is expansive enough to allow the utility to engage in DSM activities funded by ratepayers simply because there is the potential for an unquantifiable, consequential impact to future facilities or to customer demand for gas distribution services.

680. The Commission finds that the proposed DSM programs do not relate to building, upgrading and improving the gas distribution system for the purpose of providing safe reliable and economic delivery of gas to customers. Accordingly, the Commission finds that based on the meaning of the legislative text, the DSM programs

> proposed do not fall within the intended meaning of Section 4(1)(b) of the *Roles, Relationships and Responsibilities Regulation*.
>
> …
>
> 683. Application of the implied exclusion rule suggests that the legislature in enumerating a lengthy list of gas distributor functions in Section 4(1) of the *Roles, Relationships and Responsibilities Regulation* considered in a comprehensive manner the functions intended to be performed by a gas distributor. Functions not provided in the list were not indented to be functions of a gas distributor, unless a function was directed by the Commission as contemplated by the definition of "gas distribution service" or the function is provided for elsewhere in the legislation. DSM is not among the listed functions. As noted above, AG stated in its reply argument that "…neither the GUA, nor the Regulations under the GUA, refer to DSM or energy conservation initiatives." Consequently, the Commission concludes that DSM was not intended by the legislature to be among the functions of a gas distributor. (footnote excluded)
>
> …
>
> 686. The Commission denies AG's request to include in revenue requirement for the test years all costs associated with current and proposed DSM activities...[496]

625. In this proceeding, the Commission did not have before it any evidence or submissions which distinguish the proposed AltaGas DSM program from that discussed in Decision 2011-450 or any legal arguments on the applicable statutory provisions. Therefore, the Commission considers that the findings in Decision 2011-450 apply to the proposed AltaGas DSM program. As a result, the Commission finds that there is no legal basis for the proposed DSM program and denies the deferral account requested by AltaGas to capture the design and development costs of a DSM program and directs that such costs be removed from the revenue requirement.

14 Compliance filing

626. The Commission directs AltaGas to revise its 2010-2012 GRA Phase I application to reflect the Commission's findings, conclusions and directions in this decision and to make a compliance filing for its 2010-2012 GRA Phase I application by June 4, 2012. The Commission expects AltaGas, in the compliance filing, to provide a summary of all adjustments made.

[496] Decision 2011-450, Section 6.3.14.

15 Order

627. It is hereby ordered that:

(1) AltaGas Utilities Inc. shall comply with all Commission directions in this decision.

(2) AltaGas Utilities Inc. shall make a compliance filing for its 2010-2012 GRA Phase I as required by this decision, incorporating the findings, conclusions and directions in this decision by June 4, 2012.

Dated on April 9, 2012.

The Alberta Utilities Commission

(original signed by)

Mark Kolesar
Panel Chair

(original signed by)

Carolyn Dahl Rees
Vice-Chair

(original signed by)

Kay Holgate
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) **counsel or representative**
AltaGas Utilities Inc. (AUI) N. McKenzie R. Koizumi J. Coleman C. Martin
ATCO Gas R. Trovato D. Wilson D. Zavaduk V. Porter
BP Canada Energy Company C. G. Worthy G. W. Boone
Consumers' Coalition of Alberta (CCA) J. A. Wachowich A. P. Merani
FortisAlberta Inc. J. Walsh
Office of the Utilities Consumer Advocate (UCA) D. Marriott R. Daw K. Kellgren L. Kerckhof J. Pous M. Stauft R. Bruggeman

The Alberta Utilities Commission Commission Panel M. Kolesar, Panel Chair C. Dahl Rees, Vice-Chair K. Holgate, Commission Member Commission Staff V. Slawinski (Commission counsel) G. Bentivegna (Commission counsel) P. Howard M. McJannet B. Miller D. Mitchell

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) counsel or representative	Witnesses
AltaGas Utilities Inc. (AUI) N. McKenzie	<u>Inter-affiliate Shared Services Panel</u> J. Williams E. Tuele J. Green A. Mantei <u>Depreciation Panel</u> A. Mantei L. Kennedy <u>Capital Structure Panel</u> M. Vilbert <u>Debt Panel</u> J. Green E. Tuele A. Mantei <u>AUI Company Panel</u> G. Johnston N. Lesage E. Toule A. Mantei H Stribrny R. Koizumi
Office of the Utilities Consumer Advocate (UCA) K. Kellgren	<u>UCA General Panel</u> R. Bruggeman M. Stauft <u>Depreciation Panel</u> J. Pous
Consumers' Coalition of Alberta (CCA) J. Wachowich	

The Alberta Utilities Commission Commission Panel M. Kolesar, Panel Chair C. Dahl Rees, Vice-Chair K. Holgate, Commission Member Commission Staff V. Slawinski (Commission counsel) P. Howard M. McJannet B. Miller D. Mitchell

Appendix 3 – Summary of Commission 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. With respect to forecast increases in salaries, the Commission finds AltaGas's forecast salary escalator of three per cent to be reasonable in 2011 when compared against the supporting inflation indices but is not persuaded that different inflation rates should be applied to union and non-union personnel in 2012. The Commission considers that a four per cent increase in 2012 for both non-union and union personnel is reasonable and more consistent with underlying economic indices cited by AltaGas in its application. AltaGas is directed in the compliance filing to adjust its inflation rate forecast for salaried personnel to four per cent in 2012. Forecast range placement adjustment for salaried employees is addressed by the Commission in Section 6 of this decision. ..... Paragraph 43
2. The Commissions considers that the remediation costs that are the subject of the above noted business cases should be approved only if the costs are reasonable and necessary for the provision of utility service. Given the record of the proceeding, the Commission is unable to make a determination as to whether these remediation costs are necessary for the provision of utility service. At issue is the question as to whether the facilities (in this case leases) for which the remediation projects are proposed are correctly a cost of AltaGas's utility service. Accordingly, the Commission directs AltaGas to file with the Commission, at the time of the compliance filing, its views as to why these costs are necessary for the provision of utility service, along with supporting evidence. The Commission will make its determination with respect to this matter in its decision on the compliance filing. .... Paragraph 117
3. The Commission finds that the expenditure of $360,840 is reasonable and prudent and that it addressed the problems identified. This forecast is approved for inclusion in the calculation of revenue requirement. Because the solution as implemented by AltaGas resulted in lower costs than forecast in the business case, the Commission directs AltaGas to only include the actual cost of $360,840 in the calculation of revenue requirement in the compliance filing. .... Paragraph 126
4. The Commission notes the errors identified, and accordingly directs AltaGas to correct the GST capital expenditures portion of working capital with respect to GST on land and land rights, and to correct the calculation of working capital to exclude franchise tax accruals in the compliance filing. .... Paragraph 154
5. The Commission directs AltaGas to use rates of return on common equity of 9.00 per cent for 2010 and 8.75 for both 2011 and 2012 in the compliance filing. The Commission also directs AltaGas to use a common equity percentage of 43.00 per cent for 2011 and 2012 in the compliance filing. .... Paragraph 178
6. The Commission directs AltaGas, in the compliance filing, to use an interest rate of 5.49 per cent for the two debentures issued by AltaGas on October 8, 2009, and to reflect this interest rate as effective on January 1, 2010. .... Paragraph 198

7. The Commission directs AltaGas, in the compliance filing, to use an interest rate of 4.60 per cent for the $30 million seven-year debenture issued by AltaGas on October 4, 2010. .... Paragraph 206

8. The Commission directs AltaGas, in the compliance filing, to use an interest rate of 4.40 per cent for the $28 million five-year debenture it is forecasting to issue in 2012. .... Paragraph 212

9. In Section 5.3.1 of this decision, the Commission found that the deemed interest rate for the 2009 debentures is 5.49 per cent, which is the interest rate associated with AL's seven-year debenture issued on March 25, 2010. To be consistent, the Commission considers that the debt issue costs associated with the March 25, 2010 issue should be used as the basis for allocating the debt issue costs for the 2009 debentures. The total issue costs of the March 25, 2010 issue were $1.122 million, which represents 0.56 per cent of the total debt issue of $200 million. The Commission directs AltaGas, in the compliance filing, to allocate the debt issue costs on the 2009 debentures using 0.56 per cent as the basis for the calculations. .... Paragraph 220

10. In Section 5.3.2 of this decision, the Commission found that the deemed interest rate for the 2010 debenture is 4.60 per cent, which is the interest rate associated with AL's seven-year debenture issued on November 26, 2010. To be consistent, the Commission considers that the debt issue costs associated with the November 26, 2010 issue should be used as the basis for allocating the debt issue costs for the 2010 debenture. There is no evidence in this proceeding which details the issue costs associated with the medium term notes issued by AL on November 26, 2010. The Commission directs AltaGas, in the compliance filing, to use an annual issue cost percentage for the $30 million debenture issued by AltaGas on October 4, 2010, based on AltaGas's pro-rata share of the actual issue costs incurred by AL in connection with the medium term notes issued by AL on November 26, 2010. The Commission further directs AltaGas to submit an accounting of the total costs incurred by AL in connection with the medium term notes AL issued on November 26, 2010. .... Paragraph 221

11. AltaGas included a forecast annual issue cost percentage of 0.25 per cent associated with the five-year debt issue it has forecast for 2012. The last issue cost percentage associated with a five year medium term note is the one associated with the $40 million debenture issued by AltaGas on October 8, 2009. The Commission considers that this same amount should be approved for the five-year debenture that AltaGas is proposing to issue in 2012. The Commission directs AltaGas, in the compliance filing, to use the annual debt issue percentage for the $40 million debenture issued on October 8, 2009 to forecast the debt issue costs for the $28 million debenture that AltaGas is proposing to issue in 2012. .... Paragraph 222

12. The Commission notes actual bad debt expense increased from $101,700 in 2008 to $164,900 in 2009, with bad debt expense in 2010 declining to $126,100. Interveners did not object to AltaGas's forecast bad debt expenses. The Commission understands that bad debt expense is subject to significant variability due to changes in energy costs and the economy. The Commission finds AltaGas's 2010 bad debt expense as filed to be reasonable, because it is within the range of actual bad debt experienced by AltaGas in the two previous years. With regard to AltaGas's forecast 2011-2012 bad debt expense, the Commission considers that AltaGas should rely on past experience and revise its forecast for 2011 and 2012 based on a three year average of actual bad debt expense

(2008-2010) to account for the variability in historical bad debt expense. AltaGas is directed to revise its bad debt expense accordingly in the compliance filing. .... Paragraph 232

13. Other than the general reductions to FTEs proposed by the UCA related to system betterment costs, interveners did not object to any of the specific additional positions proposed by AltaGas. The Commission has reviewed all of the staff additions requested by AltaGas and considers them to be reasonable with the exception of the proposal to replace the Supervisor IFRS position originally intended to be added in 2011, with an IT support position. The Commission does not approve the addition of an IT support position because the need for this position was not substantiated. The Commission therefore directs AltaGas to remove the costs of the Supervisor IFRS position from the forecast, without the addition of an IT support position. .... Paragraph 254

14. The Commission accepts the UCA submission, which is consistent with Decision 2009-176, that historical average frictional vacancy rates are a reasonable predictor of FTE vacancy rates for the test period. Therefore, the Commission directs AltaGas, in the compliance filing, to incorporate a 2.93 per cent frictional rate in its revenue requirement in 2011 and 2012 respectively. .... Paragraph 259

15. The Commission notes that AltaGas did not respond to the CCA's recommendation with respect to statutory benefits. Due to an absence of evidence and consistent with prior year escalations in EI and WCB, the Commission accepts as reasonable the CCA's recommendation that the total statutory benefits forecast for 2011 and 2012 be reduced by $12,800 in 2011 and $30,800 in 2012. AltaGas is directed to revise its statutory benefits forecast in the compliance filing. .... Paragraph 266

16. The Commission considers that the forecasts for credit card fees should be reduced to reflect the revised timing of the implementation of the credit card payment system. The Commission therefore directs AltaGas to revise these costs to zero in 2011 and $108,000 in 2012 in the compliance filing. .... Paragraph 296

17. Both AltaGas and the UCA agree that a reduction to regulatory fees is warranted. The Commission finds that the adjustments proposed by AltaGas to be reasonable, and directs AltaGas to reflect these adjustments, in the compliance filing...................... Paragraph 301

18. The Commission acknowledges the potentially significant changes in returns which are due in part to market conditions which are outside of the company's control. However, AltaGas has not provided the evidence required with respect to materiality and predictability regarding the need to create a deferral account to capture the experience gains and losses. Therefore, the proposed deferral account is denied. However, the Commission approves the company's requested $200,000 increase in the 2012 forecast revenue requirement to reflect updated pension cost estimates. AltaGas is directed to include in the compliance filing the net $200,000 increase in its 2012 revenue requirement, as estimated by Mercer. .... Paragraph 331

19. The Commission considers that the issues raised by the CCA with respect to AltaGas's forecast costs for third party administration are valid. AltaGas did not provide any explanation to refute the CCA's critique or provide any specific evidence to explain the basis for its 2011 and 2012 forecasts. Therefore, in the compliance filing, AltaGas is directed to incorporate the CCA's recommended reductions to the third party administration plans forecast, as provided in the table above. AltaGas is also directed to

adjust these amounts of $26,532 for 2011 and $26,094 for 2012 for inflation, as suggested by the CCA. .... Paragraph 370

20. The Commission does not, however, approve the forecast for unspecified 2011 and 2012 corporate and tax project consulting expenses allocated to AltaGas. The company has failed to provide a sufficient justification for these costs. The Commission directs AltaGas to reflect this finding in its compliance filing to this decision by reducing the corporate services cost allocation by $97,506 in 2011 and $100,431 in 2012. .... Paragraph 394

21. The best evidence before the Commission in this proceeding is the total direct compensation comparison with three peer groups in the Mercer report that shows AUGI's CEO total direct compensation is above the median of all three peer groups. As such, the Commission directs AltaGas to adjust the compensation amount of AUGI's CEO to reflect the average amount of the median total direct compensation of the three peer groups before calculating the amount to be allocated to AltaGas in the test years. The Commission calculates the average of the median total direct compensation of the three peer groups to be $564,000. .... Paragraph 399

22. As AUGI has no plans to fill the vacant Manager of Corporate Reporting and Control position, the Commission agrees with the UCA that the AUGI costs to be allocated to the utility subsidiaries should be reduced by the costs related to this position for the 2010-2012 test years. AltaGas is directed to remove $134,258 for the vacant Manager of Corporate Reporting and Control position from the company's inter-affiliate costs, for each of the test years, in the compliance filing to this decision. .... Paragraph 402

23. The Commission finds that it is reasonable to use 2010 audited financial results to calculate both AL's composite allocator and AUGI's composite allocator. AltaGas is directed to use 2010 audited financial results for the purpose of calculating these allocators. With respect o the AUGI composite allocator, the Commission accepts that using 2010 audited financial statements results in a composite allocator of 54.45 per cent. Accordingly, AltaGas is directed to use an AUGI composite allocator of 54.45 per cent in the compliance filing. .... Paragraph 415

24. Accordingly, the Commission directs AltaGas to reduce to the allocated amount of AUGI costs arising from the application of the work effort allocator by 10 per cent in each of 2011 and 2012, owing to uncertainty in the level of projects and tasks affecting the calculation of the work effort allocator, and the lack of support provided for it in respect of these test years. .... Paragraph 421

25. The Commission notes that AltaGas and KPMG did not submit evidence with respect to fair market value and provided no evidence as to whether it would be less expensive for AUI to provide the services itself. Although the Commission considers that it may not always be practical, at every GRA, to file evidence or a report that evaluates whether or not it may be less expensive for AltaGas to provide these shared services itself or through a third party, a periodic review would assist the Commission in determining whether the existing shared services agreement is a prudent arrangement. The Commission also considers that Section 3.3.4 of AltaGas's Inter-affiliate Code of Conduct contemplates a periodic review of the prudence of its shared services arrangements. The Commission directs AltaGas to undertake such a review at the time its next filing where inter-affiliate costs are to be considered. .... Paragraph 428

26. Given the above, the Commission is not convinced that the life expectancy of the assets in Account 465 should be altered from 60 years to 57 years. Accordingly, AltaGas is directed to retain the life assumptions for Account 465, as approved in Decision 2009-176, in the compliance filing. .... Paragraph 457

27. Accordingly, AltaGas is directed in the compliance filing to use an Iowa curve of 45-S2.5 to calculate forecast depreciation for Account 467. .... Paragraph 464

28. Accordingly AltaGas is directed in the compliance filing to use a 50-R4 Iowa curve for the purposes of calculating depreciation for Account 473. .... Paragraph 475

29. Accordingly, AltaGas is directed, in the compliance filing to use an Iowa curve of 62.5 R2 to calculate depreciation for Account 475. .... Paragraph 488

30. The change was proposed to maintain consistency between financial and regulatory reporting. Accordingly, if under U.S. GAAP AltaGas intends to use the mid-year convention for the purposes of financial reporting, the Commission approves the use of the applied-for mid-year convention for the purpose of regulatory reporting as well. AltaGas is directed to confirm its intentions with respect to this change in practice in the compliance filing. .... Paragraph 495

31. Given the magnitude of the increases requested by AltaGas, and the fact the results of the mathematical analysis do not support the recommended rates, the Commission does not find that there is sufficient evidence to adopt the net negative salvage values proposed by the company. In the absence of sufficient evidence, the Commission denies the requested increases in net salvage rates for accounts 467 and 473 for the test period and directs AltaGas to include the results of this finding in the compliance filing. .... Paragraph 505

32. The Commission directs AltaGas, as part of the compliance filing pursuant to this decision, to remove the reduction of $1,918,919 it made to its forecast 2010 capital cost allowance claim included on Schedule 6.0 B in the July update. .... Paragraph 526

33. The Commission is not persuaded by the CCA's recommendation that the Commission should consider the ATCO Gas average usage per customer and directs AltaGas to adjust its residential customer segment forecast accordingly. The Commission accepts the company's explanation respecting the differences between its forecast and that of ATCO Gas. The Commission also recognizes the differences in the make-up of the customer classes of the two utilities. Therefore, the Commission approves the company's filed forecast for average consumption per customer for Rate 1/11. .... Paragraph 569

34. AltaGas proposed to recognize the impact of decisions 2011-311 and 2012-013, and the resulting revised 2011 interim rates and the 2012 interim rates in the compliance filing. The Commission is of the view that AltaGas must update its distribution revenue forecast to reflect the amount resulting from interim rates approved in decisions 2011-311 and 2012-013 in the compliance filing, and directs AltaGas to do so. .... Paragraph 581

35. The Commission directs AltaGas to make any necessary adjustments to the service work and special meter read forecasts for 2011 and 2012 to give effect to the inflation rates approved in this decision, and to include the adjusted forecast amounts in the compliance filing. .... Paragraph 601

36. Accordingly, the Commission requires the information regarding how the default supply administration fees included in the GRA application for 2010, 2011 and 2012 were determined. The Commission notes that AltaGas included a calculation in Schedule 6.8 –

Functionalized Customer Accounting – Long Run Avoided Costs as part of its 2008-2009 GRA Phase II filing. The Commission directs AltaGas, in the compliance filing, to prepare and submit a schedule similar in format to Schedule 6.8 of Exhibit 3 of Proceeding ID No. 651, for each of 2010, 2011 and 2012. The Commission also directs AltaGas to show how the resulting daily default supply administration fees included in Schedules 7.1C, 7.1D and 7.1E are calculated from the information shown on the schedules similar in format to Schedule 6.8 for each of 2010, 2011 and 2012 directed above. .... Paragraph 608

37. In the February 28, 2012 exemption application, AltaGas provided details of its proposed solution for implementing a settlement information system along with two alternatives and forecast costs. The Commission directs AltaGas to include this information in the compliance filing and any and all additional updated information the company has, so that the Commission can consider whether to approve the forecast costs to be incurred in 2012 (and any actual costs incurred in 2010 and 2011) in relation to AUI's implementation of a settlement information system that is compliant with Rule 028. .... Paragraph 617

38. In this proceeding, the Commission did not have before it any evidence or submissions which distinguish the proposed AltaGas DSM program from that discussed in Decision 2011-450 or any legal arguments on the applicable statutory provisions. Therefore, the Commission considers that the findings in Decision 2011-450 apply to the proposed AltaGas DSM program. As a result, the Commission finds that there is no legal basis for the proposed DSM program and denies the deferral account requested by AltaGas to capture the design and development costs of a DSM program and directs that such costs be removed from the revenue requirement. .... Paragraph 625

39. The Commission directs AltaGas to revise its 2010-2012 GRA Phase I application to reflect the Commission's findings, conclusions and directions in this decision and to make a compliance filing for its 2010-2012 GRA Phase I application by June 4, 2012. The Commission expects AltaGas, in the compliance filing, to provide a summary of all adjustments made. .... Paragraph 626

Appendix 4 – AltaGas's responses to Commission directions

AltaGas provided responses in Volume 1, Tab 1.0, AUC directives, of the GRA application to Commission directions from prior decisions. The Commission has reviewed the responses and has provided its response regarding compliance as follows.

Directions from Decision 2005-127

AltaGas 2005-2006 General Rate Application Phase I, Application No. 1378000, November 29, 2005

AUC (EUB) Directive 28, paragraph 32

The Board agrees with the CG that the traditional method used by utility companies in Alberta is to base their depreciation rates on the last historical data year available at the time of the preparation of the depreciation study, but considers the inclusion of forecast data does not materially impact depreciation rates. The Board also considers that information that may enhance matching of aged balances to the plant being depreciated may be advantageous. The Board is prepared to accept AUI's methodology that includes forecast balances in its depreciation study for the 2005 and 2006 test years, but directs AUI to justify any future use of forecasts within its depreciation study at its next GRA.

> **AltaGas response to AUC (EUB) Directive 28**
> Please see the attached evidence of Larry E. Kennedy of Gannett Fleming.
>
> **Commission findings**
> The Commission has reviewed the Gannett Fleming evidence on this matter and continues to accept the use of forecast data in AltaGas's depreciation rates. The Commission notes the use of historical versus forecast data in depreciation rates was not an issue in this proceeding. The Commission considers that AUI has complied with this directive.

Directions from Decision 2009-176

AltaGas Utilities Inc., 2008-2009 General Rate Application Phase I, Application No. 1579247, Proceeding ID. 88, October 29, 2009

AUC Directive 16, paragraph 167

Considering the above, that any future STIP amounts can be clearly understood and assessed, the Commission directs AUI, in its next GRA to provide details regarding its STIP forecast for each group of employees that are eligible for this incentive. Further, the Commission directs AUI to also include the following details as noted in Decision 2007-094:

> The explanation and details provided are to include, but not be limited to, clear and measurable targets in each key result area, the method by which AUI calculates its forecast STIP amount, and the results that AUI expects in terms of shareholder and customer value.[84]

[84] Decision 2007-094: AltaGas Utilities Inc. 2007 General Rate Application Phase I Application No. 1494406, December 11, 2007

AltaGas response to AUC Directive 16
Please refer to section 4.1.4 STIP where AUI has incorporated its response.

Commission findings
The Commission considers that AltaGas has provided the required information and has therefore complied with this directive.

AUC Directive 19, paragraph 207

Therefore, the Commission directs AUI in its next GRA to examine the options of obtaining proper indemnification from third-party suppliers and to provide a cost/benefit analysis of expanding its insurance coverage to include events such as restoration of service following a third-party gas supplier's system failure. The assessment should include but not be limited to:

a. the number of third party gas suppliers on AUI's system;
b. the number of such occurrences in the last fifteen (15) years where a third-party's gas supply system has failed;
c. a breakdown of costs actually incurred to repair and remediate service to customers;
d. details respecting any direct or indirect costs incurred by customers due to loss of service; and
e. subsequent recoveries (if any) from the gas supplier(s).

AltaGas response to AUC Directive 19
AltaGas provided a description of the third party gas suppliers on its system, the nature of the third party contracts, a summary of third party supply failures experienced over the last 15 years, the costs associated with those supply failures, the potential and reasons for financial recovery or non-recovery of the costs and several other considerations. AltaGas concluded from this assessment, "given the infrequency of significant outages and the lack of suitable insurance instruments commercially available, additional indemnification from third-party suppliers or additional insurance coverage by AUI do not appear to be viable options.

Commission findings
The Commission accepts AltaGas's assessment and conclusions as reasonable and considers that AltaGas has complied with this directive.

AUC Directive 20, paragraph 208

The Commission finds that the actual costs associated with the restoration of service to customers in the Athabasca area in 2008 were prudently incurred in the provision of utility service and properly belong in AUI's 2008 revenue requirement. Therefore, the Commission rejects CG's recommendation to disallow recovery of the $100,000 Athabasca loss until such time that AUI has exhausted its appropriate legal recourse. However, the Commission directs AUI, at its next GRA, to include details of the outcome of its attempt to get compensation from the third-party which caused the damage.

AltaGas response to AUC Directive 20
The Connecting Operator Agreement (Agreement) between Nova Gas Transmission Ltd. (NGTL) and AUI, dated December 1, 2000, contains a limitation of liability. Specifically, the Agreement states:

> 7. LIMITATION OF LIABILITY
>
> a) ***neither Party shall have any liability*** hereunder to the other Party ***for any claim, demand, suit, action, damage, cost, loss or expense*** which was ***not reasonably foreseeable*** at the time of the act, omission or default; and b) neither Party shall have any liability hereunder to the other Party for any consequential, incidental or indirect damages. {emphasis added by AltaGas}

The incident in question involved costs arising from a gas supply failure at a NGTL connection due to a catastrophic failure in one of NGTL's lines. There was no evidence of prior leaks or failures in the subject area. As the damage was the result of an unforeseeable event, AUI did not commence an action for recovery of costs associated with the outage."

Commission findings
The Commission is of the view that the NGTL limitation of liability clause clearly covers the Athabasca outage and AltaGas made the correct decision not to attempt to recover the $100,000 in costs from NGTL. The Commission therefore considers that AltaGas has complied with this directive.

AUC Directive 21, paragraph 214

However, the Commission directs AUI in its next GRA to provide details of the actual costs incurred for looping the Pincher Creek transmission line.

AltaGas response to AUC Directive 21
In 2007, a rental compressor was installed at a single location to offset the need to loop the Pincher Creek transmission line. Accordingly, AUI did not incur looping costs. However, AUI did incur compressor rental costs of $49,998, $52,610 and $48,839, for the years 2007, 2008 and 2009, respectively, as a least cost alternative.

Commission findings
The Commission accepts AltaGas's decision to use compression rather than loop the Pincher Creek transmission line, as a least cost alternative, and therefore considers that AltaGas has complied with this directive.

AUC Directive 29, paragraph 328

The Commission is aware that AUI will be paying ongoing fees to AUGI for management or other services rendered. The actual amount of those fees that are paid to AUGI on an annual basis is ordinarily not subject to the Commission's determination, unless those fees were to affect the viability of AUI's utility services. However, it is the duty of the Commission to review and assess the reasonableness of the amounts of any such inter-affiliate charges that AUI proposes to be included in its rates. Therefore, because the magnitude of the inter-affiliate shared service fees to be included in AUI's revenue requirement is clearly an ongoing issue the Commission directs AUI, for purposes of its next GRA to provide:

- detailed analyses of the time, charges and description of the services provided for each of the specific operational and financial market services to be rendered by each of the AUGI employees;
- specific details of third party costs incurred by AUGI, which AUI proposes to include in its forecast of revenue requirement for the costs for those services;
- a detailed explanation of the cost drivers of any increases for each specific operational and/or financial market service;
- a detailed explanation of the allocation of CEO and CFO costs between operational and financial market service
- identification of any changes to the methodology of allocating inter-affiliate costs compared to previous applications; and
- an evaluation of the reasonableness of the inter-affiliate costs as per each individual service instead of a conclusion based on a basket of services approach.

AltaGas response to AUC Directive 29
Please refer to section 4.22.1 of the Application. AUI has incorporated its response to this directive in its discussion of Inter-Affiliate, Shared Services costs.

Commission findings
Although AltaGas addressed the Commission's direction from Decision 2009-176 to some extent in this proceeding, the Commission finds that AltaGas, including the evidence filed by KPMG, failed to provide the level of detail requested by the Commission that was required to properly assess the reasonableness of the company's inter-affiliate shared costs. As a result, the Commission finds that AltaGas has not complied with the above direction.

AUC Directive 31, paragraph 332

The Commission notes that no party took issue with AUI's forecasts of inter-affiliate charges for profit and thus will accept AUI's forecasts. The Commission also notes that AUI's Inter-affiliate Code of Conduct states:

> When a Utility acquires For Profit Affiliate Services, it shall pay no more than the Fair Market Value of such services. The onus is on the Utility to demonstrate that the For Profit Affiliate Services have been acquired at a price that is no more than the Fair Market Value of such Services.

For purposes of AUI's next GRA, Phase I, the Commission directs AUI to demonstrate that any inter-affiliate charges for profit included in its forecasts have been priced at FMV.

AltaGas response to AUC Directive 31
AltaGas stated that there are several for profit services that it receives through affiliates, including gas operations and portfolio management, meter re-certification and repair, natural gas transportation, financing and power supply. AltaGas described each of these services, stated that each service was priced at FMV, and explained why the company believed each service was priced at or below FMV.

Commission findings
The Commission has reviewed AltaGas's explanation for each of the for profit inter-affiliate services and is satisfied with the company's explanation with respect to FMV. The Commission therefore is satisfied that AltaGas has complied with the above direction.

Directions from Decision 2010-266
AltaGas Utilities Inc. Application to Issue 2009 Debentures: 7.42 Percent in the Principal Amount of $40,000,000 and 6.94 Percent in the Principal Amount of $20,000,000, Application No. 1605686; Proceeding ID. 418, June 9, 2010.

AUC Directive 1, paragraph 54

The Commission shares the views expressed by the UCA and the CCA that any ramifications the Share Transfer has for debt financing should be examined at AUI's next GRA. As such, the Commission directs AUI to include a full and comprehensive review of AUI's debt financing as part of its next GRA. Specifically, the Commission directs AUI to fully explore and provide a comprehensive analysis of debt financing alternatives that were available to AUI at the time of AUI's Board of Directors resolution, December 3, 2009. The analysis should include the reasons for selecting a preferred option and the reasons for rejecting the others.

AltaGas response to AUC Directive 1
Please refer to section 3.2.1 where AUI has incorporated its response into the details concerning its financing.

Commission findings
The Commission is of the view that AltaGas provided the requested information with respect to the company's debt financing. The Commission therefore considers that AltaGas has complied with this directive.

Directions from Decision 2010-448
AltaGas Utilities Inc. Application to Issue a Debenture in the Principal Amount of $30,000,000, Application No. 1606535, Proceeding ID. 818, September 20, 2010.

AUC Directive 1, paragraph 16

AltaGas Utilities Inc. is directed to provide a detailed explanation of the method used to allocate issue costs of the Debenture to AUI in its next GRA filing.

AltaGas response to AUC directive 1
Please refer to section 3.2.2 where AUI has incorporated its response into the details concerning its issue costs.

Commission findings
The Commission is of the view that the company provided the requested information with respect to the method used to allocate issue costs of the debenture to AltaGas. The Commission therefore considers that AltaGas has complied with this directive.