Alberta Utilities Commission - Decision 2191-D01-2015

2013 Generic Cost of Capital

March 23, 2015

Decision **2191-D01-2015**

Alberta Utilities Commission

100 YEARS of service to Alberta 1915 2015

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2013 Generic Cost of Capital
Proceeding 2191
Application 1608918-1

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1 Introduction

1. On October 18, 2012, the Commission initiated Proceeding 2191, the 2013 Generic Cost of Capital (GCOC) proceeding, by way of a letter requesting comments from interested parties on the scope of the GCOC proceeding. This decision sets out the approved return on equity (ROE) for all affected utilities for the years 2013, 2014, and 2015. This decision also sets out individual deemed equity ratios (also referred to as capital structure) for each affected utility.

2. The affected utilities are:

- AltaGas Utilities Inc. (natural gas distribution)
- AltaLink Management Ltd. (electricity transmission)
- ATCO Electric Ltd. (electricity distribution and transmission)
- ATCO Gas (natural gas distribution)
- ATCO Pipelines (natural gas transmission)
- ENMAX Power Corporation (electricity distribution and transmission)
- EPCOR Distribution & Transmission Inc. (electricity distribution and transmission)
- FortisAlberta Inc. (electricity distribution)
- TransAlta Corporation (transmission assets)

3. In addition to the utilities listed above, there are other utilities under the Commission's jurisdiction that could be affected by this decision, and which were provided an opportunity to participate in this proceeding. These utilities include:

- EPCOR Energy Alberta GP Inc. (regulated retail electricity operations)
- ENMAX Energy Corporation (regulated retail electricity operations)
- Direct Energy Regulated Services (regulated retail electricity and gas operations)
- City of Lethbridge (electricity distribution and transmission)
- City of Red Deer (electricity distribution and transmission)
- Various investor-owned water utilities regulated by the Commission

4. None of these other utilities actively participated in the proceeding. The ROE and debt to equity ratios prescribed in this decision do not apply to EPCOR Energy Alberta GP Inc., ENMAX Energy Corporation and Direct Energy Regulated Services because they are regulated pursuant to the *Electric Utilities Act Regulated Rate Option Regulation*[1] and the *Gas Utilities Act Default Gas Supply Regulation*,[2] respectively. These statutory instruments prescribe methods for the determination of reasonable returns for regulated rate option (RRO) and default supply (DS)

[1] Alberta Regulation 262/2005.
[2] Alberta Regulation 184/2003.

providers, respectively, which address concerns relating to the development and maintenance of competitive retail energy markets in Alberta, and which flow from the implementation of terms and conditions of service applicable to those utilities.

5. The ROE established in this decision will apply to the City of Lethbridge Transmission, the City of Red Deer Transmission and to the revenue requirement established for certain TransAlta Corporation's transmission assets. The Commission has also established target debt to equity ratios for each of these utilities. Specific ROEs and capital structures for the various investor-owned water utilities under the Commission's jurisdiction were not determined in this proceeding because, in the normal course, the Commission only considers these utilities' operations in response to a complaint. However, the determinations made in this proceeding may be considered in any cost of capital determinations applicable to these utilities, should issues respecting the matters of ROE and capital structure arise for these utilities.

6. AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Utilities, ENMAX Power Corporation, EPCOR Utilities Inc. and FortisAlberta Inc., (collectively the Alberta Utilities) after registering individually, filed joint submissions during the proceeding. The remaining parties that were active in the proceeding were the Office of the Utilities Consumer Advocate (UCA), The City of Calgary (Calgary), the Consumers' Coalition of Alberta (CCA), the Canadian Association of Petroleum Producers (CAPP) and TransAlta Corporation (TransAlta).

2 Procedural summary

7. On September 12, 2012, the Commission issued Decision 2012-237[3] which approved the performance-based regulation (PBR) plans for the electric and natural gas distribution utilities: AltaGas Utilities Inc. (AltaGas), ATCO Electric Ltd. (ATCO Electric), ATCO Gas, EPCOR Distribution & Transmission Inc. (EDTI) and FortisAlberta Inc. (FortisAlberta). Decision 2012-237 indicated that any change to the risk profile of affected companies resulting from the onset of PBR would be considered by the Commission in the 2013 GCOC proceeding.[4]

8. On October 17, 2012, a procedural schedule was established for the Commission's generic Utility Asset Disposition (UAD) proceeding (Proceeding 20). The intention was to conclude the UAD proceeding prior to the commencement of the 2013 GCOC proceeding.

9. On October 18, 2012, the Commission issued a letter requesting comments from interested parties on the scope of the matters that should be considered in the GCOC proceeding.

10. On October 26, 2012, the Alberta Utilities submitted to the Commission that their GCOC evidence could not be prepared until final decisions were issued in the PBR Compliance Filings proceeding (Proceeding 2130), the 2013 Capital Tracker Applications proceeding (Proceeding 2131) and the UAD proceeding (Proceeding 20). The UCA supported the Alberta Utilities' submission in this regard. The Commission suspended the GCOC proceeding on November 9, 2012.

[3] Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.

[4] Decision 2012-237, paragraph 710.

11. On April 4, 2013, the Commission directed that the UAD proceeding would be suspended following submission of reply argument from the parties to that proceeding, which was due on June 3, 2013. In this letter, the Commission also resumed the GCOC proceeding, recognizing that the PBR compliance decision had been issued, the capital tracker proceeding was well underway, and because a limited GCOC-related proceeding had been contemplated to consider any UAD impacts that may result from determinations within the subsequently released UAD decision, if required.

12. In response to a submission from the Alberta Utilities filed on April 17, 2013, the Commission determined, by way of a letter dated April 23, 2013, that the decision in the UAD proceeding would be issued after the receipt of reply argument from parties to that proceeding, and without the need for additional GCOC process to finalize the ROE and capital structure. The Commission also confirmed that the established GCOC process schedule would allow three weeks from the release of the later of the Capital Tracker and UAD decisions for utilities to file their evidence in this proceeding.

13. On May 22, 2013, ENMAX Power Corporation and EDTI were granted two-week extensions for filing of their AUC Rule 005[5] filings. This resulted in a corresponding two-week extension of the GCOC process schedule.

14. By way of a letter dated July 15, 2013, the Commission issued the final issues list for the GCOC proceeding following its review and consideration of comments received from parties on June 14, 2013.

15. The UAD decision, Decision 2013-417,[6] and the 2013 Capital Tracker Applications decision, Decision 2013-435,[7] were issued on November 26, 2013 and December 6, 2013, respectively. In response to extension requests for submission of GCOC evidence from Calgary, the UCA and the Alberta Utilities, the Commission revised the GCOC process schedule on December 18, 2013 to provide for the filing of argument and reply argument on July 11, 2014 and August 1, 2014 respectively.

16. On December 19, 2013, the Commission issued Decision 2013-459[8] to establish an interim generic ROE of 8.75 per cent for 2014 and for each subsequent year thereafter until otherwise directed.

17. The GCOC proceeding oral hearing was conducted from May 26, 2014 to June 3, 2014 at the AUC's hearing room in Edmonton, Alberta. The Commission panel for this proceeding was Vice-Chair Mark Kolesar, Commission Member Bill Lyttle and Commission Member Tudor Beattie, QC.

18. During the course of the GCOC hearing, several parties made reference to what they perceived to be the potential significance of the Commission's upcoming decision in Proceeding 2682 on ATCO Electric's 2012 Distribution Deferral Accounts and Annual Filing for Adjustment Balances application. These parties proposed that the Commission's decision in

5 Rule 005: *Annual Reporting Requirements of Financial and Operational Results.*
6 Decision 2013-417: Utility Asset Disposition, Proceeding, Application 1566373-1, November 26, 2013.
7 Decision 2013-435: Distribution Performance-Based Regulation, 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013.
8 Decision 2013-459: 2013 Generic Cost of Capital 2014 Interim Return on Equity, Proceeding 2191, Application 1608918-1, December 19, 2013.

Proceeding 2682 would inform its subsequent assessment of regulatory risk issues germane to the GCOC inquiry.

19. On June 20, 2014, the Commission issued a letter to participants in the GCOC proceeding that included an argument outline. The provided outline referenced the anticipated decision in Proceeding 2682.

20. On June 27, 2014, the Commission issued a letter to interested parties which directed parties to file their respective GCOC arguments and reply arguments by the previously established deadlines of July 11, 2014 and August 1, 2014 respectively, but to omit argument relating to the Commission's pending decision in Proceeding 2682. This correspondence confirmed that instructions would be communicated to the parties to the GCOC proceeding regarding the process for supplemental argument and reply argument, following the issuance of the decision in Proceeding 2682.

21. On October 29, 2014, the Commission issued Decision 2014-297,[9] which concluded Proceeding 2682. Accordingly, on October 30, 2014, the Commission established a supplemental process for submission of argument and reply argument related to Decision 2014-297 to facilitate the close of record for the GCOC proceeding. Supplemental argument and reply argument was subsequently received from parties in accordance with that process.

22. On January 25, 2015, the Commission issued Decision 3100-D01-2015,[10] which concluded proceedings 3100 and 3216, dealing with EDTI's 2013 Capital Tracker True-up Application and 2014-2015 Capital Tracker Forecast Application, respectively. Accordingly, on February 10, 2015, the Commission established a supplemental process for submission of argument and reply argument related to Decision 3100-D01-2015 to facilitate the close of record for the GCOC proceeding. Supplemental argument and reply argument was subsequently received from parties in accordance with that process.

23. Expert evidence was sponsored by a number of parties. The Alberta Utilities sponsored:

- Ms. Kathleen McShane, president and senior consultant with Foster Associates Inc. of Bethesda, Maryland
- Steven M. Fetter, president of Regulation UnFettered, Port Townsend, Washington
- Michael Sloan, principal and senior economist in ICF's Fuels and Technology Group

24. The UCA sponsored:

- Dr. Sean Cleary, Ph. D., Queen's University
- Mr. Russ Bell
- Mr. Mark P. Stauft

[9] Decision 2014-297: ATCO Electric Ltd., 2012 Distribution Deferral Accounts and Annual Filing for Adjustment Balances, Proceeding 2682, Application 1609719-1, October 29, 2014.

[10] Decision 3100-D01-2015: EPCOR Distribution & Transmission Inc., 2013 PBR Capital Tracker True-up and 2014-2015 PBR Capital Tracker Forecast, Proceedings 3216 and 3100, Applications 1610565-1 and 1610362-1, January 25, 2015.

25. CAPP and Calgary individually sponsored:

- Dr. Laurence Booth, D.B.A., University of Toronto

26. Calgary also sponsored:

- Mr. Hugh W. Johnson

27. The Commission considers that the close of record for this proceeding was February 25, 2015, which is the date on which second supplemental reply argument was filed.

28. 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.

3 Overview of the Commission's approach to setting an allowed ROE and capital structure

29. In satisfying the fair return standard, the Commission is required to determine a fair ROE for the utilities under its jurisdiction. In previous GCOC decisions, including the 2011 GCOC Decision 2011-474,[11] the Commission established a generic ROE that uniformly applied to all of the affected utilities. In previous GCOC decisions, the Commission has historically accounted for the existence of particular business risks faced by utilities by making any adjustments to their respective capital structures on either a global, or individual, basis.[12] Such global and individual adjustments to capital structure have also been made concurrently. For example, in its 2009 GCOC decision, the Commission implemented a global two percentage point increase in the equity ratios of the affected utilities in order to account for generally elevated levels of risk and challenging credit market conditions arising from the 2008-2009 financial crisis, and other factors.[13]

30. Similarly, in this decision, the Commission approached setting an allowed ROE and equity structure with a view to providing recognition of changes in the overall levels of risk to which utilities have been exposed since the determination of the 2011 GCOC proceeding, including a consideration of impacts of any additional regulatory risk arising from its implementation of PBR for distribution utilities, its application of principles identified in the UAD decision, or both. The Commission also considers other potential risk factors identified by the Alberta Utilities for electric transmission utilities.

31. In determining a fair ROE for the utilities, the Commission begins, in Section 4, with an evaluation of changes in the global and Canadian financial environment since the conclusion of the 2011 GCOC proceeding. This review of the global and Canadian financial environment is a

11 Decision 2011-474: 2011 Generic Cost of Capital, Proceeding 833, Application 1606549-1, December 8, 2011.
12 See Decision 2009-216: 2009 Generic Cost of Capital, Proceeding 85, Application 1578571-1, November 12, 2009 at paragraphs 77 and 78 and Decision 2011-474 at paragraph 2.
13 Decision 2009-216, paragraph 411.

factor informing the Commission's subsequent determinations of a fair ROE and appropriate capital structures, as discussed in the relevant sections of this decision.

32. Consistent with the approach taken in previous GCOC decisions, the Commission establishes, in Section 5 of this decision, a generic ROE (or generic benchmark ROE), based on its consideration of conventional financial models such as the capital asset pricing model (CAPM), discounted cash flow (DCF) model, and others. The resultant generic benchmark ROE provides a starting point for the subsequent determination of a fair ROE for all affected utilities.

33. Having established the generic benchmark ROE, the Commission considers, in Section 6, the impact of any regulatory risk arising from the UAD decision. and the impact of any regulatory risk arising from the implementation of PBR for the affected distribution utilities. In the same section, the Commission also considers other potential risk factors identified by the Alberta Utilities for electric transmission utilities. Any requirement for adjustments to the generic benchmark ROE, capital structure, or both, are considered in that section.

34. Section 7 of the decision describes the Commission's assessment of the usefulness of an ROE automatic adjustment mechanism. In that section, the Commission also comments on the process to set an allowed ROE after 2015.

35. Capital structure matters are discussed in Section 8 of the decision. The Commission has determined deemed capital structures for each subject utility, which accounts for differences in risk among the individual companies. Approved capital structures of utilities may also be adjusted to account for any regulatory risk arising from the onset of PBR for distribution utilities, the Commission's application of UAD principles, changes in the overall levels of risk to which utilities have been exposed since the determination of the 2011 GCOC proceeding or a combination of these.

36. In this proceeding, the Commission sought parties' views on what ROE should apply on a final basis for 2013, 2014, and 2015, or whether a placeholder for 2015 should be established.[14] As discussed in Section 5.6, all parties in this proceeding put forward their recommendations on the final ROE value for 2015. The Commission is mindful that this decision is being issued in March 2015. Therefore, the Commission has determined that it will establish an ROE and capital structure on a final basis for 2013, 2014 and 2015 in this decision.

4 Relevant changes in global economic and Canadian capital market conditions since Decision 2011-474

37. All parties agreed that current global economic and Canadian capital market conditions have improved since the time of the 2011 GCOC proceeding resulting in Decision 2011-474. The parties, however, disagreed on the amount of risk remaining in capital markets.

38. The Alberta Utilities argued that despite declines since mid-2011, "systemic risks" remained higher than before the 2008-2009 financial crisis, whereas the other parties generally

[14] Exhibit 33.01, the Commission's letter with final issues list dated July 15, 2013.

contended that capital market conditions have stabilized, and that the financial pressures resulting from the 2008-2009 financial crisis have abated.[15]

39. Relying on Ms. McShane's evidence, the Alberta Utilities noted that long Canada bond yields are abnormally low, and submitted that this is not indicative of normal market conditions. They also highlighted the fact that high grade Canadian corporate bond spreads remain similar to those observed in mid-2011, which, in their view, indicates that credit risk has not been perceived to have declined. They further argued that, based on forward earnings/price ratios, the equity market risk premium does not appear to have changed materially since mid-2011.[16]

40. In her evidence, Ms. McShane cited reports by the Bank of Canada and the International Monetary Fund (IMF) to support her position that the risk of market disruptions remains elevated. The Bank of Canada's December 2013 Financial System Review identified a number of "significant vulnerabilities," which included risks stemming from the fragility of the euro-area financial system, Canada's high level of household debt, imbalances in some segments of the Canadian housing market, persistent low interest rates, and other risks from emerging markets.[17] The IMF report expressed similar concerns.[18]

41. Responding to the intervener experts' conclusions regarding the current perception of economic and financial stability, Ms. McShane cautioned that few experts actually predicted the sub-prime mortgage crisis in mid-2007 due to a perception of economic and financial stability that existed at that time.[19]

42. Based on the evidence of Dr. Cleary, the UCA submitted that growth in the Canadian gross domestic product (GDP) following the 2011 GCOC proceeding was lower than forecast because some of the potential risks identified in that proceeding had actually materialized, with the result that long Canada bond yields declined. The UCA also submitted, however, that A-rated utility yield spreads had remained stable since the 2011 GCOC proceeding, which, in conjunction with low long Canada bond yields, allowed A-rated utilities to borrow at declining costs. Despite acknowledging that this had been a challenging period, the UCA argued that the global economy was expected to grow in 2013 and improve significantly in 2014 as a result of recovery in the U.S. economy and modest growth in the Euro zone.[20] The UCA concluded that capital market conditions have stabilized, and the extreme financial pressures resulting from the 2008-2009 financial crisis have long since abated.

43. The UCA acknowledged that the Bank of Canada, in its December 2013 Financial System Review, had identified several key risks including high levels of consumer debt and inflated prices in the consumer housing market, continued uncertainty in the Euro zone, and stagnating export levels. The UCA argued that these risks, however, are not a "huge concern,"[21] nor "extremely elevated,"[22] and "do not appear to have been materially priced into the market."[23]

15 Exhibit 42.02, McShane evidence for Alberta Utilities, page 16.
16 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 16-28.
17 Exhibit 42.02, McShane evidence for Alberta Utilities, page 21, lines 546-567.
18 Exhibit 148.01, Alberta Utilities argument, pages 3-8.
19 Exhibit 148.01, Alberta Utilities argument, paragraph 6.
20 Exhibit 45.03, Cleary evidence for the UCA, pages 10-11.
21 Transcript, Volume 6, page 785, line 25 (Dr. Cleary).
22 Transcript, Volume 6, page 786, line 23 to page 787, line 1 (Dr. Cleary).
23 Exhibit 150.02, UCA argument, pages 1-6.

44. Dr. Booth was retained by both Calgary and CAPP to provide expert evidence regarding capital market conditions. Dr. Booth's evidence[24] [25] provided data concerning market and global conditions which, he argued, were consistent with traditional business cycles (e.g., the inflation rate had been lower than the T-bill rate during the first nine months of 2013). Dr. Booth also submitted that, although the yield spreads between both A and BBB-rated utility bonds and the government bond yield had widened since the previous generic cost of capital proceeding, this was the result of unusually low government bond yields and not attributable to utility bond yields being unusually high. Dr. Booth argued that current capital market conditions do not represent a "new normal," but rather, are indicative of a return to typical and expected economic conditions and business cycles, during a time period in which the U.S. Federal Reserve has eased back on monetary stimulus measures, and the U.S. economy continues to grow. Dr. Booth added that no Alberta utility has had problems raising capital. More specifically, in his assessment, Alberta utilities have been able to raise debt at very low rates for very long terms. As such, Dr. Booth argued there is no reason for the Commission to accept the Alberta Utilities' position that systemic risk is rising.[26]

45. In addressing the Bank of Canada report cited by Ms. McShane, CAPP argued that although the report determined that the overall risk of Canada's financial system remained "elevated," this is the second lowest of the four risk levels identified in the report. CAPP further added that the report indicated that this risk is decreasing.[27]

46. For its part, Calgary added that, despite the Alberta Utilities' argument that "unconventional monetary policy itself" is evidence of the persistence of abnormal economic conditions, no evidence has been provided by the Alberta Utilities that would suggest, for example, the Federal Reserve policy of quantitative easing was still directed at the financial crisis effects, as opposed to addressing normal cyclical economic conditions. Calgary argued that the Alberta Utilities are misattributing actions undertaken in prevailing economic conditions to events that occurred over five years ago. Calgary reiterated that, in its view, the central question is whether the Alberta Utilities have ready access to capital at reasonable rates. Based on its assessment of recent debt issuances undertaken by CU Inc., the parent of the ATCO utilities which issues debt on behalf of those utilities, Calgary argued that the Alberta Utilities are, in fact, currently able to raise debt for unprecedented terms at very low rates.

47. The CCA argued that there has been a significant improvement in global economic and capital market conditions since Decision 2011-474.[28] In response to the Alberta Utilities' observation that no one predicted the last crisis, the CCA replied that "whether anyone predicted the last crisis is largely irrelevant for several reasons. First, as Mr. Fetter pointed out, such one-time events are discounted by the rating agencies and, the CCA would argue, investors. Second, accepting for the moment that it was unpredicted, there is no basis to assume it will re-occur. Third, there is an assumption that if some event happens in the future it will be negative. However, booms typically follow busts as occurred in 2008 so if there is a bias to unpredictable

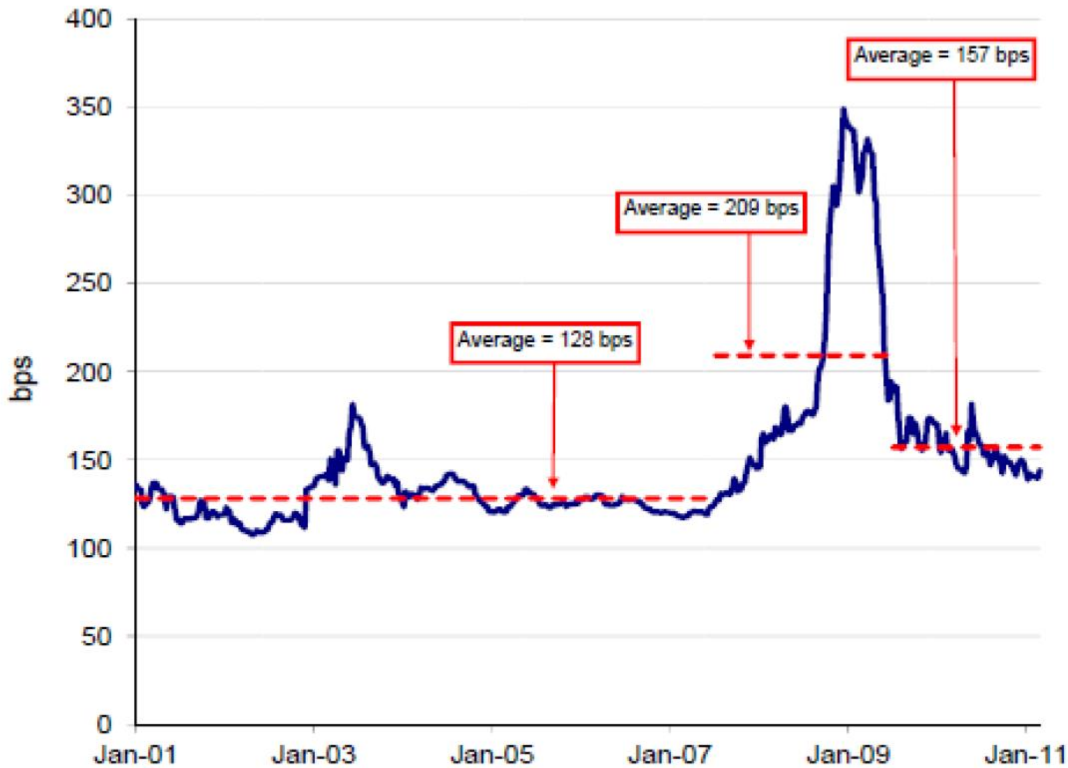
[24] Exhibit 40.02, Booth evidence for Calgary, pages 13-14.
[25] Exhibit 44.02, Booth evidence for CAPP, pages 10-33.
[26] Exhibit 79.02, Booth and Johnson rebuttal evidence for Calgary, page 4, line 15 to page 5, line2.
[27] Exhibit 151.01, CAPP argument, pages 3-7.
[28] Exhibit 149.01, CCA argument, page 5.

outcomes one would expect a positive, rather than negative outcome. Therefore, this assertion should be ignored as reason to maintain or even increase equity thickness or return on equity."[29]

Commission findings

48. In Decision 2009-216, the Commission found that the "considerable amount of uncertainty in the financial markets" resulting from the credit crisis warranted regulatory support.[30] In Decision 2011-474, the Commission found that "by the time of the 2011 hearing, bond spreads had largely, although not completely, returned to historic levels."[31] The Commission has reproduced a chart from Decision 2011-474 to illustrate the circumstances facing the industry during and leading up to the 2009 and 2011 GCOC decisions.

Figure 1 30-year bond spread for Canadian relatively pure-play regulated utilities[32]



49. Having considered the evidence on the record of this proceeding, the Commission finds that global economic and Canadian capital market conditions have improved since the issuance of Decision 2011-474 and that the risks in capital markets are no longer significantly elevated, relative to market conditions prior to the 2008-2009 financial crisis. The Commission agrees with Dr. Booth that current capital market conditions are indicative of a return to typical and expected economic conditions.

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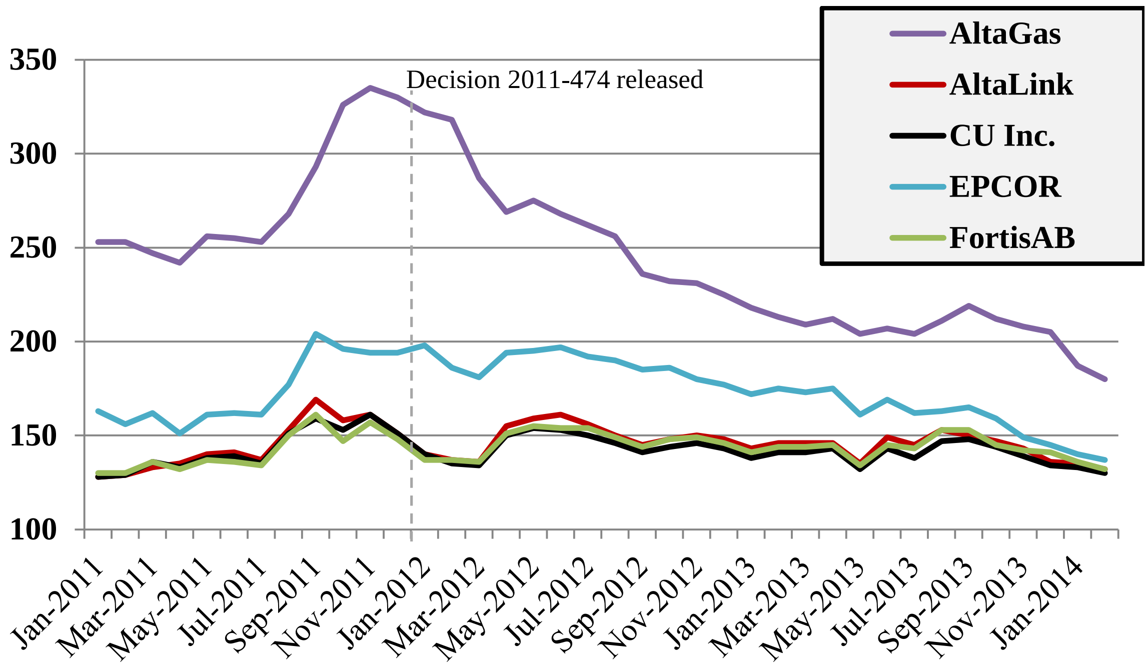
29 Exhibit 152.01, CCA reply argument, page 7.
30 Decision 2009-216, pages 88 and 106.
31 Decision 2011-474, page 7.
32 Decision 2011-474, page 6.

50. Any global economic and capital market risks, such as those considered in the Bank of Canada 2013 Financial Review, have had no perceptible impact on the ability of Alberta utilities to raise capital at reasonable rates to fund growth and operations. As pointed out by Dr. Booth, Alberta utilities have recently been able to raise debt at very low rates for very long terms (e.g., on September 18, 2013, CU Inc. issued 50-year debt at a rate of 4.855 per cent).[33] Further, indicative 30 year credit spreads have remained relatively flat, or have settled lower, since Decision 2011-474 was released, as indicated in Figure 2 below.

Figure 2 Indicative 30-year credit spreads (basis points)[34]



51. In consideration of the foregoing, the Commission finds that the risks in the financial markets observed since Decision 2011-474 have moderated. At the same time, as discussed in Section 5 of this decision, in the current environment when sovereign and commercial borrowers are able to borrow at historically low rates, market conditions may not be reflective of a typical risk-return relationship on which risk-premium models are based.

5 Return on equity

52. In this section, the Commission will establish the generic benchmark ROE, based on conventional methods grounded in financial theory. This generic benchmark ROE will be the starting point for determining an allowed ROE for all of the affected utilities for 2013, 2014 and 2015.

53. The Commission was presented with a significant body of evidence on the tests to be considered when determining a fair generic benchmark ROE and a number of opinions on the proper methodology to be employed in the application of many of these tests. Consequently, the

33 Exhibit 66.01, AUC-Utilities-20, page 4 of 18.
34 Adapted from Exhibit 66.01, AUC-Utilities-20(c).

Commission was also provided with a wide range of proposed ROEs. The record of the proceeding included evidence to support various generic benchmark ROE estimates based on:

- changes in the global and Canadian financial environment since the conclusion of the 2011 GCOC proceeding
- applicability of CAPM methodologies
- applicability of the DCF model, as applied to proxy utilities as well as to the overall equity market
- return expectations of finance professionals such as investment managers, pension fund managers and economists
- market price-to-book values
- DCF-based equity risk premium tests
- historic utility equity risk premium tests
- bond yield risk premium estimates

54. In establishing the generic benchmark ROE, the Commission will consider the evidence in this proceeding on all of these analyses. However, as set out in Section 5.6, the Commission will not give equal weight to the results of every analysis on the record of the proceeding.

55. The Commission's review of the changes in the global and Canadian economic and capital market conditions since the conclusion of the 2011 GCOC proceeding is set out in Section 4 of this decision. The remainder of this decision is organized as follows. Sections 5.1 to 5.5 address each of the remaining factors that the Commission considers to be relevant to the establishment of an appropriate generic benchmark ROE. More specifically, sections 5.1 and 5.2 address the application of CAPM and DCF methods, respectively. Section 5.3 deals with equity price-to-book ratio considerations. Section 5.4 examines return expectations of finance professionals and Section 5.5 addresses other methods of estimating a fair ROE that were employed by various experts who participated in this proceeding. Finally, Section 5.6 summarises the Commission's findings on the generic benchmark ROE for 2013, 2014 and 2015.

5.1 Capital asset pricing model

5.1.1 CAPM methodology and predictive value

56. The CAPM approach is broadly based on the principle that investors' compensation for the use of their capital must recognise two factors: their foregone time value of money and any risk attendant in the investment. The time value of money is represented in CAPM by a component of the required rate of return that corresponds to a risk-free rate, which is intended to represent the return an investor would expect to receive for investing their capital in a risk-free security over a comparable time period. The second part of CAPM incorporates an adjustment to the risk-free rate intended to reflect a premium required to address the risk that an expected return will not be achieved (the market equity risk premium or MERP), and the β, or beta, which is a measure of how sensitive the subject security's required return is to the MERP. Beta is usually derived from an examination of the past statistical relationship between historical returns for a given security and the returns of the overall capital market during the same time period. In this way, CAPM calculates the expected return for a security as the rate of return on a risk-free security plus a risk premium.

57. In general terms, CAPM can be represented by the following formula:

$$Re = Rf + \beta[E(Rm)-Rf],$$

where:

> **Re** is the required return on common equity
> **Rf** is the risk-free rate
> **β**, or **beta**, measures the sensitivity of a required return of an individual security to changes in the market return
> **E(Rm)-Rf** is the market equity risk premium (MERP); i.e., the expected market return E(Rm) minus the risk free rate, Rf

58. Expert evidence supporting various proposed ROEs based on an application of CAPM, or variations thereof, was provided by Ms. McShane for the Alberta Utilities, Dr. Booth for CAPP, and Dr. Cleary for the UCA.

59. In his evidence, Dr. Booth repeated his view on why the CAPM is widely used, also referenced in previous GCOC decisions:

> The CAPM is widely used because it is intuitively correct. It captures two of the major "laws' of finance: the ***time value*** of money and the ***risk value*** of money… [T]he time value of money is captured in the long Canada bond yield as the risk free rate. The risk value of money is captured in the market risk premium, which anchors an individual firm's risk. As long as the market risk premium is approximately correct the estimate will be in the right "ball-park." Where the CAPM normally gets controversial is in the beta coefficient; since risk is constantly changing so too are beta coefficients. This sometimes casts doubt on the model as people find it difficult to understand why betas change. Further it also makes testing the model incredibly difficult. However, the CAPM measures the right thing: which is how much does a security add to the risk of a diversified portfolio, which is the central idea of modern portfolio theory. It also reflects the fact that modern capital markets are dominated by large institutions that hold diversified portfolios.[35]

60. Dr. Booth further indicated that, currently, "the CAPM is overwhelmingly the most important model used by a company in estimating their cost of equity capital."[36] In supporting his position in this regard, he referred to a survey of 392 chief financial officers (CFOs) in the U.S., which indicated that 70 per cent of those surveyed use the CAPM methodology and that a further 30 per cent use a multi-beta variation of the CAPM.[37] Dr. Booth also referred to academic papers that provide empirical support for the CAPM, and pointed to the fact that this model has been accepted by Canadian regulators, including the AUC.[38]

61. Dr. Cleary also provided testimony related to surveys and academic studies showing that CAPM is used by over 68 per cent of financial analysts; over 70 per cent of the U.S. CFOs; and close to 40 per cent of Canadian CFOs. According to Dr. Cleary, "CFOs are using the CAPM for the same purpose as we are – to estimate a firm's cost of equity for cost of capital

35 Exhibit 44.02, Booth evidence for CAPP, paragraph 79.
36 Exhibit 44.02, Booth evidence for CAPP, paragraph 80.
37 Exhibit 44.02, Booth evidence for CAPP, paragraph 81.
38 Exhibit 44.02, Booth evidence for CAPP, paragraphs 81-84.

considerations." Dr. Cleary also commented that CAPM has been "heavily relied upon" by regulators.[39]

62. In contrast, Ms. McShane found Dr. Booth's and Dr. Cleary's focus on CAPM problematic and expressed her preference for other methods to estimate a fair ROE. In support of her view, Ms. McShane stated:

> … One of the three legs of the fair return standard is the comparable investment requirement, i.e., the return available from the application of the invested capital to other enterprises of like risk. The CAPM provides an estimate of what return the investor should require under the restrictive assumptions of the model. It does not tell us what investors do require or expect for comparable risk investments nor does it tell us what returns investors actually are able to achieve in comparable risk investments.[40]

63. Ms. McShane further indicated that "while a high proportion of companies use CAPM to estimate their cost of equity, the hurdle rates companies use for capital budgeting tend to exceed by a large margin what should be their corporate weighted average costs of capital [WACC] if they were using a simple or 'classic' CAPM to estimate their cost of equity." Ms. McShane referenced a survey which found that the actual hurdle rates used by corporations were close to twice the authors' CAPM-based WACC estimates.[41]

64. Therefore, Ms. McShane contended, while a form of CAPM may be widely used, its implementation may be quite different with material adjustments being made to the ROE estimates produced by the simple "classic" three input (risk-free rate, beta and MERP) CAPM. Ms. McShane pointed out that both Dr. Cleary and Dr. Booth made adjustments to their CAPM ROE estimates.

65. Ms. McShane indicated that she did not prefer to use a "classic" CAPM, but rather a "sort of a variant of the CAPM,"[42] which she referred to as a "risk-adjusted equity market risk premium test." In applying her variant CAPM analysis, Ms. McShane also provided two additional estimates of the equity risk premium, which were developed based on a discounted cash flow (DCF) based method and on historically achieved utility equity risk premiums. These two tests are addressed in Section 5.5 of this decision.

66. On the strength of Ms. McShane's evidence, the Alberta Utilities argued that any weighting accorded the CAPM by the Commission in the present proceeding relative to other tests (for example, the DCF analysis) must be significantly reduced. According to the Alberta Utilities, the "unsuitability of the CAPM, in current market conditions, as an indicator of the returns equity investors expect for comparable risk adjustments is widely recognized by witnesses and regulators alike."[43] The Alberta Utilities also echoed Ms. McShane's view that because practitioners and regulators must make material adjustments to the "classic" three input CAPM "expressly to avoid the results it would otherwise produce that would be patently unreasonable," the general validity of this model is questionable.[44]

39 Exhibit 45.03, Cleary evidence for UCA, page 27.
40 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 31.
41 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, pages 32-33.
42 Transcript, Volume 3, page 427, lines 15-16 (Ms. McShane).
43 Exhibit 148.01, Alberta Utilities argument, paragraph 24.
44 Exhibit 148.01, Alberta Utilities argument, paragraph 25.

67. In argument, CAPP supported the view of its expert, Dr. Booth, stating that the "CAPM, while not perfect, is conceptually valid and allows for far less error than other methods such as DCF that have bigger problems and can lead to much bigger errors."[45] The UCA[46] and Calgary[47] supported CAPP's view in this regard.

Commission findings

68. The Commission recognizes that, like any theoretical model, the applicability of CAPM has limitations. For example, as Ms. McShane pointed out, the "CAPM provides an estimate of what return the investor should require under the restrictive assumptions of the model."[48] As further discussed in Section 5.1.4 of this decision, one such restriction is the assumption that equity investors only require compensation for risk that they cannot diversify by holding a portfolio of investments.

69. As previously discussed, Ms. McShane referenced a study showing that, while a high proportion of companies use CAPM to estimate their cost of equity, the hurdle rates these companies use for capital budgeting tend to exceed "by a large margin" the cost of capital estimate obtained from a "classic" three-part CAPM.[49] As such, it appears that the results of a classic CAPM often incorporate material adjustments, when used in practice. However, as discussed during the hearing, caution needs to be exercised when comparing hurdle rates to the CAPM cost of equity estimates, since hurdle rates are often project-specific, whereas the CAPM is intended to estimate the cost of capital for the company as a whole.[50] Ms. McShane acknowledged this issue in her rebuttal evidence:

> One reasonable interpretation of the observed difference between the hurdle rates that corporations use in their capital budgeting versus what they estimate as their CAPM cost of equity is that corporations are not investing in a portfolio of securities, they are investing in irreversible projects that comprise long-term assets.[23]
>
> [23] The authors posit that the difference in the hurdle rates and the WACC reflects the availability of valuable alternative investment opportunities, i.e., the hurdle premium reflects the option to wait for better investment opportunities.[51]

70. Nevertheless, as noted in previous GCOC decisions, CAPM is a generally-accepted and theoretically well-grounded economic model for valuing securities based on the relationship between non-diversifiable risk and expected return.[52] In this proceeding, Dr. Booth indicated that currently, "the CAPM is overwhelmingly the most important model used by a company in estimating their cost of equity capital."[53] Dr. Cleary also indicated that the CAPM is widely used by CFOs, financial analysts and regulators.[54] All the experts who offered ROE evidence in this proceeding relied on some form of the CAPM in developing their ROE recommendation.

45 Exhibit 151.01, CAPP argument, paragraph 14.
46 Exhibit 156.02, UCA reply argument, page 12.
47 Exhibit 157.02, Calgary reply argument, paragraph 29.
48 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 31.
49 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 32.
50 Transcript, Volume 4, page 477, lines 7-12.
51 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 33.
52 Decision 2011-474, paragraph 29; Decision 2009-216, paragraph 223.
53 Exhibit 44.02, Booth evidence for CAPP, paragraph 80.
54 Exhibit 45.03, Cleary evidence for UCA, page 27.

71. In previous GCOC decisions the Commission has found that the CAPM warranted a notable weighting among the alternative models in estimating the allowed ROE. As in Decision 2011-474, the Commission continues to hold the view that CAPM is a theoretically sound and useful tool, among others, for estimating ROE.

72. In considering the evidence on CAPM, the Commission reviewed the proposals on the individual components of CAPM, as well as each party's overall ROE estimate based on the CAPM approach. Each CAPM component, and the overall resulting CAPM estimates of ROE, are addressed in sections 5.1.2 to 5.1.6 that follow.

5.1.2 Risk-free rate

73. The CAPM analysis requires an estimate of the risk-free rate. For practical purposes, a yield on long-term government bonds is most widely used as a proxy for the risk-free rate, although it should be recognized that long-term government bond yields are not entirely risk-free. They are considered to be free of default risk, but are subject to interest rate risk.[55]

74. Ms. McShane, on behalf of the Alberta Utilities, maintained that when one is attempting to estimate the risk-free rate under current market conditions, it is necessary to recognize that "the current level and near-term forecasts of the long-term (30-year) Government of Canada bond yield are at abnormally low levels, but that they are expected to gradually return to more normal levels."[56] Accordingly, in her calculations, Ms. McShane used a risk-free rate estimate of 4.0 per cent, which was the forecast 2014-2016 long-term government of Canada bond yield, based on the October 2013 data from *Consensus Forecasts* by Consensus Economics.

75. Because *Consensus Forecasts* do not provide any projections for the long-term government of Canada bond yields, Ms. McShane estimated the long-term yields by taking the *Consensus Forecasts* for the 10-year government of Canada bond yields and adding a spread of 45 basis points between the long-term and 10-year government of Canada bond yields. Accordingly, Ms. McShane obtained her risk-free estimate of 4.0 per cent as follows:

> Based on the October 2013 Consensus Economics, Consensus Forecasts, the forecast 2014 30-year Canada bond yield is 3.45%, equal to the average of the three-month (2.7%) and 12-month (3.1%) forward consensus forecasts of 10-year Government of Canada bond yields (2.9%) plus the October 2013 actual spread between 30-year and 10-year Government of Canada bond yields (0.55%). The forecasts for 2015 and 2016 are, respectively, 4.1% and 4.6%. They reflect the October 2013 Consensus Forecasts' anticipated 10-year Canada bond yields of 3.6% and 4.1% for 2015 and 2016 plus a spread between the 30-year and 10-year Canada bond yields of 45 basis points. The 45 basis point spread, in turn, represents the average of the recent (December 2013) spread (55 basis points) and the historic average spread (35 basis points).[57]

76. CAPP's expert, Dr. Booth, forecast long-term Canada bond yields for 2014 "to be about 3.60% … as the [U.S. Federal Reserve System's] bond buying program is still depressing interest rates."[58] This forecast was based on the Royal Bank of Canada's interest rate forecast

55 Exhibit 42.02, McShane evidence for Alberta Utilities, page 83.
56 Exhibit 42.02, McShane evidence for Alberta Utilities, page 83.
57 Exhibit 42.02, McShane evidence for Alberta Utilities, footnote 94 on pages 83-84.
58 Exhibit 44.02, Booth evidence for CAPP, page 3.

dated January 10, 2014.[59] However, Dr. Booth also expressed his view that it is necessary to adjust this estimate to account for the fact that Canadian bond yields have been depressed by the "quantitative easing" actions of the U.S. Federal Reserve System (the Federal Reserve), including the "Operation Twist" program, in accordance with which, the Federal Reserve buys U.S. government bonds to drive interest rates down. Therefore, according to Dr. Booth, U.S. and Canadian long-term bond yields are not reflective of the opportunity cost for equity investors at this time. Based on his analysis of the preferred share yield spread over long-term government of Canada bond yields, Dr. Booth estimated the impact of the "Operation Twist" on the Canadian bond market to be an overall reduction in observed yields of approximately 0.40 per cent.

77. Dr. Booth's deliberations on the risk-free rate estimate can be summarized as follows:

> In my judgment risk premium estimates should be based on interest rates that reflect the actions of ordinary investors trading off risk and return, rather than the actions of the global policy maker. By examining preferred share yields, that are not affected to the same degree by the actions of the monetary authorities, I judge a reasonable lower bound estimate of the long Canada yield for 2014 to be 4.00% and use this in my risk premium estimates. The difference between my interest rate forecast and this 4.0% I refer to as my "Operation Twist" adjustment, as the objective of the Fed's bond buying program is to "twist" the shape of the yield curve.[60] [footnote omitted]

78. To estimate the risk-free rate for 2013, Dr. Cleary, on behalf of the UCA, observed with "the benefit of perfect hindsight" that long-term government bond yields averaged 2.8 per cent in that year. Dr. Cleary used this risk-free rate value in his CAPM ROE estimates for 2013.[61]

79. Dr. Cleary stated that, based on his outlook for capital market and economic conditions, his belief is that "it is reasonable to assume that bond yields will increase, albeit slowly, in the coming months. This seems to be the view of most economists in the fall of 2013…"[62] Using the December 2013 Consensus forecasts data, Dr. Cleary estimated an average 10-year government of Canada bond yield to be three per cent for 2014, and 3.2 per cent at the start of 2015. Assuming a 50 basis point spread of long-term bond yields over 10-year yields persists throughout 2014 and 2015, this implies long-term rates be 3.5 per cent and 3.7 per cent for 2014 and 2015, respectively. Overall, Dr. Cleary considered risk-free rates in the range of 2.4 to 3.2 per cent for 2013, 3.1 to 3.9 per cent for 2014 and 3.3 to 4.1 per cent for 2015.[63]

80. The CCA, in its argument, claimed that based on a five-year history, the accuracy of the *Consensus Forecasts* is poor. In comparing forecasted interest rates to actuals at twenty-four points during the five-year time period, the CCA observed only one instance in which a forecast value was lower than an actual interest rate. Consequently, it recommended a downward revision to the *Consensus Forecasts*, "given the recent very poor track record of the Consensus Economic forecasts and the very distinct possibility of continued government intervention to keep interests low."[64] Despite these concerns, the CCA supported Dr. Booth's and Ms. McShane's risk-free forecast of approximately 4.0 per cent.

59 Exhibit 44.02, Booth evidence for CAPP, pages 25-26.
60 Exhibit 44.02, Booth evidence for CAPP, page 3.
61 Exhibit 45.03, Cleary evidence for UCA, page 27.
62 Exhibit 45.03, Cleary evidence for UCA, page 22.
63 Exhibit 45.03, Cleary evidence for UCA, pages 22 and 27.
64 Exhibit 149.01, CCA argument, paragraph 9.

81. In her rebuttal evidence, Ms. McShane took issue with Dr. Cleary's use of the actual long-term government of Canada bond yield of 2.8 per cent for 2013 in his application of the CAPM. Ms. McShane held the view that long-term government of Canada bond yields "have been kept abnormally low due in large part to ongoing unconventional monetary policy."[65]

82. The Alberta Utilities submitted that Dr. Cleary had, in his analysis, failed to "recognize that the abnormally low recent and current levels of long-term Canada bond yields do not reflect the ordinary investor trade off of risk and return."[66] The Alberta Utilities also pointed out that two Canadian regulators have accepted "normalized" risk-free rate forecasts, recognizing the abnormal risk-return relationship for long-term government of Canada bond yields.[67]

83. During the hearing, Dr. Cleary addressed this point as follows:

> … I do acknowledge that monetary policy has played a role in this, particularly in the US. But again, I think coming from the point of investor, and if you look at the models and you look at the DCF models or the bond yield plus risk premium, or you don't even look at the models, and you think of how an investor thinks, they think about what I can earn on a bond today. The fact that it should be 4 percent isn't -- it's nice to know but it is 3 percent.[68]

84. Further, according to Dr. Cleary, there is no disconnect between the equity markets and the debt markets. In Dr. Cleary's view, "the equity markets pay very close attention to what's available on the bond markets and *vice versa*."[69] Based on this evidence, the UCA submitted that Dr. Cleary's recommended risk-free rates "accurately reflect the current and forecast state of the market which align with the purpose and rationale underlying the CAPM approach."[70]

85. Finally, both the UCA[71] and CAPP[72] pointed to the fact that Ms. McShane has adjusted, or "normalized" her risk-free rate estimate to account for abnormally low interest rates, while simultaneously adjusting the MERP to account for lower government of Canada bond yields. In the views of both the UCA and CAPP, in adjusting *both* the risk-free rate and MERP aspects of the CAPM, Ms. McShane has, in fact, accounted for any impact of the low interest rate environment twice.

Commission findings

86. In past GCOC decisions, the Commission considered it reasonable to rely on the Consensus Economics *Consensus Forecasts* of long-term government of Canada bond yields to estimate the risk-free rate. However, the Commission is mindful that, as the CCA pointed out, caution needs to be exercised when using the *Consensus Forecasts* outlook, because this forecast appears to have mostly overestimated the yields on long-term government bonds in the 2010 to 2014 period.[73] For example, as observed in response to Commission's IRs, the *Consensus Forecast*-based risk-free rate estimates of 3.8 per cent to 4.3 per cent accepted in the

[65] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 35.
[66] Exhibit 148.01, Alberta Utilities argument, paragraph 41.
[67] Exhibit 148.01, Alberta Utilities argument, paragraphs 42-43.
[68] Transcript, Volume 5, page 739, lines 5-13 (Dr. Cleary).
[69] Transcript, Volume 5, page 739, lines 17-21 (Dr. Cleary).
[70] Exhibit 150.02, UCA argument, page 9.
[71] Exhibit 150.02, UCA argument, page 12.
[72] Exhibit 151.01, CAPP argument, paragraph 30.
[73] Exhibit 149.01, CCA argument, paragraphs 2-3.

2011 GCOC proceeding proved to be much higher than actual rates experienced during that time period.[74] The Commission also observes that, in the time period preceding the close of the evidentiary record for this proceeding on August 1, 2014, long-term government of Canada benchmark bond yields have continued to decline.[75]

87. Ms. McShane's evidence indicated that, based on the October 2013 *Consensus Forecasts*, the 10-year government of Canada bond yield was estimated to be 2.9 per cent in 2014 and 3.6 per cent in 2015.[76] However, the more recent April 2014 *Consensus Forecasts* estimated the 2014 rate to be 2.7 per cent, and the 2015 rate to be 3.2 per cent.[77] Adding the historical spread of approximately 50 basis points between the 10-year and the long-term bond yields results in a long-term risk-free forecast of 3.2 per cent for 2014 and 3.7 per cent for 2015.

88. Both Ms. McShane[78] and Dr. Booth[79] adjusted their risk-free estimates upwards to account for the fact that current interest rates are abnormally depressed due to the effects monetary policy which, in effect, create a situation where government long-term bond yields do not accurately reflect the expectations of equity investors with respect to risk and return trade-offs. However, in an exchange with the Commission during the hearing, Ms. McShane acknowledged that developed countries, even those with elevated sovereign debt risks such as Italy and Spain, are currently borrowing at 10-year rates below three per cent:

> Q. But then -- so I look at it and I see the 4 percent and I think okay, it's out of sync with what's going on. So I looked up my little Wall Street Journal page of 10-year bond rates and I go, Okay, US 10 years, 2.44; German 10 year, 1.35; Italy a bastion of fiscal discipline, 2.94; Japan 0.57. These are all ten-year rates. Spain 2.84 -- I think they almost went bankrupt; the UK 2.55; and Canada as of yesterday in the ten year, although we have evidence for 2.3 -- it seems to be still railing -- at 2.22. So, suddenly, it's not the Canadian rates. You're talking the risk-free rate of 4 percent. We're talking a global doubling of interest rates, not just a Canadian doubling of interest rates in the long run. You're talking a global doubling of interest rates before the reality of that 4 percent number is even near.
>
> A. MS. MCSHANE: So you're right, the low government bond rate is not just a Canadian phenomenon. It is a worldwide phenomenon that is reflective of attempts by central banks to keep rates low. And, again, I mean, the bond issuers have benefited from that behaviour.[80]

89. Ms. McShane also confirmed that Alberta utilities are borrowing at low rates and "the utilities have been -- and other debt issuers -- have been the beneficiaries of the low long-term government bond yields."[81]

90. The Commission agrees with Dr. Cleary's view that "the equity markets pay very close attention to what's available on the bond markets and *vice versa*."[82] In circumstances where

74 See, for example, preamble to Exhibit 68.02, AUC-UCA-2.
75 http://www.bankofcanada.ca/rates/interest-rates/canadian-bonds/
76 Exhibit 42.02, McShane evidence for Alberta Utilities, Table 4 on page 22.
77 Exhibit 114.01, undertaking by Ms. McShane to Mr. Finn.
78 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 35.
79 Exhibit 44.02, Booth evidence for CAPP, page 3.
80 Transcript, Volume 4, page 539, lines 2-21 (Ms. McShane).
81 Transcript, Volume 4, page 538, lines 18-20 (Ms. McShane).
82 Transcript, Volume 5, page 739, lines 17-21 (Dr. Cleary).

sovereign and commercial borrowers are able to borrow at historically low rates, the Commission does not accept that a CAPM analysis should be based on a "normalized" risk-free rate of 4.0 per cent, which represents what *should* have been in place to reflect investor risk-return expectations. As Dr. Cleary pointed out, "you think of how an investor thinks, they think about what I can earn on a bond today. The fact that it should be 4 percent isn't – it's nice to know but it is 3 percent."[83]

91. The Commission also agrees with the submissions of the UCA[84] and CAPP[85] that Ms. McShane's adjustment to both her risk-free rate estimate and MERP components of the CAPM to account for the abnormally low interest rates has the potential to result in over-compensation for the current low interest rate environment.

92. The Commission considers that it is preferable to base the risk-free estimate on the observed and expected long-term government bond rates, and account for any residual credit spread concerns by way of an adjustment to the MERP estimate, rather than adopt a normalized risk-free rate that is not adequately reflective of the actual interest rate environment. In adopting this approach, the Commission notes that all three experts agreed that adjusting the MERP is another way of dealing with an abnormal risk-return relationship triggered by ultra-low long-term bond yields.[86]

93. Based on the foregoing, the Commission considers the actual long-term rate of 2.8 per cent[87] in 2013 to be a reasonable lower bound estimate for the risk-free rate in its current analysis. Likewise, the latest *Consensus Forecasts* of 3.7 per cent for 2015 (as of April 2014) represents a reasonable upper bound of the risk-free rate. The Commission further notes that, in all likelihood, the adopted upper bound estimate may be optimistic, given that, based on recent history, the return to the long-term interest rate levels may not occur as quickly as the *Consensus Forecasts* predicted in April 2014.

5.1.3 Market equity risk premium

94. The next element of the CAPM analysis is the market equity risk premium, or MERP. The MERP value is not directly observable but can be estimated as the difference between estimates of the expected market return and the risk-free rate. The interveners' and the Alberta Utilities' experts in this proceeding differed in their estimates of the MERP.

95. Ms. McShane's MERP estimate was formulated on the basis of historic return and risk premium data drawn from both Canadian and U.S. capital markets. As Ms. McShane explained, this approach is premised on the notion that investors' return expectations and requirements are linked to their past experience. Analyzing the total equity return less bond income returns for the two long-term historic periods from 1924 to 2012 and 1947 to 2012, Ms. McShane arrived at an average achieved risk premium of approximately 5.0 per cent to 5.5 per cent for Canada and 6.5 per cent to 6.75 per cent for the U.S.[88]

83 Transcript, Volume 5, page 739, lines 11-13 (Dr. Cleary).
84 Exhibit 150.02, UCA argument, page 12.
85 Exhibit 151.01, CAPP argument, paragraph 30.
86 Transcript, Volume 3, page 430, line 3 to page 431, line 19 (Ms. McShane); Exhibit 68.02, AUC-UCA-4; Exhibit 63.02, AUC-CAPP-4.
87 Exhibit 45.03, Cleary evidence for UCA, page 27.
88 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 87-88.

96. Ms. McShane observed that the MERP is not a fixed quantity; it changes with investor experience and expectations. Based on her analysis of historical bond income returns, Ms. McShane concluded that, on a cumulative average basis, lower bond income returns have been associated with higher achieved risk premiums: "In other words, the historical data are consistent with the conclusion that the market equity risk premium is higher at lower levels of bond yields and vice versa."[89]

97. Ms. McShane also analyzed the historical relationship between inflation and real equity returns, as well as other return considerations related to the MERP. Overall, Ms. McShane concluded from her analysis:

> Given the absence of any material upward or downward trend in the nominal historic equity market returns over the longer-term, the P/E ratio analysis, the higher achieved risk premiums at lower levels of government bond yields and the observed generally negative relationship between real equity returns and inflation, a reasonable estimate of the expected value of the equity market risk premium is a range of 7.0% to 7.5% (mid-point of 7.25%) at the forecast 4.0% 30-year Government of Canada bond yield. The indicated risk premium based on an analysis of the U.S. data supports an equity risk premium of approximately 7.0% to 8.5%. With preponderant weight given to the Canadian data, the indicated equity market risk premium at the forecast 4.0% Government of Canada bond yield is a range of 7.0% to 7.5% (mid-point of 7.25%). The corresponding indicated equity market return is 11.25%.[90]

98. Dr. Booth, on behalf of CAPP, estimated that long-term historic data suggests an experienced MERP in Canada of 5.0 per cent, and indicated that a range of 5.0 to 6.0 per cent was reasonable.[91] In developing this estimate, Dr. Booth gave weight to the U.S. evidence, since, with the removal of most restrictions on capital flows in Canada, the risk premium in Canada has moved closer to that in the U.S. In arriving at this conclusion, Dr. Booth also considered the results of an academic survey of professors of finance, financial analysts and companies.[92]

99. Dr. Booth also added 26 basis points to his risk premium estimates to account for elevated credit spreads. In response to a Commission IR concerning whether this adjustment can be reasonably incorporated in the MERP component, Dr. Booth stated:

> If the AUC accepts Dr. Booth's recommendation he would be happy to collapse the credit spread adjustment into the overall market risk premium as the AUC did in paragraph 128 of Decision 2011-474. However, conceptually Dr. Booth would not agree with this. The idea of the credit spread is that the overall market risk premium is relatively stable, but through the business cycle there are periods of pessimism and optimism that affect the fair rate of return and this is what is captured in the credit spread adjustment. It essentially makes the risk premium a conditional risk premium estimate and Dr. Booth would prefer it to be separate for consistency with his ROE adjustment methodology recommendations.[93]

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89 Exhibit 42.02, McShane evidence for Alberta Utilities, page 90.
90 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 96-97.
91 Exhibit 44.02, Booth evidence for CAPP, paragraph 90.
92 P. Fernandez et al, Market Risk Premium and Risk Free Rate used for 51 Countries in 2013: A Survey with 6,237 Answers. June 26, 2013.
93 Exhibit 63.02, AUC-CAPP-4(a).

100. Dr. Cleary indicated that the MERP, over the 1900 to 2010 period, averaged 5.3 per cent in Canada and 6.4 per cent in the U.S., as measured by the market return less the long-term government bond total yield. Based on this information, as well as the referenced survey by Professor Fernandez (also referred to by Dr. Booth), Dr. Cleary made the following recommendation for the MERP value to be used in the CAPM ROE estimate:

> Based on the previous discussion of capital markets, which seem to be in a reasonably stable state today; it is reasonable to assume that market participants would be satisfied with a figure slightly above the long-term average of 5.3% MRP. Therefore, I will use 5.5% as my best estimate for 2014 and 2015, and consider a range of 5 to 6%. At the start of 2013, more uncertainties existed, so I will use 6% - at the upper bound of the commonly used range, and historical figures. These estimates lie within the 4 to 6 percent range that is normally used, and is consistent with long-term averages. This seems appropriate in today's environment, where economic and market conditions are fairly stable; albeit not overwhelmingly positive. One would normally use 6 percent when market uncertainty is high, and lean toward values in the 4 to 5 percent range during periods of extreme market and economic optimism.[94]

101. Dr. Cleary also included a 0.2 per cent "yield spread" adjustment to his CAPM estimates to account for the variation in the risk premium over time.[95] In response to a Commission IR, the UCA indicated that using "an above average MERP has the same effect as making the adjustment that he [Dr. Cleary] recommended, and is also an appropriate way to deal with abnormally high yield spreads."[96]

102. The main point of disagreement among the experts in this proceeding regarding the MERP was the issue of whether the MERP should be estimated as the total equity return less bond *income* returns, (as advocated by Ms. McShane), or the total equity return less bond *total* returns (as advocated by Drs. Cleary and Booth).[97] Since bond income returns were smaller than bond total returns over the studied period, Ms. McShane's MERP estimates using bond income returns were higher than Dr. Booth's and Dr. Cleary's estimates. In support of their positions, the experts referenced several academic publications supporting their respective views on this matter.[98]

103. Addressing a related issue, Dr. Cleary pointed out that Ms. McShane used arithmetic averages in her MERP estimates, rather than geometric averages, despite acknowledging that "there are analysts who use geometric averages or some combination of geometric and arithmetic averages to estimate the market risk premium and cost of equity from historic data."[99] Dr. Cleary showed that, while using bond total returns would lower Ms. McShane's MERP estimate from

94 Exhibit 45.03, Cleary evidence for UCA, page 29.
95 Exhibit 45.03, Cleary evidence for UCA, page 31.
96 Exhibit 68.02, AUC-UCA-4(a).
97 As Ms. McShane explained in her evidence, Exhibit 42.02, page 87, the "bond total return includes annual capital gains or losses and reinvestment of the bond coupons, i.e., it incorporates the interest rate risk that is inherent in a government bond. The bond income return reflects only the coupon payment portion of the total bond return." Dr. Booth preferred to refer to bond income returns as 'bond yields.'" (Transcript, Volume 7, page 1077, lines 18-19).
98 Exhibit 66.01, AUC-Utilities-8(b); Exhibit 68.02, AUC-UCA-7(b); Exhibit 63.02, AUC-CAPP-6(b).
99 Exhibit 73.01, UCA-Utilities-29(a) and (b).

5.4 per cent to 4.8 per cent, using geometric averages in place of arithmetic averages would further reduce Ms. McShane's historical MERP estimate to 3.8 per cent.[100]

104. Dr. Booth also expressed a concern with Ms. McShane's use of the current yield on long-term government bonds and the current rate of inflation in her MERP estimates:

> In answer to [Exhibit No. 70.01] CAPP-Utilities McShane 11(b) and (e), Ms. McShane provided the underlying data behind this analysis. What is clear is that what she has estimated is the *contemporaneous* relationship between the one-year actual equity return and the long Canada bond yield at that time. That is, her analysis does not show a relationship between the expected market risk premium for a future time period and the current level of the long Canada bond yield. To show this relationship, that is what is the expected market risk premium at the current low long Canada bond yields, we need the level of the long Canada bond yield at time t and the realised market risk premium over a subsequent, say ten year, period. If this were done the last observation would be for the bond yield in 2002 and the earned market risk premium for the period 2003-2012, rather than 2012 for 2012. I would regard the data in Tables 14 and 15 as being inappropriate with no implications for the current market risk premium.[101]

Commission findings

105. With respect to the issue of whether the bond total return or bond income return should be used in the MERP estimates, the Commission stated in Decision 2011-474 that it was not "convinced that it should base the market equity risk premium on bond income-only returns, rather than bond total returns, which is the traditional approach."[102] However, experts in this proceeding referenced several academic publications ostensibly supporting their contrary views on whether bond total returns or bond income returns should be used for estimating the MERP.[103] The academic debate on this issue appears to be unsettled. Therefore, for purposes of this proceeding, the Commission accepts that both methods may inform its judgment on the range of MERP values.

106. There is also ongoing disagreement among the expert witnesses regarding employing geometric or arithmetic averages in generating MERP estimates,[104] whether contemporaneous or forward-looking risk premiums should be used,[105] and the probative value of historical data suggesting that investors' return expectations and requirements are linked to their past experience.[106]

107. Although Ms. McShane recommended MERP values that were different from those recommended by Drs. Booth and Cleary, and employed different estimation techniques, the Commission recognizes that all three experts have largely relied on comparable long-term data, and produced similar historical estimates, before applying their expert judgment. Specifically, the long-term U.S. and Canadian capital markets data (with preponderant weight given to Canadian data) used by Ms. McShane,[107] Dr. Booth[108] and Dr. Cleary,[109] implies an average long-

100 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 6.
101 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 18.
102 Decision 2011-474, paragraph 51.
103 Exhibit 66.01, AUC-Utilities-8(b); Exhibit No. 68.02, AUC-UCA-7(b); Exhibit No. 63.02, AUC-CAPP-6(b).
104 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 6.
105 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 18.
106 Exhibit 42.02, McShane evidence for Alberta Utilities, page 86.
107 Exhibit 42.02, McShane evidence for Alberta Utilities, page 88.

run MERP in the range of approximately 5.0 to 6.0 per cent. Therefore, the Commission finds that a long-run historical MERP of 5.0 per cent continues to be a reasonable lower bound for the MERP to be used in the CAPM analysis.

108. In Decision 2011-474, the Commission observed that "it does not appear that the market equity risk premium is constant or independent of the level of interest rates, which is what is implied when an historic equity risk premium is applied to today's low interest rates. This calls into question the use of long-term historic market equity risk premiums without regard to the current level of interest rates."[110] In the same decision, the Commission determined that "the expected market equity risk premium today may be higher than its' historic average, due to today's low interest rates."[111]

109. In this proceeding, Ms. McShane concluded that "the historical data are consistent with the conclusion that the market equity risk premium is higher at lower levels of bond yields and vice versa."[112] Dr. Cleary[113] and Dr. Booth[114] have also generally accepted this proposition, although they cautioned that the relationship between MERP and the interest rate level is not a mechanical cause and effect relationship. Further, there may be other factors that lead to the MERP fluctuating over time, and only some of those factors may be reflected in the level of interest rates.

110. As discussed in Section 5.1.2, at an average of 2.8 per cent, the government of Canada long-term bond yield remained near historic lows in 2013, and is forecast to move up to 3.2 per cent and 3.7 per cent in 2014 and 2015, respectively. In these circumstances, the Commission finds it is reasonable to assume that the currently expected MERP may be higher than its long-term average value of 5.0 to 6.0 per cent.

111. Drs. Cleary and Booth recommended using a MERP in the range of approximately 5.0 to 6.0 per cent, based on the observed long-run values. Both of these experts also included some additional adjustments to their CAPM results. Dr. Cleary included a 0.2 per cent "yield spread" adjustment to his CAPM estimates for 2013 to account for the variability of risk premiums over time,[115] and Dr. Booth added 26 basis points to his risk premium estimates to account for elevated credit spreads. As well, as discussed in Section 5.1.2, Dr. Booth added a 40 basis point "Operation Twist" adjustment to his risk-free rate estimate. In total, Dr. Booth recommended adding 66 basis points to his "simple" CAPM estimates.[116]

112. In Decision 2011-474, the Commission stated the following with respect to adjusting the CAPM results to account for bond spreads:

> 128. … the Commission considers that spreads have decreased from the 2009 levels but have not returned to their historic levels. The Commission also notes that it has set the top end of its CAPM market equity risk premium, assuming, on the basis of Ms.

[108] Exhibit 44.02, Booth evidence for CAPP, paragraph 90.
[109] Exhibit 45.03, Cleary evidence for UCA, page 29.
[110] Decision 2011-474, paragraph 56.
[111] Decision 2011-474, paragraph 58.
[112] Exhibit 42.02, McShane evidence for Alberta Utilities, page 90.
[113] Exhibit 68.02, AUC-UCA-3(a) and (b).
[114] Exhibit 63.02, AUC-CAPP-3(a).
[115] Exhibit 45.03, Cleary evidence for UCA, page 31.
[116] Exhibit 44.02, Booth evidence for CAPP, paragraph 143.

> McShane's evidence, that the market equity risk premium may be higher than its historic average at this time of historically low interest rates. For these reasons, the Commission is not convinced that any addition to CAPM results is needed to account for the reduction in corporate bond spreads at this time.[117]

113. Consistent with its above-referenced findings in Decision 2011-474, and as set out in Section 5.1.2 of this decision, the Commission prefers to account for residual credit spread concerns by way of adjusting the MERP estimate, rather than adjusting the risk-free rate, or adding a separate component to CAPM. Given the beta range of 0.50 to 0.65 that the Commission finds to be reasonable in Section 5.1.4 of this decision, the adjustments proposed by Dr. Cleary and Dr. Booth imply that their MERP estimates should be increased by some 40 to 100 basis points.[118] In the Commission's assessment, this results in MERP estimate of 5.4 per cent to 7.0 per cent.

114. Ms. McShane estimated that the MERP, based on her forecast 4.0 per cent long term Canada bond yield, was 7.0 per cent to 7.5 per cent or, using the mid-point, approximately 7.25 per cent.[119] The Commission notes that this was the same value that Ms. McShane recommended in the 2011 GCOC proceeding, and which the Commission accepted as the higher end of its MERP estimate in Decision 2011-474.[120] However, as set out in Section 4, the Commission considers that market conditions have moderated since the time of the 2011 GCOC decision. Therefore, the Commission also considers the higher end of the MERP estimate should be somewhat lower than the 7.25 per cent that the Commission accepted in 2011.

115. For all of these reasons, the Commission finds that the current MERP may reasonably be as assumed to be higher than its historic average of 5.0 to 6.0 per cent, due to low interest rates. The Commission also accepts that current MERP expectations may reasonably be as high as 7.0 per cent, based on the lower range of Ms. McShane's estimate, and taking into account the adjustments to CAPM put forward by Drs. Cleary and Booth. Considering all of the above, the Commission finds that a reasonable range for the MERP is 5.0 per cent to 7.0 per cent.

5.1.4 Beta

116. Another element of the CAPM analysis is the beta value. In the CAPM, beta is a statistical measure describing the relationship of a given security's return with that of the equity market as a whole. In essence, beta measures the market risk of a security.[121] Past data (with or without adjustment) is normally used to estimate the reasonably expected beta going forward. In the Commission view, an appropriate beta to use is one which reasonably represents the relative risk of stand-alone Canadian utilities.[122]

117. Dr. Cleary observed that, based on previous decisions of Canadian regulators and expert testimony in other proceedings, as well as his own research, long-term betas for the subject utilities appear to approximate 0.5. Dr. Cleary calculated average betas using monthly total return data for the TSX Utilities Index over the 1988 to 2012 period. In doing so, he arrived at a

117 Decision 2011-474, paragraph 128.
118 As explained Exhibit 63.02, AUC-CAPP-4(b), this range was obtained by dividing the proposed credit spread adjustments (in basis points) by the Commission-approved beta values: 20/0.5=40 and 66/0.65=102.
119 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 96-97.
120 Decision 2011-474, paragraph 58.
121 Exhibit 45.03, Cleary evidence for UCA, page 27.
122 Decision 2011-474, paragraph 60.

beta estimate of 0.29 using data for the entire 25-year period. With respect to the last two periods in his sample (2003 to 2007 and 2007 to 2012), he indicated that "the recent utility index beta has been about 0.4, below the long-term average of 0.5, and at the lower end of the typical range used for utilities."[123] Dr. Cleary also calculated beta estimates for several Canadian utilities as of December 20, 2013, based on 60 months of returns and arrived at an average beta of 0.25.

118. Dr. Cleary concluded that "it seems clear that a reasonable estimate of beta for a typical Alberta utility should lie within the 0.30 to 0.60 range. I will use the mid-point figure of this range of 0.45 as my best point estimate, which is slightly below the long-term average of around 0.50."[124]

119. On behalf of CAPP, Dr. Booth stated that he would not use recent beta estimates in his analysis, which in his judgment continue to reflect the aftermath of the financial crisis. Dr. Booth continued to support the adoption of a range 0.45 to 0.55 for betas of Canadian stand-alone utilities. His position in this regard was based on long-run beta estimates, and was the same range as he recommended in the 2009 and 2011 GCOC proceedings.[125] Dr. Booth supported his position through an examination of: the relative risk of utility holding companies (which are near the 0.30 level and still below the 0.50 level that utility stocks had 10-15 years ago); the TSX utility sub-index (which he found to be just above 0.40); the stock market performance of Canadian utilities as a group (and specific Canadian utilities as safe havens) during the financial crisis; and the low risk U.S. utilities referenced in the Alberta Utilities' expert evidence. As a further check, he also compared Canadian utility companies to the U.S. S&P 500 index.[126]

120. In its argument, Calgary supported Dr. Booth's beta recommendations based on long-run values as being "a conservative estimate for use in the CAPM calculation."[127] The UCA, in its argument, supported the beta estimates advanced by both Dr. Cleary and Dr. Booth.[128]

121. Ms. McShane noted that according to the theory behind the CAPM, equity investors only require compensation for risk that they cannot diversify by holding a portfolio of investments and that in the simple, single risk variable CAPM, the non-diversifiable risk relative to the market as a whole is measured by beta. Ms. McShane offered several criticisms of the theory behind the CAPM model in this regard. For example, Ms. McShane expressed her view that total risk, and not just diversifiable risk, should be considered for an undiversified investment, such as a utility investing capital in long-term assets. Ms. McShane also contended that the observed historical betas are not good predictors of required, or expected, returns. Therefore, instead of estimating a "single risk variable beta," Ms. McShane focused on what she termed a "relative risk adjustment," which took into account her CAPM criticisms.[129]

122. First, Ms. McShane estimated the relative total market risk of utilities by looking at the ratio of the standard deviation of the S&P/TSX Utilities Index to the mean and median standard

[123] Exhibit 45.03, Cleary evidence for UCA, page 30.
[124] Exhibit 45.03, Cleary evidence for UCA, page 31.
[125] Exhibit 44.02, Booth evidence for CAPP, paragraph 116.
[126] Exhibit 44.02, Booth evidence for CAPP, pages 41-46.
[127] Exhibit 146.02, Calgary argument, paragraph 15.
[128] Exhibit 150.02, UCA argument, page 13.
[129] Exhibit 42.02, McShane evidence for Alberta Utilities, pages 97-98.

deviations of indexes for the 10 major sectors.[130] Application of this method suggested a risk adjustment to the market risk premium of 0.65 to 0.70.[131] Second, Ms. McShane undertook a regression analysis to determine the extent to which the calculated utility betas historically understated experienced returns. In isolation, that analysis demonstrated that a relative risk adjustment for a utility of approximately 0.75 is warranted.[132] Third, Ms. McShane used the adjusted betas published by two investment research firms, Bloomberg and Value Line (which give approximately two-thirds weight to the calculated "raw" beta and one-third weight to the equity market beta of 1.0), in lieu of "raw" (i.e., calculated historical) betas. These adjusted betas were in the range of 0.65 to 0.70.[133] Overall, based on these inputs, Ms. McShane supported a relative risk adjustment in the approximate range of 0.65-0.70.

123. With respect to Dr. Cleary's beta estimate of 0.45 (range of 0.30 to 0.60) and Dr. Booth's beta estimate of 0.50 (range of 0.45 to 0.55), Ms. McShane stated that:

> These relative risk adjustments bear no relationship to investor experience. My relative risk adjustment of 0.65-0.70 for a benchmark utility, in contrast, recognizes the past relationship between utility returns, both in Canada and the U.S., and the returns on the equity market as a whole. Over the longer-term, utility investors have achieved risk premiums that have been significantly higher than 45% to 50% of the risk premiums achieved on the equity market portfolio.[134]

124. Dr. Cleary, in turn, took issue with Ms. McShane's calculation of the relative total market risk of utilities using the ratio of S&P/TSX Utilities Index standard deviations to those of 10 major sectors. In Dr. Cleary's view, such an approach is inconsistent with the central premise of the CAPM:

> This is an inappropriate risk factor to be used in the CAPM. First of all, the main premise underlying the CAPM is that systematic risk (as measured by beta), and not total risk, is the relevant risk for a well-diversified investor, since unsystematic risk can be eliminated by diversification. Total risk appears nowhere in the model.
>
> Secondly, for most, if not all, individual stocks, the standard deviation will be much higher than that of the market, since each stock possesses a high level of unique (or unsystematic) risk. Thus, these ratios would almost all be greater than one, with an average that would be much higher than one. Yet the average beta across all individual stocks is one, by definition. …[135]

125. Dr. Cleary and Dr. Booth disagreed with Ms. McShane's use of adjusted betas. They both pointed out that in the 2009 GCOC decision, the Commission rejected the use of adjusted betas.[136] Dr. Cleary noted that "there is no reason to believe that utility betas, which have averaged 0.4 to 0.6 over the long run, will drift toward 1."[137] Dr. Booth stated "looking at a chart

[130] Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 10. The 10 sectors are: consumer discretionary, consumer staples, energy, financials, health care, industrials, information technology, materials, telecommunication services and utilities.
[131] Exhibit 42.02, McShane evidence for Alberta Utilities, page 99.
[132] Exhibit 42.02, McShane evidence for Alberta Utilities, pages 100-106.
[133] Exhibit 42.02, McShane evidence for Alberta Utilities, pages 106-107.
[134] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 35.
[135] Exhibit 82.02, Cleary rebuttal evidence for UCA, page 9.
[136] Decision 2009-216, paragraph 251.
[137] Exhibit No. 82.02, Cleary rebuttal evidence for UCA, page 9.

of utility betas over long periods of time … there is no indication of them trending toward 1.0. As far as I am aware no Canadian regulator has accepted the idea that utility betas regress toward 1.0."[138]

Commission findings

126. The Commission considers that Ms. McShane's approach of focussing on a "relative risk adjustment," rather than a traditional beta parameter calculated from past data, arises, at least in part, from her general criticisms of CAPM. As discussed in Section 5.1.1 of this decision, the Commission recognizes that CAPM, like any theoretical model, has its limitations. However, the Commission continues to hold the view that CAPM is a theoretically sound and useful tool, among others, for estimating ROE.

127. In this regard, Dr. Cleary stated that, in his view, Ms. McShane's total market risk estimates violate "the main premise underlying the CAPM is that systematic risk (as measured by beta), and not total risk, is the relevant risk for a well-diversified investor, since unsystematic risk can be eliminated by diversification."[139] For its part, the Commission agrees with Dr. Cleary's criticism in this regard and, consequently, assigns no weight to Ms. McShane's total market risk analysis.

128. Dr. Booth[140] and Dr. Cleary[141] indicated that the long-run utility beta is approximately 0.5. In her regression analysis, Ms. McShane obtained long-run beta estimates of 0.40 to 0.465, even though the explanatory power of the regression models was rather low, as demonstrated by low coefficients of determination.[142] Given the identified shortcomings in the predictive value of the approach advocated by Ms. McShane, the Commission accepts the 0.5 long-run beta estimate as the lower range of its reasonable beta estimate.

129. However, in arriving at this assessment of the evidence, the Commission is, nonetheless, mindful of Ms. McShane's conclusion that betas calculated using historical data may be poor predictors of an investor's required or expected return.[143] The Commission also understands that, as one possible solution to this problem, equity market practitioners may use adjusted betas, which, according to some academic research, are better predictors of returns than "raw" betas (i.e., betas calculated using historical data).[144]

130. Therefore, even though the Commission did not accept the use of adjusted betas in Decision 2009-216,[145] and Dr. Booth was not aware of any Canadian regulator that "has accepted the idea that utility betas regress toward 1.0,"[146] the Commission acknowledges the fact that the adjusted betas "are widely disseminated to investors by investment research firms, including Bloomberg, *Value Line* and Merrill Lynch."[147] However, the question still remains whether an adjustment is warranted for betas of regulated utilities.

138 Exhibit 44.02, Booth evidence for CAPP, paragraph 112.
139 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 9.
140 Exhibit 44.02, Booth evidence for CAPP, paragraph 116.
141 Exhibit 45.03, Cleary evidence for UCA, page 31.
142 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 102-103.
143 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 100-106.
144 Exhibit 42.02, McShane evidence for Alberta Utilities, page 106.
145 Decision 2009-216, paragraph 251.
146 Exhibit 44.02, Booth evidence for CAPP, paragraph 112.
147 Exhibit 42.02, McShane evidence for Alberta Utilities, page 106.

131. In light of the above considerations, the Commission accepts Ms. McShane's lower bound of beta estimate of 0.65, as representing the upper range of a reasonable beta estimate. Consequently, the Commission finds that a reasonable range for a beta estimate is 0.50 per cent to 0.65 per cent.

5.1.5 Flotation allowance

132. ROE estimates obtained through a CAPM or a DCF analysis are often adjusted upwards by a "flotation allowance." The Commission noted in previous GCOC decisions that a flotation allowance is normally included in the allowed return to account for administrative costs and equity issuance costs, any impact of under-pricing a new issue, and the potential for dilution.[148] Historically, the Commission and its predecessors have allowed 0.50 per cent (50 basis points) additional return on equity to account for the costs of flotation, and to better ensure that investors can reasonably expect to receive at least the required return.

133. In this proceeding, the interveners' experts generally agreed with the stated purpose of the flotation allowance, as set out in the Commission's 2009 and 2011 GCOC decisions.[149] Both Dr. Cleary[150] and Dr. Booth[151] added a 50 basis points flotation allowance to their respective CAPM estimates, consistent with the Commission's determinations in previous decisions. Dr. Cleary stated that this number is consistent with long-term estimates.[152]

134. In its argument, Calgary supported the inclusion of a 50 basis point allowance for flotation costs, consistent with the Commission's, and its predecessors', historical approach. Calgary also noted that this number has been used by other regulators as well, for example, by the British Columbia Utilities Commission in its 2013 GCOC decision.[153]

135. For her part, Ms. McShane recommended a higher allowance of 100 basis points to permit financing flexibility and as an adjustment for financial risk. According to Ms. McShane, the financing flexibility allowance is intended to cover three distinct aspects: "(1) flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or cushion, for unanticipated capital market conditions; and (3) recognition of the 'fairness' principle."[154]

136. Ms. McShane stated that the financing flexibility allowance should be 50 basis points, which "is adequate to allow a regulated company to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10 times."[155] However, Ms. McShane also indicated that a higher adjustment of 140 basis points may be warranted to account for financial risk:

> The cost of capital, as determined in the capital markets, is derived from market value data, and reflects a level of financial risk represented by market value capital structures. The cost of equity for the benchmark utility has been estimated using samples of proxy companies with a lower level of financial risk, as reflected in their market value capital

148 Decision 2011-474, paragraph 68; Decision 2009-216, paragraph 255.
149 Exhibit 68.02, AUC-UCA-5; Exhibit 63.02, AUC-CAPP-5.
150 Exhibit 45.03, Cleary evidence for UCA, page 32.
151 Exhibit 44.02, Booth evidence for CAPP, page 3.
152 Exhibit 45.03, Cleary evidence for UCA, page 32.
153 Exhibit 146.02, Calgary argument, paragraph 16.
154 Exhibit 42.02, McShane evidence for Alberta Utilities, page 128.
155 Exhibit 42.02, McShane evidence for Alberta Utilities, page 128.

> structures, than the financial risk inherent in the book value capital structures of the utilities to which the cost of equity is to be applied. Regulatory convention applies the allowed ROE to a book value capital structure. The application of the market-derived cost of equity to the book value of equity without taking account of the higher level of financial risk than the level inherent in the proxy utilities' cost of equity will underestimate the cost of equity and the fair return.[156]

137. During the hearing, Ms. McShane further explained the reasoning behind the 140 basis point adjustment for financial risk as follows:

> The upper end of the range that I have suggested is in the nature of what I call a financial risk adjustment, which is intended to recognize that the cost of capital is determined in the capital markets based on capital market data, including market value capital structures, but that overall cost of capital and the equity component thereof is applied to a book value common equity ratio, which is in today's markets lower than the market value common equity ratio, thereby indicating that there is more financial risk in the book value common equity ratio than in the market value common equity ratio.[157]

138. Ms. McShane therefore recommended a flotation allowance of 100 basis points, which, in her assessment, gives weight to both the minimum 50 basis points required for financing flexibility and the suggested 140 basis points adjustment for financial risk. Ms. McShane indicated that this approach "is similar to that taken by the National Energy Board in setting the allowed ROE for TransCanada Pipelines in *Decision RH-003-2011* …."[158]

139. Dr. Cleary did not agree with Ms. McShane's proposal to increase the flotation allowance to 100 basis points. He observed that since "Canadian utilities currently trade at M/B [market to book] ratios averaging 2.4, this indicates that these firms have earned and are expected to earn ROEs above the return required by investors."[159] The UCA, in its argument, submitted that "Ms. McShane offers no compelling evidence to support a deviation from the "usual regulatory convention of awarding a flotation allowance of 0.50 per cent … and the UCA recommends no such deviation is warranted."[160]

140. Dr. Booth stated that "Ms. McShane's use of 1.0% is outside anything I would regard as reasonable or found to be acceptable in Canadian regulatory decisions."[161] In this regard, Dr. Booth pointed out that some regulators actually estimate all the costs involved in issuing equity and their tax treatment. For example, the Régie de L'énergie du Québec has, in the past, assessed flotation or issuance costs at 0.30 to 0.40 per cent. However, he also pointed out that it is "a lengthy and expensive exercise to go back and track the costs attached to the shareholder's equity included in rate base."[162] As such, Dr. Booth was prepared to use a 0.50 per cent financial flexibility/issue cost allowance as a compromise, even though actual flotation costs could be lower. According to Dr. Booth, this compromise avoids significant testimony on a relatively minor issue.

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156 Exhibit 42.02, McShane evidence for Alberta Utilities, page 129.
157 Transcript, Volume 4, page 489, lines 14-24 (Ms. McShane).
158 Exhibit 42.02, McShane evidence for Alberta Utilities, page 130.
159 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 14.
160 Exhibit 150.02, UCA argument, page 15, footnote omitted.
161 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 21.
162 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 20.

Commission findings

141. The Commission has two primary concerns regarding Ms. McShane's proposal to increase this adjustment to 100 basis points to account for the fact that there is "more financial risk in the utilities' book value capital structures (to which the allowed return is applied) than in the market value capital structures which underpin the market cost of equity."[163] Firstly, as the Commission noted in Decision 2011-474, "[a]rguments that a market return should be applied to a market value based rate base, rather than a book value rate base, are circular since the market value is clearly dependent on the awarded return."[164] During the hearing, Ms. McShane acknowledged that "there is a relationship between return and market value. There's no getting around that."[165]

142. Secondly, the Commission is not persuaded that a valid purpose of the flotation allowance is to take account of the "higher cost of equity due to the higher financial risk inherent in the book value capital structures of the Alberta Utilities to which the return is applied compared to the market value capital structures of the proxy firms used to estimate the cost of equity," as was suggested by Ms. McShane.[166] As noted earlier in this section, in previous GCOC decisions the Commission included a flotation allowance in the allowed return to account for administrative costs and equity issuance costs, any impact of under-pricing a new issue, and the potential for dilution.[167] The Commission has not, in its review of the evidence and argument submitted in this proceeding, found any compelling reason to re-visit its previously stated position on this issue.

143. In this proceeding, Dr. Booth indicated that flotation or issue costs "are the discount to the market price at the time of issue, the costs of registering securities and compliance etc."[168] Dr. Cleary expressed his understanding that "this allowance … provides coverage of security issuance costs, as well as providing an additional margin of safety for firms in terms of raising financing."[169] All of Dr. Booth, Dr. Cleary and Ms. McShane,[170] agreed that a 50 basis point flotation allowance is sufficient to achieve these purposes (i.e., to cover security issuance costs, to avoid dilution of shareholders equity and to provide an additional margin of safety for firms when raising financing).

144. For the foregoing reasons, the Commission is unable to accept Ms. McShane's proposal to apply a flotation allowance of 100 basis points and finds that a flotation allowance of 50 basis points continues to be reasonable in the circumstances.

5.1.6 The resulting CAPM estimate

145. The following table sets out the recommended individual CAPM components and resulting ROE values for each of the experts that presented evidence on CAPM, or variations thereof.

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163 Exhibit 155.01, Alberta Utilities reply argument, paragraph 65.
164 Decision 2011-474, paragraph 75.
165 Transcript, Volume 4, page 495, lines 8-9 (Ms. McShane).
166 Exhibit 66.01, AUC-Utilities-5(a).
167 Decision 2011-474, paragraph 68; Decision 2009-216, paragraph 255.
168 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 20.
169 Exhibit 68.02, AUC-UCA-5(a).
170 Exhibit 42.02, McShane evidence for Alberta Utilities, page 128, line 3297 to page 129, line 3303.

Table 1. CAPM recommendations

Expert witness	Risk-free rate (%)	MERP (%)	Market return (%)	Beta	Adder (%)	Flotation allowance (%)	ROE (%)
Dr. Booth[171] 2013-2015	4.0 (Note 1)	5.0 – 6.0	9.0 – 10.0	0.45 – 0.55	0.26	0.50	7.50 (7.01 – 8.06)
Dr. Cleary[172]							
2013	2.8	6.0	8.8	0.45	0.2	0.50	6.2
2014	3.5	5.5	9.0	0.45	0.1	0.50	6.58
2015	3.7	5.5	9.2	0.45	0.0	0.50	6.68
Ms. McShane[173] 2013-2015	4.00	7.25	11.25	0.65 – 0.70 (Note 2)	-	1.00	9.9 (9.7 – 10.1) (Note 3)

Note 1: Inclusive of 40 basis points "Operation Twist" adjustment.
Note 2: Ms. McShane estimated a "relative risk adjustment," rather than a "single risk variable, beta."
Note 3: Commission staff calculations. Ms. McShane presented her risk premium test results net of flotation allowance.

Commission findings

146. Applying its findings on the individual components of CAPM, as set out in sections 5.1.2 to 5.1.5, the Commission calculates a range of CAPM cost of equity estimates for investors in stand-alone Canadian utilities of 5.80 per cent to 8.75 per cent.

Table 2. Commission's CAPM findings

Commission's CAPM findings	Risk-free rate (%)	MERP (%)	Market return (%)	Beta	Flotation allowance (%)	CAPM ROE (%)
2013-2015	2.80 – 3.70	5.0 – 7.0	7.80 – 10.70	0.50 – 0.65	0.50	5.80 – 8.75

5.2 Discounted cash flow model

5.2.1 DCF methodology and predictive value

147. The discounted cash flow (DCF) model is used to estimate the cost of a company's common equity based on the current dividend yield of the company's shares plus the expected future dividend growth rate. The DCF method calculates ROE as the rate of return that equates the present value of the estimated future stream of dividends with the current share price.

148. There are several variations of the DCF model, including the single-stage constant growth model, the multi-stage growth model, and the "H-model." A single-stage constant growth model assumes that growth in dividends and earnings is expected to occur, indefinitely, at the same annual rate. When future growth is expected to vary at different stages (e.g. in respect of a company that may experience a high growth rate in early stages of its development, transition to a slower growth rate as it matures, and finally, settle on a stable long-term growth rate), a multi-stage growth model is employed. The H-model is a variant of the two-stage model, which

171 Exhibit 44.02, Booth evidence for CAPP, page 3.
172 Exhibit 45.03, Cleary evidence for UCA, page 32.
173 Exhibit 42.02, McShane evidence for Alberta Utilities, pages 108 and 131.

assumes that growth linearly declines from a current short-term growth rate towards a future stable long-term growth rate over a specified period of time (denoted as 2H).[174]

149. Using a single-stage constant growth model framework, the estimated cost of equity can be expressed as follows:

$$R_e = \frac{D_1}{P_o} + g,$$

where:

> $\boldsymbol{R_e}$ is the required return on common equity
> $\boldsymbol{D_1}$ is the next expected dividend[175]
> $\boldsymbol{P_0}$ represents the current common share market price
> $\boldsymbol{g}$ represents the expected long-term average growth rate in dividends and earnings

150. As can be seen from the equation above, the estimated ROE under a single-stage DCF model flows from a consideration of two components: the dividend yield, (D_1/P_0), and an expected growth in dividends and earnings, g. The application of multi-stage DCF models to calculating an implied ROE is somewhat more complex.[176]

151. All three experts in this proceeding used DCF models to some extent in developing their ROE recommendations. Both Ms. McShane and Dr. Cleary pointed out that the DCF model is commonly used in North America to estimate the cost of equity.[177] However, they did not agree completely with respect to the extent to which the DCF model can be relied on for this purpose.

152. Ms. McShane acknowledged that, in developing her ROE estimate, she placed greater weight on her DCF estimates than on her CAPM results.[178] In her evidence, Ms. McShane explained that the DCF test allows one to "directly estimate the utility cost of equity, in contrast to the [CAPM], which estimates the cost of equity indirectly."[179] Ms. McShane further elaborated on this point in response to UCA-Utilities-48:

> The CAPM model relies on three variables, only one of which is directly related to utility-specific market data, i.e., the relative risk adjustment. The other two variables are a broad market risk premium and a risk-free rate, neither of which represent comparable investments. The inputs to the DCF model (dividend yield and forecast growth) are both utility-specific, and thus relate specifically to comparable investments.[180]

153. The Alberta Utilities also submitted, in argument, that "the DCF test measures the return utility investors do expect, whereas the CAPM estimates the return investors should require under the specific restrictive assumptions of the model." As such, the Alberta Utilities argued

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174 Exhibit 42.03, McShane evidence for Alberta Utilities, Appendix C; Exhibit 45.03, Cleary evidence for UCA, pages 34-35.
175 As Ms. McShane explained in Exhibit 42.03, Appendix C, D_1 can be alternatively expressed as $D_0(1+g)$, where D_0 is the most recently paid dividend.
176 See Exhibit 45.03, Cleary evidence for UCA, page 35 for the required return calculation under the H-model.
177 Exhibit 42.02, McShane evidence for Alberta Utilities, page 123; Exhibit 45.03, Cleary evidence for UCA, page 52.
178 Transcript, Volume 1, page 122, line 20 to page 123, line 10 (Ms. McShane).
179 Exhibit 42.02, McShane evidence for Alberta Utilities, page 123.
180 Exhibit 73.01, UCA-Utilities-48(a).

that given "these advantages of the DCF test, combined with the clear systemic problems of the CAPM, the DCF test should be given greater weight by the Commission than in the past."[181]

154. For his part, Dr. Cleary indicated that he would normally choose to rely more heavily on CAPM results over DCF results in determining the ROE estimate. He explained that this is because "CAPM is much more heavily relied upon in practice due to its conceptual advantages" and maintained that the CAPM model is "more intuitive from the point of view of a utility hearing."[182] In support of this position, Dr. Cleary referenced studies showing that only 12 per cent of Canadian CFOs and 15 per cent of U.S. CFOs utilize the DCF model, in contrast to the 40 per cent of Canadian CFOs and over 70 per cent of U.S. CFOs who utilize the CAPM.[183] However, Dr. Cleary also stated that, in this proceeding, he chose to give an equal weighting to the three models that he relied on because CAPM estimates are currently lower than might otherwise be expected due to low risk-free rates.[184]

155. The UCA argued that Ms. McShane "places undue weight on her benchmark utility DCF estimate in determining a proposed ROE for the Alberta Utilities, despite the obvious limitations inherent in such a model."[185] In support of its view in this regard, the UCA referenced the results of studies in Dr. Cleary's evidence demonstrating that CAPM is more widely used by Canadian and U.S. CFOs.

156. Dr. Booth indicated that, conceptually, the results of the DCF and CAPM tests should be consistent. In Dr. Booth's view, to the extent that CAPM and DCF estimates differ significantly, "it is mainly due to the difficulty in estimating the growth rate in the DCF model and the market risk premium [in the CAPM model]."[186] Dr. Booth further noted that he has traditionally viewed his DCF estimates as checks on his CAPM estimates, based on his view that CAPM estimates "are usually in the right 'ball-park.'"[187] However, because of depressed long-term interest rates, Dr. Booth indicated he had "spent more time analyzing [DCF] estimates of the fair rate of return."[188]

157. In argument, CAPP observed that the growth rate is a critical component of DCF, and also the most controversial one. CAPP submitted that "Dr. Booth provides detailed analysis to show that the growth rates used in Ms. McShane's evidence are unreasonably high."[189] Based on the evidence of Dr. Booth, CAPP reached an overall conclusion that "Ms. McShane's growth estimates are unreliable and excessive with the result that her DCF estimates are unreliable and excessive."[190]

158. In its argument, Calgary noted that "Dr. Booth did not do a DCF estimate for any specific company, as he pointed out the problems with this method when applied to specific companies"[191] and submitted that "the Commission should not rely upon a DCF approach to

181 Exhibit 148.01, Alberta Utilities argument, paragraph 71.
182 Exhibit 45.03, Cleary evidence for UCA, page 52.
183 Exhibit 45.03, Cleary evidence for UCA, page 52.
184 Exhibit 45.03, Cleary evidence for UCA, page 53.
185 Exhibit 150.02, UCA argument, page 24.
186 Exhibit 44.02, Booth evidence for CAPP, page 63.
187 Exhibit 44.02, Booth evidence for CAPP, page 63.
188 Exhibit 44.02, Booth evidence for CAPP, page 4.
189 Exhibit 151.01, CAPP argument, paragraph 56.
190 Exhibit 151.01, CAPP argument, paragraph 61.
191 Exhibit 146.02, Calgary argument, paragraph 18.

determine the fair return for the utilities under its jurisdiction."[192] In its reply argument, Calgary further submitted that it "agrees with and supports the CAPP submissions" with respect to the DCF estimates.[193]

Commission findings

159. As is the case with any theoretical model, the DCF method has advantages and drawbacks. For example, Ms. McShane indicated that one of the advantages of the DCF model is that it "directly measures expected utility returns by using utility-specific data only: prices, dividends and estimates of expected growth in the cash flows to investors."[194] However, she also conceded that the DCF model "is subject to an ongoing debate around the accuracy of investment analysts' forecasts as the measure of investor expectations of growth."[195] Similarly, Dr. Booth surmised that the main difference between the CAPM and DCF estimates is "due to the difficulty in estimating the growth rate in the DCF model and the market risk premium [in the CAPM]."[196]

160. As noted previously, the DCF method calculates ROE as the rate of return that equates the present value of the estimated future stream of dividends with the current share price. The Commission continues to hold the view that the DCF model is a relevant, and theoretically well-grounded economic method for estimating ROE. The Commission further notes that, according to the studies referenced by Dr. Cleary, although the DCF model is less widely used than the CAPM, it is nonetheless still employed by 12 per cent of Canadian CFOs and 15 per cent of U.S. CFOs.[197]

5.2.2 DCF estimates

161. To estimate the cost of equity, Ms. McShane used both a single-stage (constant growth) and a three-stage (variable growth) DCF model, applied to a sample of U.S. and Canadian utilities, which were selected to serve as proxies for the estimation of the benchmark utility cost of equity.

162. For the sample of U.S. utilities, Ms. McShane relied on two estimates of growth rates. The first estimate was based on the average of investment analysts' long-term earnings growth forecasts drawn from four sources: Bloomberg L.P., Thomson Reuters, Value Line Inc., and Zacks Investment Research. The second was an estimate of sustainable growth, calculated as an expected ROE multiplied by an earnings retention rate (a portion of the net income reinvested in a company) and then added to incremental earnings growth achievable as a result of external equity financing.[198]

163. For the Canadian sample, Ms. McShane developed her DCF results using only analysts' growth estimates provided by Reuters. Ms. McShane indicated that there are "no widely

[192] Exhibit 146.02, Calgary argument, paragraph 19.
[193] Exhibit 157.02, Calgary reply argument, paragraph 39.
[194] Exhibit 42.02, McShane evidence for Alberta Utilities, pages 74-75.
[195] Exhibit 42.02, McShane evidence for Alberta Utilities, page 75.
[196] Exhibit 44.02, Booth evidence for CAPP, paragraph 160.
[197] Exhibit 45.03, Cleary evidence for UCA, page 52.
[198] Exhibit 42.02, McShane evidence for Alberta Utilities, page 125.

available estimates of long-term expected returns on equity and earnings retention rates from which to make forecasts of sustainable growth."[199]

164. The results of Ms. McShane's DCF estimates are presented in the table below. Ms. McShane focused on sample median results in order to offset the effect of outlier forecasts that tended to skew the average.[200]

Table 3. Ms. McShane's DCF estimates (median values)

Sample/model	Dividend yield	Stage 1 growth rate	Stage 2 growth rate	Final growth rate	Investor required ROE
	(%)				
U.S. utilities sample, average analyst constant growth forecasts[201]	4.2	--	--	4.8	9.0
U.S. utilities sample, calculated sustainable growth[202]	4.2	--	--	4.2	8.5
U.S. utilities sample, average three stage growth estimates (GDP growth for final stage)[203]	3.99 (Note 1)	4.8	4.8	4.7	8.8
Canadian utilities sample, average analyst constant growth forecasts[204]	4.2	--	--	7.2	10.8
Canadian utilities sample, average three stage growth estimates (GDP growth for final stage)[205]	3.83 (Note 1)	7.2	5.8	4.3	9.8

Note 1: Median lagged dividend yield, D_0/P_0 (Commission staff calculations).

165. According to Ms. McShane's estimates, both the constant growth and three-stage DCF models indicate a utility cost of equity of approximately 8.75 per cent when applied to the U.S. sample. For the Canadian utilities sample, Ms. McShane calculated the cost of equity to be approximately 10.2 per cent, based on the mid-point of the range between the constant growth and three-stage models. Ms. McShane therefore concluded that the application of both constant growth and three-stage models to the two samples is supportive of a benchmark utility DCF cost of equity in the range of approximately 8.75 per cent to 10.2 per cent, and a mid-point of approximately 9.5 per cent, before the application of a flotation allowance.[206]

166. Dr. Booth performed a DCF analysis at both the market level, and for a sample of six U.S. utilities. In performing his analysis on the market as a whole, Dr. Booth obtained a DCF-based ROE estimate of 9.3 per cent using a high growth estimate and 7.85 per cent using a low growth estimate. According to Dr. Booth, the DCF-obtained estimate range of 7.85 per cent to 9.30 per cent "probably marginally understates the expected equity market return, since we should still expect some short term pick-up in growth in 2014."[207] This is because, at the current point in time, the Canadian economy has largely recovered from recession and is still in a growth phase of the business cycle.

199 Exhibit 42.02, McShane evidence for Alberta Utilities, footnote 152 on page 126.
200 Exhibit 42.02, McShane evidence for Alberta Utilities, footnote 154 on page 126.
201 Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 18.
202 Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 19.
203 Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 20.
204 Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 21.
205 Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 22.
206 Exhibit 42.02, McShane evidence for Alberta Utilities, page 127.
207 Exhibit 44.02, Booth evidence for CAPP, paragraph 154.

167. Dr. Booth also used a two-stage growth DCF model in order to provide for a possibility of higher growth in the near term. Using a dividend yield of 3.01 per cent, a long run growth rate at 6.1 percent, and a short-run growth of 9.1 per cent for the next three years, Dr. Booth obtained a DCF-based ROE estimate for the Canadian market of 9.56 per cent. In Dr. Booth's view, this number represents the upper bound of the "overall ROE for a low risk utility" or in other words, "the fair ROE for a utility has to be less than the estimated return for the market as whole of 9.56%."[208]

168. Dr. Booth also performed a DCF analysis for individual firms. However, he voiced a concern that DCF estimates for individual companies have "significant measurement error and of little value added over risk premium estimates."[209] Using data for six U.S. utilities, Dr. Booth estimated an expected ROE averaging 8.23 per cent, based on an average analysts' forecast growth rate of 4.02 per cent. However, Dr. Booth admitted that this estimate "suffers some problems", including that "analysts are optimistic and forecasts start out very optimistic and gradually hone in on the real number as the company releases guidance."[210]

169. In attempting to address these problems, Dr. Booth calculated DCF estimates using the sustainable growth rate formula rather than analysts' forecasts. When using sustainable growth rates, Dr. Booth obtained a DCF ROE estimate averaging 6.08 per cent. In his view, "the use of analyst forecast growth rates provides an upper bound for the fair rate of return estimates for these US utilities and probably the estimates using the sustainable growth rates are marginally low. …"[211] Dr. Booth did not employ a multi-stage DCF model for individual utilities.

170. In a manner similar to Dr. Booth, Dr. Cleary applied a DCF model to the market as a whole, and at the industry level, "using numbers that are 'representative' of a typical publicly-traded utility company in Canada."[212] For the market-level estimates, Dr. Cleary used a long-run nominal GDP growth rate of 5.4 per cent over the 1962 to 2012 period, and a dividend yield of 3.16 per cent, to arrive at an ROE estimate of 8.56 per cent. Using a lower nominal GDP growth rate of 4.65 per cent over the 1992 to 2012 period, Dr. Cleary obtained a DCF ROE estimate of 7.79 per cent.[213]

171. Dr. Cleary also employed an H-model version of the DCF analysis to account for the fact that the expected GDP growth rate for 2013-2015 is currently below the forecast 5.4 per cent long-term level, but is expected to gradually return to that level. Using estimated short-term growth rates of 2.77 per cent and 3.84 per cent, and convergence periods of four and two years, he obtained DCF estimates of between 8.40 per cent and 8.52 per cent. Overall, Dr. Cleary obtained 2013-2015 DCF ROE estimates for the market in the range of 7.8 per cent to 8.6 per cent, and settled on best estimate averages from single-stage and multi-stage DCF models of 8.31 per cent for 2013 and 8.34 per cent for 2014 and 2015. Based on his view that "the implied rate of return for the overall market … should be significantly higher than that for the average utility company which is much less risky than the 'average' company in the market,"

208 Exhibit 44.02, Booth evidence for CAPP, paragraph 157.
209 Exhibit 44.02, Booth evidence for CAPP, paragraph 173.
210 Exhibit 44.02, Booth evidence for CAPP, paragraphs 181-182.
211 Exhibit 44.02, Booth evidence for CAPP, paragraph 184.
212 Exhibit 45.03, Cleary evidence for UCA, page 33.
213 Exhibit 45.03, Cleary evidence for UCA, pages 34-35.

Dr. Cleary concluded that "[a]t minimum, we could say that market DCF estimates above suggest that utility returns should be lower than 8.3%."[214]

172. Dr. Cleary went on to apply the single-stage and H-model DCF analyses to his sample of nine Canadian utilities and obtained single-stage DCF results in the range of approximately 4.9 to 8.2 per cent by adding sustainable growth rates calculated using ROE and retention rate averages to the average dividend yield. Applying the H-model, he obtained results in the range of approximately 6.1 to 8.1 per cent. Overall, Dr. Cleary calculated DCF ROE estimates for his Canadian utility sample of 7.32 per cent for 2013, and 7.67 per cent for 2014 and 2015 before addition of a flotation allowance.[215] Dr. Cleary did not perform a DCF analysis for the U.S. utilities, stating that they are not the best comparison for Alberta utilities. Notwithstanding, Dr. Cleary did observe that the Canadian numbers from this sample were "within range of typical U.S. figures."[216]

173. Ms. McShane, Dr. Booth and Dr. Cleary, all exchanged critiques regarding the specific DCF models employed in their respective analyses, and the results they obtained. For instance, Ms. McShane[217] and Dr. Cleary[218] questioned whether each other's choices of comparator utilities were valid with respect to Alberta utilities.

174. One of Ms. McShane's primary concerns with DCF results obtained by Drs. Booth and Cleary was that their estimates of expected growth rates were based on historical earnings and retention rates, not forecasts. She stated:

> The growth embedded in current prices (and thus the dividend yield component) reflects what investors expect going forward, which may be materially different than past growth rates. Equating expected growth to historic returns and payout ratios is particularly problematic when the companies are in the midst of major growth initiatives, either through capital expenditures or acquisitions as is the case with Canadian Utilities, Emera, Enbridge, Fortis and TransCanada.[219]

175. According to Ms. McShane, because Dr. Booth and Dr. Cleary calculated sustainable growth rates, rather than relying on analysts' earnings growth forecasts, their respective DCF models underestimate the real cost of equity. For example, in her view, if Dr. Booth had used analysts' earnings growth forecasts for his sample of utilities, the resulting DCF cost of equity estimate would be approximately 9.0 per cent, a value that would be comparable to her DCF results.[220]

176. The intervener experts, in turn, expressed concerns with Ms. McShane's reliance on analyst growth estimates, which have been criticized by Canadian regulators, including the AUC, for being overly optimistic. For example, Dr. Cleary stated that even Ms. McShane's median growth estimate of 7.2 per cent "remains an extremely high long-term growth estimate, well above the long-term growth estimate for the economy, which itself seems an ambitious target for

214 Exhibit 45.03, Cleary evidence for UCA, page 36.
215 Exhibit 45.03, Cleary evidence for UCA, page 44.
216 Exhibit 45.03, Cleary evidence for UCA, page 38.
217 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 40.
218 Exhibit 82.02, Cleary rebuttal evidence for UCA, pages 10-11.
219 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, pages 40-41.
220 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 43.

low-risk mature utilities."[221] Similarly, Dr. Booth observed that Ms. McShane's constant growth DCF estimates for the Canadian sample "have long run growth rates that exceed the forecast GDP growth rate which are not only logically impossible but … have already been previously rejected by the AUC."[222]

177. Ms. McShane also expressed concerns with Dr. Booth's and Dr. Cleary's DCF estimates for the market as a whole. She took the position that a constant growth DCF model should not be applied to the market as a whole, because, in her view, the basic underlying assumption that companies' dividends and earnings are expected to grow at a constant rate in perpetuity does not apply to most companies comprising the S&P/TSX Composite Index.[223] With respect to the multi-stage DCF model employed by Dr. Cleary (the H-model), Ms. McShane argued that his assumption that the short-term expected growth rate is lower than the long-term growth rate of the economy "is at odds with the earnings forecasts made by analysts for the specific companies that make up the [S&P/TSX Composite Index]."[224] Regarding the multi-stage DCF model employed by Dr. Booth, Ms. McShane similarly stated that the addition of a dividend yield applicable to the S&P/TSX Composite Index to a sustainable growth rate based on all of "Corporate Canada" is not appropriate, as the S&P/TSX Composite Index is not equivalent to "Corporate Canada."[225]

178. For their part, both Dr. Cleary[226] and Dr. Booth[227] observed that Ms. McShane's three-stage DCF model assumes five years of high growth at the outset (based on analysts' estimates), then declines to a point mid-way between this initial estimate and the long-term expected growth rate for the years six to 10, followed by a long-run terminal growth rate beginning at year 10. Consequently, the analysts' estimated initial growth rate affects subsequent growth estimates for the first 10 years. According to Dr. Cleary, it is "unclear why one would expect 'above' average growth would persist for 10 years in a mature industry, so this also represents an aggressive assumption."[228]

Commission findings

179. There was substantial disagreement between the Alberta Utilities' expert, Ms. McShane, and the interveners' experts, Dr. Booth and Dr. Cleary, regarding many aspects of the DCF model. One of the main points of disagreement between the experts was whether to use analysts' forecasts of growth rates or to calculate sustainable growth rates based on historical data.

180. In the Commission's view, each method described by the various experts presents with its own mixture of strengths and weaknesses. For example, analysts' forecasts of growth rates are forward-looking and aim to expressly account for events expected in the future. However, these same forecasts tend to incorporate a high degree of subjectivity and may be overly optimistic.[229] On the other hand, sustainable growth rate estimates are calculated objectively using historical data, but they do not allow for the possibility that the rate of growth going forward may be

221 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 12.
222 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 5.
223 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 39.
224 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 39.
225 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 40.
226 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 13.
227 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 7.
228 Exhibit 82.02, Cleary rebuttal evidence for UCA, page 13.
229 Exhibit 44.02, Booth evidence for CAPP, paragraphs 181-182.

different from past growth rates.[230] Given these trade-offs, and considering that both methods are currently used to estimate the dividends and earnings growth component of the DCF model (as evidenced by the ongoing academic debate in the literature concerning the desirability of their use[231]), the Commission does not consider it necessary to accept one method to the exclusion of the other, but rather accepts the basic validity of both of these methods for purposes of this decision.

181. Consistent with its determinations in Section 5.4 of this decision, the Commission agrees with Dr. Cleary's and Dr. Booth's view that DCF model-generated ROE estimates for the equity market as a whole is a valid input in determining a fair cost of equity for the utilities industry. Ms. McShane contended that a constant growth DCF model should not be applied to the market as a whole because the underlying assumption that the companies' dividends and earnings are expected to grow at a constant rate in perpetuity does not apply to most of the 249 companies comprising the S&P/TSX Composite Index; the index upon which Dr. Booth and Dr. Cleary based their equity market DCF estimates.[232] However, in the Commission's view, the use of the long-term averages across many companies would tend to mute the individual characteristics of the companies comprising the index, and will, therefore, provide a reasonable approximation of both the long-term dividend yield and growth rate for the equity market as a whole.

182. The Commission observes that Dr. Cleary's and Dr. Booth's DCF ROE estimates for the market as a whole are generally consistent. In their respective analyses, both these experts estimated a dividend yield in the 3.01 to 3.16 per cent range. Dr. Cleary estimated a long-run nominal GDP growth rate of 5.4 per cent, resulting in a DCF estimate of 8.56 per cent,[233] while Dr. Booth estimated the growth rate to be in the range of 4.7 per cent to 6.1 per cent, resulting in a single-stage DCF estimate of 7.85 per cent to 9.30 per cent.[234]

183. However, the results of the multi-stage DCF models applied to the market as whole were not as consistent. Based on his H-model DCF analysis, Dr. Cleary estimated the ROE to be approximately 8.3 per cent; he was the only expert in this proceeding to assume that the short-term growth rate will be lower than the long-term nominal GDP growth. Using a two-stage DCF model, Dr. Booth obtained a DCF ROE estimate for the Canadian market of 9.56 per cent. However, this estimate assumes a short-term growth of 9.0 per cent for the first three years.[235] Due to this apparent divergence of opinion regarding appropriate short-term growth rate inputs, the Commission did not include the results of the multi-stage DCF models applied to the market as whole in its consideration of the ROE value.

184. Based on a single-stage DCF analysis applied to the market as a whole, as performed by Dr. Cleary and Dr. Booth using long-term averages, the Commission finds a DCF-based average ROE estimate for the equity market in the range of 8.0 to 9.0 per cent to be reasonable. The Commission agrees with these experts that ROE estimates for the market as a whole may be viewed as the upper bound of the fair ROE for regulated utilities, given that the average utility

230 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, pages 40-41.
231 See for example, references to academic studies in Exhibit 42.03. Appendices to Ms. McShane evidence for Alberta Utilities, Appendix C, page C-6; Exhibit 44.02, Booth evidence for CAPP, footnote 46 on page 71.
232 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 39.
233 Exhibit 45.03, Cleary evidence for UCA, page 35.
234 Exhibit 44.02, Booth evidence for CAPP, paragraphs 153-154.
235 Exhibit 44.02, Booth evidence for CAPP, paragraph 156.

company is typically less risky than the average company in the market.[236] Therefore, the Commission also considers that the higher-end estimate of 9.0 per cent may be considered an upper limit of a fair cost of equity for regulated utilities.

185. Ms. McShane, Dr. Cleary and Dr. Booth all applied single-stage DCF analyses to different samples of utilities to arrive at their respective ROE estimates. However, these three experts could not agree on the representativeness of each other's utility samples. In previous GCOC decisions, the Commission also expressed concern about using proxy companies in a DCF analysis that are utility holding companies engaged in significant unregulated activities.[237]

186. The Commission also notes that the individual experts' growth estimates varied greatly. For this reason, and in a manner consistent with its determinations in prior GCOC decisions,[238] the Commission will not accept the use of long-term or terminal growth rates that exceed estimates of the nominal long-term GDP growth rate in a single-stage DCF model. This is because, as Dr. Booth explained, the terminal growth rate in the single-stage DCF model "cannot exceed the growth rate in the economy. Otherwise, sooner or later the firm is bigger than the entire economy."[239] The Commission does, nonetheless, accept that the use of higher growth rates in initial stages of multi-stage DCF models may well be justified in some circumstances as a means of addressing a time period that precedes the establishment of a stable, terminal growth rate.

187. In response to AUC-Utilities-4(a), Ms. McShane indicated that any issues arising from forecast earnings growth rates that exceed GDP growth rates relate primarily to her sample of Canadian regulated companies. She also explained that in the case of her U.S. utility sample, the growth rate is very close to the forecast GDP growth rate.[240]

188. In attempting to discern the impact of using forecast earnings growth rates that exceed GDP on the predictive value of Ms. McShane's DCF models, the Commission observes that, if a long-run nominal GDP growth rate range of 4.3 per cent[241] to 5.4 per cent[242] is used rather than Ms. McShane's median estimate of 7.2 per cent, the resulting single-stage DCF ROE estimate for her Canadian sample (using the median dividend yield of 4.2 per cent) ranges from 8.5 per cent to 9.6 per cent.[243] The Commission further notes that Ms. McShane's three-stage DCF model for her Canadian sample, which relied on a 7.2 per cent short-term growth estimate, produced a median ROE estimate of 9.8 per cent.[244]

189. Dr. Booth obtained DCF ROE estimates for his U.S. utilities sample ranging from 6.08 per cent to 8.23 per cent using sustainable growth calculations and analysts' growth forecasts, respectively.[245] Dr. Cleary's best estimate of a single-stage DCF ROE for his Canadian utilities sample was 6.77 per cent for 2013, and 6.94 per cent for both 2014 and 2015, before

236 Exhibit 45.03, Cleary evidence for UCA, page 36; Exhibit 44.02, Booth evidence for CAPP, paragraph 157.
237 Decision 2011-474, paragraph 87; Decision 2009-216, paragraph 269.
238 Decision 2011-474, paragraph 85; Decision 2009-216, paragraph 270.
239 Exhibit 44.02, Booth evidence for CAPP, page 59, paragraph 148.
240 Exhibit 66.01, AUC-Utilities-4(a).
241 Forecast nominal rate of GDP growth from Exhibit 42.04, McShane evidence for Alberta Utilities, Schedule 22.
242 Estimated long-run nominal GDP growth rate from Exhibit 45.03, Cleary evidence for UCA, page 35.
243 Exhibit 42.04, Ms. McShane evidence for Alberta Utilities, Schedule 21.
244 Exhibit 42.04, Ms. McShane evidence for Alberta Utilities, Schedule 22.
245 Exhibit 44.02, Booth evidence for CAPP, paragraph 184.

addition of a flotation allowance.[246] The Commission notes that both Drs. Booth and Cleary relied on sustainable growth estimates in the approximately two to three per cent range in developing their estimates.[247] The Commission further notes that the short-term and long-term growth estimates used by Dr. Cleary in his H-model DCF calculation fell within a similar range.[248]

190. Dr. Booth acknowledged that the 6.08 to 6.44 per cent ROE estimates generated using sustainable growth rates were "marginally low."[249] The Commission agrees, and further observes that if a long-run nominal GDP growth rate of between 4.3 and 5.4 per cent is used as a sustainable growth rate, the single-stage DCF models of both Dr. Cleary and Dr. Booth generate cost of equity estimates in the range of approximately 8.2 to 9.4 per cent (based on an approximate dividend yield of 4.0 per cent). However, the Commission is also mindful that, as both experts acknowledged, the GDP growth rate may be an ambitious target for long-run earnings growth in respect of low-risk, mature, utilities.[250]

191. After considering the characteristics of the various DCF-based ROE estimation models employed by the participating expert witnesses, the Commission finds that reasonable DCF estimates for the Alberta Utilities are in the range of 7.0 per cent to 9.0 per cent and that this range is consistent with an expected average equity market return of between 8.0 per cent and 9.0 per cent. In arriving at this conclusion, the Commission notes that Ms. McShane's DCF results for her U.S. utility sample, for which the growth rates were very close to the forecast GDP growth rate,[251] were in the range of 8.5 per cent to 9.0 per cent.[252] However, the Commission considers growth rates that are close to the forecast GDP growth rate to be overly optimistic for regulated utilities.

192. Consistent with its treatment of estimates obtained from the submitted CAPM analyses, the Commission has included a 50 basis points flotation allowance adjustment in its DCF analysis. Although these DCF results appear to suggest that investors expect a return of between 7.5 per cent to 9.5 per cent on utility investments, inclusive of a flotation allowance, the Commission is mindful that these estimates assume that the utilities' dividends and earnings will grow at the long-run GDP growth rate, which may be an optimistic target for relatively low risk mature regulated utilities.[253]

193. Finally, the Commission observes that in this proceeding, as in previous GCOC proceedings, there was a continuing debate regarding the representativeness of the various utility samples used to generate the many DCF estimates that were submitted for the Commission's consideration. Additionally, the participating expert witnesses employed widely divergent growth estimates. As a result, the Commission found itself unable to determine whether the DCF evidence of any particular expert was clearly superior to that of another in terms of either

[246] Exhibit 45.03, Cleary evidence for UCA, Table 14, page 44.
[247] Exhibit 44.02, Booth evidence for CAPP, page 71; Exhibit 45.03, Cleary evidence for UCA, Table 11, page 39; Exhibit 45.03, Cleary evidence for UCA, Table 12, page 41.
[248] Exhibit 45.03, Cleary evidence for UCA, Table 13, page 42.
[249] Exhibit 44.02, Booth evidence for CAPP, paragraph 184.
[250] Exhibit 44.02, Booth evidence for CAPP, paragraph 185; Exhibit 82.02, Cleary rebuttal evidence for UCA, page 12.
[251] Exhibit 66.01, AUC-Utilities-4(a).
[252] Exhibit 42.02, McShane evidence for Alberta Utilities, page 127.
[253] Exhibit 44.02, Booth evidence for CAPP, paragraph 185; Exhibit 82.02, Cleary rebuttal evidence for UCA, page 12.

methodology or data. Consequently, the Commission drew on various aspects of evidence provided by all witnesses and then used its own judgment and expertise in arriving at the determination that DCF estimates in the identified range are reasonable in all the circumstances.

5.3 Price-to-book ratios

194. As the Commission explained in previous GCOC decisions, an equity price-to-book (P/B) ratio, also known as a market-to-book ratio, is calculated by dividing the current market share price of a company's stock by its current per share book value. It is often used to compare the capital market's perception of a company's value, as reflected by the price investors are willing to pay for its stock, to the company's book value.

195. For example, an equity P/B value significantly above 1.0 indicates that a company's market value of equity is significantly higher than the book value at which the owner's equity in assets is carried on the company's balance sheet. The converse is also true. A P/B value below 1.0 indicates that the company's book value of its equity exceeds the market's valuation at a particular point in time.

196. There are many reasons why a company's observed P/B ratio may deviate from a value of 1.0. For example, as Dr. Cleary explained, an equity P/B value may be significantly above 1.0 when a company's ROE is exceeds the return required by equity investors whereas a ratio close to 1.0 indicates that the company's ROE equals the return required by equity investors.[254] In practice, a P/B ratio slightly above 1.0 is preferred, as it prevents equity ownership dilution when new shares are issued. This appreciation of P/B ratios was endorsed by the Commission in Decision 2009-216, where it expressed its view that "a price-to-book ratio of approximately 1.2 for a stand-alone utility would generally indicate that the return is at least fair."[255]

197. In Decision 2011-474, the Commission considered the issue of whether the utilities' P/B ratios have any significance to the establishment of a fair ROE. The Commission concluded:

> 121. In the Commission's view, it would not be rational for investors to purchase a utility at a premium, unless it was of the view that it could earn at least a market rate of return on the investment despite paying the premium. The payment of premiums in such transactions for assets that are earning returns based on ROE awards that are allegedly below market would not appear to be rational. A possible conclusion is that such purchases, at substantial premiums, would indicate that the awarded returns were more than sufficiently attractive.
>
> 122. Again, the Commission finds, as it did in Decision 2009-216, that a price-to-book ratio of approximately 1.2 for a stand-alone utility would generally indicate that the return is at least fair. However, the Commission is unable to derive any useful information about the price-to-book ratios of stand-alone utilities from the price-to-book ratios of utility holding companies. With respect to the recent AltaLink purchase by the SNC-Lavalin Group Inc., given the above discussion, the Commission considers that there may be business reasons for this purchase that are not well understood. In these circumstances, it is difficult for the Commission to draw any conclusions about the significance of this transaction to the establishment of a fair return on equity. Nonetheless, the Commission agrees with the observation that a market-to-book ratio significantly above 1.0 indicates that the earned and allowed ROE is higher than the true

254 Exhibit 45.03, Cleary evidence for UCA, page 51.
255 Decision 2009-216, paragraph 295.

> cost of capital. Estimates of the price to book ratio for the 2011 AltaLink transaction generally exceed 1.0 by a significant margin. This appears to be evidence that the allowed ROE at the time of the purchase was at least adequate.[256]

198. On May 1, 2014, Berkshire Hathaway Energy Co. (BHE) announced it "has reached a definitive acquisition agreement whereby Berkshire Hathaway Energy will acquire AltaLink, an indirect, wholly owned subsidiary of SNC-Lavalin Group Inc. (TSX:SNC). Under the terms of the agreement, Berkshire Hathaway Energy will purchase 100 percent of AltaLink for an estimated C$3.2 billion (approximately US$2.9 billion) in cash."[257] The Commission viewed this announcement as being potentially relevant to the determinations that it would be required to make in this proceeding. Consequently, it issued a supplemental IR to AltaLink[258] and provided for the filing of supplemental evidence by all parties on how, if at all, this transaction relates to matters that are being considered in the current GCOC proceeding.

199. In supplemental evidence filed by the UCA, Dr. Cleary estimated the P/B ratio associated with the BHE's proposed acquisition of AltaLink to be in the range of 1.53 to 1.68.[259] The Commission considers, however, that strictly speaking, this calculation does not represent an equity P/B ratio, since it includes debt and goodwill, and not just the common equity, on the entity's balance sheet. During the hearing, Dr. Cleary acknowledged that he had not made adjustments in his calculations to account for goodwill and the assumed debt associated with the transaction, which, if taken into account, would have raised the P/B ratio into the range of 1.5 to 2.3.[260]

200. According to Dr. Cleary, the fact that the calculated P/B ratios are greater than 1.0 "suggests the allowed and/or expected ROEs are well above the required rate of return by equity investors."[261] Overall, while Dr. Cleary did not assign any specific weight to these estimates for purposes of determining the required ROE, he concluded that "the bottom line of this discussion is that the P/B ratio paid for AltaLink supports my estimates for Ke [required ROE], and also clearly indicates that Alberta utilities appear to be earning a more than satisfactory ROE, and have done so for quite some time."[262]

201. Ms. McShane did not agree that the P/B ratio resulting from the proposed acquisition of AltaLink by BHE had any probative value with respect to making ROE determinations for the Alberta utilities. During the hearing, Ms. McShane expressed her two concerns with relying on any P/B ratios for AltaLink:

> One is that the acquisition is not at the AltaLink LP level. It's a couple of levels up. And the second thing is that the purchase is not expected to be complete until the end of the year, so the common equity that's sitting here on the AltaLink LP balance sheet would be less than what would be expected to be in place at the time.[263]

256 Decision 2011-474, paragraphs 121-122.
257 http://www.berkshirehathawayenergyco.com/news/berkshire-hathaway-energy-announces-acquisition-of-altalink-l-p-and-joint-transmission-development-agreement-with-snc-lavalin
258 Exhibit 86.01, AUC-Utilities-AML-21.
259 Exhibit 101.02, Cleary supplemental evidence for UCA, page 2.
260 Transcript, Volume 6, page 863, line 1 to page 864, line 20 (Dr. Cleary).
261 Exhibit 101.02, Cleary supplemental evidence for UCA, page 2.
262 Exhibit 101.02, Cleary supplemental evidence for UCA, page 3.
263 Transcript, Volume 4, page 528, lines 19-24 (Ms. McShane).

202. Both Ms. McShane[264] and Mr. Fetter[265] indicated that a multitude of reasons inform the price an investor is willing to pay in utility acquisitions, including geographic diversification ("establishing … a beach head in Alberta which allows for the potential entry into unregulated or competitive markets"[266]), synergies and "efficient structuring for tax purposes."[267] Overall, Ms. McShane concluded that "given the myriad of factors that determine what price someone is willing to pay for a company like AltaLink, that you can tell whether or not they would view – that the buyer would view 8.75, for example, as a fair return."[268]

203. Based on the views of their experts, Ms. McShane and Mr. Fetter, the Alberta Utilities argued that "Dr. Cleary's speculation and observations respecting the P/B ratio associated with the contemplated BHE transaction should be given no weight in the Commission's determination of the fair return for the Alberta Utilities in this proceeding."[269]

204. Dr. Booth and Mr. Johnson, who provided expert testimony for Calgary, also took note of the BHE proposed acquisition of AltaLink. They did not attempt to calculate a P/B ratio based on the particulars of the transaction, but instead, commented generally that based on the proposed purchase price and AltaLink's equity numbers from its Rule 005 financial statements, there appeared to be "a healthy premium over the book value of the equity (market to book ratio) …[which] indicates no shareholder concerns about either the allowed ROE or common equity for a major Alberta regulated utility."[270]

205. For his part, Dr. Booth also echoed some of Ms. McShane's concerns regarding the probative value of P/B ratios, and indicated that because regulators are usually looking at P/B ratios at the holding company level, rather than a pure-play utility level (giving rise to the "dirty window" problem[271]), it is "extremely difficult to look at market-to-book ratios to get anything other than a sense of do the shareholders seem to be satisfied with the rate of return."[272] Dr. Booth also stated that to properly calculate the P/B ratio associated with the proposed purchase of AltaLink, one needs to "extract goodwill, forecast the rate base and the extra injections of equity that SNC-Lavalin is going to be putting in, and then make an estimate of the market-to-book ratio and the price-to-book ratio should the transaction go through in December 2014."[273]

206. Without performing a detailed calculation, Dr. Booth surmised that the P/B ratio associated with the AltaLink purchase by BHE "is clearly going to be well above 1.15."[274] Dr. Booth concluded:

> I would say here, at the very minimum the Commission can say what it said in previous cases, which you looked at the market-to-book ratios and can take comfort in the fact that the financial metrics currently allowed are certainly not aggressive, because otherwise

264 Transcript, Volume 4, page 529, line 14 to page 530, line 11 (Ms. McShane).
265 Transcript, Volume 4, page 530, line 23 to page 531, line 3 (Mr. Fetter).
266 Transcript, Volume 4, page 529, lines 22-25 (Ms. McShane).
267 Transcript, Volume 4, page 530, line 3 (Ms. McShane).
268 Transcript, Volume 4, page 536, lines 17-21 (Ms. McShane).
269 Exhibit 148.01, Alberta Utilities argument, paragraph 111.
270 Exhibit 79.02, Booth and Johnson rebuttal evidence for Calgary, page 8.
271 Transcript, Volume 7, page 959, line 6 to page 960, line 7 (Dr. Booth).
272 Transcript, Volume 7, page 959, lines 22-25 (Dr. Booth).
273 Transcript, Volume 7, page 1119, line 23 to page 1120, line 2 (Dr. Booth).
274 Transcript, Volume 7, page 1120, lines 3-4 (Dr. Booth).

> you wouldn't be seeing goodwill layered on top of goodwill and such a premium paid for regulated assets.
> So I wouldn't go as far as professor Cleary at this stage in calculating in part a rate of return. You can do that using the DCF model. I would just say the Commission can take comfort that it's not being particularly tough on the utilities.

207. Based on the evidence of Dr. Booth, CAPP submitted the following in its argument:

> The continued attractiveness of utilities as acquisition targets both in Canada and in the U.S. at significant premiums to book-equity supports the conclusion that allowed returns are not too low and are consistent with Dr. Booth's view that there is room to lower ROEs. Regulators are cautious when dropping allowed returns apparently for fear it may affect capital attraction. Yet regulatory lag likely explains the reason why market-to-book values for utilities remain very high in a low interest rate environment. The use of formulas has shown that ROEs can be lowered year after year when it is done in a transparent, predictable way and still maintain capital attraction and financial integrity (despite utilities endless cries of 'no fair').[275]

208. In argument, the CCA, based on the evidence of Drs. Cleary and Booth, submitted that "it is a further fair inference the allowed rate of return for Alberta utilities was sufficient to attract a significant amount of capital from an investor. The CCA submits this speaks to the current level of return being satisfactory as significant capital attraction has occurred."[276] The CCA also stated:

> It is a fair further inference [that] the due diligence of a 3.2 billion dollar investor would include some assessment of the matters currently and expected to be at risk for the owner acquiring the assets and this, we submit, includes recent, ongoing and expected regulatory events which impact the operation of the assets, their financial performance and the return to the shareholder. …[277]

209. In the CCA's view, the above observations "are indicative of the significance of the proposed acquisition and this can provide comfort to the AUC that under the status quo in [light] of what may be expected the entities regulated by the AUC do attract capital."[278]

Commission findings

210. There was considerable debate in this proceeding as to the relevance, if any, of price-to-book ratios. Ms. McShane pointed to the following three issues as supportive of her view that examining the P/B ratio resulting from the proposed acquisition of AltaLink by BHE is of little or no probative value relative to the ROE determinations for the Alberta utilities:[279]

- The acquisition is not at the AltaLink LP (the regulated utility) level. It is "a couple of levels up,"[280] with BHE proposing to acquire the equity in (i) AltaLink Holdings, L.P. and (ii) SNC-Lavalin Energy Alberta Ltd. and by doing so will acquire interest in the subsidiary entities.[281]

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275 Exhibit 151.01, CAPP argument, paragraph 89.
276 Exhibit 149.01, CCA argument, paragraph 15.
277 Exhibit 149.01, CCA argument, paragraph 16.
278 Exhibit 149.01, CCA argument, paragraph 17.
279 Transcript, Volume 4, page 528, line 19 to page 530, line 11 (Ms. McShane).
280 Transcript, Volume 4, page 528, lines 19-20 (Ms. McShane).
281 Exhibit 86.01, AUC-Utilities-AML-21(b).

- The purchase is not expected to be completed until the end of 2014, so any calculation of the P/B ratio would require a forecast of common equity on the AltaLink L.P. balance sheet at the time of the transaction.
- There are multiple reasons that inform the price an investor is willing to pay in utility acquisitions, including geographic diversification, synergies and re-structuring for tax purposes.

211. Dr. Booth referred to the first issue as a “dirty window” problem.[282] This problem describes the difficulty attendant in interpreting market-to-book value ratios of corporate shares where the subject company has significant unregulated activities in addition to regulated operations. Dr. Booth pointed out that to properly calculate the P/B ratio at the regulated company level, it is necessary to adjust the observed P/B ratio by taking into account any goodwill, debt and equity at the holding company level (for which the P/B ratio is observed), at the time of the transaction.[283] Dr. Cleary generally agreed with this type of adjustment.[284]

212. In Decision 2011-474, the Commission indicated it was “unable to derive any useful information about the price-to-book ratios of stand-alone utilities from the price-to-book ratios of utility holding companies.”[285] The Commissions previous conclusion in this regard flows from the general “dirty window” concern identified by Dr. Booth. In this case, however, the Commission considers that any “dirty window” problem associated with the proposed purchase of AltaLink by BHE does not vitiate the probative value of the observed P/B ratio in making an ROE determination. This is because although the transaction in question involves the indirect acquisition of a regulated utility through the purchase of a holding entity, the holding entity has no operations, tangible assets, or earnings arising from sources apart from the utility. In this sense, the transaction may be appreciated as being the functional equivalent of an acquisition of a “pure-play” utility.

213. The organizational chart of the AltaLink companies provided in a DBRS rating report dated September 25, 2013, shows that the capital structure of the companies “a couple of levels up” from the regulated utility, AltaLink Holdings, L.P. and AltaLink Investments, L.P., include $640 million in senior unsecured debt non-consolidated in those entities, in addition to debt at the regulated utility level, AltaLink L.P.[286] In response to AUC-Utilities-AML-21, AltaLink confirmed that, as part of the transaction, “BHE will acquire 100% of the equity interests of the AltaLink entities including the assumption of debt existing at each entity at the date of the closing.”[287] Financial statements provided in response to that IR show that the balance sheet for AltaLink L.P. as of March 31, 2014, reflects goodwill in the amount of $202 million.[288]

214. As Drs. Booth[289] and Cleary[290] indicated, the P/B ratio in respect of the AltaLink transaction may need to be adjusted to account for additional layers of debt at the holding company level in order to mitigate any “dirty window” concern and adequately address valuation

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282 Transcript, Volume 7, page 959, line 6 to page 960, line 7 (Dr. Booth).
283 Transcript, Volume 7, page 1119, line 23 to page 1120, line 2 (Dr. Booth).
284 Transcript, Volume 6, page 858; Transcript, Volume 6, pages 863-864 (Dr. Cleary).
285 Decision 2011-474, paragraph 122.
286 Exhibit 66.01, AUC-Utilities-20(d) Attachment, DBRS Rating Report on AltaLink Investments, L.P. dated September 25, 2013, PDF page 644.
287 Exhibit 86.01, AUC-Utilities-AML-21(c).
288 Exhibit 86.01, AUC-Utilities-AML-21(c)-(ii)-B, PDF page 44.
289 Transcript, Volume 7, page 1119, lines 7-22 (Dr. Booth).
290 Transcript, Volume 6, page 858, line 10 to page 859, line 2 and page 863, lines 8-20 (Dr. Cleary).

concerns relating to goodwill reflected on AltaLink L.P.'s balance sheets. Without evaluating the specific need for any such adjustments, the Commission observes that in this case, any such adjustments would directionally increase the implied equity P/B ratio for the tangible equity at the regulated utility level. The Commission also observes that AltaLink L.P. earns a regulated return on the equity invested in approved rate base (which is roughly equal to tangible book value) and that no additional return is awarded in respect of equity invested in goodwill, which is an intangible asset.

215. In relation to the second area of concern identified by Ms. McShane, the Commission considers that the magnitude of the potential adjustments discussed above is likely to exceed any effects on P/B ratio of equity injections to AltaLink L.P from March 31, 2014 (the date of the financial statements) to the end of 2014 (the date when the purchase is expected to be completed). In this regard, the Commission agrees with Dr. Booth's observation that it "would have to have huge capital injections by SNC-Lavalin to cause problems."[291]

216. Based on the above, the Commission considers that Dr. Cleary's estimate of the P/B ratio associated with the proposed purchase of AltaLink by BHE in the range of 1.5 to 2.3, after accounting for goodwill and the assumed debt associated with the transaction, is reasonable.[292] In arriving at this conclusion, the Commission notes that Dr. Booth also surmised that the P/B ratio associated with the AltaLink purchase by BHE "is clearly going to be well above 1.15."[293]

217. Ms. McShane's last identified area of concern related to reliance on P/B ratios was based on her observation that there are multiple reasons that inform the price an investor may be willing to pay in utility acquisitions, including geographic diversification, synergies and benefits associated with re-structuring for tax purposes. The Commission agrees that these are relevant considerations when assessing the significance of a P/B ratio associated with a given transaction.

218. In Decision 2011-474, the Commission stated: "With respect to the recent AltaLink purchase by the SNC-Lavalin Group Inc., given the above discussion, the Commission considers that there may be business reasons for this purchase that are not well understood."[294] Furthermore, in its report on this particular acquisition, S&P indicated that "AILP [AltaLink Investments L.P.] will be of more strategic importance to BHE than its nonstrategic status to SNC-Lavalin and that this could affect the ratings after the close."[295]

219. However, even when these considerations are taken into account, the Commission accepts the general proposition of Drs. Cleary[296] and Booth that there is "a healthy premium over the book value of the equity"[297] associated with BHE's proposed purchase of AltaLink. The Commission further considers that this apparent "healthy premium" is sufficiently large to support a reasonable conclusion that it accommodates the influence of any strategic motives on behalf of BHE (diversification, synergies and re-structuring for tax purposes), as well as a

291 Transcript, Volume 7, page 1120, lines 4-5 (Dr. Booth).
292 Transcript, Volume 6, page 863, line 1 to page 864, line 20 (Dr. Cleary).
293 Transcript, Volume 7, page 1120, lines 3-4 (Dr. Booth).
294 Decision 2011-474, paragraph 122.
295 Exhibit 86.01, AUC-Utilities-AML-21(a), Standard & Poor's Ratings Services, Research Update: AltaLink Investments L.P. Outlook Revised To Positive On Announced Sale To Berkshire Hathaway Energy Co. Issued May 5, 2014, page 2.
296 Transcript, Volume 6, page 864, lines 17-20 (Dr. Cleary).
297 Exhibit 79.02, Booth and Johnson rebuttal evidence for Calgary, page 8.

conclusion that the utilities' previously awarded or expected ROE was sufficiently attractive for BHE to support its decision to invest in the utility at the proposed price.

220. Further in this regard, the Commission notes the CCA's argument that BHE's decision to purchase AltaLink's transmission business considered the impact of the regulatory framework, including the most recent Commission award of 8.75 per cent ROE in the 2011 GCOC decision:

> It is a fair further inference [that] the due diligence of a 3.2 billion dollar investor would include some assessment of the matters currently and expected to be at risk for the owner acquiring the assets and this, we submit, includes recent, ongoing and expected regulatory events which impact the operation of the assets, their financial performance and the return to the shareholder. …[298]

221. Overall, the Commission confirms its findings in Decision 2011-474[299] that an examination of a given company's P/B ratio in isolation is unlikely to provide a foundation for definitive conclusions regarding the establishment of a specific ROE for regulatory purposes. However, it also considers that such information, where available, may supplement an investigation into the perceived fitness of a regulated utility with a view to determining the adequacy of a utility's awarded ROE to ensure that it is sufficiently able to attract investment in the capital markets at reasonable rates and maintain its financial integrity.

222. The implied P/B ratio associated with the proposed purchase of AltaLink by BHE gives the Commission comfort that its previous ROE awards have not been too low. As stated in previous GCOC decisions, and most recently in Decision 2011-474, the "payment of premiums in such transactions for assets that are earning returns based on ROE awards that are allegedly below market would not appear to be rational."[300]

223. Directionally, the Commission concludes that the implied P/B ratio associated with the proposed purchase of AltaLink by BHE is relevant and supports continuation of an ROE no higher than the Commission's allowed ROE of 8.75 percent awarded in Decision 2011-474, all other things being equal.

5.4 Pension, investment manager and economist return expectations

224. In his evidence, Dr. Cleary considered return expectations of finance professionals such as financial planners, actuaries, investment managers and pension fund managers as a means of confirming his ROE estimates. Dr. Cleary observed:

> … Indeed, aggregate stock market return expectations of 8-9% has become the "norm" in terms of planning among today's investment professionals including actuaries, pension plans, financial advisors, and most professional and retail investors. Hence, it seems that in this environment, it is reasonable to expect that the required return on regulated utility companies should be lower than the average expected market returns, given their below average risk profiles.[301]

[298] Exhibit 149.01, CCA argument, paragraph 16.
[299] Decision 2011-474, paragraph 122.
[300] Decision 2011-474, paragraph 121.
[301] Exhibit 45.03, Cleary evidence for UCA, page 2.

225. In response to AUC-UCA-6, Dr. Cleary provided support for the referenced 8.0 per cent to 9.0 per cent aggregate stock market return expectations.[302]

226. Dr. Booth referenced the TD Economics projections "of the long-run returns of the type needed in defined benefit pension plans."[303] The TD Economics projected geometric long-run return for equities was seven per cent, which equals an approximately nine per cent arithmetic average annual rate of return, as calculated by Dr. Booth.[304] Dr. Booth also referenced the RBC long-run forecast of U.S. equity market return of 4.9 per cent, however, he regarded this forecast as "unduly pessimistic." Based on these market return projections, Dr. Booth concluded that his forecast for the overall equity market return of 9.56 per cent is not low.[305]

227. In response to UCA-Utilities-33(b), Ms. McShane referenced the 2013 Towers Watson Wyatt survey of economists and portfolio managers. According to this survey, the median forecast return for the S&P/TSX composite for the long-term was seven per cent,[306] which equals a 9.75 per cent arithmetic average rate of return, as calculated by Ms. McShane.[307]

228. Ms. McShane questioned the relevance of the return expectations of finance professionals to a determination of an appropriate ROE. In her view, this value "represents the return that investors might expect from a diversified equity stock portfolio, but does not represent the returns that investors expect or require from investments in companies of comparable risk. In other words, it does not address the comparable investment requirement of the fair return standard."[308] However, during the hearing, Ms. McShane also acknowledged that returns from low risk utility investments are likely to be lower than the overall equity stock portfolio return:

> Q. But just so I'm clear, utility -- investments in utilities, lower risk, lower return than generally you'd expect in an overall portfolio that a pension fund manager invests in. Is that a fair statement?
> A. MS. MCSHANE: I would say it's a fair statement that you would expect a lower return from a utility than an average risk stock.[309]

229. Ms. McShane also pointed out that finance professionals "have every incentive to be quite conservative."[310] With reference to Ms. McShane's evidence in this regard, the Alberta Utilities submitted that the Commission should decline to give weight to return expectations by finance professionals in establishing a fair ROE.[311]

230. In Calgary's view, the use of return forecasts by finance professionals should not be relied upon by the Commission without analyzing and making adjustments to the values being considered. Calgary submitted that "the Commission has the responsibility to determine a fair

302 Exhibit 68.02, AUC-UCA-6(a).
303 Exhibit 44.02, Booth evidence for CAPP, paragraph 169.
304 Exhibit 44.02, Booth evidence for CAPP, paragraph 170.
305 Exhibit 44.02, Booth evidence for CAPP, paragraph 198.
306 Exhibit 73.01. UCA-Utilities-33(b).
307 Transcript, Volume 4, page 480, lines 22-25 (Ms. McShane).
308 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 38.
309 Transcript, Volume 1, page 127, lines 16-22 (Ms. McShane).
310 Transcript, Volume 4, page 484, lines 3-10 (Ms. McShane).
311 Exhibit 148.01, Alberta Utilities argument, paragraph 92.

return, and it should not abdicate that responsibility to another party for which it has no detailed information as to how or on what basis the party made a forecast."[312]

231. In argument, the UCA observed that in Decision 2004-052,[313] the Commission's predecessor, the Alberta Energy and Utilities Board (the board), recognized the potential for forecast pension return estimates to be conservative, but nonetheless concluded "the Board would expect the required return for utilities to be below the required overall equity market return."[314] The UCA also noted that, in its 2011 GCOC decision, the Commission weighed the market return expectations of pension funds, investment managers and economists in reaching a conclusion as to the appropriate allowed ROE.

232. Therefore, in the UCA's view, return expectations by finance professionals continue to be illustrative in the current proceeding. In the UCA's submission, the expectations of investment professionals as to market returns remain relevant to, and create a benchmark and upper bound for, estimates of an appropriate allowed ROE.[315]

Commission findings

233. As pointed out by the UCA, previous GCOC decisions of the Commission and its predecessor, the board, took the return expectations by finance market professionals such as investment managers, pensions fund managers and economists into consideration in arriving at an allowed ROE value. The Commission continues to hold the view that return expectations of finance market professionals are germane to the determination of a fair ROE for regulated utilities.

234. In Decision 2004-052, the board determined that "forecast pension returns on equity investment are a valid indicator, albeit potentially conservative, of the forecaster's current market equity return expectation."[316] The Commission agrees with its predecessor's assessment in this regard, and further notes that, in this proceeding, both Ms. McShane[317] and Dr. Booth[318] also observed that return estimates by pension fund managers tend to be rather conservative.

235. The Commission also agrees with the board's conclusion in Decision 2004-052 that it is reasonable to "expect the required return for utilities to be below the required overall equity market return,"[319] given that, on average, investments in utility stocks are typically less risky than investments in the average company stock in the market.

236. The Commission notes that while Ms. McShane expressed the view that return expectations of finance market professionals represent "the return that investors might expect from a diversified equity stock portfolio, but does not represent the returns that investors expect

312 Exhibit 146.02, Calgary argument, paragraph 21.
313 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 1271597-1, July 4, 2004.
314 Decision 2004-052, page 29.
315 Exhibit 150.02, UCA argument, page 27.
316 Decision 2004-052, page 29.
317 Transcript, Volume 4, page 484, lines 3-10 (Ms. McShane).
318 Transcript, Volume 7, page 1087, lines 13-16 (Dr. Booth).
319 Decision 2004-052, page 29.

or require from investments in companies of comparable risk,"[320] she also acknowledged that one "would expect a lower return from a utility than an average risk stock."[321] In the Commission's view, the allowed ROE should reflect the return on a utility stock required by investors who hold the stock in a diversified portfolio. This assumption is consistent with the theoretical underpinnings of the CAPM.

237. In Decision 2004-052, the board observed that "the forecast pension return is akin to a geometric average and would therefore understate the forecaster's short-term expectation for the market return."[322] In this proceeding, both Ms. McShane and Dr. Booth calculated arithmetic average rate of return numbers to correct for this understatement.

238. In her evidence, Ms. McShane referenced the 2013 Towers Watson Wyatt survey of economists and portfolio managers, which indicated that the median forecast return for the S&P/TSX composite for the long-term was seven per cent, which equals a 9.75 per cent arithmetic average rate of return.[323] Dr. Booth's evidence referenced a TD Economics projected geometric long-run return for equities of seven per cent, which equals approximately a nine per cent arithmetic average annual rate of return.[324] Dr. Cleary referenced aggregate stock market return expectations of eight to nine per cent.[325]

239. Based on its assessment of these estimates, the Commission finds that arithmetic return expectations of finance market professionals for the overall equity market can reasonably be estimated to be in the nine per cent range. The Commission further notes that this value is consistent with the results of the DCF analysis applied to the market as a whole, using long-term averages, as set out in Section 5.2. The Commission considers that, directionally, the required return for regulated utilities would be below the required overall market return.

5.5 Other methods for estimating cost of equity

240. In preceding sections of this decision, the Commission has considered the CAPM and DCF methods for estimating the cost of equity. As well, the Commission has considered the relevance of price-to-book ratios for ROE determinations, and examined return expectations of professional capital market participants such as managers of pension funds, investment managers and economists.

241. Experts who participated in this proceeding also employed a number of other methods for estimating a fair ROE. For example, Ms. McShane's ROE recommendations were influenced by the DCF-based equity risk premium test and historic utility risk premium test. Dr. Cleary used a bond yield plus risk premium estimate, in addition to his CAPM and DCF-based approaches.

5.5.1 DCF-based equity risk premium test

242. Ms. McShane explained that the DCF-based equity risk premium test estimates the utility equity risk premium as the difference between the DCF cost of equity and yields on long-term government bonds. Another variant of this test estimates the risk premium as the difference

320 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 38.
321 Transcript, Volume 1, page 127, lines 16-22 (Ms. McShane).
322 Decision 2004-052, page 29.
323 Transcript, Volume 4, page 480, lines 22-25 (Ms. McShane).
324 Exhibit 44.02, Booth evidence for CAPP, paragraph 170.
325 Exhibit 45.03, Cleary evidence for UCA, page 2.

between the DCF cost of equity and yields on long-term A-rated utility bonds.[326] According to Ms. McShane, the DCF-based equity risk premium test estimates the equity risk premium directly for regulated companies by explicitly analyzing the company equity return data, as opposed to CAPM models, which estimate the required utility equity risk premium indirectly by focusing on the risk-free rate and returns at the overall market level.[327]

243. Dr. Booth expressed the view that "Ms. McShane's DCF based risk premium analysis is also suspect." In doing so, he pointed out that the "BCUC [British Columbia Utilities Commission], when confronted with this evidence, indicated serious concerns about the *ad hoc* nature of the models used by Ms. McShane" and placed no weight on the results of this analysis.[328]

244. In its reply argument, the UCA questioned the theoretical basis for a DCF-based equity risk premium test, on the grounds that the DCF model does not include a risk parameter. Further, the UCA submitted, "Ms. McShane's DCF based equity risk premium tests suffers from the same flaws as are inherent in her overall DCF analyses – including heavy reliance on analyst's forecasts for growth and income yield and a consideration of total income returns, as opposed to total bond returns, to measure returns over the RF [risk-free] rate." On these bases, the UCA submitted "such a test suffers from serious theoretical and methodological defects, and ought not be adopted by the Commission."[329]

Commission findings

245. The Commission agrees that, as was observed by both Dr. Booth[330] and the UCA, Ms. McShane's DCF-based equity risk premium test combines elements of both the DCF and CAPM models to estimate the utility equity risk premium. The Commission also agrees with the submission of the UCA that, as a result, this approach suffers from drawbacks inherent in *both* the DCF and CAPM models, while its theoretical and methodological benefits are difficult to determine with certainty.[331]

246. In light of these identified concerns, and given that there is ample evidence on both DCF-based and CAPM-based estimates on the record of this proceeding, the Commission did not elect to include Ms. McShane's DCF-based equity risk premium test in its overall considerations in determining a fair ROE for the affected utilities.

5.5.2 Historic utility equity risk premium test

247. In her ROE analysis, Ms. McShane considered the historic market returns for utilities, which, in her view, provided an additional perspective on a reasonable expectation for the forward-looking utility equity risk premium. In her view, the historical utility equity risk premium test provides estimates of market returns that have actually been available to investors and is based on the assumption that these same returns are likely to be available to investors from

[326] Exhibit 42.02, McShane evidence for Alberta Utilities, pages 108 and 112.
[327] Exhibit 42.02, McShane evidence for Alberta Utilities, pages 108-109.
[328] Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 13.
[329] Exhibit 156.02, UCA reply argument, page 28.
[330] Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 14.
[331] Exhibit 156.02, UCA reply argument, page 28.

comparable investments.[332] According to Ms. McShane, this test and the underlying data provide a direct measure of comparable investment returns.

248. In his rebuttal evidence, Dr. Booth pointed out that, in Decision 2011-474, the Commission stated:

> 99. The Commission agrees with the UCA that part of the reason for higher historic returns may be that allowed returns have been above the actual ROE that investors expected and required for investments of comparable risk. The Commission finds that the evidence on historic returns is inconclusive with respect to the return investors expect on comparable investments.[333]

249. Dr. Booth stated "Nothing has changed in this regard and … other regulators have also disregarded historic returns." He confirmed his continued support of the conclusion drawn in Decision 2011-474, and recommended that the Commission continue to place no weight on Ms. McShane's historic utility estimate.[334]

250. During the hearing, Ms. McShane indicated that she had prepared her evidence having regard to the Commission's findings in Decision 2011-474, and focused on "the relative size historically of utilities versus the market as a whole", which ultimately led her to the conclusion that "the returns on a size-adjusted basis are quite consistent with the relative risk."[335]

251. The UCA, addressing Ms. McShane's use of historic utility return estimates in its argument, submitted that "despite these apparent adjustments, Ms. McShane's consideration of historic utility data, and her estimates arising from the same, are practically identical to those she put forth in the 2011 GCOC Decision." The UCA ultimately recommended that the Commission give no weight to this evidence in considering a fair ROE, as it did in Decision 2011-474.[336]

Commission findings

252. Despite the fact that Ms. McShane adjusted her historical utility equity risk premium test to focus on the size of the utilities relative to the market as a whole, the Commission considers that this test still relies on the actual returns achieved by the utilities and these actual returns serve as a baseline against which the historical utility equity risk premium is measured.

253. As previously noted, in Decision 2011-474, the Commission held that actual achieved utility ROEs are not necessarily reflective of the return that investors expected, and required, for investments of comparable risk.[337] In Decision 2009-216, the Commission expressed a similar view (albeit with reference to the comparable earnings test).[338] The Commission considers that it has not, in this proceeding, been persuaded on the basis of new evidence or argument that it should alter its previous assessment of the predictive value of this method. Therefore, the Commission will not consider the historical utility equity risk premium test put forward by Ms. McShane in its determination of a fair ROE.

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332 Exhibit 81.02, Ms. McShane rebuttal evidence for Alberta Utilities, page 31.
333 Decision 2011-474, paragraph 99.
334 Exhibit 80.01, Booth rebuttal evidence for CAPP, paragraph 4.
335 Transcript, Volume 4, pages 486-487 (Ms. McShane).
336 Exhibit 150.02, UCA argument, page 31.
337 Decision 2011-474, paragraph 99.
338 Decision 2009-216, paragraph 280.

254. The Commission finds support for its determination in this regard in its consideration of a table produced by Dr. Cleary, in this proceeding, which compared allowed ROEs with actual earned ROEs for eleven Alberta utilities for the period of 2009-2012. In discussing this data, Dr. Cleary observed that "overall, we can say that these utilities generate ROEs that are generally slightly above the allowed rates."[339] This being the case, the Commission concludes that one of the reasons that "utilities have earned almost as much as the average Canadian company"[340] may be that actual achieved ROEs have consistently exceeded allowed ROEs.

5.5.3 Bond yield plus risk premium estimates

255. In arriving at his recommended ROE estimate, Dr. Cleary relied on a "bond yield plus risk premium" approach, to which he attributed a one-third weight in his overall conclusions on the fair ROE. Dr. Cleary explained that the intent of this approach is to add a risk premium to the yield on a firm's outstanding publicly-traded long-term bonds.

256. Dr. Cleary noted that the usual range of risk premium utilized in this analysis is two to five per cent with 3.5 per cent being commonly utilized to reflect average risk companies; with lower values being used for less risky companies. Given the low-risk nature of Canadian regulated utilities, Dr. Cleary opined that an appropriate risk premium for these companies would be in the two to three per cent range, with a best estimate of 2.5 per cent.

257. While Dr. Cleary acknowledged that this approach appears to be somewhat *ad hoc* in nature, he maintained that it does provide a useful "reasonableness check" on CAPM and other estimates, and is intuitively attractive. The intuitive value underlying the approach is that it uses typical relationships between bond and stock markets, along with information that can be readily obtained from observable market-determined bond yields, to estimate a required rate of return on a firm's stock.[341]

258. Ms. McShane expressed concerns with the bond yield plus risk premium approach, noting that she has never seen this test used in a cost of capital proceeding in either Canada or the United States. Ms. McShane also asserted that there is no empirical support for the two to five per cent risk premium range that Dr. Cleary identified.[342]

259. In addition, Ms. McShane contended that the relative risk of regulated utilities has already been taken into account in the lower cost of debt to which the risk premium is applied. In light of this fact, she maintained that adding a lower than average risk premium to the utility cost of debt has the effect of accounting for the utilities' lower than average risk twice. Moreover, "the addition of a risk premium at the lower end of the range when the utility bond yields themselves are at the low end of historical levels fails to take account of the inverse relationship between interest rates and risk premiums. The result will thus understate the cost of equity."[343]

Commission findings

260. Dr. Cleary showed that the bond yield plus risk premium approach is commonly used by Canadian finance professionals. He conceded that "this approach appears to be somewhat

339 Exhibit 45.03, Cleary evidence for UCA, page 48.
340 Exhibit 45.03, Cleary evidence for UCA, page 49.
341 Exhibit 45.03, Cleary evidence for UCA, pages 44-47.
342 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 43.
343 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 44.

'ad hoc' in nature," but that, nevertheless, it "does provide a useful reasonableness check on CAPM and other estimates, and employs solid intuition."[344]

261. The Commission agrees with Dr. Cleary's view that the bond yield plus risk premium approach does hold a certain appeal for finance professionals because it is simple to use and is based on the same premise as the CAPM; namely, that investors require a higher return for assets with greater risk.[345] However, the Commission is also mindful that this simplicity may not always be advantageous, particularly in the current environment of historically low interest rates. Indeed, as pointed out by Ms. McShane, "the addition of a risk premium at the lower end of the range when the utility bond yields themselves are at the low end of historical levels fails to take account of the inverse relationship between interest rates and risk premiums."[346] The Commission notes by way of comparison that CAPM estimates explicitly take this inverse relationship into account, as set out in Section 5.1.3.

262. Considering that, according to Dr. Cleary, the bond yield plus risk premium test has somewhat of an *ad hoc* nature and provides a "reasonableness check on CAPM"[347] and given the ample evidence on CAPM-based ROE estimates in this proceeding, the Commission will not place significant weight on this test in determining a fair ROE for the utilities.

5.6 The Commission's awarded ROE for 2013, 2014 and 2015

263. The Alberta Utilities requested a generic benchmark ROE of 10.5 per cent for 2013 and 2014, based on the expert evidence of Ms. McShane. Regarding the 2015 ROE, Ms. McShane indicated that because her analysis is based on a normalized long-term government of Canada yield of four per cent, she would recommend the same 10.5 per cent generic benchmark ROE for 2015 as she recommended for 2013 and 2014. The Alberta Utilities endorsed Ms. McShane's approach for 2015.[348] However, the Alberta Utilities submitted that if the Commission were to base the allowed ROE on different long-term Canada bond yields for each year, the 2015 ROE should be higher than the recommended 2014 value.[349]

264. The Alberta Utilities also submitted that "it is critical that the Commission base its generic ROE decision on the results of multiple tests" and urged the Commission "to not rely on the Capital Asset Pricing Model as the 'centerpiece' of its generic ROE decision as it has in previous GCOC decisions."[350] As Ms. McShane testified:

> Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of ensuring that all three requirements of the fair return standard are met; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return. Changes to the inputs to individual tests may have different implications depending on the prevailing economic and capital market conditions. These considerations emphasize the importance of reliance on multiple tests.[351] [footnotes omitted]

[344] Exhibit 45.03, Cleary evidence for UCA, page 45.
[345] Exhibit 45.03, Cleary evidence for UCA, page 45.
[346] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 44.
[347] Exhibit 45.03, Cleary evidence for UCA, page 45.
[348] Exhibit 148.01, Alberta Utilities argument, paragraph 138.
[349] Transcript, Volume 3, page 426, line 13 to page 427, line 2 (Ms. McShane).
[350] Exhibit 148.01, Alberta Utilities argument, paragraphs 22-23.
[351] Exhibit 42.02, McShane evidence for Alberta Utilities, page 74.

265. CAPP, in its argument, submitted that Dr. Booth's evidence in this proceeding "shows that no increase in allowed ROE is warranted and if anything the ROE should be reduced."[352] Dr. Booth recommended an ROE of 7.50 per cent for 2013 and 2014.[353] For 2015, Dr. Booth indicated he would be "be quite happy with a fixed rate of return for all three years, exactly the same."[354]

266. Dr. Cleary, for the UCA, calculated a best estimate of a generic benchmark ROE of 6.78 per cent for 2013, 7.27 per cent for 2014 and 7.42 per cent for 2015.[355] The UCA, in its argument, recognized that the recommended ROEs put forth by Dr. Cleary are lower than those awarded in previous decisions. However, it nonetheless submitted that:

> … these estimates are supported by sound business and finance principles through a reasonable application of the models identified above, and are very consistent with the observed low costs of issuing market debt faced by utilities – for example, numerous examples have been entered into evidence of A-rated utilities issuing 30 and even 50-year debt with yields in the 4.0-4.5% range. These numbers are also very consistent with current long-term expectations for the overall stock market – falling in the range of 6-8.5% according to evidence reported by Dr. Cleary, as well as by Ms. McShane. The fact of the matter is that interest rates have fallen at the government level, and will remain at low levels by historical standards for the foreseeable future in our present low inflation rate environment – therefore the days of "double digit" expected returns on the overall stock market are behind us, and hence the required return by investors on low-risk utilities have also fallen below long-term averages.[356]

267. Table 4 below summarizes the recommended ROEs for 2013, 2014 and 2015.

Table 4. Summary of ROE recommendations

	Recommended by the Alberta Utilities[357] (Ms. McShane)	Recommended by the UCA[358] (Dr. Cleary)	Recommended by CAPP[359] (Dr. Booth)
	(%)		
2013	10.50	6.78	7.50
2014	10.50	7.27	7.50
2015	10.50	7.42	7.50

268. The CCA accepted the ROE recommendation of Dr. Booth for CAPP of 7.50 per cent for 2013 and 2014. It also considered that it would be appropriate to establish the 2014 ROE as a placeholder for 2015.[360]

352 Exhibit 151.01, CAPP argument, paragraph 93.
353 Exhibit 44.02, Booth evidence for CAPP, page 3.
354 Transcript, Volume 7, page 1160, line 18 to page 1162, line 8 (Dr. Booth).
355 Exhibit 45.03, Cleary evidence for UCA, page 53.
356 Exhibit 150.02, UCA argument, page 39.
357 Exhibit 148.01, Alberta Utilities argument, paragraphs 135-138.
358 Exhibit 150.02, UCA argument, page 40.
359 Exhibit 151.01, CAPP argument, paragraphs 93 and 97.
360 Exhibit 149.01, CCA argument, paragraphs 18-20.

269. Calgary adopted Dr. Booth's 2013-2015 ROE recommendations for application to ATCO Gas.[361]

Commission findings

270. In this decision, the Commission has set out to establish a fair rate of return on equity for 2013, 2014 and 2015 for the utility companies it regulates. As explained in previous GCOC decisions, most recently in Decision 2011-474, the awarded ROE must be based on an estimate of the risk-adjusted opportunity cost of equity capital. The Commission must estimate the return on equity that utility investors are foregoing by having their equity invested in these utilities rather than in other investments of similar risk that are available in the market. The difficulty that the Commission faces is that the ROEs that are available to be earned on investments of similar risk are not directly observable.[362] In keeping with the determinations in previous GCOC decisions, the Commission will establish a generic ROE to be applied to each of the utility businesses it regulates as if they were stand-alone utilities.

271. The Commission agrees with the view of Ms. McShane and the Alberta Utilities[363] that the benchmark generic ROE should be established on the results of multiple tests, as "each of the tests has its own strengths and weaknesses" and "no single test can pinpoint the fair return."[364] Indeed, as set out in preceding sections of this decision, the Commission has largely relied on the CAPM and DCF methods (including an analysis of the expected overall Canadian stock market returns) to estimate the cost of equity. As well, the Commission has considered the relevance of price-to-book ratios to ROE determinations, and examined return expectations by professional capital market participants such as managers of pension funds, investment managers and economists. While other methods were put forward in this proceeding (including Ms. McShane's DCF-based equity risk premium and historic utility risk premium tests and Dr. Cleary's bond yield plus risk premium test), the Commission assigned a lesser or nil weighting to them for the reasons discussed in Section 5.5.

272. As set out in Section 5.1, the Commission finds that a reasonable CAPM estimate is in the range of 5.80 per cent to 8.75 per cent based on its analysis of the relevant risk-free rate, MERP, beta and including the flotation allowance. This CAPM estimate is lower than the 2011 CAPM estimate of 6.4 to 9.0 per cent in Decision 2011-474,[365] because of the dramatic decrease in risk-free rates and a slight decrease in the MERP estimate, in circumstances where both beta and the floatation allowance remained unchanged.

273. In Section 5.2 of this decision, the Commission found that DCF-model results appear to suggest that investors expect a return of between 7.5 to 9.5 per cent on regulated utility investments. However, the Commission considers that these estimates assume that utilities' dividends and earnings will grow at the long-run GDP growth rate, which may be an optimistic target for low-risk mature regulated utilities.

274. In Section 5.3, the Commission considered the relevance of P/B ratios to ROE determinations with specific reference to the implied P/B ratio associated with the proposed purchase of AltaLink by BHE. In doing so, the Commission concluded that the implied P/B ratio

361 Exhibit 146.02, Calgary argument, paragraphs 26.
362 Decision 2011-474, paragraph 143.
363 Exhibit 148.01, Alberta Utilities argument, paragraph 22.
364 Exhibit 42.02, McShane evidence for Alberta Utilities, page 74.
365 Decision 2011-474, paragraph 77.

associated with the proposed purchase of AltaLink by BHE is relevant and supports continuation of an ROE no higher than the Commission's allowed ROE of 8.75 percent awarded in Decision 2011-474, all other things being equal.

275. Finally, in Section 5.4, the Commission determined that evidence provided by interveners suggests that pension fund managers', investment managers' and economists' return expectations for the market are in the nine per cent range. In the Commission's assessment, it is reasonable to expect the required return for regulated utilities to be below the required overall equity market return of approximately 9.0 per cent, given their low-risk nature.

276. Having considered and weighed all of the evidence and assessed it in the context of a further improvement in the global financial market and economic conditions since the 2011 GCOC proceeding, and considering the current environment of historically low interest rates, the Commission finds that some reduction in the ROE awarded in Decision 2011-474 is warranted. In this respect, the Commission generally agrees with the UCA's conclusion that the current environment of low interest rates may result in the creation of circumstances where, at least in the near term, "the days of 'double digit' expected returns on the overall stock market are behind us, and hence the required return by investors on low-risk utilities have also fallen below long-term averages."[366]

277. In light of the above considerations, the Commission finds that a generic ROE of 8.3 per cent is reasonable for each of 2013, 2014 and 2015.

6 Potential impact of regulatory risk requiring an ROE adjustment or capital structure adjustment, or both

278. The following sections summarize and discuss the views of the parties on the potential impacts on regulatory risk resulting from the UAD decision; the PBR framework for distribution utilities; as well as other potential risks perceived by the utilities.

6.1 Impact of Utility Asset Disposition decision

279. On November 26, 2013, the Commission issued the UAD Decision 2013-417. The Commission included on the issues list for this proceeding a consideration of what impact, if any, the issuance of the UAD decision had on the nature or amount of regulatory risk faced by the Alberta Utilities.

280. Expert evidence addressing the impacts of the UAD decision on risk was provided by Ms. McShane and Mr. Fetter for the Alberta Utilities, Dr. Cleary for the UCA, and Dr. Booth for Calgary.

281. Ms. McShane asserted that:

> … the UAD Decision has introduced a level of uncertainty for which equity investors will require additional compensation. The increased uncertainty should be compensated for in the allowed ROE, which can be expressed as a premium to the benchmark utility

[366] Exhibit 150.02, UCA argument, page 39.

> ROE. I have estimated the premium to compensate for the increased uncertainty alone created by the UAD Decision at approximately 1.25% to 1.5%.[367]

282. Ms. McShane explained that the:

> … AUC then broadly asserted that extraordinary retirements could include, according to the [UAD] decision, obsolete property, property to be abandoned, overdeveloped property and more facilities than necessary for future needs, property used for non-utility purposes and surplus land (para. 303) and property that should be removed from rate base because of circumstances including unusual casualties (fire, storm, flood, etc.), sudden and complete obsolescence, or unexpected and permanent shutdown of an entire operating assembly or plant (para. 327).[368]

283. Ms. McShane also commented that the:

> … AUC's finding in the *UAD Decision* that extraordinary retirements are to the account of the shareholder, potentially disallowing the recovery of prudently incurred costs, is at odds with that premise and at odds with mainstream regulatory practice throughout North America, including past practice in Alberta.[369]

284. Mr. Fetter, on behalf of the Alberta Utilities, concurred, stating:

> Now, with the recent issuance of its Utility Asset Disposition ("UAD") Decision, the AUC has created the risk that shareholders will bear stranded asset losses, notwithstanding the absence of any imprudent behavior on the part of utility management. Such a policy would appear to stand alone among North American utility regulatory policies, and the manner in which it is implemented could have a major effect on the way investors and the rating agencies view the regulatory climate in Alberta.[370]

285. In Mr. Fetter's view, increased regulatory risk created by the issuance of the UAD decision could impact the ability of utilities to raise debt capital. He explained that credit ratings are important to regulated utilities with regard to raising capital on reasonable terms[371] and that how a utility is regulated is highly important to its credit rating.[372]

286. Mr. Fetter stated that:

> … positive views of Alberta regulation may be affected by the AUC's issuance of its UAD decision in which it has placed shareholders at risk that they will bear stranded asset losses, notwithstanding the absence of imprudent behavior on the part of utility managements. As a former utility regulator and utility bond rater, I believe it is important to emphasize that such potential denial of recovery of prudently incurred stranded costs or assets would, to my knowledge, represent the first breaking of faith with past regulatory determinations …[373]

[367] Exhibit 42.02, McShane evidence for Alberta Utilities, page 6, lines 154-159.
[368] Exhibit 42.02, McShane evidence for Alberta Utilities, page 33, lines 831-837.
[369] Exhibit 42.02, McShane evidence for Alberta Utilities, page 34, lines 843-848.
[370] Exhibit 42.05, Fetter evidence for Alberta Utilities, page 5, lines 14-20.
[371] Exhibit 42.05, Fetter evidence for Alberta Utilities, page 7, lines 7-8.
[372] Exhibit 42.05, Fetter evidence for Alberta Utilities, page 10, lines 15-23.
[373] Exhibit 42.05, Fetter evidence for Alberta Utilities, page 16, lines 4-11.

287. On behalf of the UCA, Messrs. Bell and Stauft submitted that their "position is that the UAD Decision should have no impact on the Commission's determinations in this case."[374]

288. Messrs. Bell and Stauft explained that the:

> … difficulty that arises in connection with retirements of depreciable utility assets is that the Commission's long-standing and entirely conventional policies in relation to the fixing of depreciation rates for utility assets have the practical effect of allocating recovery risk for stranded asset and post-retirement costs largely to customers rather than utility shareholders. The Commission's approved depreciation mechanisms operate on a "mass account" basis, with depreciation reserve accounts that over time ensure that in aggregate the utilities recover in rates exactly their initial investments in depreciable assets, as well as any negative salvage and post-retirement costs associated with those assets.[375]

They discussed that unlike "the situation with land assets, the 'value' of depreciable assets when they are removed from utility service and from rate base is typically zero or, more likely, negative owing to negative salvage and post-retirement costs."[376]

289. Messrs. Bell and Stauft commented that there:

> … may be some suggestion in Decision 2013-417 that the Commission intends to examine more closely whether individual retirements of depreciable property are properly characterized as 'ordinary'", but there is no suggestion of any new and more rigorous test and no indication that the Commission will apply whatever test exists now in a way that would systematically disadvantage the Utilities.[377]

290. In response to an information request on whether the UAD decision had increased ATCO Pipelines' relative risk, Dr. Booth, on behalf of CAPP, stated that he:

> … does not believe that ATCO Gas [or ATCO Pipelines] will find any assets that are not "used and useful" in rate base since otherwise it implies that the rate base has been padded and management has not depreciated the assets correctly. If ATCO Gas [or ATCO Pipelines] does find that there are material assets likely to shortly meet this definition, Dr. Booth would expect them to file a new depreciation study so that they can be retired in normal course.[378]

291. Ms. McShane disputed Dr. Booth's assertion that ATCO Gas or ATCO Pipelines are not likely to identify assets which are not used and useful because it would mean that management has been depreciating these assets incorrectly. She argued that the Commission was responsible for approving depreciation rates, not the management. Changes to depreciation rates can be unforeseeable and depreciation rates are only as accurate as the information available when they are set. If an event qualified as an extraordinary retirement, then subsequent events would allow for recapture of the disallowed cost, and depreciation rates approved by the Commission may

374 Exhibit 45.02, Bell and Stauft evidence for UCA, page 3, lines 22-23.
375 Exhibit 45.02, Bell and Stauft evidence for UCA, page 19, lines 8-15.
376 Exhibit 45.02, Bell and Stauft evidence for UCA, page 19, lines 18-21.
377 Exhibit 45.02, Bell and Stauft evidence for UCA, page 20, lines 22-26.
378 Exhibit 72.02, UTILITIES-CALG-6(d); Exhibit 64.01, UTILITIES-CAPP-19(F).

reflect specific objectives such as public policy goals (e.g. transmission rate mitigation impacts).[379]

292. Ms. McShane indicated that she was not aware of any circumstances prior to the UAD decision where the post-retirement risk from extraordinary retirements was allocated to shareholders.[380] In an IR to the UCA, Messrs. Bell and Stauft could not identify any such cases.[381]

293. In rebuttal evidence, Messrs. Bell and Stauft submitted that the "Commission's conclusion was that *under the existing rules* 'stranded assets' are normally for the account of customers, although in cases of extraordinary retirements they will be for the account of shareholders."[382] [emphasis in original] They further argued that the "other fundamental principle the Commission relied on in the UAD Decision is that when assets are removed from rate base it is the utility that bears the risk associated with the residual value of those assets … the risks and rewards of asset ownership remain with utility shareholders once assets are no longer devoted to utility service."[383]

294. In their view, the "fact that with ordinary retirements of depreciable property any residual over-recover or under-recover risk is borne by customers is in some sense an exception to that general rule, although it is an exception that the Commission found to be consistent with the overall statutory scheme."[384]

295. Messrs. Bell and Stauft further submitted that:

> … it has been the utilities' position for many years that depreciable and non-depreciable assets that become stranded because they no longer have a utility purpose, like the Stores Block property and the Carbon and Salt Caverns storage facilities, must be removed from rate base, and the utility shareholders are at risk for the value of those assets once they leave utility service. The suggestion that it is a new or surprising concept that the Utilities might bear some "stranded asset risk" is inconsistent with the entire history of the UAD Decision …"[385]

and that "The claim that the UAD decision created new "stranded asset risk" for the Utilities is incorrect. Whatever risk the Utilities have in relation to stranded assets and extraordinary retirements has always been there, as the Commission explained in the UAD Decision."[386]

296. In their rebuttal evidence, Messrs. Bell and Stauft also disputed Ms. McShane's assertion that the UAD decision imposed new stranded asset risk on utilities, and submitted that if any stranded asset risk might be borne by the utilities it would not be significant enough to be meaningful to the market or relevant to the cost of capital.[387] They submitted that "[c]redit rating

379 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 3, lines 86-99.
380 Exhibit 42.02, McShane evidence for Alberta Utilities, page 5, lines 151-152.
381 Exhibit 65.02, UTILITIES-UCA-16(a).
382 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 27, lines 23-25.
383 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 28, lines 5-10.
384 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 28, lines 12-15.
385 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 28, lines 16-22.
386 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 29, lines 2-4.
387 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 27, lines 1-5.

reports that post-date the UAD Decision often fail to mention the Decision at all, and do not suggest any likely or potential ratings action."[388]

297. Further, and finally, they commented that the:

> … entire discussion of stranded asset risk in the evidence of Ms. McShane and Mr. Fetter is conceptual. Neither of them presented any evidence about any specific stranded or potentially stranded assets the Utilities are concerned about. The UCA asked the Utilities for information concerning historical and expected stranded assets and extraordinary retirements, and got no response.[389]

298. Dr. Booth, on behalf of Calgary, submitted that "many risks that people see for utilities and which they assume are borne by the shareholders end up being reallocated to ratepayers once they materialise,"[390] and further commented that "I would judge there to be minimal 'stranded asset risk' for ATCO Gas. I would judge that if it ever does become material, the regulatory dynamic will ensure that rates remain fair and reasonable and every effort taken to try and provide the shareholders with an opportunity to earn a fair ROE."[391]

299. In rebuttal evidence, Ms. McShane disagreed with Dr. Booth's position presented on behalf of Calgary that stranded asset risk is minimal. In her view, the UAD decision created uncertainty because it listed a wide variety of circumstances which could result in stranded asset cost disallowances. She argued that the recovery of prudent costs is uncertain based on considerations such as those under consideration in Proceeding 2682 regarding the costs related to distribution facilities destroyed in the 2011 Slave Lake fire.[392]

300. In rebuttal evidence, on behalf of CAPP, Dr. Booth submitted "there is no indication at this point from analyst reports or those of the rating agencies that there are any concerns regarding material 'stranded assets' in ATCO Gas' or ATCO Pipe's rate base."[393]

301. With regard to depreciation rates, Dr. Booth stated "it is the responsibility of the utility to determine whether the assets are used and useful and to depreciate them over the economically useful life. If there are substantial amounts of "stranded" assets in the rate base, it indicates that the rate base has been padded or the depreciation rate unduly low. Consistent with the Averch Johnson effect this could be because the allowed ROE is set too high and the utility has an incentive to keep the assets in the rate base, even when no longer used and useful."[394]

302. In rebuttal evidence on behalf of CAPP, Dr. Booth submitted that the very low debt cost of CU Inc. (50 years at 4.855 per cent) does not indicate any stress whatsoever, notwithstanding the fact that spreads are still higher than historical.[395] Dr. Booth commented that:

> … if utility witnesses push for US comparisons on the ROE why isn't it also appropriate to have comparisons with US utility bond ratings? My judgement is that CU Inc. is a Canadian utility that finances within Canada and is not cross listed in the US, so what is

388 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 29, lines 24-25.
389 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 29, lines 12-16.
390 Exhibit 40.02, Booth evidence for Calgary, page 21, lines 9-10.
391 Exhibit 40.02, Booth evidence for Calgary, page 21, lines 20-24.
392 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, pages 2-3, lines 34-66.
393 Exhibit 80.01, Booth rebuttal evidence for CAPP, page 13, paragraph 25.
394 Exhibit 80.01, Booth rebuttal evidence for CAPP, page 14, paragraph 26.
395 Exhibit 80.01, Booth rebuttal evidence for CAPP, pages 14-15, paragraphs 28-30.

> important is its DBRS rating. Here there are no indications of any problems whatsoever.[396]

303. On October 29, 2014, the Commission issued Decision 2014-297, which determined Proceeding 2682 for ATCO Electric Ltd.'s 2012 Distribution Deferral Accounts and Annual Filing for Adjustment Balances application (the Slave Lake fire decision). The Slave Lake fire decision constituted the Commission's first practical application of the principles elucidated in the UAD decision. Consequently, the Commission established a supplemental process for submission of argument and reply argument related to the Slave Lake fire decision to provide the opportunity for parties to provide their views on what, if any, impact its issuance had on the amount of regulatory risk faced by Alberta utilities.

304. The Alberta Utilities asserted that:

> With the finding of an extraordinary retirement and denial of recovery of prudently incurred costs in the Slave Lake Decision, there can be no doubt that the UAD Decision has resulted in significantly increased risk and uncertainty to the Utilities. It is therefore recommended that the pending GCOC decision adopt the upper end of the range of Ms. McShane's UAD Decision Uncertainty premium of 1.50%.[397]

305. The Alberta Utilities submitted the:

> … UAD Decision set out a long, non-exhaustive list of events: matters which include obsolete property, property that has been subjected to unusual casualties (fire, storm, flood, etc.), or that have undergone sudden and complete obsolescence, or seen an un-expected and permanent shutdown of an entire operating assembly or plant. The Slave Lake Decision has now addressed one, and only one of those circumstances, and has done so in the particular circumstances of the history of ATCO Electric's reserve for injuries and damages (RID) Account and the facts of the Slave Lake fire. …[398]

306. The Alberta Utilities also commented that they "are left without guidance as to how the myriad of uncertainties inherent in all the other matters raised by the long though only exemplary list in the UAD decision may bear on them."[399]

307. The UCA argued that the risks and costs discussed in the Slave Lake fire decision were not material for cost of capital determinations and were minor relative to the size of ATCO Electric's rate base and expected shareholder returns.[400]

308. The UCA argued that:

> … [the Slave Lake fire decision] reflects a straightforward application of accepted principles to a specific fact situation. It breaks no new policy ground in the analysis of asset retirements, and makes no change to the overall risk allocation scheme that has existed for many years and that was confirmed by the Commission in the UAD Decision.

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396 Exhibit 80.01, Booth rebuttal evidence for CAPP, page 17, paragraph 32.
397 Exhibit 161.01, Alberta Utilities supplemental argument, page 5, paragraph 15.
398 Exhibit 161.01, Alberta Utilities supplemental argument, page 4, paragraphs 10-11.
399 Exhibit 161.01, Alberta Utilities supplemental argument, page 4, paragraph 12.
400 Exhibit 160.02, UCA supplemental argument, page 4, paragraphs 11-12.

> Decision 2014-297 has no impact on, nor is it relevant to, the matters at issue in this proceeding.[401]

309. In supplemental argument, Calgary submitted that no UAD risk premium should be added to the benchmark ROE.[402] They asserted that "the relatively minor amount of the loss incurred by the ATCO Electric shareholders in the Slave Lake Decision supports the findings of Dr. Booth."[403] Dr. Booth had concluded that utilities could manage stranded asset risk by keeping their depreciation current and maintaining appropriate insurance.

310. Calgary submitted that the Slave Lake fire decision demonstrated that each case will be fact specific "as to whether any particular utility's shareholders will in fact suffer a loss (extraordinary retirement) for a particular event which destroys some of its assets."[404]

311. Calgary stated:

> … that each outcome/loss treatment will be different for each utility, depending upon the facts of the case, and particularly how the utility treats depreciation for the mass account in which the destroyed assets were placed. As such, to apply a pervasive and perpetual UAD premium for a risk that may not apply in each case of asset destruction is unreasonable and unwarranted.[405]

312. The CCA submitted that "no additional risk premium needs to be added with respect to the AUC's findings in Decision 2014-297."[406] "The CCA does not view the AUC's reliance on the Stores Block decision[[407]] and applying its reasoning to other circumstances in the area of utility dispositions and retirements as a 'forced extension'"[408] as argued by the Alberta Utilities.

313. In supplementary reply argument, the Alberta Utilities challenged Calgary's characterization of the cost recovery risk as trivial because "if the new Slave Lake assets were to succumb to the effects of another devastating fire, and if the Commission were to determine that the effects of that fire met their criteria for an extraordinary retirement, the loss that ATCO Electric would be required to absorb could well be in excess of 20 million dollars."[409]

314. The UCA concluded, in its supplemental reply argument, that:

> … there is simply no evidence, and no reasoned analysis, suggesting that Stores Block and the cases that derive from it, including the UAD and Slave Lake Decisions, have any measurable net or aggregate effect on the cost of capital, much less that they support an increase of 1.5% on ROE, or $100 million per year for the Alberta Utilities as a group.[410]

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[401] Exhibit 160.02, UCA supplemental argument, page 5, paragraph 16.
[402] Exhibit 163.01, Calgary supplemental argument, page 12, paragraph 38.
[403] Exhibit 163.01, Calgary supplemental argument, page 9, paragraph 24.
[404] Exhibit 163.01, Calgary supplemental argument, page 11, paragraph 33.
[405] Exhibit 163.01, Calgary supplemental argument, page 11, paragraph 37.
[406] Exhibit 159.01, CCA supplemental argument, page 6, paragraph 12.
[407] *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4, [2006] 1 S.C.R. 140 (*Stores Block*).
[408] Exhibit 167.01, CCA supplemental reply argument, page 5, paragraphs 13-14.
[409] Exhibit 165.01, Alberta Utilities supplemental reply argument, page 6, paragraph 17.
[410] Exhibit 164.02, UCA supplemental reply argument, page 4, paragraph 12.

315. Calgary observed, in its supplemental reply argument, that although ATCO Electric shareholders did have to absorb a loss of $400,000, the Slave Lake fire decision provided the opportunity to earn a return on the replacement plant.[411]

316. On January 25, 2015, the Commission issued Decision 3100-D01-2015 dealing with EDTI's 2013 PBR Capital Tracker True-up and 2014-2015 PBR Capital Tracker Forecast applications. Among other issues, that decision set out the Commission's determinations on the application of principles contained in the UAD decision to EDTI's Advanced Metering Infrastructure (AMI) project. Therefore, in the context of the current GCOC proceeding, the Commission will refer to Decision 3100-D01-2015 as "the EDTI AMI decision." The Commission established a process for submission of second supplemental argument and reply related to the EDTI AMI decision in order to provide an opportunity for parties to provide their views on what, if any, impact its issuance had on the amount of regulatory risk faced by utilities.

317. The Alberta Utilities noted that the EDTI AMI decision represents the second time that the Commission's application of UAD principles has resulted in a finding that an extraordinary retirement has occurred, and argued that the outcome would have been different if the proceeding had been determined before the issuance of the UAD decision.[412] As a result, the Alberta Utilities argued that "there can be no doubt that the UAD Decision has resulted in significantly increased uncertainty, and thereby risk, to the Utilities" and that, consequently, the application of a UAD decision uncertainty premium in the range of 1.5 per cent was warranted.[413]

318. The UCA submitted that the Commission's ruling in Decision 3100-D01-2015 was "a straightforward application of the principles espoused in Stores Block and examined in the UAD Decision"[414] which did not create any new or additional risk.

319. The UCA argued that "both Decision 2014-297 and Decision 3100-D01-2015 represent factual determinations as to when a particular event will be determined by the Commission to give rise to an extraordinary retirement."[415] In the UCA's view, the result of these decisions was to minimize uncertainty for the classification of retirements for the Alberta Utilities.

320. In supplemental reply argument, the Alberta Utilities rejected the UCA's position that the Slave Lake fire and EDTI AMI decisions minimized uncertainty resulting from the issuance of the UAD decision. They stated that:

> … prior to the release of the Slave Lake and EDTI Tracker Decisions, *Stores Block* had never been applied as it has been in these Decisions. As a result of these Decisions, those who provide debt and equity capital to the Alberta Utilities, and those who own and operate the Alberta Utilities, are left to speculate as to what facts will be sufficient for the Commission to reach the conclusion that an event listed in paragraph 327 of the UAD Decision is an extraordinary retirement or not, and has or has not been accounted for in a prior depreciation study.[416]

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411 Exhibit 168.01, Calgary supplemental reply argument, page 6, paragraph 25.
412 Exhibit X0008, Alberta Utilities second supplemental argument, page 1, paragraph 3.
413 Exhibit X0008, Alberta Utilities second supplemental argument, pages 3-4, paragraphs 8-10.
414 Exhibit X0005, UCA second supplemental argument, page 5, paragraph 20.
415 Exhibit X0005, UCA second supplemental argument, page 4, paragraph 13.
416 Exhibit X0009, Alberta Utilities second supplemental reply argument, page 5, paragraph 14.

321. Calgary submitted that the Slave Lake fire and EDTI AMI decisions were fact specific, and that they were not "… indicative of any underlying systemic basis for increased risk to utility shareholders." Accordingly, Calgary argued that "to apply a pervasive and perpetual UAD premium for a risk that may not apply in each case of asset removal is unreasonable and unwarranted."[417]

322. In its supplemental reply argument, the UCA submitted that the number of times the utility asset ownership principles have been applied is irrelevant because "the risk of shareholders being required to absorb the costs associated with extraordinary retirements has always existed." And that the UCA "echoes the submissions of Calgary that these decisions are fact specific and are not indicative of any increased systemic risk to utility shareholders."[418]

323. Calgary submitted that "the risk for shareholders which is associated with the undepreciated meters (including the net book value of the assets at any point in time) is, in large measure, predicated upon and a function of utility management's decisions."[419] Calgary argued that "customers should not bear the adverse consequences of decisions of utility management, when those decisions are open to reasonable question on prudence and in any event, were management's to make."[420]

324. In response to Calgary's position that EDTI should have taken steps to manage the AMI project risks resulting from *Stores Block*, which included drastically reducing the service life for the AMI assets, the Alberta Utilities commented in its supplemental reply argument that this suggestion did not address the identified concern as it presumed no difficulty in reducing the applicable depreciation service life.[421]

325. The CCA commented that the EDTI AMI decision did not alter the risk profile for Alberta utilities[422] and that EDTI had, in Proceeding 3100, implicitly indicated "that it both understands and is able to manage the consequences of the costs associated with its decision on continued use of the assets [or retirements] in accordance with the UAD decision."[423]

326. In response to CCA's assertion that EDTI had indicated it could manage the consequences of the costs from the application of the UAD decision, the Alberta Utilities responded in its supplemental reply argument that:

> … there is no basis for asserting that EDTI is somehow able to 'manage the consequences of the costs' of the Commission's application of the UAD Decision, and there is also no basis for claiming that the uncertainty and risk facing the Alberta Utilities as a result of the UAD Decision is somehow reduced.[424]

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[417] Exhibit X0007, Calgary second supplemental argument, page 5, paragraphs 16-17.
[418] Exhibit X0011, UCA second supplemental reply argument, page 3, paragraph 8.
[419] Exhibit X0007, Calgary second supplemental argument, page 4, paragraph 10.
[420] Exhibit X0007, Calgary second supplemental argument, page 4, paragraph 11.
[421] Exhibit X0009, Alberta Utilities second supplemental reply argument, page 3, paragraph 7.
[422] Exhibit X0003, CCA second supplemental argument, page 1,paragraph 4.
[423] Exhibit X0003, CCA second supplemental argument, page 2,paragraph 5.
[424] Exhibit X0009, Alberta Utilities second supplemental reply argument, page 1, paragraph 3.

327. The UCA concluded, in its supplemental reply argument, that:

> … there is insufficient evidence on the record of this Proceeding to assess and/or quantify any alleged increased risk resulting from the UAD Decision. The UCA agrees generally with the submissions of Calgary in its Supplemental Reply Argument that if the Commission does determine it is necessary to award additional compensation as a result of the UAD Decision, the Commission should convene a further process to consider the issues noted by Calgary, including the probability and quantum of potential losses and the implications of the conceptual framework of Stores Block which emphasizes the symmetry associated with the utility asset ownership by shareholders.[425]

Commission findings

328. In 2006, the Supreme Court of Canada's decision in the *Stores Block* case settled the law applicable to dispositions of utility-owned assets in Alberta. In Decision 2013-417, the Commission summarized the issues considered in *Stores Block* as follows:

> 329. Prior to the Supreme Court of Canada of Canada's [*sic*] 2006 decision in *Stores Block*, the Public Utilities Board had adopted the principle that all gains and losses on the disposition of utility assets were for the account of utility customers. This principle applied whether the assets were disposed of inside or outside of the ordinary course of business or whether or not those assets were depreciable property. In response to *TransAlta*, the Alberta regulator modified its approach by determining that gains from the disposition of utility assets outside of the ordinary course of business would be shared between the utility company and its customers while losses would continue to be for the account of the customers. The Supreme Court of Canada's 2006 decision in *Stores Block* found that all proceeds, including any gains or realized losses, on the disposition of gas utility assets outside of the ordinary course of business were for the account of utility shareholders.[426]

329. Since that time, all Alberta utilities have conducted their respective operations with the benefit of the guidance provided by the court on the law applicable to dispositions of utility-owned assets. In the time since the *Stores Block* decision was rendered, the Alberta Court of Appeal has also provided further clarity with respect to the applicable law.

330. The Commission's first practical application of the *Stores Block* principles occurred in the 2011 GCOC Decision 2011-474, where the Commission determined, in the context of Rider I issues for transmission companies, that any stranded assets, regardless of the reason for them being stranded, should not remain in rate base. The utilities must bear the risk where the assets are no longer required for the provision of utility service. Specifically, Decision 2011-474 included the following findings:

> 542 … the Commission agrees with the AESO [Alberta Electric System Operator] that the likelihood of a customer becoming insolvent at the same time as the backer of it financial security becomes insolvent is extremely small. However, the Commission finds when a utility asset is stranded and is no longer required to be used for utility service, any outstanding costs related to that asset cannot be recovered from other customers. The Commission relies on the Decision of the Supreme Court of Canada in Stores Block for this conclusion. In that decision, the Court states that any assets that are no longer

[425] Exhibit 2191-X0011, UCA second supplemental reply argument, page 3, paragraph 11.
[426] Decision 2013-417, page 83, paragraph 329.

> required to be used in utility service are to be removed from rate base. [footnotes removed]
>
> …
>
> 545 … the Commission considers that any stranded assets, regardless of the reason for being stranded, should not remain in rate base. The utilities must bear the risk where the assets are no longer required for the provision of utility service.

331. In late 2013, the Commission issued Decision 2013-417 (the UAD decision), which set out its understanding of the *Stores Block* principles, as guided by the Alberta Court of Appeal's prior treatment of the issues. At paragraph 327 of the UAD decision, the Commission made the following statement regarding situations where a utility's shareholder would be responsible for undepreciated rate base associated with retired assets:

> 327. In order to give effect to the court's guidance that the "rate-regulation process allows and compels the Commission to decide what is in the rate base, i.e. what assets (still) are relevant utility investment on which the rates should give the company a return," the Commission directs each of the utilities to review its rate base and confirm in its next revenue requirement filing that all assets in rate base continue to be used or required to be used (presently used, reasonably used or likely to be used in the future) to provide utility services. Accordingly, the utilities are required to confirm that there is no surplus land in rate base and that there are no depreciable assets in rate base which should be treated as extraordinary retirements and removed because they are obsolete property, property to be abandoned, overdeveloped property and more facilities than necessary for future needs, property used for non-utility purposes, property that should be removed because of circumstances including unusual casualties (fire, storm, flood, etc.), sudden and complete obsolescence, or un-expected and permanent shutdown of an entire operating assembly or plant. As stated above, these types of assets must be retired (removed from rate base) and moved to a non-utility account because they have become no longer used or required to be used as the result of causes that were not reasonably assumed to have been anticipated or contemplated in prior depreciation or amortization provisions. Each utility will also describe those assets that have been removed from rate base as a result of this exercise. At this time, the Commission will not require the utilities to make additional filings to verify the continued operational purpose of utility assets.[427] [footnotes removed]

332. Subsequent to the issuance of that decision, the Commission applied its findings in the UAD decision in the Slave Lake fire and the EDTI AMI decisions.

333. Since the *Stores Block* decision, any losses and any gains arising from the disposition of utility assets are for the account of the owners of those assets; the shareholders; not customers. The Commission upheld this principle in the 2011 GCOC decision and the UAD decision. As the Commission explained at paragraph 59 of Decision 2014-297:

> 59. … Since *Stores Block*, it can no longer simply be assumed that the costs of assets, once found by the regulator to be prudently acquired, will be recoverable under all circumstances (unless the actions of the utility justified different treatment). The owners of the property bear the benefits of gains on the assets and the risk of losses when those assets are no longer required for utility service.

[427] Decision 2013-417, pages 82-83, paragraph 327.

334. Given this, the Commission accepts that, in theory, utility shareholders in the period since the *Stores Block* decision may be subject to a greater degree of risk, than they were prior to the issuance of the that decision. The question before the Commission in this proceeding is whether any variability of returns that may be occasioned by the *Stores Block* decision, subsequent Alberta Court of Appeal decisions, and related Commission decisions, warrants an adjustment to the allowed ROE or capital structure, or both, for the Alberta Utilities.

335. Since 2006, the *Stores Block* decision and subsequent Alberta Court of Appeal decisions, as well as the above-noted decisions of the Commission applying the findings of the Supreme Court and the Alberta Court of Appeal, signalled to credit rating agencies and capital markets in general, information regarding changes to the regulatory landscape in Alberta. The Commission considers that credit rating agencies and capital markets have had an opportunity to consider and reflect upon, the regulatory impacts resulting from the Supreme Court of Canada's 2006 *Stores Block* decision and the subsequent line of related decisions for some time now.

336. The Commission considers that if these signals had been perceived as significantly increasing the overall riskiness of investments in Alberta utilities, any such perception could reasonably have been expected to be reflected in objective market measures. In the case of debt issues, any perceived increase in risk would have been reflected in utility credit spreads since 2006. As shown in figures 1 and 2 in Section 4 of this decision, as of the close of record of this proceeding, credit spreads for the Alberta Utilities are currently similar to those in 2006.

337. The Commission also considers that any regulatory risk specifically attributable to its own treatment of stranded assets, in light of the *Stores Block* decision, has been appreciated by capital market participants since at least the end of 2011, when Decision 2011-474 was issued. Similarly, the determinations in the UAD decision have been known to the investing public since the end of 2013. The Commission notes, however, there was no perceptible increase in credit spreads for the Alberta Utilities in either 2011 or 2013, when these decisions were issued.

338. The Commission finds no supporting evidence that the greater degree of risk postulated by the Alberta Utilities has had any impact on their ability to raise debt capital at reasonable rates, as demonstrated by the history of credit spreads for these utilities. In addition, credit rating reports available since at least 2011 do not indicate any changes to ratings for the utilities, arising from the asserted increase in risk. In this regard, the Commission agrees with Dr. Booth that the credit rating agencies have not reacted to the perception of risk that the utilities have put forward.[428]

339. In the UAD decision, the Commission indicated that a relevant consideration in determining whether a retirement is for the account of the utility shareholder is whether it is deemed extraordinary. In Decision 2014-297, the Commission applied the corporate and property law principles that were set out in the *Stores Block* line of decisions, applied in a manner consistent with the findings in the UAD decision, to the facts of that case. At paragraph 66 of Decision 2014-297, the Commission stated:

> 66. The UAD decision recognized the concepts underlying the currently-used depreciation methods as being consistent with the *Stores Block* principles because they are intended to recover the costs of assets used in utility service over their service lives in ordinary circumstances, recognizing that retirements outside of the relevant scope of

[428] Exhibit 80.01, Booth rebuttal evidence for CAPP, page 13, paragraph 25.

> considered retirement events, regardless of the effect on depreciation parameters, would be classified as extraordinary retirements and, in accordance with the *Stores Block* principles, would be for the shareholder's account. In the Commission's view it is the characteristics of the event that are relevant to the determination of whether the event had been contemplated or anticipated by a prior depreciation study …

340. In the Commission's view, the determination in the UAD decision that only "extraordinary retirements" are for the account of the utility shareholder, mitigates the risk associated with stranded assets, to which the Alberta Utilities are exposed.

341. Additionally, as Messrs. Bell and Stauft on behalf of the UCA explained:

> The Commission's approved depreciation mechanisms operate on a "mass account" basis, with depreciation reserve accounts that over time ensure that in aggregate the utilities recover in rates exactly their initial investments in depreciable assets, as well as any negative salvage and post-retirement costs associated with those assets."[429]

342. These witnesses also held the opinion that unlike "the situation with land assets, the 'value' of depreciable assets when they are removed from utility service and from rate base is typically zero or, more likely, negative owing to negative salvage and post-retirement costs."[430] The Commission agrees and considers that the use of mass property accounts for regulatory purposes further mitigates the risk associated with stranded assets.

343. In her evidence, Ms. McShane states that:

> In exposing the Alberta Utilities to stranded asset risk, the AUC increased the asymmetry in the risk to which Alberta utility shareholders are exposed. In principle, a utility's ability to earn a fair return should be symmetric, i.e., there should be an approximately equal probability that it will earn above or below its opportunity cost of capital. Under rate base/rate of return regulation, rates are generally set to ensure that utilities neither materially over-earn (i.e., the upside opportunities are limited) nor under-earn (downside risk is limited) their allowed returns. With the imposition of stranded asset risk on shareholders, the likelihood that the utility will not be able to earn a compensatory return on or fully recover the invested capital increases, without any offsetting upside potential afforded.[431]

344. The Commission is not persuaded that application of the fair return standard necessitates the creation of circumstances in which there is an "equal probability that [a utility] will earn above or below its opportunity cost of capital." In Decision 2009-216,[432] the Commission cited the following excerpt from *Northwestern Utilities Ltd. v. Edmonton (City)*[433] with approval, indicating that it was the "most authoritative source of guidance on the meaning of the term 'fair return:'"

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were

[429] Exhibit 45.02, Bell and Stauft evidence for UCA, page 19, lines 8-15.
[430] Exhibit 45.02, Bell and Stauft evidence for UCA, page 19, lines 18-21.
[431] Exhibit 42.02, McShane evidence for Alberta Utilities, page 133, lines 3413-3421.
[432] Decision 2009-216, paragraph 88.
[433] *Northwestern Utilities Ltd. v. Edmonton (City)* [1929] S.C.R. 186.

> investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[434]

345. On a plain reading of the above-referenced excerpt from the Northwestern Utilities case, the Commission notes that the idea of fair return, as conceptualised by the Supreme Court of Canada, does not incorporate a suggestion (let alone a requirement) that the standard is to be met by attempting to place affected companies in circumstances where they are exposed to equal probabilities of earning returns that exceed, or alternatively, fall short of, a company's cost of capital.

346. Consequently, the Commission finds that, insofar as its issuance of the *Stores Block* and related line of decisions may have impacted the risk profile of Alberta utilities, the fact that these may have resulted in the probabilities of over- or under-earning relative to their allowed returns being other than equal is not sufficient to require the allowance of a premium on ROE in order to satisfy the fair return standard.

347. Ms. McShane offered an example of a "significant asymmetric risk" resulting from the UAD decision. In her example, Ms. McShane assumed that there is a 15 per cent probability that the utility will not recover 10 per cent of its equity investment in rate base.[435] With regard to this example, the Commission notes Dr. Cleary's position that:

> Ms. McShane acknowledges in her responses to UCA-AU-61 (a) & (b) that no debt ratings downgrades have occurred as a result of this [UAD] Decision, nor could she estimate the probability of any such downgrades. In addition, her analysis also ignores the fact that windfall gains would accrue to utility owners, which further calls into question the reasonableness of the assumption of 10% losses.[436]

348. The Commission agrees with Dr. Cleary and notes that, in accordance with the principles set out in the *Stores Block* line of cases, shareholders may realise either gains or losses associated with dispositions of utility property. Consequently, while the Commission found that the Slave Lake fire and EDTI AMI extraordinary dispositions were ultimately for the account of shareholders, there is no basis upon which to conclude that all dispositions given regulatory consideration will result in losses for utility shareholders.

349. Ms. McShane argued that the Slave Lake fire and EDTI AMI cases resulted in increased uncertainty and risk for Alberta utilities, which support the granting of a risk premium. However, a broader assessment of the regulatory treatment of utility asset dispositions in the post *Stores Block* period illustrates that any increased uncertainty regarding the possibility of companies realising earnings below their allowed return may reasonably be expected to be offset at least to some extent by the potential for the utilities to retain profits flowing from eligible dispositions.

350. Therefore, the Commission finds that Ms. McShane's assertion that, "with the imposition of stranded asset risk on shareholders, the likelihood that the utility will not be able to earn a compensatory return on or fully recover the invested capital increases, without any offsetting upside potential afforded" is not supported. There is no pattern of gains and losses that would lead to the conclusion that an offsetting upside potential has not been afforded by the *Stores*

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[434] *Northwestern Utilities Ltd. v. Edmonton (City)* [1929] S.C.R. 186 at paragraph 192.
[435] Exhibit 42.02, McShane evidence for Alberta Utilities, page 133, lines 3423-3433.
[436] Exhibit 82.02, Cleary rebuttal evidence for UCA, pages 16, lines 1-6.

Block decision. The *Stores Block* decision clearly sets out that both gains and losses on disposition are to the account of the shareholder.

351. In light of the above considerations, the Commission finds that no adjustment to the allowed ROE or capital structure is warranted for the Alberta Utilities, to account for the application of the principles identified in the UAD decision.

352. TransAlta requested that the "Commission confirm that retirements arising from ongoing system developments such as those embodied in Approval U2013-460[[437]] will be recognized and treated as ordinary retirements."[438] The Commission considers that no advance ruling is possible or reasonable on treatment of assets related to the events identified in the UAD decision in a given set of circumstances because each situation is fact specific. The Commission will consider the treatment of TransAlta's assets with regard to the UAD decision, when the application is made.

6.2 Performance-based regulation implementation for distribution utilities

353. On September 12, 2012, the Commission issued Decision 2012-237 which included the following paragraph:

> 710. The Commission understands that a change to the risk profile of the companies may result from the transition to PBR. The Commission will consider this issue in the upcoming GCOC proceeding. If the Commission determines that there is a change to the risk profile of the companies as a result of the transition to PBR, the Commission will make a one-time adjustment to the companies‘ rates to reflect any adjustment to the companies' capital structure.[439]

354. The Commission included this topic on the issues list for the current proceeding to garner input from parties and to consider this matter. Expert evidence addressing the impacts of PBR on risk was provided by Ms. McShane for the Alberta Utilities, Dr. Cleary for the UCA, and Dr. Booth for Calgary.

355. Based on Ms. McShane's evidence, the Alberta Utilities submitted that a 0.75 per cent premium should be added to any approved ROE to compensate electric and gas distribution companies for the additional risk related to PBR.[440] To estimate the incremental risk premium, Ms. McShane compared the common equity ratios proposed by the Alberta Utilities for taxable Alberta distribution utilities to an American benchmark utility sample to derive a difference in common equity ratios of 7 per cent which was then adjusted to an after tax basis, to arrive at the referenced 0.75 per cent ROE premium.

356. Ms. McShane stated that the main change in business risk for Alberta electric and gas distribution utilities since the 2011 GCOC was the implementation of PBR[441] and that under PBR, "earnings volatility will likely be higher than under cost of service regulation …"[442]

[437] Needs Identification Document, Approval No. U2013-460, Appendix 2 to Decision 2013-369, Alberta Electric System Operator, Amendment to Southern Alberta Transmission Reinforcement, Proceeding 2001, Application 1608846-1, October 28, 2013.
[438] Exhibit 41.01, TransAlta evidence, page 4, lines 34-36.
[439] Decision 2012-237, page 153, paragraph 710.
[440] Exhibit 148.01, Alberta Utilities argument, page 1, paragraph 1.
[441] Exhibit 42.02, McShane evidence for Alberta Utilities, page 38, lines 979-980.

357. Ms. McShane also testified that:

> Under the price/revenue cap plan adopted for the Alberta utilities, prices are to a large extent decoupled from the utility's own costs, which raises the uncertainty of cost recovery relative to a cost of service environment. The ability to flow through certain recurring costs (Y factors) or seek approval for recovery of exogenous event related costs (Z factors) mitigates the risk, but does not reduce it to the cost of service model level.[443]

358. The Alberta Utilities asserted that "[i]ndividually, the[se] events [Y or Z factors] may not meet the threshold, and thus not be eligible for Y or Z factor treatment, but together, the effect could be significant."[444]

359. As noted by Ms. McShane, the PBR framework instituted by the Commission is based on a five year term as compared to cost of service regulation, which typically employs two year test periods. Furthermore, the rate of inflation that is prescribed for purposes of the I-X price mechanism may deviate materially from the actual rate of increase in costs experienced by the utility over the term of the PBR.[445] Ms. McShane further observed that the "Alberta PBR plan does not permit a flow through of changes in cost of capital, either cost of debt or allowed return on equity, as the Commission concluded that changes in the cost of capital are captured in the I factor."[446] In addition, Ms. McShane stated that the absence of a final resolution to the capital tracker proposals of utilities which account for the preponderance of the electric and gas distribution assets in Alberta adds a further element of uncertainty to PBR regulation in the province.[447]

360. The Alberta Utilities submitted that "there have been several studies that have concluded that the cost of capital is higher under performance-based regulation than under cost of service regulation"[448] and "DBRS rated the Alberta PBR framework as 'Very Good', two steps down from the 'Outstanding' rating that it afforded cost of service regulation."[449]

361. Dr. Cleary challenged Ms. McShane's recommendation of adding 0.75 per cent to the allowed ROE to account for the additional risks imposed by PBR noting that in an information response, Ms. McShane stated she was unaware of any precedents for such an adjustment by Canadian utility regulators.[450] In Dr. Cleary's view, Ms. McShane's assessment of the additional risk imposed by PBR was also based on very dated evidence pertaining to risks faced by utilities operating under price cap regulation, which did not include the various Y, Z and K factor mechanisms implemented by the Commission in its approved PBR framework.[451] Dr. Cleary further submitted that "Ms. McShane's analysis also ignores the fact that PBR provides opportunities for utility firms to earn additional returns."[452]

[442] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 6, line 183.
[443] Exhibit 42.02, McShane evidence for Alberta Utilities, page 41, lines 1046-1051.
[444] Exhibit 42.02, McShane evidence for Alberta Utilities, page 41, lines 1056-1058.
[445] Exhibit 42.02, McShane evidence for Alberta Utilities, page 41, lines 1060-1062.
[446] Exhibit 42.02, McShane evidence for Alberta Utilities, page 42, lines 1081-1083.
[447] Exhibit 42.02, McShane evidence for Alberta Utilities, page 43, lines 1125-1128.
[448] Exhibit 42.02, McShane evidence for Alberta Utilities, page 45, lines 1156-1158.
[449] Exhibit 42.02, McShane evidence for Alberta Utilities, page 44, lines 1137-1138.
[450] Exhibit 73.01, UCA-UTILITIES-63(c).
[451] Exhibit 82.02, Cleary rebuttal evidence for UCA, pages 16-18.
[452] Exhibit 82.02, Cleary rebuttal evidence for UCA, pages 18, lines 11-12.

362. Dr. Booth, on behalf of Calgary, commented that "…the experience in Canada has been that PBR has benefitted the shareholder and resulted in significant over-earning of allowed ROEs."[453] Dr. Booth ultimately concluded that:

> … looking at the experience of the four major comparators for ATCO Gas [being FortisBC Energy, Gaz Metro, Union, and EBDI], all of which have been on PBR or under settlement for extended periods of time, … none of them have suffered any increase in risk whatsoever. In fact, their ability to over-earn has increased quite significantly.[454]

363. Mr. Johnson, on behalf of Calgary, disputed Ms. McShane's opinion that PBR increases the business risk or regulatory risk of ATCO Gas on the following three bases:[455]

(i) "… ATCO Gas has gone a period of time in the past without a test year. In those circumstances there was no 'i-x' or the benefits of a 'k', 'y' or 'z factor.'"

(ii) "… in implementing PBR the Commission has had the benefit of the PBR regimes in other jurisdictions."

(iii) "… often ATCO gas has earned more than its allowed return under a cost of service regime. Further, as Dr. Booth noted, companies under PBR have generally earned at least their allowed return on equity."

364. Calgary submitted that:

> … the Commission's confirmation [in the EDTI AMI decision][456] that the AMI project could qualify for Y, Z or K factor treatment, depending upon the application, also reduces the risk to EDTI, and indicates that the PBR regime does not increase the risk of the distribution utilities and does not require an increase in either the ROE or the equity ratio.[457]

365. In supplementary reply argument, the Alberta Utilities disputed Calgary's position that "…. the potential ability to apply for the AMI project under a Y, Z, K factor demonstrates that the PBR regime does not increase the risk of the distribution utilities."[458] The Alberta Utilities commented that for the project to qualify several significant criteria must first be met.

366. Mr. Bell and Mr. Stauft's position, submitted on behalf of the UCA, is that "the implementation of PBR will not increase risk for the PBR Utilities in any way that would justify higher equity returns or adjustments to the PBR Utilities' capital structures."[459] Messrs. Bell and Stauft were of the further opinion that even if PBR had a minor negative effect that increased earnings volatility and risk, this additional risk would be offset by the expectation that PBR utilities will earn returns higher than those embedded in going-in rates.[460] In their view:

453 Exhibit 40.02, Booth evidence for Calgary, page 16, lines 13-15.
454 Exhibit 40.02, Booth evidence for Calgary, page 20, lines 4-7.
455 Exhibit 40.03, Johnson evidence for Calgary, page 4, lines 16-28.
456 EDTI Capital Tracker decision, page 708.
457 Exhibit X0007, Calgary second supplemental argument, page 4, paragraph 12.
458 Exhibit X0009, Alberta Utilities second supplemental reply argument, page 2, paragraph 5.
459 Exhibit 45.02, Bell and Stauft evidence for UCA, page 4, lines 1-2.
460 Exhibit 45.02, Bell and Stauft evidence for UCA, page 27, lines 10-13.

> If the Commission has no genuine expectation that the PBR Utilities will actually earn higher returns by making efficiency improvements during the PBR term, it cannot have a genuine expectation that PBR will benefit customers in the long run. Since the Commission clearly does have that expectation, it is clear that the expectation of higher returns is an integral part of the PBR model.[461]

367. Evidence provided by Messrs. Bell and Stauft also stated that "the Commission's PBR program appears to have been carefully designed to allocate to PBR Utility shareholders only a narrowly defined set of commercial risks that are closely connected with the efficiency objectives of PBR, with all other risks effectively allocated to customers."[462] In their view:

> ... many features of the PBR mechanism have the effect of shifting risk to customers, and in almost all cases those risks are explicitly shifted to customers *because* the risks are not reasonably within the control of the utility. Where the Commission has allocated risk to the PBR Utilities, that is generally *because* the risks are either reasonably within the control of the utility or already accounted for in either 'I' or 'X.'[463] [emphasis in original]

368. Messrs. Bell and Stauft also argued that "[i]n the design of the overall [PBR] mechanism the Commission identified a risk for gas utilities that average use per customer will decline, and prescribed a revenue per customer cap for gas utilities in order ensure that use-per-customer risk is borne by customers."[464] They also noted that in the 2013 PBR Capital Tracker Decision 2013-435, "the Commission addressed that issue by approving a 'K Factor' methodology that will have the effect of ensuring that the PBR Utilities are afforded an opportunity to recover in PBR rates identifiable capital-related costs in excess of what is funded or compensated for by the I-X escalation factor."[465]

369. In rebuttal, Ms. McShane communicated her complete disagreement with the stated position of the expert witness of the UCA and Calgary that PBR does not increase risk because earnings volatility will likely be higher than under cost of service regulation, and earnings volatility is one facet of business risk.[466] She argued that companies with more stable earnings were less risky than those with more volatile earnings and further that the Commission did not implement earnings sharing in Decision 2012-237 because "the Companies' reported earnings will 'generally vary, sometimes significantly, from year to year during the PBR term.'"[467]

370. Ms. McShane also challenged the assertion of Messrs. Bell and Stauft that any negative effect on PBR utilities risk profile would at least be offset by these utilities earning returns which are higher than the returns embedded in the going-in rates. In doing so, she maintained that the return included in going-in rates should be equal to the PBR utilities' cost of capital which reflects their level of risk. In Ms. McShane's view, " the utilities [under PBR] should be **incented** to earn returns above their cost of capital; they should not be **required** to earn returns above their allowed return in order to earn their cost of capital."[468] (emphasis in original)

461 Exhibit 45.02, Bell and Stauft evidence for UCA, page 28, lines 23-27.
462 Exhibit 45.02, Bell and Stauft evidence for UCA, page 23, lines 7-10.
463 Exhibit 45.02, Bell and Stauft evidence for UCA, page 23, lines 20-24.
464 Exhibit 45.02, Bell and Stauft evidence for UCA, page 23, lines 25-27.
465 Exhibit 45.02, Bell and Stauft evidence for UCA, page 25, lines 19-23.
466 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 6-7, line 183-196.
467 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 6, lines 185-187.
468 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 8, lines 241-243.

371. In their rebuttal evidence, Messrs. Bell and Stauft claimed that Ms. McShane had not provided any evidence showing that providing utilities subject to PBR mechanisms with higher allowed equity returns is an accepted practice in Canada, or elsewhere. In fact, they argued that the universal Canadian practise has been to not award higher equity ratios or ROE to utilities subject to PBR.[469]

372. With respect to the suggestion that the onset of PBR for Alberta distribution utilities has increased their perceived regulatory risk, the UCA maintained that:

> The only concern expressed by the rating agencies in relation to PBR was the adequacy of the Commission's capital tracker provisions, which at that time had not been decided on. The Commission fully addressed those issues and concerns in the Capital Tracker Decision by approving the capital tracker proposals of AltaGas and EPCOR essentially as-applied for. It is true that the other distributors must still conform their capital tracker mechanisms to the AltaGas/EPCOR model, but there is no reason to expect that process to result in capital trackers for those PBR Utilities that are less supportive than the AltaGas and EPCOR examples …[470]

Commission findings

373. Ms. McShane, on behalf of the Alberta Utilities, stated that implementation of PBR may result in a higher volatility of earnings, as compared to the cost of service regime, for the affected utilities, thereby resulting in higher risk.[471] In support of her view, Ms. McShane referenced Decision 2012-237 at paragraphs 820-821, where the Commission stated that "the companies' reported earnings will generally vary, sometimes significantly, from year to year during the PBR term."[472]

374. As well, Ms. McShane referenced two academic articles supporting the conclusion that the cost of capital is higher under PBR (price cap) than under cost of service regulation.[473] In response to a Commission information request, Dr. Cleary cited two newer studies which suggest the cost of capital is not higher under PBR.[474]

375. With regards to these academic publications, the Commission observes that Ms. McShane included a quote in her evidence highlighting the fact that "a regulated firm's cost of capital under PC [price cap] regulation depends on the level of the price cap, and a tightening of the regulatory contract increases this cost."[475] In a similar vein, when commenting on the articles referenced by Dr. Cleary, Ms. McShane underscored the argument that "how the method of regulation is actually imposed may offset the theoretical impact."[476] Ms. McShane continued:

> It is also possible that the results are affected by how the different methods of regulation were characterized for purposes of the study. For example, the author considered a rate freeze for a utility otherwise subject to cost of service regulation to be a "high power" form of regulation, i.e., the same as price cap regulation, whereas a rate moratorium was

469 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 33, lines 10-13.
470 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, page 32, lines 19-24.
471 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 6, line 183.
472 Decision 2012-237, paragraph 820.
473 Exhibit 42.02, McShane evidence for Alberta Utilities, page 45, lines 1156-1181.
474 Exhibit 68.02, AUC-UCA-9(b).
475 Exhibit 42.02, McShane evidence for Alberta Utilities, page 45, lines 1162-1164.
476 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 9, lines 276-277.

> considered a "medium power" form of regulation, although the terms rate freeze and rate moratorium are typically used interchangeably. In other words, the lack of relationship between systematic risk (beta) and the regulatory regime in the author's study may be due in part to the misspecification of the regulatory model faced by firms.[477]

376. The Commission agrees with Ms. McShane's view that the result of any study that compares PBR and cost of service regimes is likely to be very sensitive to the level and type of the PBR plan in effect. Drawing from Ms. McShane's example, if utilities under rate freeze are included in the PBR sample, the conclusion that the cost of capital is higher for such companies would not be surprising, given the inherent risks associated with rate freezes.

377. In this regard, Ms. McShane acknowledged that the "PBR plan adopted by the Commission for the Alberta distribution utilities is not a pure price or revenue cap model, given the adoption of Y and Z factors and some level of incremental capital funding."[478] The Commission agrees and notes that during the PBR term the Alberta distribution utilities have the opportunity to apply for Y, Z, and K factor adjustments based on a specified criteria. Therefore, the Commission is not persuaded that a conclusion that the cost of capital is higher under PBR than under cost of service regulation is valid for the Alberta utilities under PBR.

378. Furthermore, the available actual experiences since PBR implementation for 2013 in Rule 005 reports show the majority of Alberta distribution utility ROEs exceeded their interim approved ROEs of 8.75 per cent. Specifically, the Commission notes that all but one of the ROEs earned in 2013 for the Alberta distribution utilities based on their Rule 005 submissions are higher than the 2013 interim ROE level and the approved level embedded in the 2012 going in rates. These returns may have resulted from the efficiency incentives that PBR offers, but the risks as asserted by the Alberta Utilities have not manifested themselves through credit rating downgrades. For these reasons, the Commission finds that there is no evidence on the record of this proceeding which supports the contention that there is appreciably more risk under a PBR regime that would warrant an ROE premium, as proposed by the Alberta Utilities.

379. Finally, the Commission notes that the uncertainty asserted by the Alberta Utilities related to the capital tracker proposals for distribution utility assets and the adequacy of the capital tracker provisions has been addressed in Decision 2013-435, dealing with the first round of capital tracker applications.

380. For the above reasons, the Commission is not persuaded that the transition to PBR for electric and gas distribution utilities has resulted in a change in risk profile that warrants any adjustments to the approved ROE, capital structure, or both. Accordingly, the requested premium of 0.75 per cent by the Alberta Utilities is denied.

6.3 Other risks perceived by the utilities

381. Ms. McShane submitted, on behalf of the Alberta Utilities, that the "[r]isks to which the Transmission Facility Operators (TFOs) are subject are higher, resulting largely from political and regulatory developments that point to a less supportive regulatory environment."[479]

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[477] Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, page 9, line 277 to page 10, lines 284.
[478] Exhibit 42.02, McShane evidence for Alberta Utilities, page 45, lines 1176-1178.
[479] Exhibit 42.02, McShane evidence for Alberta Utilities, page 3, lines 78-80.

382. Ms. McShane identified the following areas of change which have increased risks for TFOs:

(i) amendment of the *Transmission Regulation* to remove the legislated presumption of prudence for project costs incurred by TFOs;

(ii) potential for the Cost Oversight Manager office to second guess or direct how a TFO manages the execution of capital projects;

(iii) no resolution regarding the level of CIAC-financed assets being constructed, managed and operated by the TFOs;

(iv) the introduction of competitive transmission in Alberta intended to promote the operation of competitive market forces in an area historically governed by cost of service regulation;

(v) potential deferred cost recovery mechanisms for Alberta TFOs resulting from the Transmission Cost Recovery Subcommittee Report; and

(vi) though utilities are expected to recover carrying costs incurred, the Minister of Energy sought to have rates frozen without citing statutory authority to do so, for an indeterminate period.[480]

383. The Alberta Utilities submitted that:

> Although no unique (or specific) increase in equity ratios for TFOs was recommended by Ms. McShane as a result of the increased risks identified above, since those risks are indicative of a general deterioration in regulatory support and an increase in government intervention, they support Ms. McShane's recommended across-the-board increase in the deemed common equity ratios of no less than two percentage points not just for TFOs, but for all of the Alberta Utilities.[481]

384. The UCA argued that Ms. McShane's claims were neither meaningful or relevant and therefore the utilities should not be entitled to additional compensation for risk with regard to these matters.

385. With regard to Ms. McShane's position that "amendment of s.46(1) of the Transmission Regulation to remove the legislated presumption of prudence for project costs"[482] increased risk for TFOs, the UCA submitted that this "legislative development may impose an administrative burden; however, it does not change the requirement that investments must be prudent."[483]

386. The UCA submitted that the Transmission Cost Management (TCM) policy referred to by Ms. McShane was only being discussed at the present time but that the "UCA's understanding is that the TCM Policy would be intended to reduce risk for the utilities once finalized 'by

480 Exhibit 148.01, Alberta Utilities argument, pages 71-79, paragraphs 189-214.
481 Exhibit 148.01, Alberta Utilities argument, page 79, paragraph 214.
482 Exhibit 156.02, UCA reply argument, page 51.
483 Exhibit 156.02, UCA reply argument, page 51.

ensuring that prudence issues for transmission projects are addressed early in the process, rather than only after new facilities have been constructed and put into service.'"[484]

387. Regarding Ms. McShane's assertion that there was no resolution regarding the level of CIAC-financed assets for TFOs, the UCA argued that the "current CIAC levels have no cost of capital implications."[485]

388. By way of response to an issue raised by the Commission Panel during the hearing regarding whether competitive bidding processes for construction of new electric transmission facilities represented an undermining of the regulatory compact, the UCA responded that, in its opinion, there was no intention on the part of the government or the AUC to expose operating transmission utilities to competition in the market. The UCA's understanding was that the intention of the competitive bidding process was to facilitate the construction of necessary transmission facilities on the most economical terms. In its view:

> … the transmission network would continue to be operated as it currently is, with TFOs exposed to essentially no competitive, market, or revenue risk. There is no reason for customers to compensate TFOs for the inconvenience and competitive risk associated with participating in a voluntary competitive procurement process. If TFOs are concerned as to potential increases in risk, they are not obligated to participate in the competitive procurement process.[486]

389. In response to Ms. McShane's assertion of "potential rate levelization approaches as contributing to the 'material increase in uncertainty,'"[487] the UCA responded that these approaches were only being discussed and had not been implemented or clearly defined.

390. Further, the UCA submitted that Ms. McShane's description of the 2012 rate freeze as arbitrary interference by government authorities was not an "attempt to interfere with the Commission's rate-making jurisdiction in relation to the Alberta Utilities. Rather, it was an ancillary part of the government's response to issues that arose in connection with the design of default energy supply services."[488] In addition, the UCA argued that the "rate freeze had no negative impact on the Alberta Utilities, as it was in place for less than a year (March 13, 2012 to January 29, 2013) and, upon its termination, each utility was able to apply for any carrying costs as required."[489]

Commission findings

391. As a preliminary observation, the Commission notes that the majority of the changes identified by Ms. McShane as contributing to the creation of a "less supportive regulatory environment" are related, in various ways, to the recent large-scale growth in Alberta's electricity transmission system.

392. The necessity of prudent procurement and operating practises in utility project execution has always been, and continues to be, an important feature of the Alberta regulatory

[484] Exhibit 156.02, UCA reply argument, page 51.
[485] Exhibit 156.02, UCA reply argument, page 51.
[486] Exhibit 150.02, UCA argument, pages 58.
[487] Exhibit 156.02, UCA reply argument, page 51.
[488] Exhibit 150.02, UCA argument, pages 57-58.
[489] Exhibit 156.02, UCA reply argument, page 50.

environment. In the Commission's view, recent amendments to the *Transmission Regulation*,[490] should not result in changes to transmission utilities' capital construction or operating practises, which should, in any event, be in accordance with prudent business conduct.

393. The Commission notes that the purpose of the cost oversight manager function, as identified by Ms. McShane, is to provide third-party expert review and comment on transmission project costs at specific stages of a transmission project from planning through construction completion. A pilot project is currently under way and, as identified by the UCA, the intention is to reduce risk by addressing cost related issues before new facilities are constructed and placed into service. In the Commission's view, the institution of the office of the cost oversight manager does not result in the imposition of additional risk on transmission utilities. In arriving at this conclusion, the Commission considers, to the contrary, that the creation of this oversight mechanism is intended to provide utilities, the AESO, and other stakeholders with additional certainty regarding cost consequences of direct assign project execution by TFOs.

394. The Commission is, likewise, not persuaded that Ms. McShane's concern respecting the level of TFO involvement in the construction of CIAC-financed assets has resulted in the creation of additional risk for those utilities beyond a *de minimus* level. In making this finding, the Commission notes that the AESO held a stakeholder consultation on July 22, 2014 to discuss any issues and concerns of stakeholders with the AESO's Rider I proposal, that would address the level of CIAC-financed assets, and the required next steps. In light of this fact, the Commission considers that any additional uncertainty perceived by capital market participants in relation to this aspect of TFO operations would be significantly ameliorated by the existence of active remedial steps taken by the AESO.

395. Competitive construction for transmission is under implementation and has been introduced for one project. An expanded competitive process for other major projects has been deferred pending the results of the first project. The Commission is not persuaded that the implementation of the market participant choice process for the competitive sourcing of system projects has resulted in additional volatility for transmission utilities.

396. Alternative approaches to transmission cost recovery are currently under consideration by the Commission. While the outcomes of this review are not yet determined, the Commission considers that this should not be presumed to create a material risk that would warrant an increased equity thickness or higher ROEs.

397. With respect to the Alberta Utilities' assertion that the 2012 temporary rate freeze has increased risk as perceived by credit rating agencies, the Commission does not agree that this is the case. In coming to this conclusion, the Commission notes that the 2012 rate freeze was in effect for a relatively short duration, and affected utilities were afforded an opportunity to recover carrying costs incurred as a result of the rate freeze. Further, and in any event, the Commission considers that the societal importance of utility operations means that, where and whenever they are carried out, they may be subject to conditions of the kind that resulted in the imposition of the 2012 rate freeze. This being the case, the Commission does not consider that this isolated occurrence can be appreciated to have contributed to a regulatory environment in Alberta that is "unsupportive" when compared to other Canadian jurisdictions.

[490] *Electric Utilities Act Transmission Regulation*, AR 086/2007.

398. On balance, the Commission is not persuaded that the above-referenced factors identified by the Alberta Utilities have contributed to the creation of a regulatory environment that is substantially less supportive than it was at the time of the previous GCOC proceeding. Consequently, the Commission finds that no adjustment to the utilities' respective deemed equity ratios is required to account for these factors over the test period.

7 Automatic adjustment mechanism for establishing ROE

399. In Decision 2011-474, the Commission indicated it would revisit the matter of a return to an automatic adjustment mechanism (AAM) for setting the allowed ROE on a go forward basis.[491] This mechanism is also referred to as an "ROE formula."

400. In this proceeding, expert evidence on the matter of a return to an ROE AAM was provided by Ms. McShane for the Alberta Utilities, Dr. Cleary for the UCA, and Dr. Booth for Calgary. In their evidence, Messrs. Bell and Stauft for the UCA, commented on the use of an ROE formula.[492] However, in response to an Alberta Utilities' information request, Messrs. Bell and Stauft indicated that they took no position on whether an ROE AAM should be implemented.[493]

401. Ms. McShane indicated that:

> … in light of the persistently unsettled capital markets and the unstable relationships between the utility cost of equity and Government bond yields, it is, in my view, difficult to construct an automatic adjustment mechanism for return on equity at this time that would successfully capture prospective changes in the utility cost of equity. In particular, an automatic adjustment formula tied to changes in government bond yields has the potential to unfairly suppress the allowed ROE.[494]

402. If the Commission determined that an ROE AAM is required for 2015 and beyond, Ms. McShane recommended the adoption of the following formula:[495]

ROE_{new} = Initial ROE + 50% X (Change in Forecast 30 Year GOC Bond Yield)
+ 50% X (Change in Utility Bond Yield Spread)

403. However, Ms. McShane cautioned that this ROE formula not begin to operate until the actual yield on the long-term Canada bond equals or exceeds four per cent. Ms. McShane advised that the initial spread from which subsequent years' changes would be calculated, must be compatible with the four per cent long-term Canada bond yield. Additionally, according to Ms. McShane, implementation of a 50 per cent elasticity factor on long-term Canada bond yields is only appropriate if the allowed ROE is initially set at a level that meets the fair return standard.

404. Dr. Booth supported the use of an ROE formula "but at the moment the advantages are quite slim and would only affect one year 2015."[496] In the event "the AUC wants a 'bullet proof'

491 Decision 2011-474, page 31, paragraph 168.
492 Exhibit 45.02, Bell and Stauft evidence for UCA, pages 37-39.
493 Exhibit 65.02, Utilities-UCA-23.
494 Exhibit 42.02, McShane evidence for Alberta Utilities, page 140, lines 3607-3612.
495 Exhibit 42.02, McShane evidence for Alberta Utilities, page 142, lines 3654-3656.
496 Exhibit 44.02, Booth evidence for CAPP, page 77, paragraph 199.

new ROE formula to account for events like the financial crisis," Dr. Booth recommended a two-part formula, of the type supported by Ms. McShane as referenced above. However, Dr. Booth's recommended ROE formula has a 75 per cent adjustment to changes in the forecast long Canada bond yield.[497]

405. Dr. Booth also advocated that an ROE formula does not start to operate until the yield on the long-term Canada bonds exceeds four per cent:

> I would not change the allowed ROE until the long Canada bond yield exceeds 4.0%. I expect this to happen for 2015, but the change is likely to be minor. Consequently adopting such an ROE formula is likely to result in the same ROE for 2013, 2014 and 2015. I would therefore recommend a fixed ROE for all three years and a very limited hearing in late 2015 confirming the appropriateness of any ROE formula for test year 2016.[498]

406. In his evidence, Dr. Cleary, on behalf of the UCA, presented his views on an ROE formula as follows:

> I would not advocate the use of an AAM for long periods of time, since it would be difficult to envision one that would adjust to changing capital market conditions over an extended period of time. In a 'perfect world' rates would be determined on an annual basis to reflect market and company situations – however this is obviously impractical in the real world. Hence the logistics dictate that regular hearings are a necessary burden. The trade-off is to determine intervals that consider the costs involved in such hearings versus not allowing too much time to elapse in between. Given the intervals will be every two to four years, it makes sense to implement an "interim" (but not long-term) AAM.[499]

407. During the hearing, Dr. Cleary, further commented on the implementation of an ROE formula at this time:

> So the way I would recommend it is if by 2016 there hasn't been another hearing to determine an allowable ROE, then having this in place -- and if things seem normal and it seemed fit to use the AAM -- may save the troubles of having -- you know, troubles and expense and everyone's time of having another hearing. Obviously if things are still conceived as so awry, then you can always another hearing, so.[500]

408. If the Commission determined that an ROE AAM was required, Dr. Cleary recommended the following formula be implemented to determine the 2016 ROE:[501]

> ROE (adj.) = ROE (base) + 0.75×[RF (now) – RF (base)] + 0.50×[Yield Spread (now) – Yield Spread (base)]

[497] Exhibit 44.02, Booth evidence for CAPP, page 4.
[498] Exhibit 44.02, Booth evidence for CAPP, page 4.
[499] Exhibit 45.03, Cleary evidence for UCA, page 55, lines 3704-3720.
[500] Transcript, Volume 6, page 837, lines 6-13.
[501] Exhibit 45.03, Cleary evidence for UCA, pages 56-57.

409. However, unlike Ms. McShane and Dr. Booth, Dr. Cleary did not support using a minimum government bond yield value for the formula to be in effect. According to Dr. Cleary:

> Establishing a floor of 4% implies that the ROE would be adjusted upward for increases in government yields when they increase above 4%. This is consistent with adjusting for the associated increase in the financing costs with an increase in rates and/or yield spreads. However, establishing a minimum value on government yields implies that ROEs would not be adjusted downward if rates declined, even though this would result in lower financing costs, unless there was an associated increase in yield spreads.[502]

Commission findings

410. The Commission observes that all three expert witnesses recommended that, if an ROE formula was to be adopted, it should incorporate the two elements: changes in government bond yields, and changes in utility bond spreads. In Decision 2011-474, the Commission agreed that this type of a formula has advantages over the single-variable formula, as it is likely to better reflect any fluctuations in capital market conditions.[503]

411. Also in that decision, the Commission had considered evidence of continuing credit market volatility and determined that a return to the ROE AAM was not warranted at that time.[504] In Section 4 of this decision, the Commission observes that the risks in the financial markets have moderated since Decision 2011-474. However, it also considers that in the current environment of historically low interest rates, market conditions may not be reflective of a typical risk-return relationship for an investor. This is important in the current case because one of the components of the proposed two-part formula tracks changes in government long-term bond yields. Accordingly, the Commission finds that an abnormal risk-return relationship triggered by ultra-low interest rates would be a valid concern, if such a formula was to be implemented for this test period.

412. The Commission notes that submissions from all parties regarding the use of an ROE formula included suggestions for the incorporation of "safety valve" hearings, reviews, or other reopener mechanisms to ensure proper operation of any adopted formula, given the economic conditions prevailing at a particular time. The Commission agrees that the institution of such mechanisms as part of an AAM are reasonable and that, furthermore, the desirability of such controls provides additional support for the idea that correct operation of AAMs such as ROE formulae are dependent on prevailing market conditions falling within a range of normalcy.

413. The Commission notes that both Ms. McShane and Dr. Booth recommended against use of an ROE formula until the government of Canada long-term bond yield exceeds 4.0 per cent. The Commission notes that as of the close of record of this proceeding, the long-term Canada bond yield is well below 3.0 per cent.

414. For the above reasons, the Commission will not reintroduce the use of an ROE formula or other AAM at this time. The Commission is prepared to revisit the desirability of an ROE formula as part of future GCOC proceedings if its adoption would be warranted in light of the market conditions present at that time.

[502] Exhibit 82.02, Cleary rebuttal evidence for UCA, page 20, lines 10-15.
[503] Decision 2011-474, paragraphs 164-165.
[504] Decision 2011-474, paragraph 165.

415. For the purpose of regulatory efficiency, the ROE and equity ratios awarded in this decision will remain in place on an interim basis for 2016 and for subsequent years until changed by the Commission. The Commission considers that establishing an allowed ROE for 2015 and setting an interim ROE for 2016 and subsequent years will provide for a more supportive, and predictable regulatory environment.

8 Capital structure matters

8.1 Introduction

416. To satisfy the fair return standard, the Commission is required to determine a capital structure (also referred to as an equity ratio) for each of the affected utilities. In this decision, the Commission has established an allowed ROE of 8.30 per cent for all of the affected utilities. The Commission will account for the differences in risk among the individual utilities by adjusting their capital structures, if required, and recognizing changes in overall levels of risk to which utilities have been exposed, in a manner consistent with the approach in previous GCOC decisions.

417. This section of the decision determines the allowed percentage of rate base (net of no-cost capital) supported by common equity as opposed to debt. Where preferred share capital is present, it is considered, for the purposes of determining the common equity ratio, to be a substitute for a portion of the debt and does not affect the required common equity ratio. Whether or not a utility should use preferred shares in place of some of its debt is not considered in this proceeding.

418. As the Commission noted in previous GCOC decisions, in general, the return on investment-grade debt required by investors is lower than the return required on equity. This is because the return paid to investment-grade debt investors, barring extreme and unexpected circumstances, is set by the initial terms of the debt instrument and therefore, is not normally subject to uncertainty. Debt holders have priority over equity holders in the distribution of earnings from operations and, in the event of bankruptcy, in the disposition of the assets of the firm. As the proportion of debt in capital structure increases, a greater portion of the earnings from operations of the firm are required to cover the increased interest costs on debt. Therefore, as the proportion of debt rises, both debt and equity investors will perceive an increase in risk. This is because if debt levels are too high, debt holders will be concerned that the debt obligations of the firm may not be met, and equity investors will be concerned that there will be insufficient earnings from operations to both cover the debt obligations of the firm and to provide them with their expected return.

419. The risk to debt investors is usually assessed, in part, by various interest coverage and debt ratio calculations that measure the ability of the firm to pay its debt obligations. Bond rating agencies, such as Standard & Poor’s (S&P) and DBRS Limited (DBRS) assess the risk of individual firms on the basis of various credit metrics and an overall assessment of the risk that the firm will not be able to cover its debt obligations. Ultimately, it is debt investors that assess the risk of investing in various debt instruments. Investors rely greatly, but not exclusively, on credit ratings. The consensus judgment of debt investors is reflected in the credit spreads that can be observed in the primary and secondary debt markets for individual debt issues and issuers, including utilities.

420. The Commission's approach, consistent with past decisions, is to award common equity ratios that are intended to allow the affected utilities, on a stand-alone basis, to target credit ratings in the A-range.[505] As in past decisions, in setting the ROE, the Commission has considered that it will determine an equity ratio that, in its view, will allow the utilities (with the possible exception of the three smallest utilities) to target credit ratings in the A-range, when assessed on a stand-alone basis.

421. In determining capital structure, the Commission will analyze the equity ratios that are required for a typical pure-play regulated utility to attain the minimum credit metrics that were identified and used in both Decision 2009-216 and Decision 2011-474. This analysis has also been used to provide an indication of whether an overall uniform adjustment to existing equity ratios is required, in addition to any adjustments to account for differences in risk among individual utilities. The Commission will then turn to an assessment of the various types of utilities, and each individual utility, to determine whether their risk rankings have changed, and whether specific adjustments to each company's equity ratio are warranted.

8.2 Equity ratios requested by the Alberta Utilities

422. The following table (grouped by sector) compares the equity ratios that were approved by the Commission in Decision 2011-474 with the equity ratios recommended by the utilities and interveners in this proceeding.

Table 5. Recommended vs. last approved equity ratios

	Last approved[506]	Recommended by the Alberta Utilities[507]	Recommended by the UCA[508]	Recommended by the CCA[509]	Recommended by CAPP[510]	Recommended by Calgary[511]
	(%)					
Transmission						
ATCO Electric	37	39	33 – 35	35		
AltaLink	37	39	33 – 35	35		
ENMAX	37	39	35	35		
EPCOR	37	39	35	35		
ATCO Pipelines	38	44.5	33	35	35	
Distribution						
ATCO Electric	39	41	36	37		
ENMAX	41	43	38	39		
EPCOR	41	43	38	39		
ATCO Gas	39	41	36	35		35
FortisAlberta	41	43	38	39		
AltaGas	43	45	40	41		

505 Decision 2009-216, paragraphs 78, 273, 327, 334, 357 and 411.
506 Decision 2011-474, page 53, Table 10.
507 Exhibit 148.01, Alberta Utilities argument, page 2.
508 Exhibit 150.02, UCA argument, page 98-99.
509 Exhibit 149.01, CCA argument, paragraphs 134-146.
510 Exhibit 151.01, CAPP argument, page 32, paragraph 110.
511 Exhibit 146.02, Calgary argument, page 18, paragraph 61.

8.3 Credit ratings and credit metric analysis

8.3.1 Financial ratios, capital structure and actual credit ratings

423. Credit ratings measure the credit-worthiness of a firm as assessed by a credit rating agency. A higher credit rating signals higher confidence in the firm's ability to meet its interest payments and to repay principal. This, in turn, allows the company to borrow at a lower interest rate. Canadian regulated utilities usually seek to maintain a credit rating in the A-range. In previous GCOC decisions, the Commission has recognized the importance of maintaining a credit rating in the A-range for the utilities under its jurisdiction, to facilitate their ability to obtain debt financing at optimal rates.

424. Credit metrics (financial ratios) are an important, although not the only, component that bond rating agencies consider when assessing the risk of any particular company and assigning a credit rating. As noted in the 2009 GCOC decision, there are three principal credit metrics:[512]

- EBIT coverage (interest coverage ratio): which is the company's earnings measured before deducting interest and taxes divided by total interest costs.
- FFO/debt (funds from operations): which is the company's funds from operations (net income plus depreciation and the increase in future income taxes) as a percentage of total debt.
- FFO coverage: which is the company's funds from operations plus interest divided by total interest costs.

425. The Commission observed in Decision 2009-216 that a number of Alberta utility companies finance their debt requirements through direct participation in the debt market and independently of any affiliated companies, making it possible to directly observe equity ratios and credit metrics of stand-alone regulated utilities maintaining credit ratings in the A-range. Consequently, in that proceeding, the Commission examined the credit ratings and credit metrics of companies for which credit rating reports were available, in order to gain insight into the credit metrics required to achieve an investment-grade credit rating for a stand-alone utility.

426. In Decision 2009-216, the Commission observed the following minimum credit metrics to be associated with regulated utilities with an A-range credit rating:[513]

- EBIT coverage of 2.0 times
- FFO coverage of 3.0 times
- FFO/debt ratio of 11.1 to 14.3 per cent

427. The sample group of utilities that were examined in arriving at these observed credit metrics were exclusively Alberta utilities: AltaLink L.P., AltaLink Investments L.P., Fortis Inc., FortisAlberta and CU Inc., the parent of the ATCO group of utilities.

428. Additionally, after examining the actual credit ratings achieved by Canadian regulated utilities and the actual (as opposed to awarded) equity ratios associated with these credit ratings, the Commission observed that the actual equity ratios of the companies with a credit rating of A- or better ranged from 32.9 to 44.1 per cent, with a mid-point of 38.5 per cent.[514] The sample

[512] Decision 2009-216, paragraph 345.
[513] Decision 2009-216, Table 12 and paragraphs 348, 354 and 356.
[514] Decision 2009-216, paragraph 359.

group of utilities that were examined in arriving at this observed range of actual equity ratios were the same Alberta utilities that were examined with respect to credit metrics (set out above) plus Newfoundland Power Inc.

429. The minimum credit metrics and the actual equity ratios that were observed to be associated with A-range credit ratings were associated with all of the risks that the credit rating agencies perceived for the observed Alberta utilities at that time. These risks would implicitly have included all perceived financial and business risks, including regulatory risk, market risk, supply risk, and operating risk, including the impact of contributions in aid of construction (CIAC).

430. In Decision 2011-474, the Commission agreed with the parties to that proceeding that the minimum credit metrics associated with an A-range credit rating, which were observed in Decision 2009-216, could be accepted as reasonable guidelines for the purposes of that proceeding.[515]

431. In this proceeding, Ms. McShane, who provided evidence on behalf of the Alberta Utilities, did not propose increases to the minimum credit metrics, but instead argued that the Commission should target metrics well above the minimums.[516] In argument, the Alberta Utilities stated that because the Commission has previously found the FFO/debt ratio to be the most critical credit metric, it should, at a minimum, target the high end of the range for this metric in its analysis.[517] The Alberta Utilities noted the evidence of Ms. McShane regarding current capital market conditions, increased regulatory risk, and the high levels of contributions in aid of construction being financed by the Alberta Utilities. They argued that this, along with the credit metric analysis, indicated that a two percentage point across-the-board increase in common equity is conservative.[518]

432. Messrs. Bell and Stauft, for the UCA, provided an analysis of the equity ratio that would be required to achieve the Commission's credit metric minimums or ranges, but did not propose an update to the observed target credit metrics. In argument, the UCA submitted that "based on the base case assumptions used by Messrs. Bell and Stauft, as shown in Table 1 at page 9 in their direct evidence, the minimum equity ratio that will meet all of the Commission's minimum standards is 34%, or 3% lower than the lowest equity ratio that was approved in Decision 2011-474."[519]

433. Mr. Fetter, on behalf of the Alberta Utilities, addressed the Commission's previous findings on credit metric ratios necessary to achieve A-range credit ratings. He generally agreed with the ranges used by the Commission but felt that the targets should be towards the top of the ranges as the top of the ranges provided greater ratings security.[520]

434. Dr. Booth, on behalf of CAPP, indicated that he did not agree with the Commission's practice of using credit metrics to target an equity ratio. In his view, targeting particular credit metrics ignores the fact that this is only part of what generates an actual bond rating. He

515 Decision 2011-474, paragraph 194.
516 Exhibit 42.02, McShane evidence for Alberta Utilities, line 1538.
517 Exhibit 148.01, Alberta Utilities argument, paragraphs 234-235.
518 Exhibit 148.01, Alberta Utilities argument, paragraph 229.
519 Exhibit 150.02, UCA argument, page 81.
520 Exhibit 42.05, Fetter evidence for Alberta Utilities, page 23, line 12 to page 26, line 3.

submitted that “putting undue weight on financial metrics, such as the interest coverage ratio or the funds flow to debt ratio, misses the point, which is can the utility access credit on fair and reasonable terms?”[521]

435. In rebuttal, Ms. McShane submitted that Dr. Booth’s approach of relying on the equity ratios awarded by other regulators was both circular and based on an assumption that those equity ratios were exactly correct.[522]

436. In rebuttal evidence submitted on behalf of Calgary, Dr. Booth and Mr. Johnson, stated that “we are not aware of any justification for allowing the equity holder a higher ROE, or larger common equity ratio, for bond market problems.”[523]

Commission findings

437. Consistent with the approach in past GCOC decisions, the Commission awards, in this decision, common equity ratios that are intended to allow the affected utilities, on a stand-alone basis, to target credit ratings in the A-range.[524] The Commission observes that, except for the period around January 2009, interest paid on debt sourced by A-range utilities has typically averaged approximately 150 basis points above that payable on 30-year government of Canada bonds, as can be seen in figures 1 and 2 in Section 4. Recently, some utilities have been able to obtain 40-year and 50-year debt at spreads minimally above those for 30-year debt, highlighting the advantage of enabling utilities to achieve and maintain A-range credit ratings. In addition, this allows the utilities to more easily match the existing life expectations of the underlying assets to the maturity of their long-term debt.

438. In the Commission’s view, increases in capital market risks, regulatory risks, and high levels of contributions in aid of construction for Alberta utilities should, if significant, lead to changes in the observed credit metrics that are associated with A-range credit ratings. In Decision 2009-216, the Commission referenced certain minimum credit metrics that were observed to be associated with regulated utilities with an A-range credit rating.[525] In this proceeding, none of the parties provided updated evidence on the actual credit metrics associated with A-range credit ratings, or proposed to change the ranges of the credit metrics referenced by the Commission in Decision 2009-216.

439. Based on its review of the evidence and argument in this proceeding, and in a manner consistent with its approach to determining capital structure in previous GCOC proceedings, the Commission finds it is helpful to continue the use of the target credit metrics referenced in Decision 2009-216, and subsequently applied in Decision 2011-474. The use of these target credit metrics will aid the Commission in determining the equity ratios that would be expected to be supportive of A-range credit ratings for Alberta utilities, on a stand-alone basis.

440. Dr. Booth did not agree with the Commission’s practice of using credit metrics to target an equity ratio. The Commission does not share Dr. Booth’s view. Since the issuance of Decision 2009-216, interest rates have declined significantly as capital markets reflect the continuing economic recovery. The Commission continues to consider that its credit metric ratio analysis

521 Exhibit 44.02, Booth evidence for CAPP, page 16, lines 6-8.
522 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, lines 665-673.
523 Exhibit 79.02, Booth and Johnson rebuttal evidence for Calgary, page 3, lines 1-2.
524 Decision 2009-216, paragraphs 78, 273, 327, 334, 357 and 411.
525 Decision 2009-216, Table 12 and paragraphs 348, 354 and 356.

contributes to a better understanding of the impact of issues currently facing utilities, while being cognizant of how these ratios must be interpreted within the context of an evolving market, and taking into account the differing growth rates and financing requirements faced by the Alberta Utilities. In the Commission's view, this approach provides an objective analysis to determine the equity ratios that would be expected to be supportive of A-range credit ratings for Alberta utilities, on a stand-alone basis.

441. As well, the Commission disagrees with Dr. Booth's and Mr. Johnson's recommendation, made on behalf of Calgary, against using a higher equity ratio, which they assert benefits the equity holder, to account for perceived problems in the bond market. In the Commission's view, the primary driver of minimum equity ratios is the need to provide an acceptable level of risk for bond investors. This in turn ultimately minimizes debt costs which are eventually borne by ratepayers. The primary vehicle of lowering risk for debt investors exposed to a given level of business risk is to allow increased equity. If earnings are ultimately less than forecast, bond interest must still be paid. A higher forecast level of equity earnings, associated with a higher equity ratio, provides a larger margin of safety for debt investors. When the Commission increases its awarded equity ratios, it does so to maintain a reasonable level of risk for debt investors by targeting an A-range credit rating that contemporaneously minimizes associated debt costs for ratepayers. Once incurred, these debt costs, borne by ratepayers, may last for 30 to 50 years and marginal increases can impose a costly burden in the long term.

8.3.2 Equity ratios associated with minimum credit metrics

442. In Decision 2011-474, at Table 9, the Commission provided a sensitivity analysis illustrating the impact of a range of equity ratios on the levels of the three principal credit metrics. The analysis was based on certain input parameters associated with the various applicant utilities. The analysis indicated that the following minimum equity ratios were required to achieve the observed minimum credit metrics:[526] The awarded equity ratios that were subsequently approved in that decision ranged from 37 to 43 per cent.

- The minimum equity ratio to achieve a 2.0 EBIT coverage ratio was 37 per cent.
- Minimum equity ratios in the range of 30 to 38 per cent would achieve FFO/debt percentages of 11.1-14.3.
- A minimum equity ratio of 35 per cent was required to achieve an FFO coverage ratio of at least 3.0.

443. In this proceeding, the parties suggested revised and updated input parameter values to be used in calculating the resulting credit metric values at various equity ratios. The proposed revised parameter values are summarized in the following table, along with the values the Commission elected to use in its updated analysis. The Commission's reasons for selecting the identified updated parameter values follow.

[526] Decision 2011-474, paragraph 222.

Table 6. Parameters for calculating credit metrics

Parameter	Parameter values applied in Decision 2011-474	Proposed by the Alberta Utilities	Proposed by the UCA	Parameter values applied in this decision
			(%)	
Embedded average debt cost	6.4	5.7	5.1	5.1
ROE	8.75	8.75	8.0	8.3
Income tax rate	25.0	25.0	25.0	25.0
Depreciation	6.0	5.0	6.0	5.0
Construction work in progress (CWIP)	5.0	8.0	5.0	5.0

444. In arriving at the updated parameters, the Commission has considered the recommendations of parties and has reviewed the actual parameters from the 2013 Rule 005 filings.

445. The ROE input parameter is common to all utilities, as is the income tax rate input parameter (non-taxable utilities are considered in a later section). The Commission has summarized the other parameter values for each utility based on their respective 2013 Rule 005 filings, as shown below:

Table 7. Parameters by utility (excludes the smallest utilities)

Utility	Invested capital ($000)	Debt cost per cent	Depreciation as a percentage of invested capital	Mid-year CWIP as a percentage of invested capital
ATCO distribution	1,696,400	5.40	5.14	8.22
Fortis	2,285,200	5.34	6.75	2.92
ENMAX distribution	900,568	4.45	5.35	7.98
EPCOR distribution	674,431	5.70	4.46	1.40
AltaLink	3,592,600	3.90	3.82	36.73
ATCO transmission	3,640,600	5.02	2.90	34.00
ENMAX transmission	251,667	4.45	3.73	18.62
EPCOR transmission	471,067	4.78	3.59	15.53
AltaGas	195,732	5.08	5.25	1.05
ATCO Gas	1,860,195	5.90	6.51	2.45
ATCO Pipelines	868,417	5.64	5.42	7.28
Average		**5.06**	**4.81**	**12.38**

Commission findings

446. As set out in Section 8.3.1, the Commission's credit metric ratio analysis contributes to a better understanding of the impact of issues currently facing utilities, while recognizing that these ratios must be interpreted and appreciated within the context of an evolving market, and taking into account the differing growth rates and financing requirements faced by the Alberta Utilities. As shown in Table 7 above, the mid-year CWIP as a percentage of invested capital ranges from 1.05 per cent to 36.73 per cent. Given the range of this metric, the Commission considers that it cannot slavishly follow a numeric credit metric ratio analysis without understanding the reasons underlying the ratios.

447. In its credit metric analysis, the Commission employed the following five parameters: average embedded debt interest cost, ROE value, income tax rate, depreciation as a percentage of invested capital and CWIP as a percentage of invested capital.

448. In her credit metric analysis, Ms. McShane proposed that the average embedded debt interest cost be updated to 5.7 per cent.[527] The UCA proposed that the average embedded debt interest cost be updated to 5.1 per cent.[528] The Commission is cognizant that ENMAX has a debt cost that is lower than the typical utility due to its access to the Alberta Capital Financing Authority. The transmission utilities that have recently experienced rapid growth, will have lower than average debt costs reflecting a higher proportion of more recent debt issues. The Commission is also aware that the average embedded debt costs will likely continue to decline as older, higher-cost debt is retired, and assuming current debt issue costs will remain lower than the average historical embedded cost of debt. Therefore, the Commission finds the UCA's proposal to use an average embedded debt interest cost of 5.1 per cent in the Commission's credit metric analysis, to be reasonable.

449. Consistent with the Commissions' findings in Section 5.6, the Commission has applied an ROE value of 8.3 per cent in its credit metric analysis.

450. There was no controversy among the parties regarding the continued use of an income tax rate assumption of 25 per cent for a typical Alberta utility, prior to any utility-specific adjustments.

451. In addressing depreciation as a percentage of invested capital, Ms. McShane recommended, on behalf of the Alberta Utilities, that the value be decreased from 6.0 per cent to 5.0 per cent.[529] The UCA acknowledged that the depreciation rate as a percentage of invested capital was less than 6 per cent, but nonetheless suggested the use of 6.0 per cent as a rounded figure.[530] Based on the data in Table 7 above, the Commission finds the Alberta Utilities' recommendation of 5.0 per cent for the depreciation parameter to be reasonable.

452. Regarding CWIP as a percentage of invested capital, Ms. McShane and the Alberta Utilities recommended that the assumed value be increased to 8.0 per cent,[531] whereas the UCA recommended the continued use of 5.0 per cent.[532] The Commission notes that CWIP as a percentage of invested capital varies widely. The Commission is also cognizant that the utilities with the highest level of CWIP have previously been granted relief through the inclusion of CWIP in rate base. As a result, these utilities now have minimal CWIP as a percentage of their total capital, if CWIP in rate base is excluded from the calculation.

453. Given anomalies, such as low CWIP percentages for companies with CWIP in rate base, on one extreme, and companies with a CWIP percentage in the 30 per cent range, on the other extreme, the Commission finds that it is inadvisable to assign significant weight to such outlier values in its credit metric analysis. The purpose of the credit metric analysis is to estimate equity ratios for a typical Alberta utility. It therefore considers it reasonable to maintain the 5.0 per cent

527 Exhibit 42.02, McShane evidence for Alberta Utilities, line 1594.
528 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, paragraph A4.
529 Exhibit 42.02, McShane evidence for Alberta Utilities, line 1602.
530 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, paragraph A9.
531 Exhibit 42.02, McShane evidence for Alberta Utilities, line 1605.
532 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, paragraph A6.

CWIP assumption that it used in the previous decision. Utilities that believe that they are experiencing difficulties associated with materially higher levels of CWIP can apply to the Commission for approval to include CWIP in rate base as a means of addressing such difficulties, if such action proves necessary.

454. Ms. McShane and the Alberta Utilities also proposed that the credit metric analysis reflect the impact of operating leases, debt/equity hybrids, pension liabilities and asset retirement obligations. The proposal was to increase the reported debt levels by 10 per cent to reflect the analytical adjustments that the S&P credit rating agency makes to reflect these items.[533] In its rebuttal evidence, the UCA indicated that any upward adjustments required to account for these variables were not warranted and that, in any event, any adjustment for preferred shares would require the amount of debt to be reduced rather than increased.[534]

455. The Commission is not convinced that typical Alberta distribution or transmission utilities are materially affected by operating leases, unfunded pension liabilities or asset retirement obligations. With respect to any potential impact of debt/equity hybrids such as preferred shares, the Commission notes that its method of setting common equity ratios already effectively categorizes preferred shares as a component of debt, as opposed to common equity. Based on the foregoing, the Commission finds that no adjustments to its credit metric analysis are required to account for these factors.

456. Based on the foregoing, the Commission's updated credit metric analysis is provided in the following table:

[533] Exhibit 42.02, McShane evidence for Alberta Utilities, lines 1569-1583 and 1608-1609.
[534] Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, paragraph A17.

Table 8. Credit metrics compared to equity ratios – Commission analysis

	EBIT coverage		FFO / debt %		FFO coverage	
Equity Ratio	Decision 2011-474 Table 9	Updated	Decision 2011-474 Table 9	Updated	Decision 2011-474 Table 9	Updated
30%	1.7	1.8	11.73	10.19	2.79	2.95
31%	1.7	1.9	12.03	10.45	2.83	3.00
32%	1.8	1.9	12.32	10.72	2.88	3.05
33%	1.8	**2.0**	12.63	11.00	2.93	**3.11**
34%	1.8	2.0	12.95	**11.29**	2.98	3.17
35%	1.9	2.1	13.28	11.58	3.03	3.22
36%	1.9	2.1	13.62	11.89	3.08	3.28
37%	2.0	2.2	13.96	12.20	3.13	3.34
38%	2.0	2.2	14.32	12.53	3.19	3.41
39%	2.1	2.3	14.70	12.86	3.25	3.47
40%	2.1	2.3	15.08	13.21	3.31	3.54
41%	2.2	2.4	15.48	13.56	3.37	3.61
42%	2.2	2.4	15.89	13.93	3.43	3.68
43%	2.3	2.5	16.31	**14.32**	3.5	3.76
44%	2.3	2.6	16.75	14.71	3.57	3.84
45%	2.4	2.6	17.21	15.13	3.64	3.92

457. The bolded figures correspond to the minimums for each credit metric. Based on this analysis, minimum equity ratios associated with the targeted credit metrics, are set out in the following table:

Table 9. Minimum equity ratios to achieve target credit metrics

Credit metric target	Decision 2011-474	Updated
	(%)	
2.0 EBIT coverage	37	33
3.0 FFO coverage	35	33
11.1 – 14.3 FFO to debt ratio	30 to 38	34 to 43

458. The above analysis indicates that the minimum equity ratio to achieve the targeted EBIT ratio of 2.0 has decreased by four percentage point and the minimum equity ratio to achieve the targeted FFO coverage ratio of 3.0 has decreased by two percentage points. In contrast, the minimum equity ratio to achieve the lower end of the range for the FFO to debt ratio has increased by four percentage points.

459. In Decision 2011-474, the Commission awarded an equity ratio of 39 per cent to distribution companies (prior to company-specific adjustments). In that decision, the Commission considered this value to be a representative equity ratio for an average risk utility. Table 8 demonstrates that, as a result of updating the parameters of the Commission's credit metric analysis in this proceeding, a decrease of the 39 per cent representative equity ratio is warranted. In addition, having considered the findings in Section 4 with respect to global and

Canadian capital market conditions, there is less reason at this time to award equity ratios significantly higher than the minimums indicated by the credit metric analysis.

460. In light of the above considerations, the Commission finds that a one percentage point reduction of the 39 per cent representative equity ratio approved in Decision 2011-474 is warranted. In the Commission's view, the resulting 38 per cent equity ratio is sufficient to attain the targeted A-range credit rating for an average risk utility.

461. In the sections that follow, the Commission considers whether any further utility-specific adjustments to the one percentage point overall reduction are required so that the awarded equity ratio for each utility reflects the business risk ranking of the various industry segments.

8.4 Ranking risk by regulated sector

462. In previous GCOC decisions, the Commission ranked the riskiness of the various utility sectors in Alberta based on an analysis of business risk. Business risk represents the perceived uncertainty in future operating earnings before the impact of financial leverage (earnings before interest and income taxes) and, hence, determines the capacity for a business to be financed with debt as opposed to equity.

463. In Decision 2009-216, the Commission observed that the electric transmission sector had the least risk. The Commission also found that, in general, the electric distribution sector was slightly more risky than the electric transmission sector. The Commission also agreed, in that case, that ATCO Gas had a similar level of business risk compared to electric distribution companies, and that AltaGas was more risky than ATCO Gas due to its small size. ATCO Pipelines (transmission) was found to be more risky than ATCO Gas (distribution).[535]

464. In Decision 2011-474, the Commission reaffirmed many of its previous findings with respect to the business risk attributable to the various utilities. In particular, the Commission found that the electric transmission sector has the least risk. The electricity distribution segment is slightly more risky than the electric transmission sector. ATCO Gas has a similar level of business risk as compared to electric distribution companies. Due to its small size, AltaGas is more risky than ATCO Gas. However, it also lowered the risk ranking of ATCO Pipelines in the company-specific considerations section of that decision to reflect the impact of its integration agreement with NOVA Gas Transmission Ltd. (NGTL).

8.5 Additional Adjustments

8.5.1 PBR and UAD impacts

465. As indicated in sections 6.1 and 6.2 of this decision, the Commission determined that no adjustments are required with respect to the transition to PBR regulation or the UAD decision.

8.5.2 Adjustment for non-taxable status

466. In Decision 2011-474, the Commission reaffirmed its previous findings in Decision 2009-216 that, while income tax exempt status lowers a company's costs, it increases the volatility of earnings and decreases the interest coverage ratio, thereby adding to risk from the debt holder's perspective. Accordingly, in Decision 2011-474, the Commission continued its addition of a two percentage point increase to the equity ratios of income tax exempt utilities.

[535] Decision 2009-216, paragraphs 370-371.

467. In Decision 2011-474, the Commission found that treating FortisAlberta as a non-taxable entity for the purposes of that proceeding was warranted, since it had not paid any income taxes since 2006, and was not expected to do so until at least 2016. The Commission indicated that its treatment of FortisAlberta would change if the company became an income tax paying entity, or if, in the future, the Commission were to change from the flow-through method of accounting for income taxes for regulatory purposes, to normalized taxes or another similar method.

468. In this proceeding, both the Alberta Utilities and the UCA supported the retention of the two percentage point increase for income tax exempt utilities, as well as for FortisAlberta, which was not collecting income tax in its revenue requirement. For its part, Calgary noted Dr. Booth's position that lower income tax does not increase the risk to a utility, but he did not propose any change to the Commission's approach.

Commission findings

469. The Commission finds that its practice of adding two percentage points to the equity ratio of non-taxable utilities and to FortisAlberta continues to be warranted.

8.5.3 ATCO Pipelines

470. Ms. McShane for the Alberta Utilities submitted that ATCO Pipelines' (AP) business risks are higher than they were when assessed at the time of the 2011 GCOC proceeding. She stated that:

> This conclusion is valid, in my opinion, despite the fact that NGTL is responsible for paying ATCO Pipelines' approved revenue requirement under the Integration Agreement. The degree of certainty that the approved revenue requirement will be recovered due to the existing regulatory framework or contractual arrangements is not synonymous with uncertainty of future earnings.[536]

471. Ms. McShane also submitted that, in contrast to the NGTL Alberta System and ATCO Pipelines, the Alberta electric distributors continue to have a monopoly for delivery of power.[537]

472. In rebuttal evidence, Ms. McShane disagreed that the primary risk to ATCO Pipelines was the credit risk of not getting paid by NGTL. In her view, the primary risk to ATCO Pipelines is the risk that its costs will not be approved for recovery by the Commission. Dr. Booth did not address the utility's uncertainty with respect to its ability to expand its business or any risks arising from competition.[538]

473. Mr. Sloan for the Alberta Utilities submitted that:

> The changes in North American natural gas markets that have occurred since the execution of the System Integration Agreement, and since the most recent 2011 Generic Cost of Capital was concluded, have increased existing market risks and created new sources of risk for the Alberta System and for AP.
> …

536 Exhibit 42.02, McShane evidence for Alberta Utilities, lines 1334-1347.
537 Exhibit 42.02, McShane evidence for Alberta Utilities, lines 1827-1828.
538 Exhibit 81.02, McShane rebuttal evidence for Alberta Utilities, lines 417-435.

> At the same time, the Alberta System Integration has reduced AP's ability to effectively respond to the increase in market risk.[539]

474. The Alberta Utilities' argument included the following:

- Post integration, while test period throughput risk no longer exists, ATCO Pipelines nevertheless remains at risk for recovery of its costs of providing transportation service as a result of the ongoing GRA process.[540]
- When valuing a stock, a prospective investor makes an initial assumption about growth in capital (what will the stock be worth at the time the investor expects to sell it?), and an initial assumption about dividends (what dividend will the stock pay and at what rate will the dividend grow?)[541]
- Investors make initial base growth assumptions that require recovery and growth of capital, and achievement and growth of future earnings to pay and grow dividends. Changes in business risks affect these assumptions because business risks affect future earnings and asset cost recovery.[542]
- Market risks are relevant, and the Commission should accept the conclusions of Mr. Sloan's expert evidence and Ms. McShane's assessment of his findings in determining ATCO Pipelines' business risk and capital structure.[543]
- The record clearly supports the conclusion that changes in market demand, competition and supply have made the business of transporting natural gas in Alberta far more uncertain, and that these changes have increased ATCO Pipelines business risks.[544]

475. The Alberta Utilities also quoted the Commission's finding from 2011-474 that: "Unlike the AESO, the combined ATCO Pipelines/NGTL system faces certain competition and supply risks … which should be taken into account."[545]

476. In his evidence, submitted on behalf of CAPP, Dr. Booth stated:

> In terms of the capital structure of ATCO Pipe, I note that barring some minor asset swaps that still have to be settled, it is now completely integrated into the Alberta system. While ATCO Pipe's revenue requirement has to be approved by the AUC it is completely recovered as a prior charge in Nova Gas Transmission's (NGTL) revenue requirement. This is an irreversible change in ATCO Pipe's risk and essentially makes its risk similar to that of NGTL's junior subordinated debt. Further NGTL sits on top of enormous reserves in the Western Canadian Sedimentary Basin (WCSB), where its move to federal regulation allows it to be the major player in the shipment of reserves in North East BC. Here, the Montney formation is becoming one of the most prolific gas plays in North America.[546]

539 Exhibit 42.07, Sloan evidence for ATCO Pipelines, page 2.
540 Exhibit 148.01, Alberta Utilities argument, paragraph 296.
541 Exhibit 148.01, Alberta Utilities argument, paragraph 300.
542 Exhibit 148.01, Alberta Utilities argument, paragraph 305.
543 Exhibit 148.01, Alberta Utilities argument, paragraph 319.
544 Exhibit 148.01, Alberta Utilities argument, paragraph 323.
545 Exhibit 148.01, Alberta Utilities argument, paragraph 308.
546 Exhibit 44.02, Booth evidence for CAPP, page 4.

> …
> In my judgement there is minimal risk to the equity holders in ATCO Pipe and I continue to recommend a 35% common equity ratio. As in 2011, I would point out the double leverage involved in Altalink and its effective common equity ratio at about 27% where DBRS notes that AltaLink's 37% common equity is financed by its parent with 27% equity and 10% debt. So ATCO Pipe is eminently financeable on 35% common equity.[547]
>
> In particular the ATCO Pipe revenue requirement is now recovered as a monthly charge in NGTL's tolls and collected from customers of the Alberta System. In 2011 my judgment was that this was substantially the same as the way AltaLink and other transmission facilities owners (TFO's) recover their system costs from the distributors via the Alberta Electric Systems Operator (AESO).[548]
> …
> If there are any shocks to NGTL's revenue requirement these do not seem to affect ATCO Pipe's recovery of its revenue requirement. Instead, the cost is effectively borne first by NGTL's shippers in terms of a readjustment of tolls, and then by NGTL's shareholders.[549]
> …
> My understanding is that ATCO Pipe is not going to be placed on performance based regulation and the asset swap transactions with NGTL imply no significant stranded assets.[550]
> …
> There may be some very minimal long run risk due to competition and supply, but if they exist they are smaller than they were in 2011 and I regard them as de minimus. Further to emphasise, ATCO Pipe must by definition be lower risk than NGTL and I would continue to recommend a common equity ratio no higher than 35%.[551]

477. For its part, CAPP argued that the two per cent adder from 2009 is no longer needed due to improved financial market conditions.[552]

478. CAPP noted Dr. Booth's argument that ATCO Pipelines' risk is no higher than that of electric transmission companies due to the integration agreement.[553]

479. CAPP acknowledged that the Alliance pipeline is a competitor, but also stated that this is not a new development, and that, in any event, the risk is to the combined NGTL/ATCO Pipelines entity and not to ATCO Pipelines alone. CAPP submitted that ATCO Pipelines has a claim for recovery of its costs from NGTL "come what may," in perpetuity.[554]

480. CAPP submitted that arguments about increased regulatory risk meriting a higher return are "fatally flawed" because, as a matter of law, utilities are exposed to fundamental market risks and Dr. Booth was unaware of allowances being given for increased regulatory risks.[555]

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547 Exhibit 44.02, Booth evidence for CAPP, page 5.
548 Exhibit 44.02, Booth evidence for CAPP, paragraph 240.
549 Exhibit 44.02, Booth evidence for CAPP, paragraph 246.
550 Exhibit 44.02, Booth evidence for CAPP, paragraph 266.
551 Exhibit 44.02, Booth evidence for CAPP, paragraph 267.
552 Exhibit 151.01, CAPP argument, paragraph 102.
553 Exhibit 151.01, CAPP argument, paragraph 104.
554 Exhibit 151.01, CAPP argument, paragraphs 105 and 109.
555 Exhibit 151.01, CAPP argument, paragraph 13.

481. CAPP reiterated in reply that ATCO Pipelines will recover all its costs from NGTL, and that ATCO Pipelines has failed to show how any of the market risks spoken of by its witnesses translate into the inability to recover its cost of service.[556]

482. In rebuttal evidence, Messrs. Bell and Stauft submitted, on behalf of the UCA, that any risks to ATCO Pipelines are divorced from those attributable to NGTL. They argued that ATCO Pipelines' shareholders "will be paid the full revenue requirement associated with the ATCO Pipelines system, including return, taxes, and depreciation, out of the revenues generated by the NGTL system, before NGTL shareholders are paid a dime of equity return, income taxes, or depreciation in connection with the facilities that NGTL itself owns."[557]

Commission findings

483. In Decision 2011-474, the Commission reiterated its earlier finding from Decision 2010-228[558] that post-integration, ATCO Pipelines will collect its Commission-approved revenue requirement through a monthly charge to NGTL (the AP charge) and that NGTL's revenue requirement, including the AP charge, will be collected from customers using the combined ATCO Pipelines and NGTL regulated gas transmission systems (the Alberta System). Customers would pay one toll for use of the Alberta System and be subject to a single tariff with a single set of terms and conditions of service.[559]

484. In Decision 2011-474, the Commission found that ATCO Pipelines' post-integration business risk is higher than the level of risk faced by the electric transmission sector, but is somewhat lower than the risk of electric and gas distribution sectors. The Commission's determination with respect to ATCO Pipelines' capital structure for 2011 and 2012 reflected these findings by setting the equity ratio at the average of those two sectors.[560]

485. In Decision 2011-474, the Commission did not consider that its determination in this regard would have a significant impact on ATCO Pipelines' credit metrics. In the Commission's view at that time, setting the equity ratio for ATCO Pipelines at the midpoint of equity ratios for the transmission and distribution utilities was sufficient to attain the minimum credit metrics associated with credit ratings in the A-range. In the Commission's view, this conclusion was reasonable because it had awarded equity ratios to those two sectors designed to achieve A-range ratings, and found that ATCO Pipelines' risk was midway between the risk of those two sectors. Furthermore, the Commission considered that if, after assessing the impacts of Decision 2011-474, ATCO Pipelines remained concerned about its credit metrics, the matter could be addressed at the time of the company's next general tariff application.[561]

486. The Commission is not convinced that the relative risk ranking of ATCO Pipelines has changed since it made its determinations in Decision 2011-474. The Commission acknowledges that ATCO Pipelines faces a risk that costs will not be approved by the Commission for recovery. However, that is true for all of the utilities and does not change the relative risk ranking of ATCO Pipelines. With respect to the market risks discussed by Mr. Sloan, the

556 Exhibit 151.01, CAPP argument, paragraph 14.
557 Exhibit 82.03, Bell and Stauft rebuttal evidence for UCA, paragraph A23.
558 Decision 2010-228: ATCO Pipelines, 2010-2012 Revenue Requirement Settlement and Alberta System Integration, Proceeding 223, Application 1605226-1, May 27, 2010.
559 Decision 2011-474, paragraph 264.
560 Decision 2011-474, paragraph 267.
561 Decision 2011-474, paragraph 268.

Commission again notes that ATCO Pipelines will collect its Commission-approved revenue requirement through a monthly charge to NGTL, which considerably lowers its exposure to market risk. The Commission continues to consider that ATCO Pipelines' risks are higher than those of an electric transmission company and lower than those of the distribution utilities.

487. Regarding the risk of lower growth for ATCO Pipelines, the Commission found in Decision 2011-474 that, in theory, investors should be indifferent to growth if growth is only expected to provide a risk-adjusted return readily available elsewhere in the market.[562] The Commission considers that the awarded ROE is attempting to provide a proxy for just such a return. Utilities are entitled to an opportunity to earn a fair return on prudent investments that they have actually made. They are not entitled to additional return related to the lack of an opportunity to make investments to fuel future growth.

488. For all of the above reasons, the Commission finds that ATCO Pipelines' equity ratio will continue to be set midway between those of the electric transmission and the electric distribution sectors before considering any company-specific adjustments in those sectors.

8.5.4 ATCO Electric and AltaLink TFOs

489. In Decision 2009-216, the Commission awarded a one percentage point equity increase in the capital structure of ATCO Electric TFO, AltaLink TFO and TransAlta related to credit metric relief associated with their large capital growth programs.[563] In Decision 2011-474, the Commission awarded an additional one percentage point of equity in the capital structure of ATCO Electric TFO and AltaLink TFO related to credit metric relief associated with their large capital growth programs.[564]

490. In argument, the UCA discussed the impact of the "big build" on these two utilities and discussed the impact of CWIP in rate base. The UCA ultimately recommended that all of the utilities should have their approved equity ratios reduced by two per cent, but did not recommend a sector-specific change for these two TFOs.[565]

Commission findings

491. The Commission will continue to award a two percentage point equity increase in the capital structure of ATCO Electric TFO and AltaLink TFO related to credit metric relief associated with their large capital growth programs, and for the reasons outlined in Decision 2009-216 and Decision 2011-474. In doing so, the Commission also notes that it anticipates that this additional two per cent may no longer be required after most of the recent large transmission projects are completed and brought into rate base.

8.5.5 TransAlta

492. TransAlta noted that in Decision 2011-474, it had been awarded an equity ratio of 36 per cent, while the other taxable electric transmission utilities had been awarded 37 per cent,[566] and that the Commission had also awarded an additional one per cent to AltaLink

[562] Decision 2011-474, paragraph 136.
[563] Decision 2009-216, paragraph 412.
[564] Decision 2011-474, paragraphs 291-292.
[565] Exhibit 150.02, UCA argument, pages 88-91.
[566] Exhibit 145.01, TransAlta argument, paragraph 13.

and ATCO Electric transmission to provide credit metric relief necessitated by their large capital growth programs.[567]

493. TransAlta submitted that it should be awarded the same equity ratio as the taxable electric transmission utilities for a number of reasons. It claimed that its small size, its significant growth for which it has not received credit relief in the form of CWIP in rate base or the collection of future income taxes, and the fact that it has adopted AltaLink's cost of debt, which it could not attain on a stand-alone basis, all militate in favour of the Commission approving a debt/equity ratio for it that is the same as what will be provided to other taxable transmission utilities.

Commission findings

494. The Commission finds that TransAlta should be awarded the same equity ratio as the taxable electric transmission utilities for the reasons proposed by TransAlta, including its small size, and its capital growth and the fact that it does not have CWIP in rate base.

8.6 Summary of equity ratio findings

495. Given all of the above findings, the equity ratios awarded to each of the affected utilities are summarized in the following table:

Table 10. Equity ratio findings

	Last approved	2013-2015 approved	Change in approved common equity ratio
	(%)		
Electric and gas transmission			
ATCO Electric (transmission)	37	36	-1
AltaLink	37	36	-1
ENMAX (transmission)	37	36	-1
EPCOR (transmission)	37	36	-1
Red Deer	37	36	-1
Lethbridge	37	36	-1
TransAlta	36	36	0
ATCO Pipelines	38	37	-1
Electric and gas distribution			
ATCO Electric (distribution)	39	38	-1
ENMAX (distribution)	41	40	-1
EPCOR (distribution)	41	40	-1
ATCO Gas	39	38	-1
FortisAlberta	41	40	-1
AltaGas	43	42	-1

496. As set out in Section 7, the ROE and equity ratios awarded in this decision will remain in place on an interim basis for 2016 and for subsequent years until changed by the Commission.

567 Decision 2011-474, paragraphs 291-292.

9 Implementation of GCOC decision findings

497. In Section 5.6 of this decision, the Commission determined that a generic benchmark ROE of 8.3 per cent is reasonable for each of 2013, 2014 and 2015. In Section 8.6, the Commission set out the approved capital structures for the affected utilities for the 2013 to 2015 period. In Section 6, the Commission determined that no adjustments to the generic benchmark ROE or capital structures are warranted to account for the application of principles identified in the UAD decision or the implementation of a PBR framework for certain distribution utilities; as well as some other risks perceived by the Alberta Utilities.

498. Any affected utility that has a Commission-approved revenue requirement under cost of service regulation for 2013, 2014 and 2015 was required to use ROE and capital structure placeholders until values could be approved by the Commission on a final basis. The Commission directs these utilities to apply, by July 31, 2015, to adjust their respective revenue requirements for 2013, 2014 and 2015, to reflect the final approved ROE and capital structure determinations set out in this decision. These proceedings may take the form of separate rider applications or be a part of a larger (and possibly ongoing) application dealing with other rate matters (e.g., a general rate or tariff application).

499. 2013 was the last year of the formula-based ratemaking (FBR) plan approved for ENMAX's distribution and transmission utilities in Decision 2009-035. In that decision, the Commission determined that the ROE approved in the subsequent GCOC proceeding would not be used in resetting ENMAX's distribution or transmission rates under the FBR plan.[568] Accordingly, no changes to 2013 FBR rates for ENMAX distribution or transmission result from the findings in this decision. However, as set out in Decision 2009-035, the approved 2013 GCOC ROE will be used as a target ROE for ENMAX's earnings sharing mechanism calculation for its distribution and transmission utilities.[569] In addition, the 2013 approved ROE and capital structure may be used in calculation of certain of ENMAX's flow-through items, where required (e.g., certain deferral account calculations that include WACC).

500. In Decision 2014-347,[570] the Commission approved the revenue requirement for ENMAX's distribution utility for the 2014 test period and ENMAX's transmission utility for the 2014-2015 test period, under a cost of service framework. As noted in that decision, ENMAX does not intend to apply for another term of FBR for its transmission utility.[571] The Commission directs ENMAX to apply on behalf of its distribution utility to adjust its revenue requirement for the 2014 test period to reflect the final approved ROE and capital structure determinations set out in this decision. The Commission also directs ENMAX to apply on behalf of its transmission utility to adjust its revenue requirement for the 2014-2015 test period to reflect the final approved ROE and capital structure determinations set out in this decision. The Commission further directs that any such application or applications must be made by July 31, 2015. Any adjustment proceeding may take the form of a separate rider application or be a part of a larger application dealing with other rate matters.

568 Decision 2009-035, paragraph 417.
569 Decision 2009-035, paragraphs 418-419.
570 Decision 2014-347: ENMAX Power Corporation ,2014 Phase I Distribution Tariff Application, 2014-2015 Transmission General Tariff Application, Proceeding 2739, Application 1609784-1, December 16, 2014.
571 Decision 2014-347, paragraph 2.

501. ENMAX has indicated on several occasions that it intends to file an application for a PBR plan to set rates for its distribution utility commencing in 2015.[572] Any issues associated with reflecting the 2015 approved ROE and capital structure in ENMAX's 2015 rates will be considered in a future proceeding dealing with ENMAX's second generation PBR plan.

502. As noted in Section 2, the following electric and natural gas distribution utilities are regulated under the 2013-2017 PBR plans approved in Decision 2012-237: AltaGas, ATCO Electric, ATCO Gas, EDTI and FortisAlberta. In that decision, the Commission determined that no specific changes to customer rates should be made to take into account changes in either the approved ROE, or changes in the cost of debt during the PBR term.[573] However, as noted in that decision, the then current approved ROE will be used as the ROE input for calculation of the +/-300 or +/-500 basis point reopener thresholds in a given PBR year.[574]

503. With respect to the impact of changes in capital structure on PBR rates, the Commission stated at paragraph 710 of Decision 2012-237:

> 710. The Commission understands that a change to the risk profile of the companies may result from the transition to PBR. The Commission will consider this issue in the upcoming GCOC proceeding. If the Commission determines that there is a change to the risk profile of the companies as a result of the transition to PBR, the Commission will make a one-time adjustment to the companies' rates to reflect any adjustment to the companies' capital structure.[575]

504. In Section 6.2 of this decision, the Commission determined that there is no evidence within this proceeding which supports the Alberta Utilities' assertions of appreciably more risk resulting from implementation of the current PBR regime. Consequently, no adjustment to capital structure was directed by the Commission as a result of certain distribution utilities coming under a PBR regime. Therefore, in accordance with paragraph 710 of Decision 2012-237, the Commission finds that no adjustment to rates for the utilities under PBR for changes in capital structure is required during the PBR term.

505. Finally, the Commission confirms that the ROE and capital structures approved in this decision may be used in calculation of certain flow-through items, where required (e.g., in treatment of deferral accounts that use WACC for the calculation of carrying charges). The Commission also confirms that the 2013-2015 approved ROE and equity ratios will also be used in the calculation of K factor amounts under the capital tracker mechanism. As set out in Section 4.4 of Decision 2013-435, the accounting test incorporated in the K factor calculation (as it relates to revenue) is comprised of two components. The first component is the revenue provided under the I-X mechanism for a project or program proposed for capital tracker treatment. The second component is the revenue requirement calculations based on forecast or actual capital additions for the identified project or program for the PBR year. In Decision 3434-D01-2015,[576] the Commission determined that revenue requirement calculations in the second

572 Decision 2014-347, paragraph 2.
573 Decision 2012-237, paragraph 706.
574 Decision 2012-237, paragraph 738.
575 Decision 2012-237, paragraph 710.
576 Decision 3434-D01-2015: Distribution Performance-Based Regulation, Commission-Initiated Review of Assumptions Used in the Accounting Test for Capital Trackers, Proceeding 3434, Application 1610877-1, February 5, 2015.

component of the accounting test should be based on the approved ROE and capital structure for that year.[577]

10 Order

506. It is hereby ordered that:

(1) The final approved ROE for 2013, 2014, and 2015 is set at 8.3 per cent.

(2) The final approved deemed equity ratios for the Alberta Utilities for 2013, 2014 and 2015, are as set out in the table below.

(3) The ROE, and deemed equity ratios set out in the table below are approved on an interim basis for 2016, and for each subsequent year thereafter, unless otherwise directed by the Commission.

(4) The Alberta Utilities are to apply to adjust their rates to implement the findings of this decision, as directed in Section 9.

	Last approved	2013-2015 approved	Change in approved common equity ratio
		(%)	
Electric and gas transmission			
ATCO Electric (transmission)	37	36	-1
AltaLink	37	36	-1
ENMAX (transmission)	37	36	-1
EPCOR (transmission)	37	36	-1
Red Deer	37	36	-1
Lethbridge	37	36	-1
TransAlta	36	36	0
ATCO Pipelines	38	37	-1
Electric and gas distribution			
ATCO Electric (distribution)	39	38	-1
ENMAX (distribution)	41	40	-1
EPCOR (distribution)	41	40	-1
ATCO Gas	39	38	-1
FortisAlberta	41	40	-1
AltaGas	43	42	-1

577 Decision 3434-D01-2015, paragraph 70.

Dated on March 23, 2015.

Alberta Utilities Commission

(original signed by)

Mark Kolesar
Vice-Chair

(original signed by)

Bill Lyttle
Commission Member

(original signed by)

Tudor Beattie, QC
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
ATCO Electric Ltd.
AltaLink Management Ltd. Borden, Ladner Gervais LLP
ATCO Gas
ATCO Pipelines
AltaGas Utilities Inc.
The City of Calgary (Calgary) McLennan Ross
Canadian Association of Petroleum Producers (CAPP)
Consumers' Coalition of Alberta (CCA)
EPCOR Distribution & Transmission Inc.
Encana Corporation
ENMAX Power Corporation
FortisAlberta Inc.
Industrial Power Consumers Association of Alberta (IPCAA) Drazen Consulting Group Inc.
City of Lethbridge Chymko Consulting Ltd.
NOVA Gas Transmission Ltd.
The City of Red Deer Chymko Consulting Ltd.
TransAlta Corporation (TransAlta)
Office of the Utilities Consumer Advocate (UCA) Reynolds, Mirth, Richards & Farmer LLP

Alberta Utilities Commission

Commission Panel
M. Kolesar, Vice-Chair
B. Lyttle, Commission Member
T. Beattie, QC, Commission Member

Commission Staff
R. Finn (Commission counsel)
D. Cherniwchan
S. Allen
O. Vasetsky
C. Pham

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) counsel or representative	Witnesses
Alberta Utilities L. Smith, QC C. Warkentin	Panel 1 K. McShane M. Sloan Panel 2 K. McShane S. Fetter
AltaLink Management Ltd. R. Block	
FortisAlberta Inc. T. Dalgleish, QC S. Nagina	
AltaGas Utilities Inc. N. McKenzie	
TransAlta Corporation (TransAlta) L.-M. Berg	C. Codd A. Bosu
EPCOR Distribution & Transmission Inc. C. Bystrom J. Liteplo	
ENMAX Power Corporation L. Cusano D. Wood	
Consumers' Coalition of Alberta (CCA) J. A. Wachowich	
Office of the Utilities Consumer Advocate (UCA) R. McCreary B. Schwanak I. Hanson	S. Cleary M. Stauft R. Bell
Canadian Association of Petroleum Producers (CAPP) N. Schultz	L. Booth
The City of Calgary (Calgary) D. Evanchuk G. Henderson	L. Booth H. Johnson

Alberta Utilities Commission

Commission Panel
- M. Kolesar, Vice-Chair
- B. Lyttle, Commission Member
- T. Beattie, QC, Commission Member

Commission Staff
- R. Finn (Commission counsel)
- D. Cherniwchan
- S. Allen
- O. Vasetsky
- C. Pham

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. Any affected utility that has a Commission-approved revenue requirement under cost of service regulation for 2013, 2014 and 2015 was required to use ROE and capital structure placeholders until values could be approved by the Commission on a final basis. The Commission directs these utilities to apply, by July 31, 2015, to adjust their respective revenue requirements for 2013, 2014 and 2015, to reflect the final approved ROE and capital structure determinations set out in this decision. These proceedings may take the form of separate rider applications or be a part of a larger (and possibly ongoing) application dealing with other rate matters (e.g., a general rate or tariff application). .... Paragraph 498

2. In Decision 2014-347, the Commission approved the revenue requirement for ENMAX's distribution utility for the 2014 test period and ENMAX's transmission utility for the 2014 2015 test period, under a cost of service framework. As noted in that decision, ENMAX does not intend to apply for another term of FBR for its transmission utility. The Commission directs ENMAX to apply on behalf of its distribution utility to adjust its revenue requirement for the 2014 test period to reflect the final approved ROE and capital structure determinations set out in this decision. The Commission also directs ENMAX to apply on behalf of its transmission utility to adjust its revenue requirement for the 2014-2015 test period to reflect the final approved ROE and capital structure determinations set out in this decision. The Commission further directs that any such application or applications must be made by July 31, 2015. Any adjustment proceeding may take the form of a separate rider application or be a part of a larger application dealing with other rate matters. .... Paragraph 500