Decision **20622-D01-2016**

Alberta Utilities Commission

2016 Generic Cost of Capital

October 7, 2016

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Contents

1 Introduction ... **1**

2 Procedural summary ... **3**

3 Overview of the Commission's approach to setting an allowed return on equity and approved deemed equity ratios ... **6**

4 Relevant changes in global economic and Canadian capital market conditions since the 2013 GCOC decision ... **7**

5 Relationship between capital structure and return on equity ... **21**

6 Return on equity ... **24**
- **6.1** Capital asset pricing model ... 25
  - **6.1.1** Risk-free rate ... 26
  - **6.1.2** Market equity risk premium ... 31
  - **6.1.3** Flotation allowance ... 35
  - **6.1.4** Beta ... 36
  - **6.1.5** The resulting capital asset pricing model estimates ... 40
- **6.2** Empirical capital asset pricing model and the multifactor model ... 43
- **6.3** Bond yield plus risk premium model and the predictive risk premium model ... 45
- **6.4** Discounted cash flow model ... 51
  - **6.4.1** Discounted cash flow methodology and predictive value ... 51
  - **6.4.2** Discounted cash flow estimates ... 52
    - **6.4.2.1** Return on equity estimates for the equity market based on discounted cash flow models ... 58
    - **6.4.2.2** Return on equity estimates for the utilities equity market based on discounted cash flow models ... 61
- **6.5** Stock market return expectations of market professionals ... 63
- **6.6** Other considerations in establishing a fair allowed return on equity ... 65
- **6.7** Overall recommendations and the allowed return on equity for 2016 and 2017 ... 66

7 Capital structure matters ... **73**
- **7.1** Overview ... 73
- **7.2** Deemed equity ratios requested ... 75
- **7.3** Credit ratings and credit metric analysis ... 78
  - **7.3.1** Financial ratios, capital structure and actual credit ratings ... 78
  - **7.3.2** Equity ratios associated with credit metrics ... 88
- **7.4** Business risk analysis ... 98
  - **7.4.1** Generic business risks ... 98
    - **7.4.1.1** Impact of the Commission's utility asset disposition decision ... 100
    - **7.4.1.2** Risk of credit rating downgrade ... 106
    - **7.4.1.3** Regulatory lag ... 111
    - **7.4.1.4** Other generic business risk considerations ... 111
  - **7.4.2** Business risk utility sector analysis ... 115
  - **7.4.3** Company specific equity ratio adjustments ... 118
    - **7.4.3.1** Adjustment for non-taxable status ... 118

7.4.3.2 AltaLink and ATCO Electric Transmission deemed equity ratio premium for large capital programs 123
7.4.3.3 ATCO Pipelines and ATCO Gas.. 125
7.4.3.4 AltaGas Utilities Inc. 128
7.4.3.5 Actual capital structure of ENMAX Power Corporation 128
7.5 Determination of Commission-approved deemed equity ratios................................ 131

8 ATCO Electric Transmission compliance filing 134

9 Implementation of generic cost of capital decision findings 135

10 Order 137

Appendix 1 – Proceeding participants 139

Appendix 2 – Oral hearing – registered appearances 140

Appendix 3 – Summary of Commission directions.. 142

Appendix 4 – Abbreviations.. 144

List of tables

Table 1. Allowed final ROE for 2016 and 2017, with the exception of ATCO Electric Transmission. Approved final deemed equity ratios for 2016 and 2017, with the exception of ENMAX and ATCO Electric Transmission. 2

Table 2. CAPM recommendations of Dr. Booth and Dr. Cleary 41

Table 3. CAPM results of Mr. Hevert.. 41

Table 4. CAPM results of Dr. Villadsen – without leverage adjustment........................... 42

Table 5. Dr. Villadsen’s ECAPM estimates... 44

Table 6. Results of Dr. Villadsen’s multi-stage DCF estimates – without leverage adjustment 53

Table 7. Inputs and results of Dr. Cleary’s single stage DCF analysis 56

Table 8. Inputs and results of Dr. Cleary’s H-model 56

Table 9. DCF-based ROE estimates for the equity market provided by Dr. Cleary, Dr. Booth and Mr. Hevert.. 59

Table 10. ROE recommendations of Dr. Villadsen, Mr. Hevert, Dr. Cleary and Dr. Booth based on DCF models 62

Table 11. Summary of ROE recommendations 67

Table 12. 2013 GCOC decision: Commission's CAPM, DCF and allowed ROE findings . 69

Table 13. Deemed equity ratios approved in the 2013 GCOC decision and the deemed equity ratios recommended in this proceeding 76

Table 14. Credit ratio benchmarks for A-rating and realized ratios for A range utilities . 81

Table 15. Credit ratio benchmarks for A-rating discussed by Mr. Stauft 83

Table 16. Forecast credit metrics of AltaLink for 2016 and 2017 – with and without S&P adjustments 86

Table 17. Parameters for calculating credit metrics 89

Table 18. Embedded average debt rates, depreciation rates and CWIP percentages by utility 90

Table 19. Additional analysis of information included in Table 18 91

Table 20. Credit metrics compared to equity ratios – Commission calculations – distribution utilities – income tax rate of 27 per cent 95

Table 21. Credit metrics compared to equity ratios – Commission calculations – distribution utilities – income tax rate of zero 96

Table 22. Credit metrics compared to equity ratios – Commission calculations – transmission utilities – income tax rate of 27 per cent 96

Table 23. Credit metrics compared to equity ratios – Commission calculations – transmission utilities – income tax rate of zero 97

Table 24. Commission guidelines for equity ratios to achieve a credit rating in the A category 98

Table 25. Deemed equity ratios from the 2013 GCOC decision 132

Table 26. Commission-approved deemed equity ratios 134

List of figures

Figure 1 Yield curves for Government of Canada and the U.S. government bonds as of June 10, 2016 11

Figure 2 30-year Canadian A-rated utility bond yields, 30-year GOC bond yields and the resulting spread 12

Figure 3 Credit spread between 30-year Canadian A-rated utility bond yields and 30-year GOC bond yields 14

Figure 4 Indicative 30-year credit spreads for Alberta utilities (basis points) as provided by Mr. Hevert 15

Figure 5 Canadian and U.S. stock market volatility indexes 17

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2016 Generic Cost of Capital **Proceeding 20622**

1 Introduction

1. This decision sets out the allowed return on equity (ROE) for the years 2016 and 2017 on a final basis, with the exception of the allowed ROE for the transmission operations of ATCO Electric Ltd., as explained in Section 8. The allowed ROE applies uniformly to the utilities listed below.

- AltaGas Utilities Inc. (AltaGas)
- AltaLink Management Ltd. (AltaLink)
- ATCO Electric Ltd. (ATCO Electric)
- ATCO Gas
- ATCO Pipelines
- ENMAX Power Corporation (ENMAX)
- EPCOR Distribution & Transmission Inc. (EPCOR)
- FortisAlberta Inc. (FortisAlberta)
- City of Lethbridge (Lethbridge)
- City of Red Deer (Red Deer)
- TransAlta Corporation (TransAlta)

2. This decision also sets out the approved deemed equity ratios (also referred to as capital structure) for the years 2016 and 2017 on a final basis, with the exception of the deemed equity ratios for ENMAX and the transmission operations of ATCO Electric Ltd., as explained in Section 7.4.3.5 and Section 8, respectively.

3. A number of the utilities listed above have both a distribution operation and a transmission operation, and there are separate approved deemed equity ratios for each of these operations.

4. The Commission has identified the operations of these utilities separately, and the utilities, as so designated below are referred to collectively in this decision as the affected utilities:

- AltaGas (natural gas distribution)
- AltaLink (electricity transmission)
- ATCO Electric Distribution (electricity distribution)
- ATCO Electric Transmission (electricity transmission)
- ATCO Gas (natural gas distribution)
- ATCO Pipelines (natural gas transmission)
- ENMAX Distribution (electricity distribution)
- ENMAX Transmission (electricity transmission)
- EPCOR Distribution (electricity distribution)

- EPCOR Transmission (electricity transmission)
- FortisAlberta (electricity distribution)
- Lethbridge (electricity transmission)
- Red Deer (electricity transmission)
- TransAlta (transmission assets)

5. Given that the allowed ROE is uniformly applied to all of the affected utilities, the Commission has accounted for differences in the risk of each of the affected utilities by adjusting the approved deemed equity ratios. The allowed final ROEs for 2016 and 2017 for all the affected utilities, with the exception of ATCO Electric Transmission, and the approved final deemed equity ratios for 2016 and 2017, with the exception of ENMAX and ATCO Electric Transmission, are set out in Table 1. As explained in Section 7.4.3.5 and Section 8, the allowed ROE for 2016 and 2017 for ATCO Electric Transmission, and the approved deemed equity ratios for ENMAX and ATCO Electric Transmission set out in Table 1 are placeholders only.

Table 1. Allowed final ROE for 2016 and 2017, with the exception of ATCO Electric Transmission. Approved final deemed equity ratios for 2016 and 2017, with the exception of ENMAX and ATCO Electric Transmission.

	2016 approved (%)	2017 approved (%)
ROE	8.3 (Note 1)	8.5 (Note 1)
Deemed equity ratios		
Electricity and natural gas transmission		
AltaLink	37	37
ATCO Electric Transmission (Note 2)	37	37
ATCO Pipelines	37	37
ENMAX Transmission (Note 2)	37	37
EPCOR Transmission	37	37
Lethbridge	37	37
Red Deer	37	37
TransAlta	37	37
Electricity and natural gas distribution		
AltaGas	41	41
ATCO Electric Distribution	37	37
ATCO Gas	37	37
ENMAX Distribution (Note 2)	37	37
EPCOR Distribution	37	37
FortisAlberta	37	37

Note 1 – approved on a placeholder basis for ATCO Electric Transmission.

Note 2 – approved on a placeholder basis.

6. The allowed ROEs and approved deemed equity ratios for 2016 and 2017 from this decision do not apply to EPCOR Energy Alberta GP Inc., ENMAX Energy Corporation and Direct Energy Regulated Services because these utilities 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 and default supply providers, respectively, which address 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.

7. Specific ROEs and deemed equity ratios for the various investor-owned water utilities under the Commission's jurisdiction were not determined in this proceeding. However, the determinations made in this proceeding may be considered in any cost of capital determinations applicable to these various investor-owned water utilities, should issues respecting the matters of ROE and deemed equity ratios arise for these utilities.

8. Each of the affected utilities, excepting Lethbridge, Red Deer and TransAlta, participated in this proceeding. AltaGas, the ATCO Utilities,[3] ENMAX and FortisAlberta (collectively, the Utilities), after registering individually, filed joint submissions during the proceeding. AltaLink and EPCOR co-sponsored evidence. AltaLink also provided company-specific evidence.

9. The remaining parties that were active in the proceeding were the Canadian Association of Petroleum Producers (CAPP), The City of Calgary (Calgary), the Consumers' Coalition of Alberta (CCA) and the Office of the Utilities Consumer Advocate (UCA). Each of these four parties sponsored evidence.

2 Procedural summary

10. On March 23, 2015, the Commission issued Decision 2191-D01-2015[4] (2013 Generic Cost of Capital (GCOC) decision), which set an allowed ROE and approved deemed equity ratios for the years 2013, 2014 and 2015. With respect to the year 2016, the Commission stated the following:

> 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.[5]

11. On April 30, 2015, the Commission issued a letter initiating a 2016 GCOC proceeding, Proceeding 20371. The Commission requested written submissions respecting the scope of the proceeding.

12. On May 7, 2015, AltaGas, AltaLink, the ATCO Utilities, ENMAX, EPCOR and FortisAlberta submitted a letter to the Commission that outlined a procedural proposal for the

1 Alberta Regulation 262/2005.
2 Alberta Regulation 184/2003.
3 Consisting of ATCO Electric Ltd. and ATCO Gas and Pipelines Ltd. ATCO Gas and ATCO Pipelines are operating divisions of ATCO Gas and Pipelines Ltd.
4 Decision 2191-D01-2015: 2013 Generic Cost of Capital, Proceeding 2191, Application 1608918-1, March 23, 2015.
5 Decision 2191-D01-2015, paragraph 415.

Commission's consideration. In essence, it was proposed that, to reduce the potential for regulatory lag and to ensure certainty for the public, the Commission should consider finalizing the 2016 ROE and deemed equity ratios at levels approved on an interim basis for that year pursuant to the 2013 GCOC decision. The Commission treated the procedural proposal as an application to set the allowed ROE and approved deemed equity ratios for the year 2016, subject to certain conditions, and cancelled the schedule set out in its April 30, 2015 letter.

13. As described in more detail in Decision 20371-D01-2015,[6] which was issued on July 8, 2015, the Commission denied the application and advised that it planned to initiate a normal course GCOC process for 2016 and 2017.

14. On July 30, 2015, the Commission again initiated a 2016 GCOC proceeding, Proceeding 20622. Notification of the proceeding was distributed electronically to parties registered in the 2013 GCOC proceeding. Notice was also distributed to those named on the Commission's email notification list for electricity, natural gas and natural gas pipelines proceedings. Parties were invited to comment on any issues that should be considered as part of the proceeding, as well as on procedural alternatives that might facilitate completion of the proceeding in a timely manner.

15. On September 2, 2015, the Commission held a pre-proceeding conference to hear from parties on the scope of matters to be considered in this proceeding. A transcript of the pre-proceeding conference was produced.

16. By letter[7] dated September 10, 2015, the Commission confirmed that the 2016 GCOC proceeding would establish an allowed ROE and approved deemed equity ratios for the years 2016 and 2017 and that the final issues list for the proceeding would include:

(a) How should the Commission consider the relationship between capital structure and ROE with respect to overall return?

(b) Assessment of the impacts, if any, of the completion of the large capital projects for the transmission utilities on the capital structure of the affected utilities.

(c) Should the Commission continue to use the observed credit metric ratios it currently relies on in its capital structure analyses? Should other credit metrics also be considered?

(d) Can forecast data be used to calculate expected credit metric ratios? If so, how?

(e) Is an adder for tax-free or municipally owned utilities still warranted, and if so, how much should the adder be?

17. In the final issues list letter the Commission excluded the consideration of an automatic adjustment formula for establishing the allowed ROE for 2016 and 2017. The Commission found that current capital market conditions do not support a return to a formula-based approach in the near term. 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.

[6] Decision 20371-D01-2015: 2016 Generic Cost of Capital, Application for Finalization of 2016 Approved Return on Equity and Capital Structures, Proceeding 20371, July 8, 2015.

[7] Exhibit 20622-X0029.

18. On September 17, 2015, the Commission held a roundtable meeting to discuss the procedural alternatives that might facilitate completion of this proceeding in a timely manner.

19. On September 30, 2015, AltaGas, AltaLink, the ATCO Utilities, ENMAX, EPCOR and FortisAlberta filed a request for approval to initiate a negotiated settlement process with respect to the matters at issue in this GCOC proceeding. The Commission approved this request on October 2, 2015. On November 2, 2015, the Commission was advised that the negotiations were unsuccessful.

20. An initial process schedule, a list of minimum filing requirements and a summary of findings related to the roundtable discussion on procedural alternatives was issued by the Commission on December 22, 2015.[8] This letter also set out the Commission's plan to address the anticipated delay in receipt of related information from the Commission's decision on ATCO Electric Transmission's 2015-2017 general tariff application (GTA). The Commission has addressed this issue in Section 8 of this decision. A revised process schedule was issued by the Commission on January 20, 2016.[9]

21. The division of the Commission assigned to this application comprises Commission Member Bill Lyttle; Commission Member Henry van Egteren and Vice-Chair Mark Kolesar, who chaired the panel.

22. The oral hearing commenced on May 31, 2016 in the Commission's hearing room in Edmonton, Alberta. The sitting days for the oral hearing were as follows: May 31, 2016 to June 3, 2016 inclusive; June 6, 2016 to June 10, 2016 inclusive; and June 13, 2016. On June 28, 2016, the Commission heard separate oral argument from AltaGas, AltaLink, the ATCO Utilities, ENMAX, EPCOR and FortisAlberta. This was followed by oral argument from Calgary, CAPP, the CCA and the UCA on June 29, 2016 and separate reply argument on June 29, 2016 from AltaGas, AltaLink, the ATCO Utilities, ENMAX, EPCOR and FortisAlberta.

23. Evidence was sponsored as follows:

On behalf of the Utilities:

- Dr. Bente Villadsen, PhD, principal of The Brattle Group
- Dr. Paul Carpenter, PhD, principal of the Brattle Group
- Mr. Robert Buttke, president and founder of Twin Brooks Ltd. of Toronto, Ontario

On behalf of AltaLink and EPCOR:

- Mr. Robert Hevert, managing partner of Sussex Economic Advisors, LLC of Westborough, Massachusetts
- Mr. Steven Fetter, president of Regulation UnFettered of Port Townsend, Washington

On behalf of AltaLink:

- Mr. David Koch
- Mr. Chris Lomore

8 Exhibit 20622-X0041.
9 Exhibit 20622-X0047.

On behalf of CAPP:

- Dr. Laurence Booth, PhD, professor of finance at the Rotman School of Management at the University of Toronto, Toronto, Ontario

On behalf of Calgary:

- Dr. Laurence Booth, PhD
- Mr. Hugh Johnson, partner in the firm of Stephen Johnson Chartered Accountants of Calgary, Alberta

On behalf of the CCA:

- Mr. Jan Thygesen, principal of Icarus Regulatory Services Ltd. of Edmonton, Alberta

On behalf of the UCA:

- Dr. Sean Cleary, PhD, BMO Bank of Montreal professor of finance at the Smith School of Business at Queen's University, Kingston, Ontario
- Mr. Mark Stauft

24. The Commission considers that the close of record for this proceeding was June 29, 2016.

25. 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 return on equity and approved deemed equity ratios

26. In satisfying the fair return standard, the Commission is required to determine a fair ROE for the affected utilities. In Decision 2009-216[10] (2009 GCOC decision), Decision 2011-474[11] (2011 GCOC decision) and the 2013 GCOC decision,[12] the Commission established an allowed ROE that uniformly applied to all of the affected utilities and accounted for particular business risks faced by the affected utilities by incorporating any required adjustments into their respective approved deemed equity ratios, either collectively or on an individual basis.

27. For the purposes of this decision, the Commission's point of departure is the allowed ROE and approved deemed equity ratios established in the 2013 GCOC decision. From this starting point, the Commission has evaluated the evidence and argument in this proceeding to determine whether changes in the allowed ROE and approved deemed equity ratios from the 2013 GCOC decision are warranted. To that end, the Commission generally considered the directional effect of elements of the evidence and argument in this proceeding on the allowed ROE and approved deemed equity ratios from the 2013 GCOC decision.

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[10] Decision 2009-216: 2009 Generic Cost of Capital, Proceeding 85, Application 1578571-1, November 12, 2009, paragraphs 77-78.

[11] Decision 2011-474: 2011 Generic Cost of Capital Proceeding, Proceeding 833, Application 1606549-1, December 8, 2011, paragraph 2.

[12] Decision 2191-D01-2015, paragraph 416.

28. The Commission has approached setting an allowed ROE and approved deemed equity ratios with a view to providing recognition of changes in the overall levels of risk to which the affected utilities have been exposed since the conclusion of the 2013 GCOC proceeding.

29. In determining a fair allowed ROE, the Commission begins, in Section 4 of the decision, with an evaluation of changes in the global economic and Canadian capital market conditions since the conclusion of the 2013 GCOC proceeding. This review is a factor informing the Commission’s subsequent determinations of a fair allowed ROE and approved deemed equity ratios, as discussed in the relevant sections of this decision.

30. In Section 5 of the decision, the Commission examines the question of how it should consider the relationship between capital structure and ROE with respect to establishing the overall fair return for the affected utilities.

31. In Section 6 of the decision, the Commission establishes the allowed ROEs for 2016 and 2017 on a final basis, with the exception of ATCO Electric Transmission, after consideration of all the relevant factors, including changes in global economic and Canadian capital market conditions, financial models and the effect of potential regulatory risk factors identified by parties. The Commission also sets out the interim allowed ROE for 2018.

32. In Section 7 of the decision, the Commission establishes the approved deemed equity ratios for 2016 and 2017, with the exception of ATCO Electric Transmission, ENMAX Distribution and ENMAX Transmission, after consideration of all the relevant factors, including credit metric analysis, business risk analysis, generic business risks, business risk utility sector analysis, and any company specific adjustments. The Commission also sets out the next steps toward establishing the final approved deemed equity ratios for ENMAX Distribution and ENMAX Transmission for 2016 and 2017. The Commission also sets out the interim approved deemed equity ratios for the affected utilities for 2018.

33. In Section 8, the Commission sets out the next steps toward establishing the final approved ROE and deemed equity ratios for ATCO Electric Transmission for 2016 and 2017.

34. In Section 9 of the decision, the Commission sets out how the allowed ROE and approved deemed equity ratios are to be implemented by the affected utilities.

4 Relevant changes in global economic and Canadian capital market conditions since the 2013 GCOC decision

35. Prevailing capital market conditions inform the Commission’s determinations of a fair allowed ROE and deemed equity ratios. In the 2013 GCOC decision, the Commission concluded that global economic and Canadian capital market conditions had improved since the issuance of the 2011 GCOC decision. In particular, the Commission found that the risks in capital markets were no longer significantly elevated relative to market conditions prior to the 2008-2009 financial crisis. However, the Commission accepted that at the same time, as discussed in Section 4 of the 2013 GCOC decision, in an environment where sovereign and commercial

borrowers were able to borrow at historically low rates, market conditions may not have been reflective of a typical risk-return relationship on which risk-premium models are based.[13]

36. In the current proceeding, the parties debated the importance of several changes in global economic and capital market conditions that have arisen since the 2013 GCOC decision. As discussed in more detail below, these changes included developments of a macroeconomic nature, like changes in inflation and interest rates, as well as changes in credit spreads and market volatility.

Macroeconomic conditions

37. Parties pointed out that several important developments had unfolded since the 2013 GCOC proceeding. These developments include: the gradual withdrawal of monetary stimulus by the United States (U.S.) Federal Reserve System (the Fed) in light of the continuing growth in the U.S. economy; the decline in oil prices to the U.S. $30 range and the decline in other commodity prices; the slowdown in the Chinese economy and other emerging market economies and the resulting stock market turbulence; and the continued strengthening of the U.S. dollar (USD). Parties pointed out that these events affect the economic and capital market conditions in Canada.[14]

38. In their oral evidence as well as argument and reply submissions, some parties[15] also referenced that the result of the referendum in the United Kingdom (U.K.) to leave the European Union, the so called "Brexit," and the continuing Eurozone crisis had affected market conditions around the world.

39. The parties also noted the difference in performance of the Canadian economy as compared to the U.S. economy. Mr. Buttke, who testified on behalf of the Utilities, referenced Bloomberg data showing that in the time period of the 2013 GCOC proceeding, the U.S. real gross domestic product (GDP) growth gathered momentum and was 1.5 per cent in 2013, 2.4 per cent in 2014 and 2.4 per cent in 2015. In contrast, while Canada outperformed the U.S. economy in the immediate aftermath of the 2008-2009 financial crisis, the Canadian real GDP growth, at 2.2 per cent, 2.5 per cent and 1.1 per cent in 2013, 2014 and 2015, respectively, slowed down.[16]

40. According to the Bloomberg data referenced by Mr. Buttke, the U.S. economy was expected to grow at 2.5 per cent in 2016 and 2.4 per cent in 2017.[17] Dr. Cleary on behalf of the UCA referenced comparable numbers from the Bank of Canada and Consensus Economics forecasts, both as of January 2016, projecting real GDP growth for the U.S. at 2.4 per cent in 2016 and 2.5 per cent in 2017.[18]

13 Decision 2191-D01-2015, paragraphs 49 and 51.
14 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 3; Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 13.
15 Transcript, Volume 2, pages 323-324 (Mr. Hevert). Transcript, Volume 7, pages 1037-1040 (Dr. Booth). Transcript, Volume 10, pages 1666-1667 (Dr. Cleary). Transcript, Volume 11, page 1749 (counsel for AltaLink). Transcript, Volume 11, page 1867 (counsel for the ATCO Utilities). Transcript, Volume 12, pages 1961-1962 (counsel for Calgary). Transcript, Volume 12, page 1996 (counsel for CAPP). Transcript, Volume 12, pages 2062-2063 (counsel for the CCA). Transcript, Volume 12, pages 2091-2093 (counsel for the UCA).
16 Exhibit 20622-X0126, evidence of Mr. Buttke, Table 1 on PDF page 7; updated in Exhibit 20622-X0573.
17 Exhibit 20622-X0126, evidence of Mr. Buttke, Table 4 on PDF page 12.
18 Exhibit 20622-X0306, evidence of Dr. Cleary, Table 2 on PDF page 16.

41. Mr. Buttke noted that according to Bloomberg's survey of 29 economists, Canadian real GDP growth is expected to continue to lag behind that of the U.S. in 2016 and 2017.[19] He added that according to Bloomberg, Canadian real GDP is expected to grow at 1.8 per cent in 2016 and 2.1 per cent in 2017.[20] This is in line with the Consensus Economics forecast estimate of 1.7 per cent in 2016 and 2.2 per cent in 2017 for Canadian real GDP growth that was put forward by Dr. Cleary.[21] Dr. Booth noted that the Bank of Canada estimates real Canadian GDP growth to be 1.4 per cent in 2016, picking up to reach 2.4 to 2.5 per cent in 2017.[22]

42. As an explanation for the difference in performance for the two economies, experts in this proceeding pointed to a significant drop in global commodity prices, especially crude oil prices, that led to a contraction in the Canadian resource and energy sectors.[23] Dr. Cleary observed that as of early 2016, oil prices had declined by over 70 per cent from their June 2014 peak,[24] although Mr. Hevert commented that they were close to the U.S. $50 range by May 2016.[25] According to Mr. Buttke, the market consensus is that energy prices will remain relatively soft throughout 2017, albeit at a slight recovery from current prices. Mr. Buttke also pointed out that futures markets (where future production can actually be sold or hedged) forecast significantly lower prices compared to the forecasts of economists.[26]

43. Mr. Buttke indicated that natural gas prices have followed a pattern similar to oil prices, bottoming out in early 2016.[27] Dr. Booth presented a chart with the Bank of Canada's commodity price index showing a drop in commodity prices starting in mid-2015, "that severely affected Canada's resource sector and triggered a technical recession in 2015Q2."[28]

44. Dr. Cleary pointed out that reduced commodity prices have led to an appreciation in the currencies of commodity importers and a depreciation in the currencies of commodity exporters. In this context, several experts[29] indicated that while the Canadian dollar (CAD) traded around par with the USD at the start of 2013, in the period leading up to this proceeding, the Canadian dollar to the U.S. dollar (CAD/USD) exchange rate weakened to its lowest level in over 10 years due to the economic and monetary divergence between Canada and the U.S., as discussed further below. The CAD/USD exchange rate dropped to $0.65 USD in early 2016 before recovering to a $0.80 USD range as oil prices partially recovered. However, Mr. Buttke[30] and Dr. Cleary[31] agreed that economic and market forecasts point to a gradual recovery of the CAD versus the USD over the coming years.

45. Mr. Buttke, Dr. Booth and Dr. Cleary indicated that while a significant drop in global commodity prices hurts the Canadian resource and energy sectors, the resulting weaker CAD

19 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 7.
20 Exhibit 20622-X0126, evidence of Mr. Buttke, Table 1 on PDF page 7.
21 Exhibit 20622-X0306, evidence of Dr. Cleary, Table 3 on PDF page 20.
22 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 17.
23 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 13. Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 16. Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 17.
24 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 17.
25 Transcript, Volume 1, page 24.
26 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 18.
27 Exhibit 20622-X0126, evidence of Mr. Buttke, Figure 5 on PDF page 18.
28 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 14.
29 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 126. Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 18.
30 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 18.
31 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 18.

will provide stimulus to non-commodity sectors such as manufacturing. These experts also generally agreed that this shifting of resources to non-energy sectors, should low oil prices persist, will take time. However, while Dr. Booth and Dr. Cleary pointed out that the Bank of Canada expects economic growth to reach 2.4 to 2.5 per cent in 2017, Mr. Buttke stated that one cannot assume that non-commodity growth will offset the commodity decline in the near term.

46. Mr. Buttke drew the Commission's attention to a speech delivered on March 30, 2016, in which one of the Bank of Canada's deputy governors, Lynn Patterson, referred to the transition of resources from commodity to non-commodity sectors stating that "our best guess is that the full adjustment will take longer than two years, (which is) our normal forecast horizon." Mr. Buttke also quoted from the Bank of Canada's January 2016 Monetary Policy Report (also referenced by Dr. Cleary), which indicated that the "adjustment process is expected to be protracted, extending well beyond the projection horizon."[32]

Inflation

47. Dr. Booth explained that the Bank of Canada has had a two per cent target rate of inflation since 1991, with a one to three per cent operating band. The 1992-2014 statistics presented by Dr. Cleary show that inflation rates, as measured by the consumer price index, have generally been in line with the two per cent Bank of Canada target, exhibiting an average of 1.86 per cent and a median of 1.99 per cent.[33]

48. Both Dr. Booth and Dr. Cleary presented data on the difference between the nominal yield and the yield on a real-return bond, referred to as the break-even inflation rate (BEIR), which is often taken as a measure of the market's inflationary expectations. Dr. Cleary pointed out that since 1991, the BEIR remained within the Bank of Canada's target band of 1.0 to 3.0 per cent, averaging 2.2 per cent overall.[34] However, when commodity prices started to weaken in late 2014, the BEIR started to decline, particularly since the summer of 2015. Dr. Booth indicated that as of March 2016 (when his evidence was filed), the BEIR was at 1.3 per cent, reflecting a persistent downward trend over 2015.

49. Dr. Booth also indicated that the actual average rate of inflation for 2015 was 1.13 per cent, down from 1.91 per cent in 2014. However, despite the low BEIR rates, he expected the inflation rate to rebound, particularly as the inflationary impact of a weak CAD is passed through.[35] In a similar vein, Dr. Cleary pointed out that the Bank of Canada forecasts the inflation rate to be 1.40 per cent in 2016, before increasing to 1.90 per cent in 2017, in line with the long-term normal level.[36]

Interest rate environment

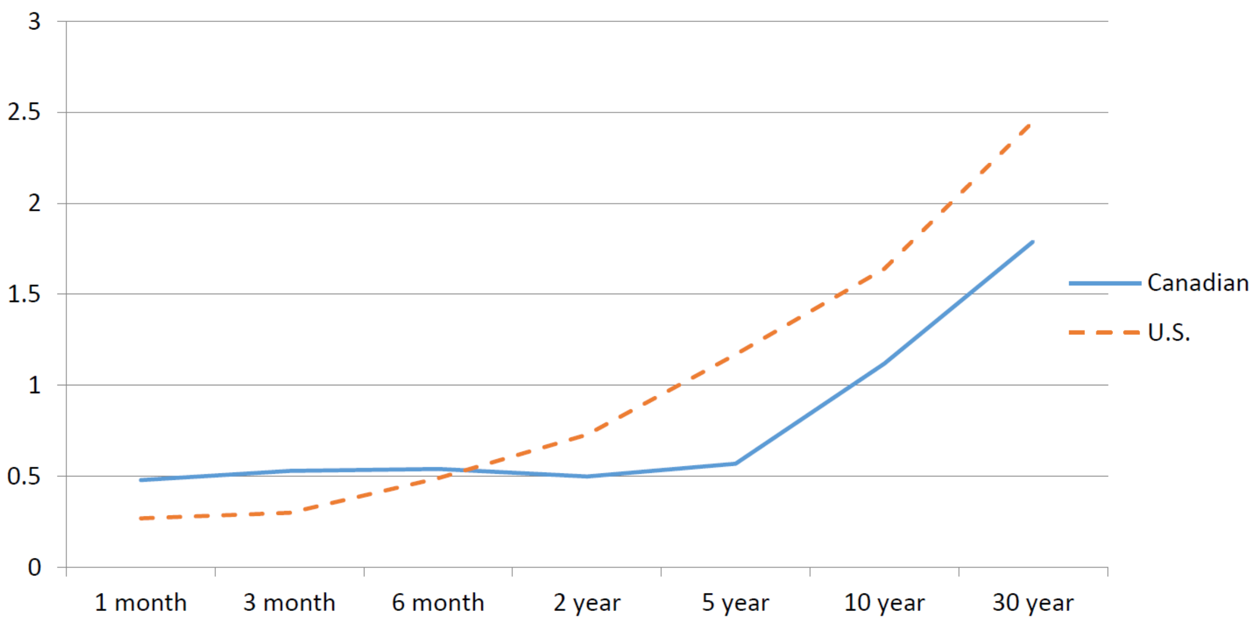
50. The actions of the U.S. and Canadian monetary authorities also differed since the close of the 2013 GCOC proceeding. At its December 16, 2015 meeting, the Fed raised the U.S. federal funds rate for the first time in the last seven years to 0.50 per cent, up from the 0.25 per cent rate in place since the end of 2008. This signalled the Fed's confidence in the U.S. economy to

32 Exhibit 20622-X0449, rebuttal evidence of Mr. Buttke, PDF page 12.
33 Exhibit 20622-X0306, evidence of Dr. Cleary, Table 1 on PDF page 8.
34 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 9.
35 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 19.
36 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 9.

maintain its tenuous recovery of the last few years.[37] In contrast, the Bank of Canada lowered its target for the Canadian overnight interest rate twice, in January 2015 and then July 2015, to the current level of 0.50 per cent, down from the 1.0 per cent rate in place since 2010.[38]

51. Figure 1 below depicts the yield curves for Government of Canada (GOC) and U.S. government bonds as of June 10, 2016, provided by Dr. Cleary. Dr. Booth explained that monetary policy works at the short end of the yield curve via the overnight rate and its influence then weakens as the maturity of the bond increases. Therefore, normally yields on long-term GOC bonds are not as affected by current monetary policy as are short-term interest rates.[39]

Figure 1 Yield curves for Government of Canada and the U.S. government bonds as of June 10, 2016[40]



52. Dr. Cleary observed that aside from the extremely low levels, the yield curves above exhibit the positive Canada-U.S. spread for short-term rates. However, at the long end of the curve, long-term U.S. rates exceed those in Canada, by some 50 to 70 basis points (bps), depending on the period observed.[41] Dr. Cleary also pointed out that forecasts from the large Canadian banks[42] show that they expect the negative spread between Canada and U.S. 10-year bond yields to continue during the years 2016-2017, "with only a slight widening to -74 bps in 2016 and -72 bps in 2017."[43]

53. Dr. Booth and Dr. Cleary pointed out that since 2011, most economic forecasters were expecting that, as the economy recovered, long-term interest rates on government bonds would increase to the 4.0 per cent level experienced prior to the crisis. However, at this time, these

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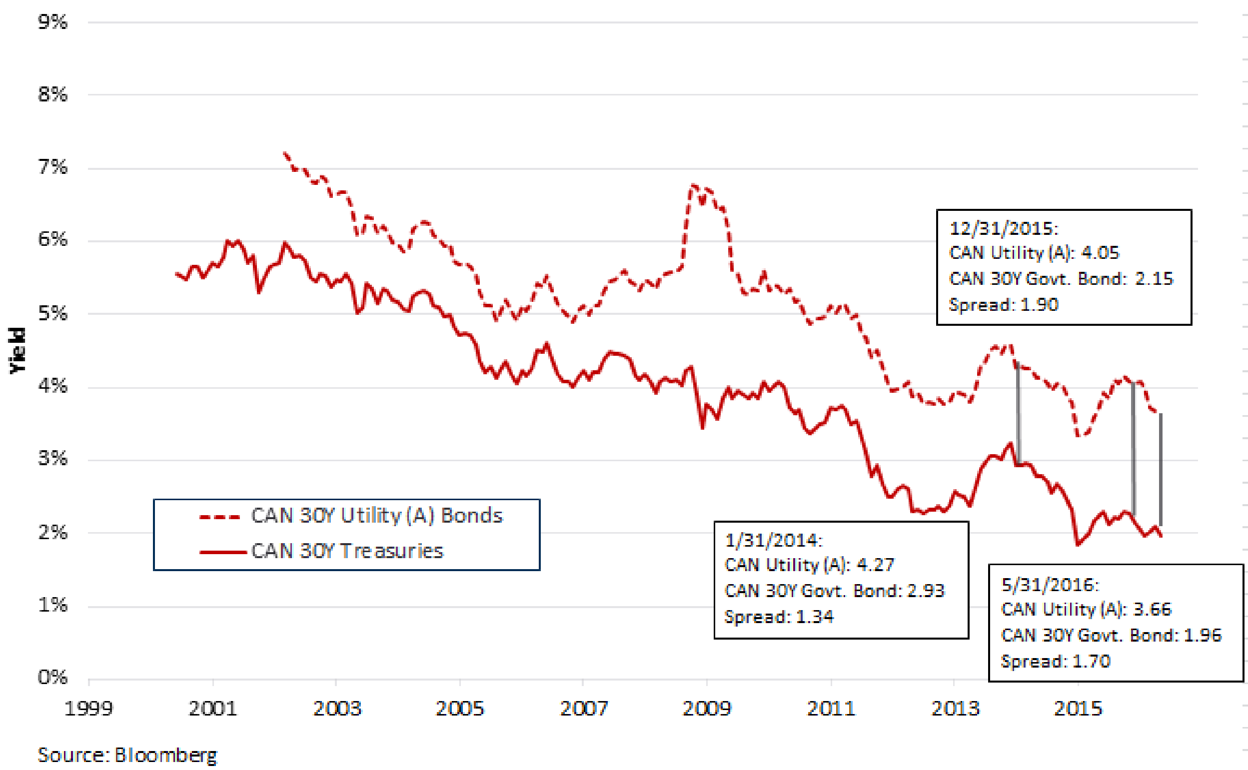
37 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF pages 10-11.
38 Exhibit 20622-X0130, Figure 2 BoC Rate.
39 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 19.
40 Exhibit 20622-X0306, evidence of Dr. Cleary, Figure 9 on PDF page 26; updated in Exhibit 20622-X0611.
41 In his evidence filed on March 23, 2016 (Exhibit 20622-X0306), Dr. Cleary indicated the spread between 10-year Canada and U.S. bond yields to be 68 bps. During the oral hearing, Dr. Cleary indicated the then-current spread was 52 bps (Exhibit 20622-X0611).
42 BMO Bank of Montreal (BMO), Bank of Nova Scotia (Scotiabank), Canadian Imperial Bank of Commerce (CIBC), Royal Bank of Canada (RBC) and Toronto-Dominion Bank (TD).
43 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 25-26.

forecasts have failed to materialize. The long-term GOC bond yields remained low during the 2013-2015 period leading up to this proceeding, and fell even further in the first half of 2016, as depicted in Figure 2.

Figure 2 30-year Canadian A-rated utility bond yields, 30-year GOC bond yields and the resulting spread[44]



54. As an explanation for why the long-term rates in Canada remain low, Dr. Booth testified that the interest rates in Canada have been affected by the actions of other monetary authorities, such as the U.S. Fed, the Bank of Japan, the Bank of England and the European Central Bank. In Dr. Booth's view, these authorities continue to follow "easy" monetary policies, including "the quantitative easing" (QE) programs that involve "the central bank buying bonds with freshly printed money: the more bonds they buy the higher the increase in bond prices and the lower the interest rate."[45]

55. To explain this concept, Dr. Booth provided a bathtub analogy. He explained that even for those countries that ended QE programs (as the U.S. Fed did in October 2014), the amount of accumulated securities that have been issued but are not in the public markets is creating a "liquidity overhang." If these securities were sold into the market, the huge increase in supply would depress prices and increase interest rates.[46] As a result:

> … while the U.S. and U.K. baths have stopped filling up but are incredibly full, the baths in Europe and Japan still have the taps completely open. The result is twofold: the supply of liquidity (money) used to buy securities has enormously increased, while the supply of bonds has decreased, since trillions have been taken off the market by central banks. The

44 Based on Exhibit 20622-X0579.
45 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 21.
46 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 22.

> result has been a dramatic increase in bond prices and drop in market yields.… [W]ith open capital markets Canada is affected by what has happened in the U.S., U.K., Japanese and European financial markets.[47]

56. According to Dr. Booth, as global interest rates have dropped, the “search for yield” has become very important and investors have started to take note of Canada. Because Canada is one of a small number of AAA-rated countries, it is a particularly attractive location to invest government reserves. Dr. Booth referenced a Bank of Canada chart showing that almost 30 per cent of the GOC bond market is now owned by non-residents. Dr. Booth concluded:

> As non-residents have searched for yield, they have invested in the Canadian government bond market driving up market prices and driving down government bond yields. The result is that current Canadian yields are far below where they would have been, but for the massive bond buying programs in the major financial markets in the rest of the world.[48]

57. Dr. Cleary generally agreed with Dr. Booth’s explanations. He added that, in addition to a lot of liquidity in the system, global financial market uncertainty is making Canada an attractive place for investing funds. Despite not being a global currency, Canada with its AAA rating looks attractive with relatively higher rates than other AAA-rated countries, such as Germany.[49]

58. Mr. Buttke, whose views on this subject were shared by Dr. Villadsen,[50] stated that while long-term interest rates can be affected by the influence of central banks on short-term rates and the supply of financial assets through QE programs, they are ultimately determined by the market. Mr. Buttke pointed out that although the level of securities held by the central banks of countries that have engaged in QE programs may seem large, it is relatively small when compared to the size of the bond market overall and, indeed, is comparable to the holdings by some large private funds.[51] Mr. Buttke also took issue with Dr. Booth’s view that significant foreign ownership of Canadian government bonds due to Canada’s AAA rating contributed to low interest rates in Canada.[52]

59. Additionally, both Mr. Buttke and Dr. Villadsen expressed their views that the U.S. Fed and other central banks will manage monetary policy and the disposition of assets accumulated during QE cycles in response to economic activity and capital market conditions. As economic conditions improve, central banks will likely move away from QE and accommodative monetary policies. As a result, interest rates are likely to rise above their current low levels.[53] Mr. Hevert,[54] Dr. Cleary[55] and Dr. Booth[56] generally agreed with this view; however, they pointed to uncertainty as to when and how fast the unwinding of QE assets by central banks is going to happen.

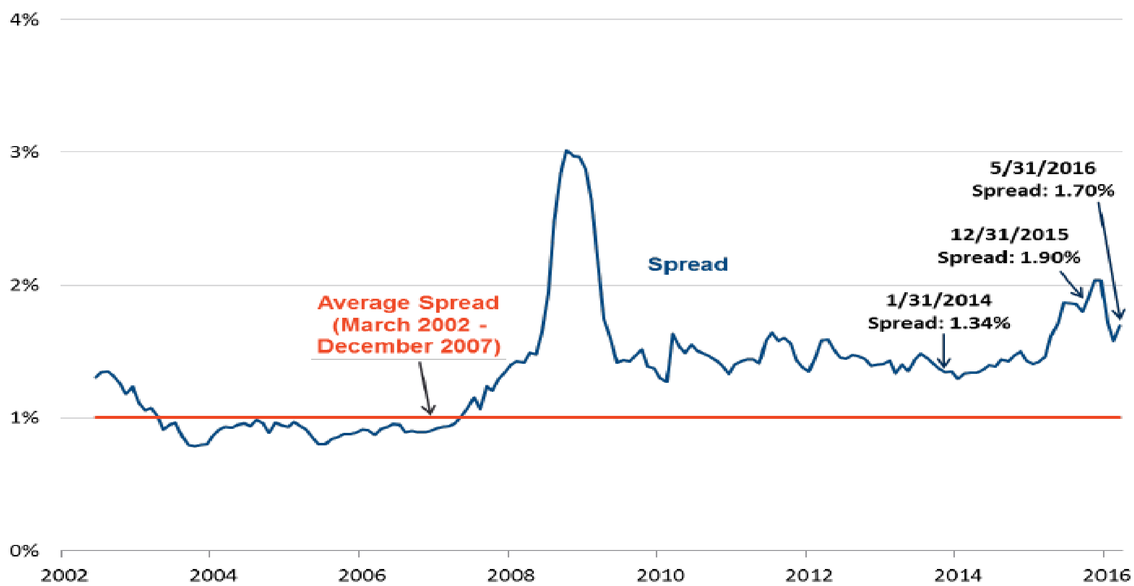
47 Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 23-24.
48 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 24.
49 Transcript, Volume 9, page 1447, lines 3-12.
50 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 14.
51 Exhibit 20622-X0449, rebuttal evidence of Mr. Buttke, PDF page 16.
52 Exhibit 20622-X0449, rebuttal evidence of Mr. Buttke, PDF pages 19-26.
53 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 14; Exhibit 20622-X0449, rebuttal evidence of Mr. Buttke, PDF page 5.
54 Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF pages 12-13.
55 Transcript, Volume 9, pages 1440-1444.
56 Transcript, Volume 7, pages 1052-1054.

Credit spreads

60. In past GCOC decisions, the Commission has accepted that credit spreads are an objective measure that helps to inform the Commission about investors' risk perceptions. "Credit spread" as referred to in this decision, is the difference between the yield on a 30-year Canadian A-rated utility bond(s) and the yield on 30-year GOC bonds. In this proceeding, the parties pointed out that credit spreads for many of the Canadian A-rated utilities have widened since the 2013 GCOC proceeding.

61. Specifically, as demonstrated in Figure 3 below,[57] the average credit spread prior to the financial crisis (2001-2007) was around 100 bps, and the average credit spread after the financial crisis (late 2009-early 2015) remained relatively stable in the 130 to 150 bps range. In late June 2015, credit spreads began to widen above 150 bps and reached 190 bps by the end of 2015. Credit spreads then increased further to 206 bps by February 3, 2016, before declining to about 170 bps as of the start of the oral hearing in late May 2016. Thus, Dr. Villadsen, Dr. Booth and Dr. Cleary pointed out that, at the start of the current proceeding, the credit spread was elevated by some 100 bps relative to what they considered to be its typical or "normal" level.[58] Mr. Hevert pointed out that credit spread volatility has increased as well.[59]

Figure 3 Credit spread between 30-year Canadian A-rated utility bond yields and 30-year GOC bond yields[60]



62. Mr. Hevert[61] and Mr. Buttke[62] indicated that credit spreads for certain Alberta utilities have widened since the time of the 2013 GCOC proceeding, as shown in Figure 4 below.

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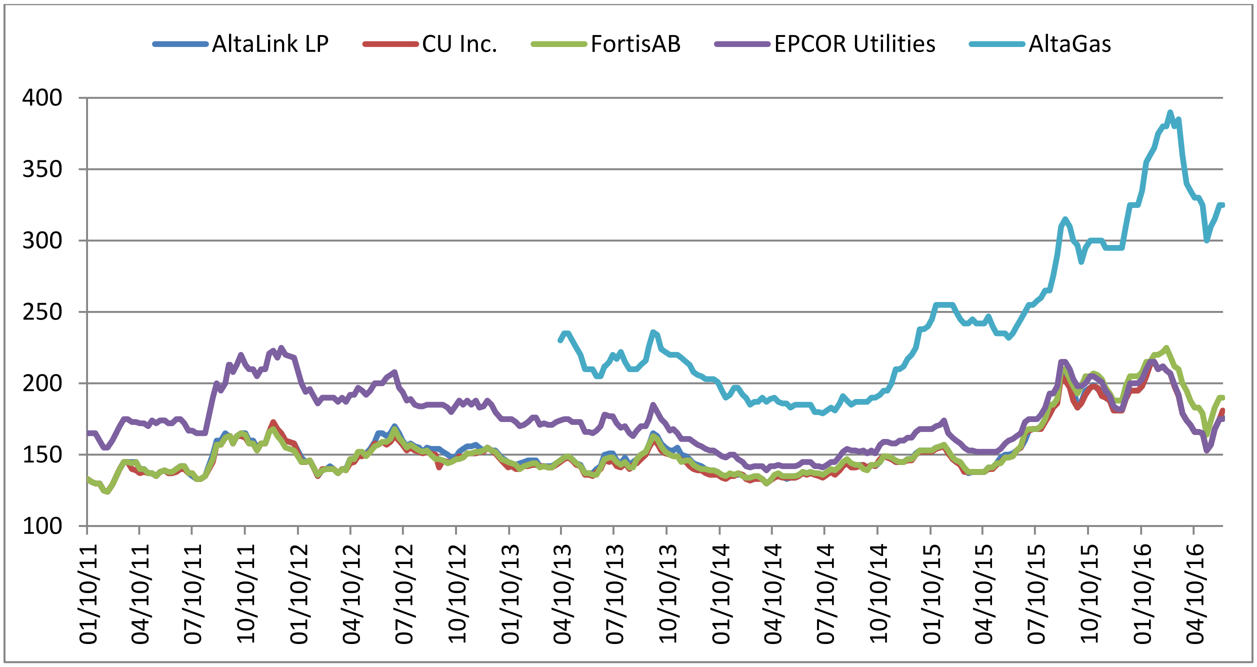
57 Underlying data provided in Exhibit 20622-X0579.
58 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 21. Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 59; Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 30.
59 Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF pages 7-8.
60 Exhibit 20622-X0104, evidence of Dr. Villadsen, Figure 3, PDF page 21; updated in Exhibit 20622-X0578.
61 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 41-42.
62 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF pages 28-29.

Figure 4 Indicative 30-year credit spreads for Alberta utilities (basis points) as provided by Mr. Hevert[63]



Note: Scotiabank did not provide 30-year indicative rates for AltaGas until April 2013.

63. Dr. Villadsen noted that the increase in the credit spreads indicates that the current long-term government bond yields are depressed relative to their normal levels or that investors are demanding a premium higher than required historically to hold securities that are not risk free, or a combination of both. She added that regardless of the interpretation, as a consequence, if the cost of equity is estimated using the current risk-free rate and a market equity risk premium (MERP) based on historical data, then it will be downward biased. Dr. Villadsen concluded that hence, it is necessary to "normalize" the risk-free rate, take into account the current (rather than historical) MERP, or employ a combination of these two interpretations.[64]

64. Mr. Hevert noted that, consistent with the view that credit spreads are a barometer of business risk, credit spreads have moved somewhat in tandem with the S&P/TSX 60 VIX index (VIXC). Although they may not be a full measure of equity risk, Mr. Hevert concluded that there is little question that the increase in credit spreads suggests some measure of increased risk perception among Canadian utility investors.[65]

65. Mr. Buttke similarly highlighted the increase in credit spreads in the U.S. and Canadian markets, which he attributed to increased volatility in the "underlying rate" and the unfolding of certain geopolitical and economic events.[66] Mr. Buttke noted that since the release of the 2013 GCOC decision, credits spreads have widened enough to offset lower GOC bond yields. He referenced recent 2015 bond issues of CU Inc. and FortisAlberta, both of which were executed at higher credit spreads than bonds with similar maturities that were executed in 2014.[67]

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[63] Underlying data provided in Exhibit 20622-X0607.
[64] Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 23.
[65] Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 42-43.
[66] Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 28.
[67] Exhibit 20622-X0126, evidence of Mr. Buttke, PDF pages 25-31.

66. Dr. Cleary pointed out that despite not being at the record highs experienced during the financial crisis, current credit spreads are still indicative of slightly heightened risk aversion. Dr. Cleary explained that Bank of Canada research indicated that much of the increase in credit spreads is due to liquidity problems, but still reflects some increased risk premiums for even low risk companies like CU Inc.[68]

67. Dr. Booth did not agree that higher credit spreads indicated increased risk for corporate bonds or increased risk aversion in Canada. Rather, the influx of foreign capital into the GOC segment of the Canadian bond market has pushed up prices, depressing yields and increasing spreads.[69]

Market volatility

68. Mr. Hevert,[70] Dr. Cleary[71] and Dr. Booth[72] drew the Commission's attention to the fact that stock market volatility had increased by late 2015 and early 2016. Mr. Hevert[73] and Dr. Villadsen[74] referred to two measures of the market's expectations for volatility: (1) the VIXC, which measures the 30-day implied volatility of the S&P/TSX 60 index (representing the stock market in Canada) and (2) the VIX, which measures the 30-day implied volatility of the S&P 500 index (representing the stock market in the U.S.). In particular, Mr. Hevert noted that both of these indexes are "highly visible, and often-reported barometers of investor risk sentiments."[75] Similarly, Dr. Villadsen noted that these indices are often referred to as the "investor fear gauge"[76] and referenced academic research that has found that investors expect a higher risk premium during more volatile periods, even when investor risk aversion remains unchanged.[77]

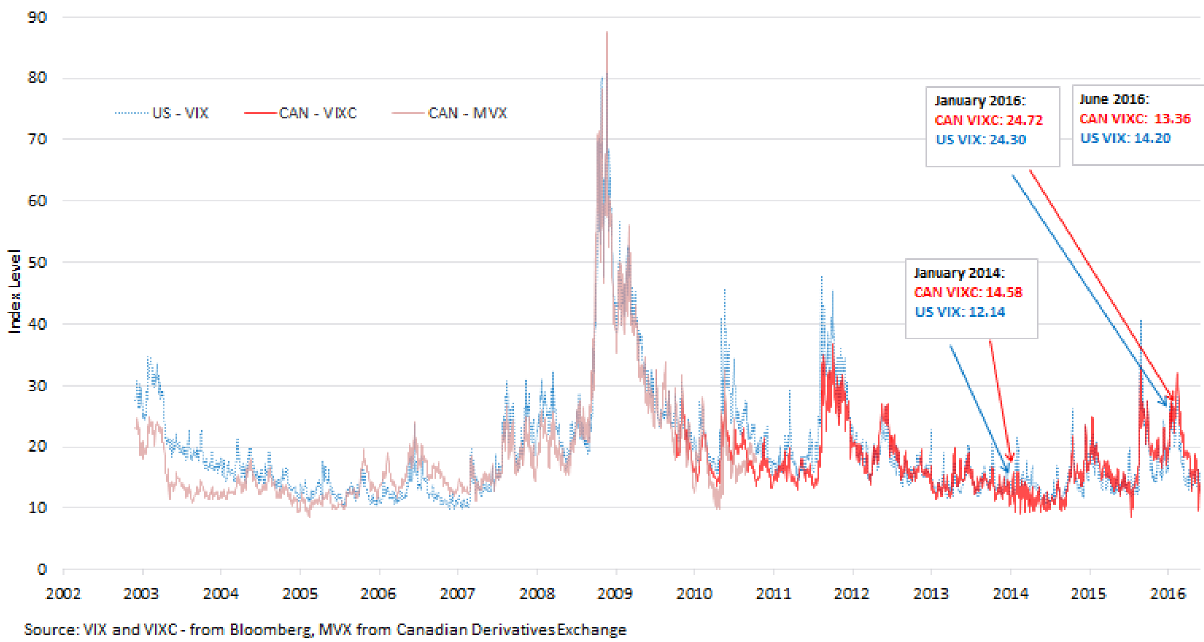
69. Experts in this proceeding indicated that the long-term average for both the VIXC and VIX is about 20.[78] As shown in Figure 5 below, the volatility stayed at relatively low levels during 2013 and 2014. However, in August 2015, the VIXC and VIX spiked to 33 and 40, levels not seen since October 2011.[79] Mr. Hevert and Dr. Villadsen indicated that as of the date of filing their evidence in January 2016, the volatility was elevated and stood at about 26 for both indices. Dr. Villadsen provided the following explanation for the elevated market volatility in 2015 and early 2016:

> … the first couple of weeks of 2016 have seen very large market declines across the globe (including in Canada) and trading on the Chinese market was halted. For example, the Toronto index, the S&P/TSX 60 has shown substantial volatility in early 2016 and was down by about 7% during the first two weeks of 2016. The development in the U.S.

68 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 42.
69 Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 31 and 32.
70 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 33.
71 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page14.
72 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 38.
73 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 31.
74 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 24.
75 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 32.
76 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 24.
77 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 24.
78 On PDF page 32 of his evidence (Exhibit 20622-X0082), Mr. Hevert explained that although the VIXC and VIX are not presented as percentages, they should be understood as such. That is, if the VIXC stood at 17.00, it would be interpreted as an expected standard deviation in annual returns on the market index of 17.00 per cent over the coming 30 trading days; the same applies to the VIX.
79 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 24.

> major index, the S&P 500 is similar. At the same time, market volatility is high […]. Further, oil prices are currently very low by historic standards – with a substantial impact on oil producing countries and regions. Finally, unrest in the Middle East (e.g., Syria and Saudi Arabia / Iran) plausibly has contributed to continued uncertainty and thereby an increase in the market equity risk premium that investors require.[80] [footnote omitted]

Figure 5 Canadian and U.S. stock market volatility indexes[81]



Note: Dr. Villadsen explained that the Canadian VIXC index until December 2008 was the Montreal Exchange's MVX index.

70. When Dr. Cleary filed his evidence in March 2016, he indicated that the VIXC and the VIX indexes stood at 21.6 and 17.3, respectively, indicating normal volatility in both Canada and the U.S., and nowhere near the level of 70 experienced in 2008-2009.[82] In his oral testimony, Dr. Cleary indicated that the VIX was at 14, or below the norm.[83] Dr. Booth made a similar observation:

> … we can see the huge increase in uncertainty during the financial crisis as the VIX hit a peak value of 80% or 4X the average value. The VIX reflected the huge panic during the financial crisis but, as always, the panic subsided, and since January 2011 (the last five years) has been below average at 16.2% despite periodic attacks of nerves in August 2015 as the first China fears hit the stock market and the first week of 2016 when they returned. The most recent value for the VIX (March 4, 2016) is 16.86%, which is similar to where it was in 2014 and reflects the stability in the stock market as oil prices have recovered somewhat from their free recent fall.[84]

71. Some experts in this proceeding also relied on other broad market indicators to support their positions. Mr. Hevert indicated that a further measure of market uncertainty is the volatility

[80] Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 28.
[81] Exhibit 20622-X0104, evidence of Dr. Villadsen, Figure 4, PDF page 25; updated in Exhibit 20622-X0577.
[82] Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 14.
[83] Transcript, Volume 9, page 1460.
[84] Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 59.

of the VIXC and the VIX themselves (i.e., the volatility of volatility, as measured by the standard deviation of the VIXC and the VIX). As well, Mr. Hevert considered the VVIX, which is a traded index of the expected volatility of the VIX.[85] He indicated that as of the date of filing his evidence in January 2016, the VVIX was 94.82 on average in 2015 and to date in 2016, it was 110.34, compared to the approximate average long-term value of 85.00.[86]

72. As evidence that the return premium demanded by investors for taking risk is higher than it was prior to the financial crisis period from 2002 through 2007, Dr. Villadsen relied on the increase in actual and forecast MERP since 2007 put forward by both academic research and Bloomberg.[87]

73. Dr. Booth referenced the Kansas City Financial Stress Index (KCFSI) developed by the Federal Reserve Bank of Kansas City as a broader measure of the stress in the financial system.[88] He advised that as measured by the KCFSI, capital market conditions have been relatively easy or stress-free since 2014, and have recently returned to average conditions.[89]

74. Dr. Cleary referred to the Mercer Pension Health Index, a commonly used measure of overall pension health, which tracks the funded status of a hypothetical defined benefit pension plan.[90] He commented that while the value of this index declined from its value of 106 per cent at the beginning of 2014 to 93 per cent at the end of 2015, these figures are well above the all-time low of approximately 70 per cent in early 2009.[91]

75. Dr. Villadsen and Mr. Hevert argued that the market volatility is higher today than at the time of the 2013 GCOC proceeding and the period leading up to that proceeding.[92] Such volatility indicates that, although interest rates are still near historical lows in both the Canadian and U.S. capital markets, there remains significant, if not greater, uncertainty in today’s equity markets, with investors requiring greater returns to bear that risk.[93] In contrast, Dr. Cleary submitted that, while it has been a volatile period for stock markets, market conditions are far from those that existed during the 2008-2009 financial crisis.[94]

Parties’ overall conclusions

76. Mr. Buttke’s view was that the global market in 2016 will likely be very volatile and interest rates are expected to gradually rise. He testified that certain segments of credit markets (such as the high yield market and the emerging markets) are under considerable stress, and broader capital market conditions are unlikely to be as favourable to issuers as they were in recent years.[95]

85 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 33-34.
86 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 34.
87 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF pages 25-27.
88 Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 34-35.
89 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 35.
90 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 14-15.
91 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 14-15.
92 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 5; Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 43.
93 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 34.
94 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 14.
95 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 51.

77. Mr. Hevert observed that the current capital market is distinguishable from that which prevailed during 2013. He referenced widened credit spreads, increased equity market volatility and several events that support increasing risk perceptions among investors.[96] Mr. Hevert concluded that given these factors, the cost of equity has increased since the 2013 GCOC proceeding.

78. Dr. Villadsen observed that investors have been dramatically affected by the credit crisis and ongoing market volatility, such that risk aversion remains elevated relative to pre-crisis periods. Likewise, monetary policy has artificially lowered the risk-free rate, resulting in credit spreads on utility debt remaining elevated. Based on this information, Dr. Villadsen concluded that the equity risk premium is higher today than it was prior to the crisis, for all risky investments, including lower-than-average risk investments such as utility equity.[97]

79. Dr. Booth observed that the overall sequence of changes in long-term GOC bond yields and long-term Canadian A-rated utility bond yields since 2014 provide no support for an increase in the allowed ROE.[98] Dr. Booth's view was that market conditions have remained much as they were in 2014; that is, very receptive to lending funds to borrowers with good credit ratings, such as utilities, for example CU Inc.[99]

80. Dr. Cleary submitted that global economic conditions have stabilized, as have Canadian capital market conditions. He added that, while real GDP growth for Alberta is predicted to be below average in 2016, it is expected to be positive and will increase above two per cent in years subsequent to 2016. He commented that oil prices are expected to continue to rise. Dr. Cleary stated that overall, the Canadian and Alberta economies are entering a recovery period that will be followed by more normal growth in the intermediate term. He added that in any event, economic and capital market conditions are far from those that existed at the peak of the 2008-2009 financial crisis. Dr. Cleary stated that regulated utilities with established territories are not as influenced by economic cyclicality as traditional businesses.[100]

Views of the Commission

81. Based on the evidence in this proceeding, the Commission considers that current global and Canadian economic capital market conditions are different from the conditions that existed during the global financial crisis of 2008-2009, although currently the evidence shows a similar directional move in the risk-free rate.[101] The Commission also agrees with the observation of Mr. Buttke that market participants have underestimated the lingering effect of the global financial crisis.[102]

82. As the data from Bloomberg presented by Mr. Buttke demonstrates, it was not until 2014 that the U.S. economy appears to have embarked on a steady growth path of some 2.4 per cent per annum. In contrast, while the Canadian economy fared better in the aftermath of the crisis, it stumbled over low commodity prices and especially low oil prices in 2015, and posted GDP

96 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 43.
97 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 32.
98 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 7.
99 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 40.
100 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 5.
101 See Figure 2.
102 Exhibit 20622-X0449, rebuttal evidence of Mr. Buttke, PDF page 8.

growth of only 1.1 per cent in 2015.[103] As a result, forecasts from various sources in this proceeding indicate the continued lacklustre performance of the Canadian economy with the 2016 GDP growth and inflation forecasts below historical averages, as referenced by Dr. Cleary.[104] However, forecasts from the Bank of Canada and Consensus Economics suggest that the Canadian economy will recover somewhat by the end of 2017.

83. Another important development was that, rather than increasing as predicted in the 2013 GCOC proceeding, yields on long-term GOC bonds fell by some 100 bps since the time of the 2013 GCOC proceeding, from approximately 3.0 per cent to approximately 2.0 per cent. Accordingly, the Commission maintains its finding from the 2013 GCOC decision that, in this historically low interest rate environment, market conditions may not be reflective of a typical risk-return relationship on which risk premium models are traditionally based.[105] As further set out in Section 6.3 of this decision, based on these findings, the Commission has adjusted the weight it assigns to the risk premium models accordingly.

84. Without engaging in the debate as to the degree to which the current interest rates have been influenced by central banks, (and accordingly, whether they should be labelled "artificially low" or just "low"), the Commission observes that all experts in this proceeding[106] have generally agreed that the U.S. Fed and other central banks will manage monetary policy and the reduction of their portfolios accumulated during QE cycles, in response to economic conditions. The experts also generally agreed that as economic conditions improve, central banks will likely move away from QE and accommodative monetary policies, with the effect that interest rates are expected to rise.

85. Given that, as set out earlier in this section, all economic forecasts on the record of this proceeding point to some recovery of the Canadian economy by the end of 2017, the Commission agrees that interest rates are likely to increase in 2017, as further discussed in Section 6.1.1. However, given the lingering economic problems in the Canadian economy and uncertainty about the timing and the speed of the disposition of the accumulated QE assets, the Commission shares Dr. Booth's sentiment that the markets are becoming increasingly pessimistic about the possibility of short-term increases in the long-term GOC bond yield.[107] Therefore, although the Commission agrees with the view that interest rates are likely to increase in 2017, there is uncertainty with respect to the speed and magnitude of the expected increase.

86. Whether viewed at a broad level, (i.e., the Bloomberg Canadian A-Rated Utility Bond Index shown in Figure 3), or at the company-specific level (as shown in Figure 4), credit spreads have widened since the 2013 GCOC proceeding and in early 2016 were sitting at 200 bps. In past GCOC decisions,[108] the Commission accepted credit spreads to be an objective, market observed measure of investors' risk perceptions. Even though credit spreads have started to decline, they were still sitting at about 170 bps as of May 31, 2016, as shown in Figure 3.

103 Exhibit 20622-X0573.
104 Exhibit 20622-X0306, evidence of Dr. Cleary, Table 1, PDF page 8; Table 3, PDF page 20; Table 4, PDF page 21.
105 Decision 2191-D01-2015, paragraphs 49 and 51.
106 Transcript, Volume 7, pages 1062-1063 (Dr. Booth); Transcript, Volume 9, page 1450 (Dr. Cleary); Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 14; Exhibit 20622-X0449, rebuttal evidence of Mr. Buttke, PDF pages 16-17.
107 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 28.
108 Decision 2009-216, paragraph 308; Decision 2191-D01-2015, paragraph 336.

87. Dr. Booth opined that the reason for the increase in credit spreads was the influx of foreign capital into the GOC segment of the Canadian bond market that has pushed up prices, depressing yields and increasing spreads. Dr. Cleary's opinion was that much of the increase in credit spreads is due to liquidity problems, based on Bank of Canada research. Mr. Buttke attributed the increase in credit spreads to increased volatility in the "underlying rate" and the unfolding of certain geopolitical and economic events.

88. Mr. Hevert submitted that "as a measure of directional change, there is little question that credit spreads have increased which suggests some measure of increased risk perceptions among Canadian utility investors."[109] Given his opinion on the cause of widened credit spreads, Dr. Booth did not agree that higher credit spreads indicated increased risk for corporate bonds or increased risk aversion in Canada.

89. The Commission's view is that there is no definitive evidence on the record to explain the increased credit spreads, and accordingly it could be the result of a combination of factors. If there is no clear rationale for the increase in credit spreads, then the Commission cannot conclude that the widening of credit spreads indicates increased risk perceptions among Canadian utility bond investors and by extension, Canadian utility equity investors. Equally, the Commission cannot conclude that the widening of credit spreads does not indicate, at least in part, increased risk perceptions among utility bond and equity investors.

90. The Commission notes that Mr. Hevert and Dr. Villadsen provided evidence on the investor expectations of heightened market volatility, with reference to a number of market indicators, and Dr. Villadsen's observation that investors expect a higher risk premium during more volatile periods, even when investor risk aversion remains unchanged.[110] Mr. Hevert and Dr. Villadsen also observed that market volatility is higher today than at the time of the 2013 GCOC proceeding and the period leading up to that proceeding. The Commission notes that Dr. Cleary and Dr. Booth referred to recent declines in market perceptions of volatility, as evidenced by broad market indicators and Dr. Cleary acknowledged that stock markets are experiencing slightly more volatility than at the time of the 2013 GCOC decision.[111]

91. Based on Figure 5 above and considering the evidence of the parties with respect to market volatility, the Commission considers it reasonable to conclude that recent instability in estimators of investor perceptions of near-term market uncertainty, including the VIX and the VIXC, are indicative of increased investor uncertainty in the 2016-2017 period compared to investor uncertainty which existed at the time of the 2013 GCOC proceeding.

5 Relationship between capital structure and return on equity

92. As set out in the final issues list for this proceeding, the Commission was to examine the question of how it should consider the relationship between capital structure and ROE with respect to establishing the overall fair return for the affected utilities.[112]

[109] Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 42-43.
[110] Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 24.
[111] Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 14.
[112] Exhibit 20622-X0029, final issues list.

93. Dr. Villadsen stated that capital structure is important in determining the cost of equity because, as the debt to equity ratio increases, the ROE increases as shareholders face more equity risk.[113] Noting that there are several ways to translate a cost of equity measured for a group of comparable companies to a cost of equity for a company with a different capital structure, Dr. Villadsen used two methods to develop a range of ROE estimates to adjust for leverage.

94. The first method Dr. Villadsen used was to estimate the ROE implied by the overall cost of capital. This concept is based on the Modigliani-Miller theorem which posits that, under the assumptions of no taxes and no risk to the use of excessive debt, debt has no effect on a company's operating cash flow; therefore, the value of the firm and the overall cost of capital is not affected by the debt ratio.[114] If these assumptions are satisfied, then

> [t]his reasoning suggests that one could compute the overall cost of capital for each of the sample companies and then average to produce an estimate of the overall cost of capital associated with the underlying asset risk. Assuming that the overall cost of capital is constant, one can the rearrange the overall cost of capital formula to estimate what the implied cost of equity is at the target company's capital structure on a book value basis [footnote omitted].[115]

95. The second approach used by Dr. Villadsen is an example of a Hamada adjustment and involves working within the capital asset pricing model (CAPM) framework to account for financial risk by adjusting betas for leverage. The Hamada adjustment involves unlevering beta estimates to obtain an all-equity beta and then re-levering the beta to determine the beta associated with the target regulatory capital structure.[116] Dr. Villadsen used two formulations for the Hamada adjustment, noting that both formulations account for the fact that increased financial leverage increases the systematic risk of equity that will be captured by its market beta.[117]

96. Dr. Villadsen applied these approaches selectively to generate ROE estimates using her CAPM and discounted cash flow (DCF) models. To estimate a leverage adjusted ROE range using CAPM, Dr. Villadsen adjusted her betas using two Hamada adjustment formulations and also calculated the implied cost of equity based on the Modigliani-Miller concept. Similarly, Dr. Villadsen estimated leverage adjusted DCF ROE estimates based on the Modigliani-Miller concept.[118]

97. In an exchange with Commission counsel, Dr. Villadsen was asked if the Commission would need to assess what the weighted average cost of capital for each company should be if the Commission were to consider the application of the Modigliani-Miller theorem approach or the Hamada adjustments approach.[119] Dr. Villadsen replied:

> No, it would not. As I view it, the weighted average cost of capital can be used as a simple method to indicate where the cost of equity would be for a given deemed equity.

113 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 15.
114 Exhibit 20622-X0105, evidence of Dr. Villadsen, Appendices, PDF pages 35-36.
115 Exhibit 20622-X0105, evidence of Dr. Villadsen, Appendices, PDF page 36.
116 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 16.
117 Exhibit 20622-X0105, evidence of Dr. Villadsen, Appendices, PDF page 38.
118 Dr. Villadsen's calculations for estimating ROEs with leverage adjustments using CAPM and DCF can be found in Exhibit 20622-X0115, BV Workpaper 06.
119 Transcript, Volume 5, pages 677-678.

> And if you instead rely on, say, the Hamada adjustments, which go strictly to looking at unlevering and then re-levering betas, you do not need at all to know what the weighted average cost of capital is.[120]

98. Regarding the effect of leverage on cost of equity, Mr. Hevert also referred to the Modigliani-Miller theorem approach and the Hamada adjustments approach, describing that under either approach, one could estimate the effect of leverage on the weighted average cost of capital.[121] Mr. Hevert applied both approaches to estimate a range of ROEs that could be compared to his other ROE estimates. Mr. Hevert described that his analytical results are consistent with the proposition that the financial leverage and the cost of equity are inextricably related and where financial leverage increases, so does the cost of equity. However, Mr. Hevert cautioned it is important to recognize that the results from using these adjustments are imprecise due to complexity and to the dynamic nature of the relationship.[122]

99. Mr. Hevert was also asked if the Commission would need to assess what the weighted average cost of capital for each company should be if the Commission were to consider the application of the Modigliani-Miller theorem approach or the Hamada adjustments approach. Mr. Hevert responded as follows:

> Well, I think the natural consequence of much of the work that the Commission does would be an assessment of the weighted average cost of capital. One thing I would say, though, is, as we say on hard copy page 131, is that I think these types of models, at least, again, in my experience, they're helpful to understand the effect of leverage; but they, like all models are subject to some assumptions. And they can differ in their results. And they can differ in the way you interpret the results.[123]

100. Dr. Cleary discussed the relationship between ROE and capital structure through discussion of the 3-point DuPont equation, which decomposes the ROE into three basic components: net income margin, asset turnover ratio and leverage ratio. A firm's ROE is the result of multiplying the three components together. Dr. Cleary distinguished that non-regulated firms typically choose a leverage ratio to generate higher ROEs, whereas, regulated utilities earn higher net income if they have lower leverage ratios, since they earn allowed ROE on the higher equity dollar figure. In addition to higher net income, lower leverage ratios reduce financial risk and associated volatility in ROEs. Therefore, Dr. Cleary concluded that the Commission's approach of setting one allowed ROE and then adjusting for deemed equity ratios to accommodate company-specific risk levels, as used in previous GCOC decisions, is a logical approach because granting higher deemed equity ratios to utilities deemed to have greater business risk "appropriately reduces the financial risk of such utilities."[124]

Commission findings

101. The Commission invited submissions on the relationship between capital structure and ROE as part of this proceeding. The parties advanced various models to illustrate a connection between capital structure and ROE. Each model demonstrated a positive relationship between the proportion of debt in the capital structure and ROE. However, given the various assumptions

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120 Transcript, Volume 5, page 678.
121 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 129.
122 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 131.
123 Transcript, Volume 2, pages 210-211.
124 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 92-93.

underlying the models, the Commission considers that none of the models, on a stand-alone basis, fully describes this relationship. Specifically, with regards to Dr. Villadsen's evidence with respect to estimated ROEs considering financial leverage, the Commission notes the assertion of Mr. Hevert that "these types of models, at least, again, in my experience, they're helpful to understand the effect of leverage; but they, like all models are subject to some assumptions. And they can differ in their results. And they can differ in the way you interpret the results."[125] As a consequence of the uncertainty created by the number of untested assumptions as well as the lack of sensitivity analysis provided for some of the models, the Commission will not employ any of these suggested models in its determination of the deemed equity ratios or the allowed ROE in this proceeding except to illustrate that a relationship exists.

6 Return on equity

102. Generally, the cost of equity to a firm is the return that investors require to make an equity investment in the firm. That is, investors will only provide funds if the ROE that they expect to receive is sufficient to compensate them for the risks they are assuming in making the investment.

103. The Commission was presented with a significant body of evidence on the tests to be considered when determining a fair allowed ROE and a number of opinions on the proper methodology to be employed in the application of many of these tests. Consequently, the Commission was also provided with a wide range of proposed ROEs. The record of the proceeding included evidence to support various ROE estimates based on:

- Changes in the global and Canadian financial environment since the conclusion of the 2013 GCOC proceeding.
- The CAPM methodologies, including the empirical CAPM (ECAPM) results.
- Other risk premium models such as the bond yield plus risk premium model (BYPRPM) and the predictive risk premium model (PRPM).
- The DCF model, as applied to proxy utilities as well as to the overall equity market.
- Stock market return expectations of finance professionals such as investment managers, pension fund managers and economists.
- Other considerations such as market price-to-book (P/B) values, returns awarded by other Canadian regulators and market returns of utilities across North America.

104. Evidence presented in this proceeding demonstrated that, in the current economic environment, there are considerable challenges in following approaches that have been used traditionally in previous GCOC proceedings for the determination of a fair allowed ROE. These challenges are highlighted in the following exchange between the Commission and Dr. Villadsen:

> Q. … what's happening to the financial markets and the impacts of negative rates, which I don't think most economists considered could happen, how trustworthy are all these models that we have? Or how do we rank them now? How much faith can the Commission have in this historic modeling exercise that we use to determine rates considering the changes that has occurred over the last six or seven years and considering

[125] Transcript, Volume 2, pages 210-211.

> the state of the financial markets where even economists are having a hard time understanding why interest rates and equities are performing the way they are?
>
> A. DR. VILLADSEN: That's a good question. And there's no question that the finance professions and economists have been challenged in recent years because things are so unusual for us. And I think that's one of the reasons I would emphasize that it's very important we don't just look at one model, because there's no one model that's going to give us the right answer in this kind of a market. We have seen negative rates. I think, one, as I said before, they don't really happen in North America; but I do think they're an indication that especially in places like Europe, there's a lot of investor uncertainty. Otherwise they would not be so concerned of preserving wealth compared to earning a return. So I think when we apply the models to get to your direct question, how reliable are they, it's very important we take a cohort of models and not just one and also look at do they make sense in regards to what else we know about the markets. Is it that the return we're recommending over and above the returns we can measure such as utility yields, such as the yield of preferreds [sic], taking into account the bounds that's on them, is it what we're recommending reasonable compared to that? So I think all of these are very important aspects.[126]

105. The Commission agrees with the concerns expressed by Dr. Villadsen and considers it is instructive, particularly in light of the current economic conditions, as detailed in Section 4, to evaluate a variety of approaches and models in determining a fair allowed ROE.

106. The Commission's review of the changes in global economic and Canadian capital market conditions since the conclusion of the 2013 GCOC proceeding, which may affect investors' assessments of the required return on an equity investment, is set out in Section 4 of this decision. Section 6 is organized as follows. Sections 6.1 to 6.6 address each of the remaining factors that the Commission considers to be relevant to the establishment of an allowed ROE. More specifically, sections 6.1, 6.2, 6.3 and 6.4 address the application of the CAPM, ECAPM, BYPRPM and PRPM, and DCF model, respectively. Section 6.5 examines stock market return expectations of finance professionals and Section 6.6 addresses other considerations in establishing a fair allowed ROE that were employed by various experts who participated in this proceeding. Finally, Section 6.7 summarizes the Commission's findings and sets out the allowed ROE for 2016 and 2017.

6.1 Capital asset pricing model

107. 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 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, referred to as the MERP, and the beta, or β, 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

126 Transcript, Volume 7, pages 1000-1001.

premium specific to that security or type of security. In other words, the CAPM formally assumes that all securities are priced such that the required return on the security is equal to the risk free rate plus the securities beta risk measure times the difference between the required return on the overall market and the risk-free rate.

108. 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 MERP; i.e., the expected market return E(Rm) minus the risk free rate, Rf

109. Expert evidence supporting various proposed ROEs based on an application of CAPM, or variations thereof, was provided by Mr. Hevert for AltaLink and EPCOR, Dr. Villadsen for the Utilities, Dr. Booth for CAPP, and Dr. Cleary for the UCA. As well, Mr. Thygesen for the CCA presented his CAPM recommendations based on the values approved in previous GCOC decisions. Each CAPM component, and the overall resulting CAPM estimates for ROE, are addressed in sections 6.1.1 to 6.1.5 that follow.

110. As set out in Section 3, the Commission's approach in this area of the decision is to examine the changes in each of the components of the CAPM for purposes of determining whether a change in the allowed ROE set out in the 2013 GCOC decision is required.

6.1.1 Risk-free rate

111. The CAPM analysis requires a value for the risk-free rate. For practical purposes, a yield on long-term government bonds is used widely as a proxy for the risk-free rate. Dr. Villadsen explained that in developed economies like Canada and the U.S., government bonds are generally considered to be "risk-free" in a sense that they have no default risk. However, unless they are held to maturity, the rate of return on government bonds may in fact differ from their stated or expected yields, thus making them subject to interest rate risk.[127]

112. Mr. Hevert indicated that, consistent with the Commission's determinations in the 2013 GCOC decision, he used both observed and expected measures of the long-term government bond rates for both Canada and the U.S. Specifically, Mr. Hevert calculated the risk-free rate for Canada to be 2.59 per cent. To reach this value, Mr. Hevert used the average of two different values: the then-current (as of the date of his written evidence) 30-day average yield on 30-year GOC bonds of 2.14 per cent and the near-term (through the fourth calendar quarter of 2017) projected 30-year GOC bond yield of 3.04 per cent.[128] Mr. Hevert calculated his risk-free rate value for the U.S. as 3.20 per cent. This value represented an average of the then-current 30-day

[127] Exhibit 20622-X0105, evidence of Dr. Villadsen, Appendix B, PDF page 18.
[128] Mr. Hevert indicated that the 3.04 per cent figure was derived based on information included in a publication issued by RBC Economics Research entitled *Financial Markets Monthly*. Mr. Hevert added that this publication was dated December 9, 2015.

average yield on 30-year U.S. treasury bonds of 2.96 per cent and the near-term (through the second calendar quarter of 2017) projected 30-year U.S. treasury bond yield of 3.45 per cent.[129]

113. Mr. Hevert explained that he relied on data through the fourth calendar quarter of 2017 for 30-year GOC bonds and through the second calendar quarter of 2017 for 30-year U.S. treasury bonds because he used two different sources for the forecasts of those bonds. Mr. Hevert further noted that both sources are based on multiple forecasts and in his opinion are representative of the market consensus.[130]

114. Dr. Villadsen expressed the view that current yields on long-term GOC bonds are near historic lows for a variety of circumstances that should not be expected to persist. Therefore, she submitted that long-term GOC bonds are not a good estimate for the risk-free rate that will prevail over the time period relevant to the 2016-2017 time period.[131] Dr. Villadsen relied on a forecast of what GOC bond yields will be at the end of 2016.[132] Specifically, Dr. Villadsen relied on the December 2015 Consensus Forecasts report issued by Consensus Economics, which predicted that the yield on a 10-year GOC bond will be 2.2 per cent at the end of 2016. Because consensus forecasts reports do not provide any projections for the long-term GOC bond yields, Dr. Villadsen then adjusted this value upward by 40 bps, which was her estimate of the representative maturity premium for the 30-year over the 10-year GOC bond over the 1990-2015 period. This resulted in a lower bound of her risk-free rate recommendation of 2.6 per cent.

115. Dr. Villadsen also considered a scenario in which the risk-free rate was 3.4 per cent[133] to account for her observation that “current and near-term expected levels of government bond yields are artificially depressed due to global monetary policy.”[134] This upper bound risk-free rate recommendation was based on the application of an 80 bps adjustment to her lower bound estimate to reflect the “downward pressure on the government bond yield or an increase in the MERP.”[135] Dr. Villadsen considered the proposed 80 bps adjustment to be conservative based on her observation of the currently prevailing elevated spreads between utility and government bond yields relative to the historical norm (i.e., the pre-crisis period of 2002-2007).[136] Dr. Villadsen also indicated that this upper bound risk-free estimate is consistent with the December 2015 Consensus Forecasts report issued by Consensus Economics, which predicted 10-year GOC bond yields to increase to 3.5 per cent by 2018.

116. Dr. Booth based his risk-free estimates on the RBC Economics Research publication titled “Financial Markets Monthly,” dated March 11, 2016. Specifically, for 2016, Dr. Booth estimated a 30-year GOC bond yield of 2.30 per cent, calculated as the average of the forecasts for each of the four quarterly periods of 2016. In a similar vein, and using the same reference material, by averaging the forecasts for each of the four quarterly periods for 2017, Dr. Booth’s risk-free estimate for 2017 was 3.14 per cent. Dr. Booth observed that the March 7, 2016

129 Mr. Hevert indicated that the 3.45 per cent figure was derived from information obtained from Blue Chip Financial Forecasts, dated December 1, 2015. In Exhibit 20622-X0215, in response to AML/EDTI-AUC-2016FEB18-005(b) and (d), PDF page 57, Mr. Hevert indicated that the correct date was January 1, 2016.

130 Exhibit 20622-X0215, response to AML/EDTI-AUC-2016FEB18-005(a) and (b), PDF pages 56-57.

131 Exhibit 20622-X0105, evidence of Dr. Villadsen, Appendix B, PDF page 19.

132 Transcript, Volume 4, page 588, lines 2-9.

133 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 45.

134 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 22.

135 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 45.

136 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 45. Exhibit 20622-X0105, evidence of Dr. Villadsen, Appendix B, PDF page 20.

Consensus Forecasts report issued by Consensus Economics, generally supports the RBC Economics Research forecast material.[137]

117. While Dr. Booth was prepared to use these estimates for his CAPM model, he noted that under current conditions in the Canadian bond market, the underlying assumption behind the CAPM model that the risk-free bond yield plus a risk premium is a representative opportunity cost for an equity investor does not hold. To account for this, Dr. Booth proposed making an adjustment to the CAPM model for the "the abnormally low Canada bond yields resulting from rampant bond buying programs by central banks."[138] Dr. Booth referred to this as an "operation twist" adjustment, meaning that major central banks around the world are flattening or twisting the shape of the yield curve, trying to get long-term rates down via QE programs.[139] Dr. Booth calculated this adjustment to be 80 bps, representing the difference in yields between the long-term GOC bonds and the U.S. bonds as of the first quarter of 2016.[140]

118. Dr. Cleary rounded up the actual prevailing 30-year GOC bond yield as of February 2016 of 1.94 per cent to two per cent and used it as his lower bound of the risk-free rate estimate. By adding a long-term average spread between 10-year and 30-year GOC bond yields of 50 bps to the January 2016 Consensus Forecasts report forecast for 10-year GOC bond yields of 2.1 per cent for January 2017, Dr. Cleary obtained an upper limit of 2.6 per cent for his risk-free rate estimate.[141]

119. In his evidence for the CCA, Mr. Thygesen expressed his view that the 10-year GOC bond yield forecasts included in the consensus forecasts reports "should be viewed at best as an upper limit to where the 10-year Canada bond will be."[142] Mr. Thygesen presented a table comparing the 10-year GOC bond yield forecasts included in various consensus forecasts reports to actual 10-year GOC bond yields for selected months in the 2010-2015 period. Mr. Thygesen stated that this analysis demonstrates that the forecasts included in the consensus forecasts reports have only under-forecast the actual 10-year GOC bond yield rates once.[143]

120. As an alternative to using information from the consensus forecasts reports, Mr. Thygesen proposed using the forward curve rates for the 30-year GOC bond yield. Based on his view that the forecasts included in the consensus forecasts reports consistently over-forecast the 10-year GOC bond yields, a review of historical forward curve rates demonstrates that they were both above and below the actual rate on the date forecast. Based on this review, Mr. Thygesen submitted that forward curve rates do not seem to have the same systematic bias that the forecasts included in the consensus forecasts reports have.

121. In support of his view that the forward curve rates may be less biased, Mr. Thygesen referenced the following material provided by Mr. Buttke during the interrogatory process:

> Futures prices are a current indicator of future prices (excluding some costs noted above). Economic forecasts are harder to characterize because, despite being forward-looking,

137 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 25.
138 Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 57-58.
139 Transcript, Volume 7, page 1052, lines 9-14.
140 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 89.
141 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 37.
142 Exhibit 20622-X0343, evidence of Mr. Thygesen, PDF page 5.
143 Exhibit 20622-X0413, response to CCA-AUC-2016APR28-001, PDF page 1.

> they are sometimes viewed as a lagging indicator, since by definition they are revised only periodically, not every day based on new data.[144]

122. In addition, Mr. Thygesen pointed to the following determinations made by the Commission in Decision 3539-D01-2015:[145]

> 836. The Commission is of the view that the *Consensus Forecast* is unrelated to market transactions, while forward curves reflect actual market transactions. Accordingly, the Commission accepts the forward curve as a reasonable indicator of interest rates during the test period.[146]

123. In light of the above, Mr. Thygesen contended that a forecast risk-free rate implied by forward curve rates "is helpful as it adds another data point to cross check against the *Consensus Forecasts* and assist in determining the risk-free rate."[147] In a similar vein, with reference to forward curves, Dr. Booth stated that "the market is usually a better forecaster than economists."[148]

124. In this regard, Mr. Thygesen noted the forecast figure of 1.5 per cent for the 10-year GOC bond yield for May 2016 included in the Consensus Forecasts report from February 2016. Adding a 50-60 bps term spread to estimate the 30-year GOC bond yield resulted in a risk-free rate of 2.0 to 2.1 per cent. Given that this estimate was "at or slightly above the Forward Curve rate of 1.94–1.97% for 2016," Mr. Thygesen stated that a rate of 2.0 per cent appeared to be a reasonable upper limit for the 2016 risk-free rate.[149]

125. For the 2017 forecast, Mr. Thygesen noted the forecast figure of 1.9 per cent for the 10-year GOC bond yield for May 2017 included in the Consensus Forecasts report from February 2016. Adding a 50 to 60 bps term spread to estimate the 30-year GOC bond yield resulted in a risk-free rate of 2.4 to 2.5 per cent. However, this rate was "substantially above the Forward Curve rate of 2.01-2.04% for 2017."[150] According to Mr. Thygesen, given the "historical over-statement and the Consensus Forecast bias, more weight should be put on the forward curve rate of 2.01-2.04 [per cent] for 2017." Therefore, Mr. Thygesen recommended a risk-free rate of 2.1 per cent for 2017.[151]

126. Dr. Villadsen did not agree with Mr. Thygesen's view that the consensus forecasts reports exhibit a consistent systematic upward bias. As she explained:

> While Mr. Thygesen relies on a narrow sample to assert that Consensus Forecasts consistently over-predicts actual government bond yields, academic analyses of economic forecasts of government bond yields more generally have found that any "bias" in forecasts is not consistently upward or downward, but rather towards the status quo. In other words, economic forecasters place too much weight on yields prevailing at the time they are predicting future yields. Under the "status quo bias" hypothesis, forecasts will

144 Exhibit 20622-X0343, evidence of Mr. Thygesen, PDF page 6.
145 Decision 3539-D01-2015: EPCOR Distribution & Transmission Inc. 2015-2017 Transmission Facility Owner Tariff, Proceeding 3539, Application 1611027-1, October 21, 2015.
146 Decision 3539-D01-2015, paragraph 836.
147 Exhibit 20622-X0343, evidence of Mr. Thygesen, PDF page 7.
148 Exhibit 20622-X0396, response to CAPP-AUC-2016APR12-002(d), PDF pages 6-7.
149 Exhibit 20622-X0343, evidence of Mr. Thygesen, PDF page 7.
150 Exhibit 20622-X0343, evidence of Mr. Thygesen, PDF pages 7-8.
151 Exhibit 20622-X0343, evidence of Mr. Thygesen, PDF page 9.

tend to over-predict actual yields when yields are decreasing (as they have done recently) and under-predict yields when yields are increasing.[152]

127. As such, Dr. Villadsen indicated that Mr. Thygesen's results only show consistent over-prediction on the part of the consensus forecasts reports as an artifact of the period he chose: one in which interest rates declined steadily (and at times steeply) following the onset of the crisis.[153] A similar view was expressed by Mr. Hevert.[154]

128. In addition, Dr. Villadsen did not agree with Mr. Thygesen and Dr. Booth that forward interest rates are better predictors of future bond yields than economic forecasts. She pointed out that it is impossible to draw statistically meaningful conclusions based on Mr. Thygesen's sample of three data points, especially when they all relate to the same "actual" date. Dr. Villadsen referenced an academic paper that found that "the accuracy of the six month-ahead futures and survey forecasts is comparable;" however, in her view, this conclusion did not hold for the forward interest rates because of the time-varying premium in the forward rate.[155]

129. In a similar vein, Mr. Hevert pointed out that, while forward yields have been quite volatile, they have consistently indicated expectations for interest rate increases.[156] Mr. Hevert also noted that the implied forward curve yields are certainly known and considered by the professionals that contribute to consensus-type long-term bond yield projections[157] and as such, it can be assumed that they are reflected in economists' projections.[158]

130. The CCA noted that the affected utilities did not explain why it is appropriate to use forward curves in currency and energy markets, but not for interest rates.[159] In support of their submission, the CCA pointed out that Mr. Hevert did not object to looking at the forward curve; Mr. Buttke relied on forward curves in his evidence; and Dr. Carpenter used forward curves when examining other markets.

Commission findings

131. In the 2013 GCOC decision, the Commission considered a reasonable risk-free rate to be in the range of 2.8 to 3.7 per cent. As noted in Section 4 of this decision, rather than increasing as predicted in the last proceeding, yields on 30-year GOC bonds fell another 100 bps, from approximately 3.0 per cent to some 2.0 per cent. Dr. Booth attributed falling interest rates to the monetary policies of central banks and increased foreign ownership in Canadian government bonds in a "search for yield." All experts generally agreed that when economic conditions improve, more central banks will likely move away from accommodative monetary policies, with the effect that interest rates are expected to rise.

132. Experts in this proceeding have formed an expectation, supported by consensus forecasts reports, that interest rates are likely to rise by the end of the 2016-2017 period. Although this expectation is consistent with the evidence discussed in Section 4, that economic forecasts point

[152] Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF pages 8-9.
[153] Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 12.
[154] Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF page 15.
[155] Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF pages 12-13.
[156] Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF page 16.
[157] Such as the consensus forecasts reports.
[158] Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF page 18.
[159] Transcript, Volume 12, pages 2072-2073.

to recovery in the Canadian economy by the end of 2017, experts differed on the speed and magnitude of any interest rate increase in the short term.

133. Based on the foregoing, the Commission notes that although the prevailing risk-free interest rate is lower than at the time of the 2013 GCOC decision, general expectations are that interest rates will rise during the 2016-2017 period. Uncertainty remains, however, regarding the speed and magnitude of the expected interest rate increases.

6.1.2 Market equity risk premium

134. The next element of the CAPM analysis to be addressed is the MERP. The MERP value is not directly observable but can be estimated as the difference between estimates for the expected market return and the value used for the risk-free rate. The experts in this proceeding varied in their views of what MERP value to use for the 2016-2017 period.

135. Dr. Booth recommended a MERP value between 5.0 and 6.0 per cent based on two considerations. First, this range was drawn from historic Canadian and U.S. market data spanning a period of approximately 100 years.[160] Second, Dr. Booth gave weight to survey results by Professor Fernandez, "who annually surveys thousands of academics, financial analysts and corporate executives making investment decisions."[161] Dr. Booth referenced the results of Professor Fernandez's 2015 survey,[162] which estimated the MERP in Canada to be around 6.0 per cent, while the U.S. MERP was estimated at approximately 5.5 per cent. According to Dr. Booth, this survey demonstrated "an obvious 5.0-6.0% grouping" of MERP values for the 41 developed countries surveyed, which included Canada.[163]

136. Dr. Cleary also took note of survey results by Professor Fernandez. Based on an independent research publication,[164] Dr. Cleary indicated that the long-term MERP for U.S. and Canadian markets averaged 6.4 per cent and 5.3 per cent, respectively, over the 1900 to 2010 period. Dr. Cleary pointed out that these long-term MERP values were consistent with the 2011-2013 MERP results from the 2013 survey by Professor Fernandez,[165] which were in the 5.5 to 6.0 range for Canada and the U.S.[166] Dr. Cleary ultimately recommended a MERP of 6.0 per cent for the following reasons:

> Based on the previous discussion of capital markets, I concluded that stock markets reflect fairly normal conditions, but are experiencing slightly more volatility than at the time of the 2013 Hearings. Therefore, I will use an [MERP] of 6%, which is at the upper bound of the commonly used 4-6% range, 70 basis points above the long-term average of 5.3%. This seems appropriate in today's environment, where economic and market conditions are fairly normal in terms of valuation metrics like P/E [price/earnings] ratios and dividend yield measures. This is consistent with the practice of using 6 percent when market uncertainty is above average, using 5 percent when markets are normal, and using

160 Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 46-47.
161 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 47.
162 *Market Risk Premium and Risk-Free Rate Used for 41 countries in 2015*, IESE Business School, November 19, 2015.
163 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 48.
164 Dimson, Elroy, Marsh, Paul, and Staunton, Mike, *Equity Premiums Around the World,* in *Rethinking the Equity Risk Premium* (Research Foundation of the CFA Institute, December 2011).
165 *Market Risk Premium and Risk Free Rate used for 51 countries in 2013: a survey with 6,237 answers*, 2013, by Pablo Fernandez, Javier Aguirreamalloa, and Pablo Linares, Working Paper, IESE Business School.
166 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 37-38.

> 4 percent during periods of extreme market and economic optimism. These estimates are also consistent with previous Decisions by the AUC. For example, the AUC used an [MERP] range of 5-7% in 2013 and 5.0-7.25% in 2011.[167]

137. Based on an independent study, Dr. Villadsen indicated that the average Canadian MERP from 1935 to present is 5.7 per cent. Dr. Villadsen used this value of the MERP as a lower bound in her CAPM analysis. However, based on her view that investors' level of risk aversion remains elevated relative to the time before the global financial crisis of 2008-2009, Dr. Villadsen also performed CAPM calculations using a MERP of 8.0 per cent. In her opinion, a MERP of 8.0 per cent was justified for three primary reasons. First, this higher value was "in between Bloomberg's forecasted Canadian and U.S. MERP." Specifically, Dr. Villadsen explained that at 10.75 per cent, the Bloomberg forecast for the Canadian MERP is high relative to the forecast for the U.S. MERP of 6.5 per cent to 7.5 per cent. As a result, her 8.0 per cent upper bound recommendation gives substantial weight to the lower forecast U.S. MERP.[168] Second, Dr. Villadsen noted that the forward-looking MERPs calculated by Bloomberg are broadly consistent with the findings in a recent journal article by Duarte and Rosa of the Federal Reserve Bank of New York,[169] which shows that the U.S. MERP was lower than its long-term historical average in the early 2000s but is currently at an all-time high. Finally, Dr. Villadsen stated that the 8.0 per cent value for MERP "is justified by the elevation in the spread between A-rated utility and government bond yields."[170]

138. Mr. Hevert obtained his MERP estimates for the Canadian stock market using two methods. Under one method, Mr. Hevert first calculated the expected return on the S&P/TSX index of 12.65 per cent as a weighted average of all expected returns for the companies included in the index for which Bloomberg data were available. The individual company returns were derived using the constant growth DCF model by adding the expected dividend yield to the estimated long-term growth in earnings per share (EPS) for each company. Subtracting the risk-free rates of 2.14 per cent and 3.04 per cent for Canada from the obtained market return of 12.65 per cent, produced expected MERPs of 10.51 per cent and 9.61 per cent, respectively, for an average of 10.06 per cent.

139. Mr. Hevert's second method was based on a semi-log form regression,[171] in which the historical annualized MERP was expressed as a function of the natural logarithm of the annualized 30-year GOC bond yields. For this regression, the MERP dependent variable was calculated as monthly historical returns on the S&P/TSX index relative to monthly historical yields on 30-year GOC bonds.[172] At the hearing, Mr. Hevert was asked by Commission counsel whether this particular methodology was an established method in the field or something that he had come up with on his own. In response, Mr. Hevert explained that:

> This is a methodology that is consistent with a methodology that we've seen used elsewhere in estimating the bond yield plus risk premium result. In some studies -- in some studies there will be a different measure of the expected return, but what we're trying to measure here is a relationship that I think the Commission has recognized,

[167] Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 39.
[168] Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 46.
[169] Fernando Duarte and Carlo Rosa, *The Equity Risk Premium: A Consensus of Models*, *Federal Reserve Bank of New York*, December 2015 (Duarte & Rosa 2015).
[170] Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 47.
[171] Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF page 39.
[172] Exhibit 20622-X0164, response to AML/EDTI-UCA-2016FEB18-028(e), PDF page 126.

> which is that the market risk premium [MRP] is not stable in that the market risk premium changes with the level of interest rates. That's the relationship that we're capturing here with this data.[173]

140. Applying the obtained regression coefficients to his lower and upper bound of risk-free estimates of 2.14 per cent and 3.04 per cent for Canada, respectively, Mr. Hevert obtained MERPs of 8.59 per cent and 6.06 per cent, for an average of 7.33 per cent. The average expected Canadian MERP between the two methods was 8.69 per cent.[174]

141. In deriving his MERP estimates for the U.S. stock market, Mr. Hevert used the same two methods as described above for his MERP estimates for the Canadian stock market, as well as an additional method which is subsequently described.

142. Mr. Hevert calculated the expected return on the S&P 500 index of 13.78 per cent as a weighted average of all expected returns for the companies included in the index for which Bloomberg data were available. The individual company returns were derived using the constant growth DCF model by adding the expected dividend yield to the estimated long-term growth in EPS for each company. Subtracting the risk-free rates of 2.96 per cent and 3.45 per cent for the U.S. from the expected market return of 13.78 per cent, produced expected MERPs of 10.82 per cent and 10.33 per cent, respectively, for an average of 10.58 per cent.[175]

143. Mr. Hevert's regression analysis MERP estimate for the U.S. stock market was derived using monthly historical returns on the S&P 500 relative to monthly historical yields on long-term U.S. government bonds.[176] Applying the obtained regression coefficients to his lower and upper bound of risk-free estimates of 2.96 per cent and 3.45 per cent for the U.S., respectively, Mr. Hevert obtained expected MERPs of 9.64 per cent and 8.72 per cent, for an average of 9.18 per cent.[177]

144. Mr. Hevert also provided a MERP estimate of 9.03 for the U.S. stock market. This estimate was derived from the average of the most recent 13 weeks' three- to five-year estimated median market price appreciation potential, and (the average of) the median estimated dividend yield for the common stocks of the approximately 1,700 firms covered in the Value Line Investment Survey (Standard Edition) product. The resulting expected price appreciation of 9.92 per cent (on a geometric average basis) was added to the dividend yield of 2.31 per cent to arrive at an expected total market return of 12.23 per cent. Subtracting the risk-free rates for the U.S. of 2.96 per cent and 3.45 per cent from the expected total market return of 12.23 per cent, produced expected MERPs of 9.27 per cent and 8.78 per cent, respectively, for an average of 9.03 per cent.[178]

145. When averaged, the three estimates of the MERP for the U.S. stock market provided by Mr. Hevert equaled 9.60 per cent.[179]

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173 Transcript, Volume 1, pages 127-128.
174 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 67-68.
175 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 68.
176 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 69.
177 Exhibit 20622-X0083, "Sch1 p13 MRP SBBI RA."
178 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 69.
179 Average of 10.58, 9.18 and 9.03.

146. Mr. Hevert disagreed with the MERP recommendations of Dr. Booth and Dr. Cleary for a number of reasons. First, Mr. Hevert opined that relying on historical average MERPs during periods of low interest rates understated the cost of equity. Mr. Hevert also stated that Professor Fernandez's survey results referenced by Dr. Booth and Dr. Cleary produced unreasonable estimates of the cost of equity for AltaLink and EPCOR. Finally, in Mr. Hevert's opinion, Dr. Booth understated the historical MERP by subtracting the total return on long-term government bonds from the total return on stocks instead of subtracting the income only portion of government bond return from the total return on the benchmark equity index.[180]

147. Dr. Villadsen also had concerns with Dr. Booth's and Dr. Cleary's MERP estimates. She perceived them to downward bias their CAPM models by failing to recognize: (1) elevations in the yield spread between 30-year GOC bonds and equivalent maturity A-rated utility bonds;[181] (2) the widening of the spread on preferred shares since the release of the 2013 GCOC decision;[182] and (3) lingering market uncertainty.[183]

Commission findings

148. In the 2013 GCOC decision, the Commission estimated a reasonable range of the MERP to be 5.0 to 7.0 per cent. The Commission arrived at this estimate because it expected the MERP in the relevant period to be higher than the long-run average MERP of 5.0 to 6.0 per cent, as a result of continued historically low, long-term GOC bond yields.

149. In this proceeding, Dr. Villadsen, Dr. Booth and Dr. Cleary have largely relied on comparable long-term data, and produced similar estimates for the long-term average MERP, before applying their expert judgments. Specifically, they referenced an average long-run MERP in the range of approximately 5.0 to 6.0 per cent. These estimates are consistent with the long-run MERP values in the 2013 GCOC decision.[184]

150. The evidence presented in this proceeding generally supports the view that the MERP likely to prevail over the 2016-2017 period is higher than previously accepted estimates for the long-run average MERP. As discussed in Section 4, the Commission found it reasonable to accept the claim that credit spreads constitute an objective, market observed measure of investors' risk perceptions. As observed in Figure 3, the credit spreads prior to the financial crisis (2001-2007) averaged approximately 100 bps. This average was approximately:

(a) One hundred bps lower than the credit spreads observed early in February, 2016.

(b) Seventy bps lower than the credit spreads observed in late May, 2016.

(c) Thirty to 50 bps lower than the credit spreads observed during the late 2009-early 2015 period.

151. The Commission notes Mr. Hevert's statement that consistent with the view that credit spreads are a barometer of business risk, although they may not be a full measure of equity risk,

180 Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF pages 23-26.
181 Exhibit 20622-X0442, rebuttal evidence of Dr. Villadsen, PDF page 30.
182 Exhibit 20622-X0442, rebuttal evidence of Dr. Villadsen, PDF page 31.
183 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 5.
184 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 46. Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 46. Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 37-39.

there is little question that the increase in credit spreads suggests some measure of increased risk perception among Canadian utility investors.[185] Consequently, the Commission considers that an examination of trends in credit spreads is important to examine when attempting to set a fair allowed ROE. The Commission also considers that trends in credit spreads may be directionally indicative of changes in utility equity investor return expectations.

152. Also as discussed in Section 4, experts in this proceeding relied on a number of broad market indicators to support their positions on the current level of volatility in the market. Generally, Dr. Villadsen and Mr. Hevert argued that market volatility is higher today than at the time of the 2013 GCOC decision, which indicated to them that there remains significant uncertainty in today's equity markets, with investors requiring greater returns to bear that risk.

153. In contrast, Dr. Cleary submitted that while it has been a volatile period for stock markets, market conditions are far removed from those experienced during the financial crisis. Nonetheless, Dr. Cleary acknowledged that stock markets are experiencing slightly more volatility than at the time of the 2013 GCOC hearing. As a result of this admission, Dr. Cleary incorporated the effects of this higher volatility and concluded that the current and forecast MERP is likely at the upper end of the long-run average MERP range of 5.0 to 6.0 per cent.

154. Based on the ranges provided by the expert witnesses for the long-run average MERP, as well as the factors discussed above that argue for the likelihood of higher levels of risk in financial markets now and over the 2016-2017 period, the Commission accepts the assertion that the current MERP will continue to experience upward pressure relative to long-run levels.

6.1.3 Flotation allowance

155. ROE estimates obtained through CAPM, DCF or risk premium models are often adjusted upwards by a "flotation allowance" or "flotation costs." In previous GCOC decisions, the Commission has included a flotation allowance in the allowed ROE to account for administrative costs and equity issuance costs, any impact of under-pricing a new issue, and the potential for dilution.[186] In the 2013 GCOC decision, the Commission upheld this definition and declined to broaden the purpose of the flotation allowance to account for the presumed increased financial risk arising from the difference between the utilities' capital structures at book value and market value.[187]

156. In this proceeding, all experts (Dr. Villadsen,[188] Mr. Hevert,[189] Dr. Booth[190] and Dr. Cleary[191]) adopted the 50 bps flotation cost adjustment allowed by the Commission in previous GCOC decisions, including the 2013 GCOC decision.[192]

Commission findings

157. Historically, the Commission and its predecessors have allowed 50 bps of additional ROE to account for the costs of securities flotation, and to ensure that investors can reasonably

185 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 42-43.
186 Decision 2011-474, paragraph 68; Decision 2009-216, paragraph 255.
187 Decision 2191-D01-2015, paragraph 142.
188 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 8, PDF page 54.
189 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 128.
190 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 57.
191 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 42, PDF page 56, PDF page 58.
192 Decision 2191-D01-2015, paragraph 144.

expect to receive at least the required return. All experts in this proceeding have adopted this value in developing their ROE recommendations. The Commission finds that a flotation allowance of 50 bps continues to be reasonable and will apply this adjustment to the ROE results obtained through CAPM, DCF or risk premium models.

6.1.4 Beta

158. Another element of the CAPM analysis is the beta (β) coefficient. 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 is the measure of market risk of an equity security.[193] Past data (with or without adjustment) is normally used to estimate the reasonably expected beta going forward. As expressed in previous GCOC decisions, the Commission considers that the appropriate beta to use is one that reasonably represents the relative risk of stand-alone Canadian utilities.

159. A point of disagreement between experts in this proceeding was whether unadjusted betas, often referred to as "raw betas," or adjusted betas, should be used in the CAPM. Adjusted betas refer to betas derived from making adjustments to raw betas for the purpose of forward estimation. For example, the "Blume" adjustment (named after Professor Marshall Blume) is a well-known method by which adjusted betas are calculated by giving two-thirds weight to the calculated raw beta and one-third weight to the market average beta of one.[194]

160. Mr. Hevert and Dr. Villadsen both supported the use of adjusted betas. Mr. Hevert pointed to the theoretical underpinnings of adjusting betas according to the "Blume" adjustment. In addition, he observed that, "given the commercial use and acceptance of adjusted beta coefficients, it is in my view that they are the proper measure of systemic risk in the CAPM."[195] Similarly, Dr. Villadsen noted that the "Blume" adjustment procedure is routinely performed by providers of financial data and analysis, such as Bloomberg and Value Line and, therefore, it is widely relied upon by financial practitioners and many regulatory agencies.[196]

161. Mr. Hevert also referred to the following quote from Dr. Morin's text where he referred to the tendency for the beta of all stocks to trend towards one:

> Several authors have investigated the regression tendency of beta and generally reached similar conclusions [as Blume]. High-beta portfolios have tended to decline over time toward unity, while low-beta portfolios have tended to increase over time toward unity…[197]

162. In estimating his proxy group specific betas, Mr. Hevert relied on adjusted beta estimates from Value Line and Bloomberg. Where Value Line estimates were not available, Mr. Hevert calculated his own betas based on the Value Line methodology of using five years of weekly return data and the New York Stock Exchange as the market index. Mr. Hevert's resulting average of the adjusted beta estimates ranged from 0.462 to 0.735 for his Canadian proxy group and 0.513 to 0.820 for his U.S. proxy group.[198]

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193 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 36.
194 For an example calculation, see Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 64.
195 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 64-65.
196 Exhibit 20622-X0105, evidence of Dr. Villadsen, Appendix B, PDF page 23.
197 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 64.
198 Exhibit 20622-X0083, evidence of Mr. Hevert, Schedules, "Sch2 p1 CAPM(CA)" and "SCH2 p2 CAPM (US)."

163. Dr. Villadsen relied on adjusted historical betas sourced from Bloomberg, using weekly returns over a three-year estimation period. For her Canadian utility sample, she used the S&P/TSX as the measure for market returns and for her U.S. samples, she used the S&P 500 for overall market returns. For her Canadian utility sample, betas ranged from 0.67 to 1.20, averaging 0.92.[199] For her U.S. electric utility and natural gas utility samples, betas ranged from 0.55 to 0.84 and 0.66 to 0.77, averaging 0.70 and 0.71, respectively.[200]

164. Dr. Booth and Dr. Cleary both objected to the use of the "Blume" adjustment to adjust betas. Dr. Booth argued that Professor Blume's beta adjustment to one is based on correcting sampling errors for random stocks, which is not what one would do with respect to utilities.[201] As evidenced by Dr. Booth in response to a Commission information request (IR)[202] and as further explained at the hearing:

> Marshall Bloom looked at a sample, a random sample of all companies on the U.S. market, one period; they estimate their betas. And then a subsequent period, he estimated their betas. And he noticed that there was sampling error. That if you estimated unusually low betas, they tended to get higher the next period. And when you estimated unusually high betas, they tended to get lower the next period. And when you do that over the whole sample of 18 companies, you'd expect them, the average to be 1. So nobody would dispute Marshall Bloom's work for the overall stock market. But it is a naïve estimate because it says I don't know anything about these stocks. I'm just going to randomly adjust based upon the overall stock market. But we know a lot about utilities. We know that the betas -- if we get a beta of .5, and in Marshall Bloom's analysis we say we don't know anything about that stock, let's adjust it to because our prior belief is that random stock should be 1. So we adjust it upwards. We get a beta for a utility of .5, we don't say we don't know anything about that. We know it's a utility. And we know .5, well, we've got a history for the last 30 years it's around .5. So why would I adjust it? So that's not sample error. So the whole motivation for adjusting betas for 11 utilities is not what Marshall Bloom did.[203]

165. Dr. Booth also argued that finance had moved on from adjusting betas to models for better betas, stating that:

> We then moved on from that by saying, well, it's not a question of a small stock having a higher beta. Perhaps small stocks are different, and we ended up moving towards multifactor models. And the state of the market at the moment is not adjusting betas to one. It's estimating multifactor models and estimating whether small firms or high dividend yield stocks have got a special risk factor in estimating their rate of return.[204]

166. Dr. Cleary expressed a similar critique stating: "... adjusting a beta up towards one where it's never hit one just makes no intuitive sense to me whatsoever."[205]

167. Dr. Booth judged beta values for Canadian utilities in a range of 0.45 to 0.55 to be reasonable. He. In developing this range for his betas based on his judgment, Dr. Booth stated

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199 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 37.
200 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF pages 41-42.
201 Transcript, Volume 8, pages 1194-1195.
202 Exhibit 20622-X0396, response to CAPP-AUC-2016APR12-005, PDF pages 12-14.
203 Transcript, Volume 8, pages 1194-1195.
204 Transcript, Volume 8, page 1196.
205 Transcript, Volume 10, page 1502.

that he based his judgment on direct estimates for Canadian utilities, the Canadian utility sub-index and the "low risk" U.S. utilities, and the recognition that the interest sensitivity of the Canadian utilities and the "low risk" U.S. utilities has recently been very important.[206]

168. Dr. Cleary estimated that beta values for a typical Alberta utility should lie within a range from 0.30 to 0.60, using the midpoint of 0.45 as his best point estimate. Dr. Cleary based his estimate on average betas calculated using monthly total return data for the TSX Utilities Index over various time periods between 1998 and 2015, current beta estimates for several Canadian utilities using 60 months of return data, and consideration of long-term evidence provided in previous decisions.[207]

169. Another point of divergence between the experts was the use of monthly versus weekly return data in estimating betas. As mentioned above, Dr. Booth directly estimated betas for utility companies. To derive his estimates, Dr. Booth used a five-year estimation window and monthly data ending in 2015, describing in his testimony that it is the standard used in the academic profession to use monthly data.[208] Dr. Booth further noted that if the underlying risk is constant, then the use of monthly data versus weekly data should not make a difference.[209]

170. Dr. Cleary derived beta estimates for individual Canadian utilities and the Canadian utility index to support his point estimate of a reasonable beta for utilities. Dr. Cleary relied on five years of monthly data, indicating that it is the accepted norm and that monthly betas have traditionally been the benchmark because they have less "noise" in them than betas estimated using weekly returns data.[210] Dr. Cleary also noted that monthly betas are used by sources such as the Financial Post and Standard & Poor's (S&P).[211]

171. In contrast, Dr. Villadsen and Mr. Hevert both relied on commercial providers' beta estimates, which are derived using weekly return data. They took issue with Dr. Booth's and Dr. Cleary's use of monthly betas.

172. Dr. Villadsen observed that, although in most circumstances both monthly and weekly betas are acceptable for estimating a company's beta,[212] Dr. Booth and Dr. Cleary failed to recognize that monthly betas for the majority of the Canadian utilities have become unreliable following the global financial crisis. To demonstrate this point, Dr. Villadsen compared the confidence intervals of Dr. Booth's five-year monthly betas for his utility sub-index for the TSX, to her Canadian sample companies calculated with three years of weekly return data. She observed that the confidence intervals for weekly estimates are much smaller, indicating that weekly estimates are more precise, while monthly estimates are subject to more uncertainty.[213]

173. Dr. Villadsen also looked at scatterplots of monthly and weekly beta estimates from 2008-2013 and 2011-2015 and observed that monthly betas are low and statistically insignificant whereas weekly betas are not. Using this analysis, she observed that during the 2008-2013 period, the linear regression of monthly utility returns on monthly market returns provided a

206 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 57.
207 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 40-42.
208 Transcript, Volume 8, page 1164.
209 Transcript, Volume 8, page 1169.
210 Transcript, Volume 10, page 1506.
211 Transcript, Volume 10, page 1507.
212 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 46.
213 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF pages 48-49.

weak fit to the data, whereas the weekly returns gave a much stronger signal with fewer random departures from the linear relationship. For the 2011-2015 period, the monthly and weekly returns were much less volatile, but the monthly data still implied a low beta and even worse fit.[214] As summarized in her testimony:

> So in my opinion, it's not so much a matter of monthly verse [sic] weekly in terms of reliability. It's a matter of you need to be contemporaneous and not reach back into a period of time that was affected by a financial crisis. You can't do that statistically reliably using monthly data.[215]

174. Similarly, Mr. Hevert did not agree with the use of monthly betas. In his view, monthly periods give less weight to market movements experienced in shorter return periods and may dampen their estimates of the current systemic risk of Canadian utilities.[216] To assess the difference in results, Mr. Hevert calculated beta coefficients for Dr. Booth's and Dr. Cleary's Canadian proxy companies, alternatively using monthly and weekly return data. He found the monthly return based betas to be much lower and indicated that the results suggest that Dr. Booth's and Dr. Cleary's beta coefficients did not capture the full extent of the risk faced by equity investors.[217]

Commission findings

175. In the 2013 GCOC decision, experts recommended beta estimates in the range of 0.45 to 0.70 per cent and the Commission found a reasonable range for the beta estimate to be 0.50 to 0.65 per cent. In the current proceeding, experts have recommended a wider range of beta estimates relative to the 2013 GCOC proceeding, extending from 0.45 per cent to 0.92 per cent, depending upon a number of factors including the frequency of the return data (weekly vs monthly) used to estimate betas, and adjustments to raw betas.

176. Dr. Booth stated that it should not matter whether weekly or monthly return data are used if the underlying risk is constant.[218] However, Dr. Booth,[219] Dr. Villadsen,[220] and Dr. Cleary[221] agreed that weekly and monthly betas for Canadian utilities have historically given comparable results but go through periods where the weekly betas are higher than the monthly betas and vice versa. Mr. Hevert found that using the same proxy group and timeframe, estimating betas using weekly return data currently generates higher betas, as compared to using monthly return data.

177. Experts in this proceeding generally agree that weekly and monthly betas are both commonly accepted[222] and professional data sources such as Value Line, Bloomberg, Financial Post and S&P, do not have a common standard approach for estimating betas. The Commission accepts that beta estimates derived from both weekly and monthly return data are commonly used. However, it is unclear from the record of this proceeding whether, in all circumstances or even the current circumstances, the Commission should base its determination of the fair rate of return for regulated utilities on CAPM estimated betas using weekly or monthly data.

214 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF pages 49-53.
215 Transcript, Volume 6, pages 793-794.
216 Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF page 20.
217 Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF page 21.
218 Transcript, Volume 8, page 1169.
219 Transcript, Volume 8, page 1178.
220 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 47.
221 Transcript, Volume 10, page 1502.
222 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 46.

178. Turning to the use of adjusted betas, in the 2013 GCOC decision, the Commission acknowledged that adjusted betas are widely disseminated to investors by investment research firms, including Bloomberg, Value Line and Merrill Lynch. However, the Commission also indicated that the question still remained whether an adjustment is warranted for the betas of regulated utilities.[223]

179. Dr. Booth, Dr. Villadsen and Mr. Hevert all employed adjustments to raw betas, although their methods of adjustment differed. Dr. Booth adjusted his betas closer to a long-term average utility beta of 0.5, while Dr. Villadsen and Mr. Hevert both relied on beta estimates from commercial providers who adjusted their betas closer to one.

180. The Commission accepts the evidence of Dr. Villadsen and Mr. Hevert that adjusting betas to one is a common approach used by commercial providers of financial data and this information is widely disseminated to investors. Mr. Hevert also referred to the proposition that the betas for stocks tends to move towards one over time. Accordingly, the Commission considers that it is a reasonable practice when using CAPM for utility stocks to adjust the betas towards one, as for example in the "Blume" adjustment. However, the Commission also recognizes that with the "Blume" adjustment, as raw betas decline so too will adjusted betas.

181. The Commission finds that both raw betas and adjusted betas provide useful directional information with respect to utility risk. In this regard, the Commission agrees with Dr. Booth's statement that "it is important to know what the beta estimates are *before* an analyst adjusts them. Otherwise, it is very easy for initial estimates of, for example, 0.25 to end up with recommended values much, much higher as the result of numerous "hidden" or not obvious adjustments."[224]

182. Based on all of the evidence above, the Commission observes that the varying methods and inputs used to estimate beta in this proceeding result in a wider range of beta estimates than presented in the 2013 GCOC proceeding. The Commission observes that all experts have employed methods to estimate beta that are generally accepted. Nonetheless, none of the methods employed is perfect and, as a result, each method has received legitimate and reasonable criticism. In this proceeding, the Commission observes an unusually wide range of recommended betas spanning approximately 470 bps (0.45 to 0.92), which is also substantially larger than the 250 bps span observed in the 2013 GCOC proceeding. The Commission has considered the positions and critiques of all the parties with respect to beta and notes that these positions and critiques are reasonable and generally valid. Consequently, the Commission cannot identify, with any reasonable degree of confidence, a method that allows the Commission to narrow the range of betas recommended by the experts in this proceeding.

6.1.5 The resulting capital asset pricing model estimates

183. The following tables set out the individual CAPM components and resulting ROE values for each of the experts that presented evidence on CAPM or variations thereof.

223 Decision 2191-D01-2015, paragraph 130.

224 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 54.

184. Table 2 contains the recommendations for Dr. Booth and Dr. Cleary:

Table 2. CAPM recommendations of Dr. Booth and Dr. Cleary

	Risk-free rate (%)		MERP (%)		Beta		Flotation allowance (%)	ROE before adders[225] (%)		Adders (%)		ROE after adders[226] (%)		Fair ROE (%)
Expert witness	Min	Max	Min	Max	Min	Max		Min	Max	Credit spread	Operation twist	Min	Max	
Dr. Booth[227]														
2016	2.30	2.30	5.00	6.00	0.45	0.55	0.50	5.05	6.10	0.50	0.80	6.35	7.40	6.85
2017	3.14	3.14	5.00	6.00	0.45	0.55	0.50	5.89	6.94	0.50	0.80	7.19	8.24	7.70
Dr. Cleary[228]	2.00	2.60	5.50	6.50	0.30	0.60	0.50	4.15	7.00	0.50		4.15[229]	7.50	6.00

185. Table 3 contains the CAPM results of Mr. Hevert (the beta values are not included because Mr. Hevert used the average of two beta values for each individual company in his Canadian and U.S. samples). Mr. Hevert calculated the CAPM results for each individual company in his Canadian and U.S. samples and then calculated the combined overall mean, median and the average of the mean and median CAPM figures for the Canadian and U.S. sample.

Table 3. CAPM results of Mr. Hevert

	Canadian sample %	U.S. sample %
Risk-free rate		
Measure one	2.14	2.96
Measure two	3.04	3.45
Average	2.59	3.20
MERP		
Measure one	10.06	10.58
Measure two	7.33	9.18
Measure three		9.03
Average	8.69	9.60
CAPM results before flotation allowance[230]		
Mean	8.12	9.79
Median	8.46	9.72
Average of mean and median	8.29	9.75
Flotation allowance	0.50	0.50
CAPM results after flotation allowance		
Mean	8.62	10.29
Median	8.96	10.22
Average of mean and median	8.79	10.25

186. Table 4 contains the CAPM results of Dr. Villadsen. As with Mr. Hevert, the beta values are not included because Dr. Villadsen used beta values for each individual company in her Canadian and U.S. samples. Dr. Villadsen calculated the CAPM results for each individual

225 Calculated as follows: risk free rate + (MERP * Beta) + flotation allowance.
226 Calculated as follows: ROE before adders + adders.
227 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 89. Exhibit 387, response to Booth-Utilities-2016APR12-001, PDF pages 1-3.
228 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 43.
229 In his minimum ROE, Dr. Cleary did not include an adjustment for the credit spread.
230 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 124-125.

company in her Canadian and U.S. samples and then calculated the overall CAPM figures for the total sample and the subsample. Dr. Villadsen calculated the overall CAPM figure for the portfolio using the average overall beta.[231]

Table 4. CAPM results of Dr. Villadsen – without leverage adjustment

	Canadian sample[232] %	U.S. natural gas sample[233] %	U.S. electric utility sample[234] %
Risk-free rate			
Scenario one			
Consensus 10-year forecast	2.20	2.20	2.20
Maturity premium adjustment	0.41	0.41	0.41
Further adjustment	0.80	0.80	0.80
Total	3.41	3.41	3.41
Scenario two			
Consensus 10-year forecast	2.20	2.20	2.20
Maturity premium adjustment	0.41	0.41	0.41
Total	2.61	2.61	2.61
MERP			
Scenario one	5.70	5.70	5.70
Scenario two			
Base	5.70	5.70	5.70
Adjustment	2.30	2.30	2.30
Total	8.00	8.00	8.00
Flotation allowance	0.50	0.50	0.50
CAPM results after flotation allowance			
Scenario one			
Average method	9.10	7.90	7.90
Average method for subsample[235]	8.80		
Portfolio method[236]	9.50	7.90	7.70
Scenario two			
Average method	10.40	8.80	8.70
Average method for subsample[237]	10.00		
Portfolio method[238]	10.90	8.80	8.50

231 The resulting ROE ranges under the two scenarios for the Canadian sample are included in Exhibit 20622-X0104, evidence of Dr. Villadsen, Figure 15, PDF page 54. The resulting ROE ranges under the two scenarios for the U.S. natural gas sample and the U.S. electric utility sample are included in Exhibit 20622-X0104, evidence of Dr. Villadsen, Figure 16 and Figure 17 respectively, PDF page 55.

232 Information was obtained from Exhibit 20622-X0115.

233 Information was obtained from Exhibit 20622-X0116.

234 Information was obtained from Exhibit 20622-X0117.

235 The information for AltaGas Ltd. is excluded in calculating the Canadian subsample results.

236 For the Canadian sample, this consists of 3.41 for the risk-free rate, 5.70 for the MERP, and an average overall beta of the Canadian sample of 0.97. 3.41 + (.97*5.7) = 9.00 plus 0.50 for flotation allowance results in a final figure of 9.50.
For the U.S. natural gas sample, this consists of 3.41 for the risk-free rate, 5.70 for the MERP, and an average overall beta of the U.S. natural gas sample of 0.71. 3.41 + (.71*5.7) = 7.40 plus 0.50 for flotation allowance results in a final figure of 7.90.
For the U.S. electric utility sample, this consists of 3.41 for the risk-free rate, 5.70 for the MERP, and an average overall beta of the U.S. electric utility sample of 0.67. 3.41 + (.67*5.7) = 7.20 plus 0.50 for flotation allowance results in a final figure of 7.70.

237 The information for AltaGas Ltd. is excluded in calculating the Canadian subsample results.

Commission findings

187. The Commission finds the information gathered from its consideration of the risk-free rate, MERP, and flotation allowance to be instructive. Conversely, the Commission finds the information gathered from its consideration of the beta, and resulting CAPM estimates, to be less instructive than in past decisions.

188. The Commission further notes that experts in this proceeding for both the utilities and interveners have indicated a greater reliance on DCF due to current issues with CAPM.

189. For these reasons, the Commission has placed less weight on the resulting CAPM estimates in this decision.

190. As discussed later in Section 6.7, Dr. Booth, Dr. Cleary and Dr. Villadsen have indicated that they have concerns with the current results of CAPM.

6.2 Empirical capital asset pricing model and the multifactor model

191. Dr. Villadsen and Mr. Hevert noted that empirical research has shown that the actual security market line (SML) described by the CAPM formula is not as steeply sloped as the predicted SML. In other words, low-beta securities earn returns somewhat higher than CAPM would predict, and high-beta securities earn less than predicted.[239] The ECAPM adds an empirical adjustment factor to CAPM (referenced as "X" by Mr. Hevert and as "alpha" by Dr. Villadsen) that is intended to adjust the SML to account for the difference between the predicted returns for a given beta when using CAPM and future, realized returns for the same or similar beta.[240]

192. Both Mr. Hevert and Dr. Villadsen relied on the use of the ECAPM in developing their ROE estimates, although their models were of a different form and used different notation.[241]

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[238] For the Canadian sample, this consists of 2.61 for the risk-free rate, 8.00 for the MERP, and an average overall beta of the Canadian sample of 0.97. 2.61 + (.97*8.00) = 10.40 plus 0.50 for flotation allowance results in a final figure of 10.90.
For the U.S. natural gas sample, this consists of 2.61 for the risk-free rate, 8.00 for the MERP, and an average overall beta of the U.S. natural gas sample of 0.71. 2.61 + (.71*8.00) = 8.30 plus 0.50 for flotation allowance results in a final figure of 8.80.
For the U.S. electric utility sample, this consists of 2.61 for the risk-free rate, 8.00 for the MERP, and an average overall beta of the U.S. electric utility sample of 0.67. 2.61 + (.67*8.00) = 8.00 plus 0.50 for flotation allowance results in a final figure of 8.50.

[239] Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 65.

[240] See Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 65 and Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 50, for examples of ECAPM formulas.

[241] However, Dr. Villadsen confirmed in an IR response (Exhibit 20622-X0211, response to AUC-Utilities-2016FEB18-006, PDF page 10) that Mr. Hevert's ECAPM equations represent a rearrangement of her equation applicable for an alpha in the range of 1–2 per cent. In a similar vein, Mr. Hevert submitted in an IR response (Exhibit 20622-X0215, response to AML/EDTI-AUC-2016FEB18-007, PDF Pages 79-80) that Dr. Villadsen's Equation [2] and his Equation [6] both appear correct for the slope of the Security Market Line predicted by the CAPM. He added they do so, however, in somewhat different manners and depending on the values used, may produce somewhat different results. Mr. Hevert concluded that nonetheless, the approaches yield the same result if the following assumptions are used: beta of 0.75; risk-free rate of 2.61 per cent; market risk premium of 8.00 per cent; alpha of 2.00 per cent; "x" of 25.00 per cent; and ROE of 9.11 per cent.

193. In applying his version of the ECAPM l, Mr. Hevert used an X factor of 0.25, based on published work of Dr. Morin.[242] The resulting estimates were an average ROE of 8.91 per cent and 10.54 per cent for his Canadian and U.S. proxy groups, respectively, which were approximately 80 bps larger than his estimates using CAPM.[243] Mr. Hevert's resulting estimates do not include any amounts for flotation costs.[244]

194. Dr. Villadsen used an alpha factor of 1.5 per cent, which was based on an average adjustment factor from academic literature.[245] This factor was adjusted downwards to account for differences in government bond maturities and to be conservative.[246] Dr. Villadsen's resulting ROE estimates for her Canadian and U.S. utility proxy groups are presented in Table 5 below. Consistent with her CAPM estimates, Dr. Villadsen included flotation costs and generated results under two scenarios of risk free rates and MERP.

Table 5. Dr. Villadsen's ECAPM estimates

	ROE	
	Scenario 1	Scenario 2
	(%)	
Canadian utility sample	9.0 - 9.5	10.2 - 10.9
U.S. gas utility sample	8.4	9.2
U.S. electric utility sample	8.2 - 8.3	9.0 - 9.1

Source: Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF pages 54-55.

195. Dr. Booth did not use ECAPM to generate ROE estimates, but he did discuss alternatives to CAPM. Dr. Booth observed that there are a wide variety of multi-factor models, which essentially extend the one factor CAPM to include additional factors. The current 'standard' multifactor model, known as the Fama-French three factor model, includes a size premium to address the return difference between small firms and large firms and a value premium to address the return difference between value and growth stocks.[247] Dr. Booth did not use this model or advocate for its use, as he stated this model is unlikely to generate any significant value over the use of the CAPM. He noted that he included this information in his evidence to demonstrate academic support for other risk premium based models.

Commission findings

196. The use of ECAPM is an approach recognized in the academic literature and is used to address a perceived issue with the CAPM, when the CAPM-based SML is steeper than empirical evidence suggests it should be. The ECAPM adjusts the SML by introducing an empirical adjustment factor to flatten the SML.

242 Exhibit 20622-X0215, response to AML/EDTI-AUC-2016FEB18-007, PDF pages 79-80. Transcript, Volume 1, pages 139-140.

243 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 76.

244 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 124.

245 The academic literature references are listed in Exhibit 20622-X0105, evidence of Dr. Villadsen, Appendices, PDF page 27.

246 Transcript, Volume 5, PDF pages 647-648.

247 Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 42-43.

197. In exchanges with Commission counsel, both Mr. Hevert[248] and Dr. Villadsen[249] agreed that the empirical adjustment factor used in their respective ECAPMs is a function of the sample used and the time period over which the returns were examined. During the oral hearing, Commission counsel asked Mr. Hevert if there are any kinds of standards or best practices that are employed by professionals in determining what the dataset should be when estimating the empirical adjustment factor. In response, Mr. Hevert described that there have been different studies that produce a range of estimates for the empirical adjustment factor and in his view, the selection of the empirical adjustment factor will inevitably be a matter of judgement.[250]

198. Mr. Hevert's view is supported by the evidence in this proceeding with respect to the empirical adjustment factors selected by the experts who employed an ECAPM. Mr. Hevert relied on an adjustment factor based on Dr. Morin's 1989 empirical study that used data from 1926 to 1984 and Dr. Villadsen used an empirical adjustment factor based on average estimated adjustment factors from academic studies that she then adjusted downwards in order to be conservative. The studies relied upon by Dr. Villadsen used different timeframes, with none of the studies including years beyond 1991.[251]

199. In the Commission's view, the ECAPM appears to be a model that could contribute to the Commission's determination of a fair allowed ROE. Generally speaking, the Commission is supportive of models and methods that attempt to improve upon CAPM results. The Commission agrees with Mr. Hevert that the selection of an empirical adjustment factor is a matter of judgement. Based on the evidence in this proceeding, however, the Commission has been unable to assess adequately the empirical adjustment factors employed by the experts in exercising their judgement. Consequently, the Commission will not rely heavily on the ECAPM results in this proceeding. In order for the Commission to adequately assess the judgement exercised by the experts, the Commission would require a full explanation justifying the sample and time periods adopted.

200. The Commission also notes that the empirical adjustment factors to CAPM used in the ECAPMs in this proceeding does not resolve the issues discussed in Section 6.1.4 regarding the reasonable degree of confidence in the estimated ranges for beta.

6.3 Bond yield plus risk premium model and the predictive risk premium model

201. In addition to relying on their CAPM results in estimating a fair allowed ROE, Mr. Hevert, Dr. Villadsen and Dr. Cleary presented results generated by risk premium models. All of the risk premium models presented in this proceeding are based on the fundamental assumption of modern corporate finance that risk averse investors require higher returns for bearing higher risk. In their general form, risk premium models add a premium to account for equity risk to a measure of interest rates.[252]

202. Mr. Hevert gave primary weight to the results of his CAPM and risk premium models in arriving at his recommended ROE range, and less weight to the results of his DCF model.[253]

248 Transcript, Volume 1, page 138, lines 10-20.
249 Transcript, Volume 5, page 646, lines 7-24.
250 Transcript, Volume 1, page 139.
251 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 27.
252 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 76. Exhibit 20622-X0164, response to AML/EDTI-UCA-2016FEB18-010, PDF page 29.
253 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 159.

Dr. Villadsen did not indicate how much weight she placed on the results of any of her models in arriving at her ROE estimate. However, she stated that the ROE range she considered to be reasonable was within the range of the results of her risk premium model.[254] Dr. Cleary placed equal weighting on the results of his CAPM, risk premium model and DCF model in arriving at his final ROE estimate.[255]

203. With respect to bond yields, Dr. Villadsen provided evidence with respect to 30-year Canadian A-rated bond yields from January 1, 2000 to May 31, 2016, which is reflected in Figure 2. This evidence shows that during the course of the 2013 GCOC proceeding, the 30-year Canadian A-rated bond yields were 4.12 per cent on May 31, 2014, and 4.06 per cent on July 31, 2014. On December 31, 2015, near the start of the proceeding, Dr. Villadsen's evidence shows that the 30-year Canadian A-rated bond yields were 4.05 per cent and on May 31, 2016, yields were 3.66 per cent.

204. Similar to his evidence in the 2013 GCOC proceeding, in arriving at his recommended ROE estimate, Dr. Cleary provided an analysis using a BYPRPM. Under this model, a risk premium in the two to five per cent range is added to the yield on a firm's outstanding publicly-traded, long-term bonds to arrive at a company's cost of equity estimate, with 3.5 per cent generally added to reflect average risk companies and lower values 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.

205. Dr. Cleary noted that as of February 3, 2016, the yield on long-term A-rated Canadian utility bonds was 4.03 per cent according to the Bloomberg data. Because this number was close to the yields on outstanding Canadian utility bonds, Dr. Cleary concluded that the 4.03 per cent bond yield was a reasonable starting point for his BYPRPM estimate. After adding his risk premium estimate of 2.5 per cent, Dr. Cleary obtained an ROE estimate of 7.03 per cent, after adding 50 bps for the flotation allowance.[256]

206. Dr. Cleary referenced a number of authorities on finance to support his statement that a risk premium to be used in the BYPRPM lies generally in the two to five per cent range.[257] Dr. Cleary acknowledged that the referenced authorities recognize that the BYPRPM has somewhat of a subjective, *ad hoc* nature, represents a "quick estimate based on experience" that market practitioners use, and involves a great degree of judgement regarding the value to use for the risk premium.[258] Nevertheless, in Dr. Cleary's view, the BYPRPM approach provides a useful check on CAPM and other estimates, and is intuitively attractive because it relies on typical relationships between bond and stock markets. In addition, the approach requires information that can be readily obtained from observable, market-determined bond yields to estimate a required rate of return on a firm's stock. Dr. Cleary pointed out that the BYPRPM approach is used more widely by analysts and chief financial officers than the DCF models but not as much as the CAPM.[259]

254 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 83.
255 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 5.
256 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 57-58.
257 Exhibit 20622-X0408, response to UCA-AUC-2016APR12-005, PDF pages 13-14.
258 Transcript, Volume 10, page 1530, lines 12-21.
259 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 57.

207. Mr. Hevert considered two risk premium model approaches: the PRPM applied to the Canadian and U.S. proxy groups; and a variant of a BYPRPM approach using authorized returns for U.S. electric utility companies. The latter approach was also employed by Dr. Villadsen, as discussed further below.

208. Mr. Hevert explained that the risk premium derived from the PRPM is based on the premise that the volatility of stock returns and risk premiums changes over time and is related from one period to the next and, as such, could be estimated by using time series analysis tools such as the autoregressive conditional heteroscedasticity (ARCH) model and its generalized form the GARCH model. The inputs to the PRPM-derived model are the historical returns on the common shares of each proxy company, less the historical monthly yield on long-term government bonds. Using statistical software, Mr. Hevert calculated each proxy company's projected risk premium.[260]

209. For the Canadian utilities proxy group, Mr. Hevert calculated the average and median risk premiums to be 7.12 per cent and 6.83 per cent, respectively. By adding these risk premiums to his recommended average risk-free rate value for Canada of 2.59 per cent, Mr. Hevert obtained ROE estimates of 9.42 per cent and 9.71 per cent. For the U.S. utilities proxy group, the calculated average and median risk premiums were 7.15 per cent and 7.06 per cent, respectively. When added to Mr. Hevert's recommended average risk-free rate value for the U.S. of 3.20 per cent, the resulting ROE estimates were 10.35 per cent and 10.26 per cent.[261]

210. As well, Mr. Hevert and Dr. Villadsen employed a variant of the BYPRPM that adds a risk premium (calculated as the difference between the authorized ROE granted by the U.S. regulators and the then-prevailing level of the long-term Treasury yield) to a long-term government bond yield. These experts then modeled the relationship between interest rates and the risk premium using regression analysis, in which the observed risk premium was the dependent variable, and the average 30-year Treasury yield was the independent variable.[262]

211. Each of these experts opted for a different functional form and time period for their respective regression models.[263] Specifically, Mr. Hevert's data set included 1,467 U.S. electric rate proceedings between 1980 and 2016, as Canadian allowed ROE data was not available. According to Mr. Hevert, his regression analysis demonstrated that over time there has been a statistically significant, negative relationship between the 30-year Treasury yield and the risk premium. Based on the obtained regression coefficients, applied at his recommended risk-free rate values for Canada and the U.S, the implied ROE ranges for the Canadian utility proxy group were from 10.05 per cent to 10.13 per cent, and from 10.04 per cent to 10.47 for the U.S. utility proxy group.[264]

212. Dr. Villadsen also obtained a negative slope coefficient, indicating that this "is consistent with past observations that the premium investors require to hold equity over government bonds increases as government bond yields decline."[265] Dr. Villadsen applied her regression equation at

260 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 77-78.
261 Exhibit 20622-X0083, Schedule "Sch3 PRPM (CA & US)." Average and median ERPs were calculated by Commission staff using data in column [E].
262 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages79-80.
263 Mr. Hevert used a semi-log form, where the independent variable was the natural logarithm of the 30-year Treasure yield. Dr. Villadsen used a linear form.
264 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 81.
265 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 63.

her recommended normalized risk-free rate of 3.4 per cent to arrive at a risk premium estimate of 6.7 per cent, for a cost of equity estimate of 10.1 per cent.

213. Both Mr. Hevert and Dr. Villadsen acknowledged that in past GCOC decisions, the Commission has rejected the use of ROEs awarded to utilities in other jurisdictions in its considerations of a fair ROE for the affected utilities. Mr. Hevert indicated that in his "practical experience investors consider a broad range of data, including returns authorized in other jurisdictions, in establishing their return requirements." Mr. Hevert further expressed his view that "the market-based data and models on which the Commission relies are reflected in authorized returns in other jurisdictions."[266]

214. In a similar vein, Dr. Villadsen noted that the allowed ROEs granted by U.S. state regulatory agencies is data that is "… observable by investors and therefore inform their investment decisions."[267] Additionally, Dr. Villadsen indicated that because her model uses contemporaneous government bond yields and her data set on awarded U.S. ROEs distinguishes between settled and fully litigated cases, it addresses the Commission's concerns, as expressed in the 2011 GCOC decision, that some of the ROE decisions by other jurisdictions were made in different interest rate environments and were the result of negotiated settlements.[268]

215. Mr. Hevert pointed out that generally, the results of his PRPM and BYPRPMs, which add a calculated risk premium to government bond yields, should not be conceptually different from Dr. Cleary's BYPRPM, which adds a risk premium to corporate bond yields. He explained that this is because the corporate bond yield can be decomposed into a risk-free rate (exemplified by a government bond yield) plus a credit spread:

> So in studies that I've done, there's really no material difference in looking at, for example, a bond yield plus risk premium analysis if we were to use the -- an underlying, say, utility bond yield index or if we were to decompose that and say that the equity risk premium is a function of, one, treasury yields, and then, two, separate variable for the credit spread. That gives you effectively the same result as saying that the risk premium is a function of bond yields.[269]

216. In an exchange with Commission counsel, Mr. Hevert confirmed that because his PRPM and BYPRPMs measure risk premiums over the risk-free rate represented by long-term government bonds, the resulting risk premiums can be analogous to the MERP value used in the CAPM.[270] Dr. Cleary advised that the risk premium value in his BYPRPM should not be confused with the MERP value used in CAPM.[271]

217. Both Mr. Hevert[272] and Dr. Villadsen[273] expressed concerns with Dr. Cleary's BYPRPM. First, they disagreed with Dr. Cleary's reliance on the Canadian utility bond yield as of February 3, 2016 as an indicator for the 2016-2017 test period, without considering forecast interest rates or expected higher interest rate trends. Second, they indicated that Dr. Cleary does

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266 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 79.
267 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 62.
268 Decision 2011-474, paragraphs 101 and 102.
269 Transcript, Volume 1, page 166, line 19 to page 167, line 2.
270 Transcript, Volume 2, page 182, line 3 to page 183, line 11.
271 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 56.
272 Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF page 38.
273 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 62.

not provide any analysis to support the employed risk premium range of two to three per cent and fails to recognize that the risk premium commonly increases as interest rates decline.

218. AltaLink noted that in contrast to Dr. Cleary's approach, Mr. Hevert's risk premium models utilized forecast bond yields and recognized the inverse relationship between risk premiums and currently low interest rates.[274] The UCA submitted that because Dr. Cleary's BYPRPM incorporates the entire amount of the utility yield spread into the estimate, it accurately reflects current capital market conditions and the current prevailing low interest rate environment.[275]

219. The UCA expressed concerns with Mr. Hevert's and Dr. Villadsen's risk-premium models that rely on allowed or approved returns for regulated utilities in other jurisdictions. The UCA submitted that the Commission rejected this approach in the 2009 GCOC decision.[276] In the UCA's submission, for the reasons identified in that decision, awarded returns in other jurisdictions cannot be considered relevant market data for the purposes of estimating the cost of equity for the affected utilities for many of the reasons the Commission has already identified. The UCA added that nor is reliance on them necessary, given the various other accepted theoretical models which exist to estimate the cost of equity.[277]

Views of the Commission

220. Dr. Cleary, Dr. Villadsen and Mr. Hevert all prepared versions of a BYPRPM. Mr. Hevert also used a PRPM, which calculates a projected risk premium for each proxy company as a function of past values of the risk premium volatility using an ARCH-based time series analysis. Dr. Cleary indicated he has not seen this type of model before,[278] but he did not otherwise criticize the model.

221. The results of Mr. Hevert's PRPM were fairly consistent for his Canadian and U.S. samples and produced a risk premium estimate of some 7.0 per cent.[279] In this regard, the Commission observes that Mr. Hevert's 7.0 per cent risk premium obtained from the PRPM is above the long-term average equity risk premium for the Canadian and U.S. stock markets of approximately 5.0 to 6.0 per cent and is directionally consistent with the Commission's views expressed in Section 6.1.

222. Because Mr. Hevert's PRPM is based on the premise that the volatility of stock returns and risk premiums changes over time and is related from one period to the next and it has been observed that financial time series data often exhibit these properties, the Commission is interested in exploring these types of models and approaches further in subsequent GCOC proceedings. However, the PRPM analysis advanced by Mr. Hevert was not fully developed on the record of the proceeding. The Commission also notes that Mr. Hevert expressed a preference for the CAPM and risk premium models without distinguishing the advantages and disadvantages of each. Therefore, for the purposes of this decision, the Commission will place little weight on Mr. Hevert's PRPM study.

274 Transcript, Volume 11, page 1768, line 20 to page 1770, line 5.
275 Transcript, Volume 12, page 2095, lines 12-18.
276 Decision 2009-216, paragraph 200.
277 Transcript, Volume 12, page 2110, line 19 to page 2111, line 5.
278 Transcript, Volume 10, page 1535, lines 3-5.
279 Exhibit 20622-X0083, Schedule "Sch3 PRPM (CA & US)." Average and median risk premiums were calculated by Commission staff using data in column [E].

223. Regarding the variants of the BYPRPM used by Mr. Hevert and Dr. Villadsen, which calculated the risk premium as the difference between the authorized ROEs granted by U.S. regulators and the then-prevailing level of the long-term Treasury yield, the Commission recognizes that Mr. Hevert's and Dr. Villadsen's risk premium calculations are different from the practice of directly using the ROEs awarded by other regulators in determining the fair rate of return for the affected utilities. These models also address some of the Commission's concerns, expressed in the 2011 GCOC decision because they take into account the interest rate environment at the time and attempt to model the inverse relationship between the level of interest rates and the risk premium. Additionally, Dr. Villadsen did not include the allowed ROEs arising from negotiated settlement agreements and made adjustments for some specific issues. Nonetheless, the underlying assumption for these models is still that authorized returns serve as a proxy for the market-required return.[280]

224. As the UCA pointed out, the Commission has previously considered the issue of using returns awarded by other U.S. and Canadian regulators as indicators of a market-required return and concluded in the 2009 GCOC decision that the better approach is to examine the evidence of experts in a GCOC proceeding on required returns estimated using methods founded on sound principles of finance and, particularly, because the awards by other regulators were established on a basis of a different record.[281] This conclusion is consistent with another finding in that decision, subsequently discussed in Section 6.6, that while the Commission will accept U.S. data on expected market-based rates of return, returns awarded by U.S. regulators cannot be directly used in determining a fair return for the affected utilities.[282]

225. Dr. Villadsen acknowledged that although risk premium models based on historical allowed returns can provide useful benchmarks for evaluating appropriate rates of return, she stated that "risk premium models based on historical allowed returns are not underpinned by fundamental finance principles in the manner of the CAPM or DCF models."[283] Additionally, even though Dr. Villadsen distinguished between settled and non-settled allowed returns and made some adjustments for specific issues in the allowed returns (such as removing the incentive portion of an allowed return awarded by a regulator in Virginia[284]), in the Commission's view, it is hard to ascertain whether further adjustments to account for aberrations of this kind are required, without scrutinizing each regulatory decision in detail. Consistent with its determinations in the 2009 GCOC decision, the Commission did not place any weight on the results of Mr. Hevert's and Dr. Villadsen's risk premium models that use the authorized ROEs granted by the U.S. regulators.

226. The Commission accepts the views of Dr. Villadsen and Mr. Hevert that a potential issue, which has become more pronounced because of further declines in the level of interest rates, with Dr. Cleary's BYPRPM is that it does not account for the inverse relationship between returns and the interest rate. Although Dr. Cleary explained that the BYPRPM captures any changes in credit spreads, as they are directly embedded in the bond yield element of the model,[285] he also acknowledged that another driver of the risk premium, market volatility, is

280 Transcript, Volume 2, page 186, lines 4-7.
281 Decision 2009-216, paragraphs 283 and 284.
282 Decision 2009-216, paragraph 200.
283 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 64.
284 Transcript, Volume 5, page 662, line 15 to page 663, line 12.
285 Transcript, Volume 10, page 1487, lines 10-24.

captured in both the bond yield and the risk premium component of the BYPRPM.[286] Still, Dr. Cleary recommended using the same 2.5 per cent risk premium value he recommended in the 2013 GCOC proceeding. Given the Commission's observations in Section 4 with respect to market volatility, the risk premium component of the BYPRPM may need to be higher than Dr. Cleary's proposed premium.

227. Notwithstanding this criticism with respect to the risk premium, bond yield observations, particularly as they may change from one GCOC proceeding to the next, are of assistance to the Commission in understanding directional changes in investor risk perceptions. In this regard, the Commission observes from the evidence of Dr. Villadsen that during the course of the 2013 GCOC proceeding, the 30-year Canadian A-rated bond yields were 4.12 per cent on May 31, 2014, and 4.06 per cent on July 31, 2014, and from the evidence of Dr. Cleary, that long-term A-rated Canadian utility bond yields on February 3, 2016, were 4.03 per cent. In comparing the similarity of Canadian A-rated bond yields to the yields on Canadian A-rated utility bond yields, the Commission notes the comment of Dr. Booth that "currently the market seems to be valuing similarly rated utility and non-utility A-rated debt the same."[287]

228. In the 2013 GCOC decision, the Commission agreed with Dr. Cleary's view that the BYPRPM approach holds a certain appeal for finance professionals because it is simple to use and conforms with the basic principle of finance that investors require a higher return for assets with greater risk. However, the Commission also observed that this approach has somewhat of an *ad hoc* nature and may not be advantageous in the environment of historically low interest rates because unlike CAPM, it may not precisely account for the inverse relationship between the risk premium and the level of interest rates. As a result, the Commission did not place a significant weight on this test in determining a fair allowed ROE for the affected utilities.[288] The Commission also considered the fact that there was ample evidence on CAPM in the 2013 GCOC proceeding.

229. The Commission continues to agree with its views in the 2013 GCOC decision that this approach is *ad hoc* and it may not apply in an environment of historically low interest rates. However, in the Commission's view, the BYPRPM method does provide the Commission with information on the direction in which a fair allowed ROE must move in order to meet utility equity investors' perceptions of changes in risk.

230. The Commission considers that the underlying factors within the BYPRPM method are directionally informative when estimating a fair ROE. The Commission will consider the results of Dr. Cleary's BYPRPM, recognizing that Dr. Cleary's risk premium of 2.5 per cent may need to be higher.

6.4 Discounted cash flow model

6.4.1 Discounted cash flow methodology and predictive value

231. The DCF approach 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 to the current share price.

286 Transcript, Volume 10, page 1480, lines 4-14.
287 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 33.
288 Decision 2191-D01-2015, paragraphs 260-262.

232. There are several types of DCF models and variations, including single-stage growth models and multi-stage growth models. Single-stage, constant growth models assume that growth in dividends will occur indefinitely at the same constant rate. Multi-stage models allow the expected dividend growth to vary over different time periods. For example, the “H-model” is a version of a multi-stage model in which growth linearly converges from a short-term rate towards a future long-term rate over a specified period of time. Given multiple growth periods, calculating an implied ROE is, to some extent, more complex.[289]

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

$$R_e = \frac{D_1}{P_0} + g,$$

where:

$\boldsymbol{R_e}$ is the required return on common equity
$\boldsymbol{D_1}$ is the next period expected dividend
$\boldsymbol{P_0}$ represents the current period common share market price
$\boldsymbol{g}$ represents the expected long-term growth rate in dividends

234. As indicated in the above equation, the estimated ROE under a standard single-stage DCF model flows from a consideration of two components: the dividend yield (D_1/P_0), and an expected growth in dividends, g.

235. In this proceeding, witnesses representing the affected utilities and interveners used various DCF estimates to develop their ROE recommendations. However, the type of DCF models, methodologies and weightings assigned to the results varied across witnesses.

6.4.2 Discounted cash flow estimates

236. Dr. Villadsen used both single-stage and multi-stage DCF models to develop ROE estimates for her utility sample groups. However, in developing her recommendation, Dr. Villadsen primarily relied on the results from the multi-stage model.[290]

237. The multi-stage model used by Dr. Villadsen included three growth stages. In the first five-year stage, dividends grow at a company-specific rate based on forecast earnings growth rates. In the second five-year stage, growth rates linearly converge from the first stage to the final growth rate. In the third and final stage, dividends grow at the overall rate of growth of the economy, which she described as the long-term GDP growth rate forecast to be in effect 10 years or more into the future.[291]

238. Dr. Villadsen applied her DCF models to three utility proxy groups: a group of Canadian utilities, a group of U.S. natural gas local distribution company (LDC) utilities and a group of U.S. electricity utilities. The Canadian utility proxy group was presented as a full sample and

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[289] See Exhibit 20622-X0306, Evidence of Dr. Cleary, PDF page 46 for the formula to derive Re using the H-model.
[290] Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 82.
[291] Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 58.

also a smaller subsample in which the companies with the highest and lowest growth rate estimates were removed.

239. For the Canadian proxy group, Dr. Villadsen used investment analysts' forecast earnings growth rates from Thomson Reuters Institutional Brokers' Estimate System (IBES) as the short-term growth rate and the Canadian GDP forecast from Towers Watson for the long-term growth rate. For the U.S. samples, Dr. Villadsen used investment analysts' forecast earnings growth rates from Value Line and Thomson Reuters IBES as the short-term growth rate and the U.S. GDP growth forecast from Blue Chip Economic Indicators as the long-term growth rate.

240. The results of Dr. Villadsen's multi-stage DCF estimates are presented in Table 6 below. Dr. Villadsen included flotation costs of 50 bps. Similar to her CAPM estimates, she presented the results with and without adjustments for leverage, although Table 6 does not include the leverage adjustment figures.[292]

Table 6. Results of Dr. Villadsen's multi-stage DCF estimates – without leverage adjustment

	Dividend yield of sample (average)*	First stage growth rate (average)	Long-term growth rate	ROE
	(%)			
Canadian utility full sample	4.57	9.17	4.25	11.40
Canadian utility subsample	4.29	9.47	4.25	11.00
U.S. gas utility sample	3.32	7.20	4.30	9.10
U.S. electric utility sample	3.70	4.86	4.30	8.90

*Commission staff calculation (most recent dividend paid *4) / stock price.

241. Dr. Villadsen observed that her multi-stage analysis across all sample groups supports an ROE above 11.5 per cent after considering financial risk[293] and flotation costs. Without considering financial risk, Dr. Villadsen proposed that her Canadian sample supports an ROE range of 11.0 to 11.5 per cent. In consideration of results both with and without a financial risk adjustment, Dr. Villadsen concluded that her DCF estimates support an ROE range of approximately 9.0 to 11.5 per cent.[294]

242. Dr. Villadsen reran her DCF analysis as of June 1, 2016 for her Canadian sample. Her multi-stage analysis across the full sample group yielded ROE results that were 140 bps lower, while her subsample yielded results that were 100 bps lower. The U.S. results were less dramatic, but dropped as well.[295]

243. Using a single-stage constant growth DCF model, Mr. Hevert performed a DCF analysis to estimate the returns for the overall Canadian (S&P/TSX) and U.S. (S&P 500) markets. He also performed this DCF analysis to estimate the returns for his Canadian utility proxy group and his U.S. utility proxy group. At the market level, Mr. Hevert calculated the ROE estimates using

[292] Inputs for the table can be found in Exhibit 20622-X0115, Exhibit 20622-X0116 and Exhibit 20622-X0117.
[293] Dr. Villadsen stated the following at PDF page 8 of her evidence, Exhibit 20622-X0104: "When adjusting the results of my market derived cost of equity to account for financial risk, I simply consider the impact of different levels of financial leverage on the required return on equity. To reiterate, I present my results both with and without such adjustments."
[294] Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 82.
[295] Exhibit 20622-X0612.

analysts' earnings growth expectations sourced from Bloomberg as growth rates. The results were an expected total return of 12.65 per cent and 13.78 per cent for the S&P/TSX and S&P 500, respectively. Mr. Hevert accepted the results noting that they were consistent with the historical observed returns from 1926-2014.[296]

244. For his Canadian and U.S. utility proxy groups, Mr. Hevert calculated the ROE estimates using security analysts' EPS growth rate forecasts as the growth component. Mr. Hevert selected the maximum high and minimum low EPS growth estimates from Value Line, Zacks and First Call for each company in the proxy groups, to calculate a range of high and low ROE estimates.[297] The results were an ROE range of 12.49-13.88 per cent and 8.53-10.02 per cent for the Canadian and U.S. proxy groups, respectively, exclusive of flotation cost adjustments.[298]

245. Mr. Hevert indicated that he gave little weight to his Canadian utility proxy group DCF results as they were high compared to his U.S. utility proxy group results[299] and the overall market results. While Mr. Hevert acknowledged that in the 2013 GCOC decision, the Commission did not accept growth estimates greater than the nominal long-term growth rate for the economy in the single-stage DCF model, he stated that he disagreed with that opinion and did not use GDP as a "ceiling." As he explained in his evidence, GDP represents average growth in the market and some sectors grow more or less than the national averages.[300]

246. Dr. Booth used a single-stage DCF model to estimate the returns for the broad market, for the U.S. utilities listed on the S&P 500 and for a sample of low risk U.S. natural gas utilities. Dr. Booth used both sustainable growth rates and the long-term GDP growth forecast to estimate a fair return for the Canadian market in the range of 8.50-9.50 per cent. Dr. Booth explained that he arrived at this recommendation by making adjustments to the model results. In his view, the simple application of the DCF model likely understated the market's fair return because Canada "still has a couple of years of above average growth ahead."[301]

247. Dr. Booth calculated a median required ROE of 8.53 per cent for his S&P electricity group sample using a median sustainable growth rate of 3.13 per cent and a median dividend yield of 4.49 per cent. For his S&P natural gas sample, Dr. Booth estimated a median required ROE of 7.17 per cent using a median sustainable growth rate of 3.23 per cent and a dividend yield of 3.24 per cent.[302]

248. Dr. Booth also performed a DCF analysis for individual firms. However, he testified that estimates for individual companies are less reliable than estimates for the market and utility indexes due to significant error in forecasting future growth rates.[303] Using data for eight U.S. utilities, Dr. Booth estimated a required ROE averaging 8.50 per cent based on an average forecast growth rate of 5.45 per cent and an average dividend yield of 2.90 per cent.

296 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 71.
297 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 84-85.
298 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 125.
299 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 92.
300 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 90-91.
301 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 68.
302 Exhibit 20622-X0292.
303 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 80.

249. Dr. Booth noted that these results present "formidable problems."[304] The first is that the DCF model assumes growth forever at an average forecast growth rate of 5.45 per cent, which, with the forecast U.S. inflation at a long run rate of two per cent, means about 3.3 per cent long run real growth; whereas, at least in the shorter run, the U.S. economy is forecast at best, to grow at less than three per cent. Dr. Booth submitted that it is impossible that these utilities will grow faster than the growth rate of the U.S. economy forever and there is no evidence that they have at least grown at the U.S. GDP growth rate consistently in the past. Dr. Booth added whereas the average growth rate over the previous five years was 0.19 per cent for the eight U.S. utilities, the forecast growth rate averages 5.45 per cent, which is significantly more. Dr. Booth indicated that the DCF model over-estimates the required rate of return due to analyst optimism.[305]

250. In an attempt to resolve some of these problems, Dr. Booth derived new DCF estimates through two methods. Under the first method, Dr. Booth adjusted the analyst growth expectations downwards to account for the "known optimisms of analyst forecasts." Under this method, Dr. Booth reduced the analyst growth estimates from 5.54 to 3.71 per cent to estimate an average required ROE of 6.71 per cent.[306] The second method involved Dr. Booth substituting analyst growth expectations for sustainable growth rates. Using an average sustainable growth rate of 2.88 per cent, Dr. Booth estimated a median equity cost of 6.09 per cent for his utility sample group.[307] Dr. Booth noted that the U.S. DCF estimates would need a flotation cost addition and further, that they reflected USD returns, rather than CAD returns.

251. Dr. Cleary used both a single-stage and a multi-stage DCF model to estimate the ROE at the broad market level as well as the utility industry level. At the Canadian market level, Dr. Cleary applied a single-stage model, estimating a maximum required ROE of 8.98 per cent using a growth rate of 5.4 per cent (based on historic GDP growth from 1962-2014 and the Bank of Canada inflation target) and a dividend yield of 3.4 per cent. He also estimated a minimum required ROE of 8.21 per cent[308] using a lower growth rate of 4.65 per cent (based on historic GDP growth since 1992 and the inflation target). Combined, Dr. Cleary provided a best estimate for the Canadian market required ROE of 8.6 per cent.

252. In an attempt to overcome the limitation of constant growth in the single-stage model, Dr. Cleary used the H-model version of a multi-stage model to estimate the Canadian market required ROE. In the application of the model, Dr. Cleary used a short-term growth estimate of 3.53 per cent and a long-term growth rate estimate of 5.4 per cent. Based on timeframes of two and four years for the short-term rate to converge to the long-term rate, the ensuing required ROE estimates were 8.92 and 8.85 per cent, respectively, resulting in a best estimate of 8.9 per cent.[309] Combining the results from both models, Dr. Cleary arrived at a best estimate of 8.75 per cent market required ROE and suggested that, at minimum, utility returns should be lower than 8.75 per cent.

253. Turning to the utility estimates, Dr. Cleary derived a best estimate required ROE for utilities in a similar fashion as his market level estimates. Dr. Cleary estimated a required ROE for a Canadian utility proxy group of nine companies as well as two other Canadian utility

[304] Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 81.
[305] Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 80-82.
[306] Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 82-83.
[307] Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 84.
[308] Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 45-46.
[309] Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 47.

groups consisting of subsamples of seven of the nine companies and four of the nine companies. The inputs and results of Dr. Cleary's single stage DCF analysis is presented in Table 7 below.

Table 7. Inputs and results of Dr. Cleary's single stage DCF analysis

Sample	Dividend yield (five-year average)	Dividend yield (2016 average)	Growth rate (2014 average)	Growth rate (2006-2014 average)	Required ROE estimates (average)
	(%)				
Canada utility sample					
Nine companies	4.19	4.86	2.06	3.33	7.02 – 7.66
Seven companies	3.34	3.83	3.10	4.51	7.04 – 8.00
Four companies	3.59	4.03	1.51	3.40	5.60 – 7.11

Source: Input for table can be found in Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 49-51.

254. Based on his results, Dr. Cleary estimated the average required ROE to be 7.07 per cent and the median average required ROE estimate to be 7.02 per cent. Based on the midpoint, Dr. Cleary provided a best estimate required ROE using the single-stage DCF model of 7.04 per cent, equating to a 7.54 per cent estimate after adding flotation costs.[310]

255. Dr. Cleary also applied the H-model to his three Canadian utility groups. The inputs and results of the analysis are presented in Table 8 below.

Table 8. Inputs and results of Dr. Cleary's H-model

	Dividend yield (average)	Short-term growth rate	Long-term growth rate	ROE using four-year transition period	ROE using two-year transition period
	(%)				
Canada utility sample					
Nine companies	4.86	2.06	3.33	8.22	8.29
Seven companies	3.83	3.10	4.51	8.40	8.46
Four companies	4.03	1.51	3.40	7.41	7.48

Source: The inputs for this table can be found in Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 53-54.

256. Based on his results, Dr. Cleary observed the required ROE estimate to lie within the range of 7.9 to 9.0 per cent, after including flotation costs, and arrived at a best estimate of 8.54 per cent.[311] Weighting his constant growth and H-model results equally, Dr. Cleary suggested a required return in the range of 6.1 to 9.0 per cent and best estimate of 8.04 per cent, inclusive of a flotation cost allowance.[312]

257. Mr. Hevert, Dr. Villadsen, Dr. Booth and Dr. Cleary all exchanged critiques regarding the specific DCF models employed, the inputs used and the corresponding results.

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310 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 51-52.
311 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 54.
312 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 55.

258. Mr. Hevert and Dr. Villadsen critiqued the results obtained by Dr. Booth and Dr. Cleary because of their use of sustainable growth rates. In particular, Mr. Hevert indicated that sustainable growth rates may be an inferior measure of growth in the DCF model.[313]

259. Mr. Hevert also critiqued Dr. Cleary's growth estimates as unduly low, stating that based on Dr. Cleary's short- and long-term growth rates, the corresponding implied real growth rates would be less than six bps and 1.27 per cent, respectively. For these real growth rates, investors would not accept the risks of equity ownership and "likely would see themselves as far better off investing in debt, with a higher yield and considerably lower risk of capital loss (if held to maturity)."[314]

260. Similarly, Dr. Villadsen critiqued Dr. Cleary's use of sustainable growth rates. For example, Dr. Villadsen considered Dr. Cleary's sustainable growth rate estimation to be flawed, stating that "by not including the growth from the issuance of new shares, Dr. Cleary biases his results downward."[315]

261. According to Dr. Villadsen, the DCF estimates put forward by Dr. Cleary and Dr. Booth were flawed because they failed to consider the impact of share buybacks and, therefore, underestimated the expected market returns.[316] Dr. Villadsen disagreed with the use of the historic average Canadian GDP growth rate as a long-term growth rate, stating that the time period used to derive the estimate was unsupported and that "future growth of dividends will not necessarily follow the past growth of the economy."[317]

262. Additionally, Dr. Villadsen criticized Dr. Cleary's use of forecast GDP as a short-term growth rate because it implicitly assumed the stock market could not grow faster than GDP in the short-term.

263. Finally, Dr. Villadsen noted that Bloomberg estimates the expected returns for the Canadian market for 2016 using a multi-stage model that uses a dividend discount methodology similar to Dr. Cleary's, to derive long-term growth rates. Compared to Dr. Cleary's estimates, the Bloomberg-derived implied expected return was three per cent higher.[318]

264. The intervener experts, in turn, critiqued the ROE estimates obtained by Mr. Hevert and Dr. Villadsen because of their use of analysts' earnings growth estimates. They noted that these estimates have been criticized by Canadian regulators, including this Commission, for being overly optimistic. Dr. Cleary described analysts' growth expectations to be "extremely optimistic" and "totally unreliable."[319] Dr. Cleary further noted that Dr. Villadsen's growth estimates are above the long-term nominal growth rate for 10 years and, therefore, violate the upper limit on growth in the DCF model from the 2013 GCOC decision.[320]

313 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 92.
314 Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF page 35.
315 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 60.
316 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 58.
317 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 58-59.
318 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF pages 59- 60.
319 Transcript, Volume 10, page 1523.
320 Transcript, Volume 10, pages 1527-1528.

265. Dr. Booth similarly argued that analyst growth forecasts are biased-high estimates of the future growth rate in dividends because they are based on earnings and not dividends.[321] To demonstrate his point, Dr. Booth submitted that based on the 2011-2014 timeframe, removing analyst bias from a forecast requires reducing the starting analyst forecast growth rate to 68 per cent of the original forecast. Applying that bias to his sample group of natural gas utilities required adjusting the median growth rates from 5.54 to 3.71 per cent, and resulted in a decline in the average equity cost from 8.50 to 6.71 per cent.[322]

Commission findings

266. In this proceeding, ROE estimates for the equity market as a whole based on DCF analyses were provided by Dr. Cleary, Dr. Booth and Mr. Hevert. ROE estimates for the utility market based on DCF analyses were provided by Dr. Villadsen, Mr. Hevert, Dr. Cleary and Dr. Booth.

6.4.2.1 Return on equity estimates for the equity market based on discounted cash flow models

267. In the 2013 GCOC decision, the Commission agreed with Dr. Booth's and Dr. Cleary's views that DCF model-generated ROE estimates for the equity market as a whole are a valid input in determining the ROE for the utilities industry.[323] The Commission continues to be of the view that DCF model-generated ROE estimates for the equity market as a whole are useful in determining the fair cost of equity for the utilities industry.

268. In this proceeding, there was disagreement among the experts over the assumptions and applicability of specific DCF models and ultimately, the resulting DCF-based overall equity market ROE estimates.

269. Table 9 below sets out the DCF-based ROE estimates for the equity market provided by Dr. Cleary, Dr. Booth and Mr. Hevert.

321 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 83.
322 Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 82-83.
323 Decision 2191-D01-2015, paragraph 181.

Table 9. DCF-based ROE estimates for the equity market provided by Dr. Cleary, Dr. Booth and Mr. Hevert

	Equity market	Dividend yield (%)		Long-term growth rate (%)		Half-life (H)		Short-term growth rate (%)		Required ROE for the equity market (%)		
Expert witness		**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Min**	**Max**	**Best estimate**
Dr. Cleary: single stage[324]	Canada	3.40	3.40	4.65	5.40					8.21[325]	8.98[326]	8.60
Dr. Cleary: multi-stage[327]	Canada	3.40	3.40	5.40	5.40	2	1	3.53	3.53	8.85[328]	8.92[329]	8.90
Dr. Cleary: overall[330]	Canada											8.75
Mr. Hevert: single stage[331]	Canada	3.64[332]	3.64	8.85[333]	8.85					12.65[334]	12.65	12.65
Mr. Hevert: single stage[335]	U.S.	2.37[336]	2.37	11.28[337]	11.28					13.78[338]	13.78	13.78
Dr. Booth: single stage[339]	Canada	3.26	3.26	5.20	5.83					8.63[340]	9.28[341]	8.50-9.50

270. Each of Dr. Cleary, Dr. Booth and Mr. Hevert provided single stage DCF ROE estimates for the overall equity market. Variations among the single-stage DCF ROE estimates of Dr. Cleary, Dr. Booth and Mr. Hevert were largely due to differences in assumed growth rates. Dr. Cleary used growth rates ranging from 4.65 to 5.40 per cent to estimate a market return between 8.21 and 8.98 per cent. Dr. Booth used growth rates ranging from 5.20 to 5.83 per cent to estimate a market return of 8.50 to 9.50 per cent and Mr. Hevert used a growth rate of approximately 8.85 per cent to arrive at his market return estimate of 12.65 per cent.

271. Dr. Booth used sustainable growth rates of 5.5 per cent and 5.83 per cent based on data going back to 1987, and an average long-term GDP growth forecast of 5.2 per cent based on the real Canadian growth rate from 1961 plus inflation, to estimate a fair return for the Canadian equity market. However, Dr. Booth argued that the simple application of the DCF model likely understated the market's fair return because, in his view, Canada "still has a couple of years of above average growth ahead." On this basis, Dr. Booth proposed an overall equity market ROE of 8.50 to 9.50 per cent.

324 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 45-46.
325 Calculated as follows: .034*(1+.0465) +.0465 = .0821 or 8.21 per cent.
326 Calculated as follows: .034*(1+.054) +.054 = .0898 or 8.98 per cent.
327 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 46-47.
328 Calculated as follows: .034*((1+.054)+2*(.0353-.054))+.054=.0885 or 8.85 per cent.
329 Calculated as follows: .034*((1+.054)+1*(.0353-.054))+.054=.0892 or 8.92 per cent.
330 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 47.
331 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 67.
332 Derived from Exhibit 20622-X0083, Sch1 p2-5 MRP TSX.
333 Derived from Exhibit 20622-X0083, Sch1 p2-5 MRP TSX.
334 Calculated as follows: .0364*(1+(.0885*.5)) +.0885 = .1265 or 12.65 per cent.
335 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 68.
336 Derived from Exhibit 20622-X0083, Sch1 p7-12 MRP S&P 500.
337 Derived from Exhibit 20622-X0083, Sch1 p7-12 MRP S&P 500.
338 Calculated as follows: .0237*(1+(.1128*.5)) +.1128 = .1378 or 13.78 per cent.
339 Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 68-69.
340 Calculated as follows: .0326*(1+.0520) +.0520 = .0863 or 8.63 per cent.
341 Calculated as follows: .0326*(1+.0583) +.0583 = .0928 or 9.28 per cent.

272. Dr. Cleary applied a single-stage model using a growth rate of 5.40 per cent based on historic GDP growth from 1962-2014 and the Bank of Canada inflation target and a dividend yield of 3.40 per cent. He also applied a single-stage model using a lower growth rate of 4.65 per cent, based on historic GDP growth since 1992 and the Bank of Canada inflation target. Based on his single stage models, Dr. Cleary provided a best estimate for the Canadian overall equity market ROE of 8.60 per cent.

273. Dr. Cleary also used an H-model version of a multi-stage DCF model to estimate the Canadian market ROE. For this analysis, Dr. Cleary first used a short-term growth estimate of 3.53 per cent for two years based on the consensus forecasts real GDP growth outlook for 2016 and corresponding inflation forecast, and a long-term growth rate estimate of 5.40 per cent, based on historic Canadian GDP growth from 1962-2014. Dr. Cleary then used the same short-term growth estimate of 3.53 per cent for four years, also with a long-term growth rate estimate of 5.40 per cent. This resulted in estimates of 8.92 and 8.85 per cent, respectively. From these analyses, he estimated the overall Canadian equity market ROE at 8.90 per cent. Combining the results from both his single stage and multi-stage models, Dr. Cleary arrived at a best estimate of 8.21 to 8.98 per cent for the overall Canadian equity market ROE and suggested that, at most, utility returns should be lower than 8.75 per cent.

274. Mr. Hevert estimated the market return of the S&P/TSX using a subset of 109 companies from the index for which the necessary data was available. For the growth component of the model, Mr. Hevert used a long-term earnings growth rates forecast sourced from Bloomberg for each of the respective companies.

275. The results were an expected total return of 12.65 per cent and 13.78 per cent for the S&P/TSX and S&P 500, respectively. Mr. Hevert argued that the results were consistent with the historical observed returns from 1926-2014.

276. Substantial argument was provided on the validity of using analyst earnings growth expectations as the growth rate component of the DCF model rather than other growth rate sources, such as historical growth rates or calculated sustainable growth rates. Analysts' forecasts of growth rates are forward-looking and aim to expressly account for events expected in the future. However, intervener experts argued these forecasts tend to incorporate a high degree of subjectivity and may be overly optimistic.[342] Alternatively, sustainable growth rate estimates are calculated objectively using historical data, but require an assumption of stability in the factors underlying their calculations on a go forward basis.[343]

277. Given these trade-offs, and considering that both methods are currently used to estimate the dividends and earnings growth component of the DCF model, consistent with the findings in the previous decision,[344] the Commission accepts the basic validity of both of these methods for the purpose of this decision.

278. Dr. Cleary was the only expert to use a multi-stage model to estimate the market return. Mr. Hevert critiqued Dr. Cleary's estimates as too conservative and Dr. Villadsen agreed, referencing a multi-stage Bloomberg model for the 2016 market return that uses analyst earnings

342 Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 81-82.
343 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 90.
344 Decision 2191-D01-2015, paragraph 180.

growth expectations and forward looking sustainable growth rates to generate a materially larger estimate.

279. The Commission observes that relative to the 2013 GCOC proceeding, both Dr. Booth and Dr. Cleary's DCF derived market return estimates increased. Using a single-stage DCF model, Dr. Booth estimated the expected market return to be 7.85 to 9.30 per cent in the 2013 GCOC proceeding.[345] In this proceeding, Dr. Booth estimated the expected market return to be 8.50 to 9.50 per cent. Using both single-stage and multi-stage DCF models, Dr. Cleary arrived at best estimates for the market return in the 2013 GCOC proceeding to be 8.31 per cent for 2013 and 8.34 per cent for 2014 and 2015.[346] In this proceeding, Dr. Cleary provided a market return best estimate of 8.75 per cent. Mr. Hevert's market return estimate was considerably more optimistic than those of Dr. Booth and Dr. Cleary, largely because he relied on a long-term earnings growth rate forecast sourced from Bloomberg.

280. In the 2013 GCOC decision, the Commission determined that a reasonable DCF-based estimate of the average ROE for the equity market was in the range of 8.0 to 9.0 per cent.[347] The evidence in this proceeding shows that the minimum forecast ROE for the equity market (Dr. Cleary's single-stage DCF model) is 8.21 per cent. The minimum recommended ROE estimate for the equity market was 8.50 per cent (the lower bound of Dr. Booth's recommended range). The Commission finds that this information is of assistance and directionally indicative of an increase in anticipated market returns.

6.4.2.2 Return on equity estimates for the utilities equity market based on discounted cash flow models

281. Turning to the utility estimates, Dr. Villadsen, Mr. Hevert, Dr. Booth and Dr. Cleary all applied DCF analyses to samples of utilities to inform their respective estimated ROE recommendations. However, the experts used different utility samples, different models and different methods for estimating variables such as growth, and they weighted their results differently in developing their estimates.

282. The ROE recommendations of the experts from their DCF models are included in Table 10.

345 Decision 2191-D01-2015, paragraph 166.
346 Decision 2191-D01-2015, paragraph 171.
347 Decision 2191-D01-2015, paragraph 184

Table 10. ROE recommendations of Dr. Villadsen, Mr. Hevert, Dr. Cleary and Dr. Booth based on DCF models

	ROE
Dr. Villadsen – without leverage	9.0 – 11.5
Mr. Hevert – Canadian utility proxy group[348]	12.99 – 14.38
Mr. Hevert – U.S. utility proxy group[349]	9.03 – 10.52
Dr. Cleary	8.04
Dr. Booth – U.S. utility proxy group	6.09 – 6.71[350]

283. Dr. Villadsen primarily relied on her multi-stage DCF analysis in which she estimated a range of ROEs from 9.0 to 11.5 per cent, after considering flotation costs and both with and without considering financial risk. Dr. Villadsen indicated that because she used short-term growth rates that converge to the long-term GDP growth estimates for the economy, her approach was consistent with the approach accepted by the Commission in its 2013 GCOC decision.[351] In Dr. Villadsen's model, utilities are expected to achieve 10 years of growth above the long-term GDP forecast in the short-term before reaching an assumed terminal period with a growth rate equivalent to forecast GDP. This approach was critiqued by Dr. Cleary, who commented that "ten years is not short term."[352]

284. Mr. Hevert applied a single-stage DCF model to Canadian and U.S. utility proxy groups, but did not give weight to his Canadian results because he considered them to be comparatively high compared to his U.S. utility proxy group results and overall market results. Using analyst earnings growth expectations of 4.92 to 5.68 per cent, Mr. Hevert estimated the average ROE for his U.S. utility sample to range from 8.60 to 10.02 per cent.

285. Similarly, Dr. Booth did not estimate ROEs for a Canadian utility proxy group. Instead, he estimated ROEs for U.S. utilities listed on the S&P 500, and for a sample of U.S. natural gas utilities, using a single-stage model. For his U.S. natural gas utility group, Dr. Booth used an analysts' growth rate forecast of 3.71 per cent, which had been adjusted downwards to account for optimism bias, and a sustainable growth rate estimate of 2.88 per cent. Dr. Booth estimated median ROEs of 6.71 and 6.09 per cent for his S&P 500 utility sample and U.S. natural gas utility sample, respectively, prior to considering flotation costs.

286. Dr. Cleary applied both a single stage and an H-model version of a multi-stage DCF model to three sub-samples of Canadian utility stocks. Weighting his constant growth and H-model results equally, Dr. Cleary suggested a required return in the range of 6.1 to 9.0 per cent and a best estimate of 8.04 per cent, inclusive of a flotation cost allowance.

348 Mr. Hevert's results as presented in his evidence did not include a flotation allowance. Dr. Villadsen's and Dr. Cleary's results do include 50 bps for flotation allowance. For comparison purposes, Mr. Hevert's results contained in the table include 50 bps for flotation allowance.

349 Mr. Hevert's results as presented in his evidence did not include a flotation allowance. Dr. Villadsen's and Dr. Cleary's results do include 50 bps for flotation allowance. For comparison purposes, Mr. Hevert's results contained in the table include 50 bps for flotation allowance.

350 Based on Dr. Booth's estimates using sustainable growth rates and analyst growth expectations, adjusted for optimisms of analyst forecasts. Dr. Booth noted that the U.S. DCF estimates would need a flotation cost addition, and further, that they reflected USD returns, rather than CAD returns.

351 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 58.

352 Transcript, Volume 10, page 1527.

287. As noted above, Mr. Hevert used a single-stage model with a growth rate based on analyst earnings growth expectations that exceeded the long-term estimates for nominal GDP growth. Consistent with its determinations in prior GCOC decisions,[353] the Commission will not accept, in a single-stage DCF model, the use of long-term or terminal growth rates that exceed estimates of the nominal long-term GDP growth rate for the economy. The Commission does, however, accept that the use of growth rates above the nominal long-term GDP growth for the economy in the initial stages of multi-stage DCF models may be reasonable in some circumstances.

288. Given the Commission's findings in Section 4 of this decision with respect to the outlook for economic growth, the Commission considers the utility earnings growth expectations used by Dr. Villadsen, in the first-stage of her multi-stage model, and by Mr. Hevert, in his single-stage model, are overly optimistic. In addition, the Commission finds that the combination of Dr. Villadsen's first stage growth rate and the combined duration of the first and second stages of her multi-stage model are biased upward.

6.5 Stock market return expectations of market professionals

289. As in the 2013 GCOC proceeding, in his evidence in this proceeding, Dr. Cleary considered market return expectations of investment professionals such as actuaries and research-institutes, as a means of confirming his ROE estimates. Dr. Cleary observed:

> If the overall market return expectations are in the 7% to 9% range, as the evidence supports, this implies that investors will be satisfied with return expectations below these numbers for low-risk regulated utilities. In other words, a reasonable required rate of return for utilities should be below the mid-point of the range of overall market expectations.[354]

290. Dr. Booth also relied on reports from market professionals. In support of his market return expectations, Dr. Booth referenced analysis from TD Economics, which estimated a 9.00 per cent average annual return,[355] and AON Hewitt, which estimated an 8.30 per cent average annual return. Dr. Booth testified that it was appropriate to use expected returns from reports such as these as a basis for an allowed ROE because they are the best estimates provided for external users and are circulated in the investment community.[356] While Dr. Booth noted that he had previously critiqued pension fund reports on the basis that they are conservative, he testified that his critique did not apply to the AON Hewitt report because it was a capital market report, not a pension report.[357]

291. Witnesses for the utilities critiqued the use of pension manager and actuary reports. Mr. Hevert testified that the projections in the reports are conservative estimates that do not reflect measures of investor-required returns on the market. Therefore, in his view, they are not applicable in the regulatory arena.[358]

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353 Decision 2191-D01-2015, paragraph 186; Decision 2011-474, paragraph 87; Decision 2009-216, paragraph 269.

354 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 32.

355 Based on the 7.00 per cent geometric mean plus an additional 2.00 per cent increase to convert to arithmetic mean as discussed by Dr. Booth in his testimony at Transcript, Volume 8, page 1250.

356 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 73.

357 Transcript, Volume 8, page 1248.

358 Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF page 32.

292. Dr. Villadsen voiced similar concerns with the potential conservatism of forecast return estimates for pension funds, stating that "it is imperative that any use of such forecasts is evaluated cautiously and be assigned limited weight."

293. Dr. Villadsen also raised specific issues with the AON Hewitt report referenced by Dr. Booth. She described the estimates in the report to be likely downward biased due to the reliance on forecast earnings instead of cash flow. Additionally, she observed that the purpose of the report is for portfolio application, which serves a different purpose than cost of equity estimation, and may be downward biased due to expectation management or actuarial conservatism.[359]

Commission findings

294. Dr. Booth and Dr. Cleary relied on a number of sources from various market participants to confirm their market estimates. Dr. Booth referenced reports from AON Hewitt (2016) and TD Economics (2012). Dr. Cleary referenced the same AON Hewitt report as well as a Financial Post article (2014) and reports from the Canadian Institute of Actuaries (2012), the U.S. Society of Actuaries (2012) and the C.D. Howe Institute (2013).

295. In regards to the 2016 AON Hewitt study, Dr. Villadsen and Mr. Hevert expressed concerns with the report being conservative along with broader concerns over the conservatism of pension funds. The Commission continues to agree with its stance disclosed in the 2013 GCOC decision that pension funds managers tend to be rather conservative.

296. In the 2013 GCOC decision, the Commission confirmed its view that return expectations of finance market professionals are germane to the determination of a fair ROE for regulated utilities.[360] The Commission continues to hold this view and agrees with Dr. Booth's assessment that these reports are informative, since these types of reports are circulated in the investment community, although they may be used for different reasons.[361] Therefore, the Commission will consider return expectations of finance market professionals in arriving at an allowed ROE value. The Commission is not indicating a preference for one type of report versus another. The reports and any potential perceived biases in those reports will be evaluated on their merits.

297. In this proceeding, the Commission has concerns with the potential suitability of the reports cited by the experts. Of the reports referenced, only one was published since the 2013 GCOC decision. The Commission agrees with Dr. Cleary that long-term expectations of the majority of the investment professionals play a role in determining overall market expectations.[362] However, it is unclear to the Commission if the referenced reports and articles on the record, published in the 2012-2014 period, reflect the current expectations of investment professionals, in light of the capital market conditions discussed in Section 4. Therefore, the Commission finds that with the exception of the 2016 AON Hewitt report, the evidence on the record does not support an ROE range that can be reasonably estimated based on finance market professionals' expectations. Accordingly, in this decision, little weight will be given to the finance market professionals' return expectations for the Canadian market in determining an allowed ROE value. With regards to the 2016 AON Hewitt report, the Commission finds there

359 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF pages 64-65.
360 Decision 2191-D01-2015.
361 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 76.
362 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 32.

may be value in the report despite the criticisms. Therefore, the report's findings were considered in Section 6.4 with Dr. Cleary's and Dr. Booth's market return expectations.

6.6 Other considerations in establishing a fair allowed return on equity

298. In her evidence, Dr. Villadsen testified that it is important to recognize what ROEs utilities have recently been granted in other jurisdictions because investors compare returns across jurisdictions. As such, she presented information on the allowed ROE and capital structure for other Canadian and U.S. utilities for 2014 and 2015. Additionally, Dr. Villadsen noted allowed ROEs of 10.57 and 10.32 per cent recently awarded in a couple of rate cases in the U.S.[363]

299. Based on the information she provided regarding ROEs and capital structures approved for natural gas and electricity utilities in other parts of Canada and the U.S., Dr. Villadsen submitted it is clear that they are substantially higher than the 8.3 per cent ROE approved in the 2013 GCOC decision. She added that the approved average ROEs for the other areas of Canada (excluding crown corporations) were about 9.4 per cent in 2014 and 2015 and the deemed equity ratio averaged about 40 per cent for both years. She noted that there is no apparent difference between the allowed ROE for fully litigated cases and those arrived at by negotiations, which was a concern raised by the Commission in previous GCOC decisions.[364]

300. Mr. Hevert and Dr. Cleary presented evidence on the relevance of market P/B values in assessing the cost of equity. They reached opposite conclusions. Specifically, Mr. Hevert contended that the market P/B values have little informational value and are not linked to the relationship between ROE and shareholder return requirements. Consistent with this view, Mr. Hevert also examined the P/B ratio associated with the purchase of AltaLink by Berkshire Hathaway Energy Co. (considered by the Commission in the 2013 GCOC decision and in the review and variance Decision 20456-D01-2016).[365] Based on his analysis, Mr. Hevert could not agree that the P/B value associated with that single transaction was "firmly supporting" the Commission's conclusions regarding an ROE ceiling.[366] In contrast to Mr. Hevert's view, Dr. Cleary concluded that the market P/B values are relevant when considering the value for a fair ROE and indicate that "Canadian utilities appear to be earning a satisfactory (or more than a satisfactory) ROE, and have done so for quite some time."[367]

Commission findings

301. As the UCA pointed out, the Commission has previously considered the issue of using returns awarded by other U.S. and Canadian regulators as indicators of a market-required return and concluded in the 2009 GCOC decision that the better approach is to examine the evidence of experts in a GCOC proceeding on required returns estimated using methods founded on sound

363 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF pages 65-66.
364 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF pages 65-66.
365 Decision 20456-D01-2016: AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd. ATCO Gas and Pipelines Ltd., ENMAX Power Corporation, EPCOR Distribution and Transmission Inc., and FortisAlberta Inc., Decision on Preliminary Question: Application for review and variance of Decision 2191-D01-2015: 2013 Generic Cost of Capital, Proceeding 20456, January 18, 2016.
366 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 92-100.
367 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 64.

principles of finance and, particularly, because the awards by other regulators were established on the basis of a different record.[368]

302. The Commission has also previously considered the use of U.S. awarded returns for regulated utilities and market returns for these utilities in the 2009 GCOC decision. In that decision, the Commission determined that although returns awarded by U.S. regulators cannot be used directly in determining a fair return for Alberta utilities, it is reasonable to rely on the U.S. market returns data given the globalization of the world economy and an integration of North American capital markets. Specifically, the Commission stated:

> 200. The Commission considers that it must make a distinction between utility returns awarded by U.S. regulators and expected market based returns for U.S. utilities when considering the use of U.S. data in determining a fair return for Alberta utilities. Allowed returns, including both ROE and capital structure, are determined by a regulator after considering a number of factors including relevant overall factors like the applicable legislation and case law and individual factors that are specific to the utility, like the business risk of the utility. Also as noted above, the capital structure for U.S. utilities is frequently determined by management within a range acceptable to the regulator. The Commission has determined that returns awarded by U.S. regulators cannot be directly used in determining a fair return for Alberta utilities for the reasons provided above. Properly determined, however, expected market based returns in respect of a particular industry segment are a present reflection of the future return expectations of prospective investors given the perceived risk of that industry segment and the economy as a whole….[369]

303. The Commission finds that the material presented by Dr. Villadsen in Figure 21 of her evidence[370] simply lists the allowed ROEs and common equity ratios for a sample of U.S. and Canadian utilities. This information does not permit the Commission to address the deficiencies identified in the 2009 GCOC Decision such as applicable legislations and case law, and individual factors specific to the utility, like the business risk of the utility.

304. When specifically comparing allowed ROEs and equity ratios between the U.S. and Alberta, the Commission is aware, for example, that the risk-free rates in Canada and the U.S. are different. In addition, the regulatory structure in the U.S., where the ROE and capital structures are determined retroactively, differs from the regulatory structure in Alberta, where the ROE and capital structures are determined on a prospective basis.

305. With respect to the relevance of P/B values, the Commission notes that the experts disagreed on the merits of using P/B values in assessing the cost of equity. The Commission further notes that no new transactions affecting Alberta utilities were cited in evidence since the 2013 GCOC proceeding for the Commission to consider. Therefore, the Commission has not given any material weight to P/B evidence in this proceeding.

6.7 Overall recommendations and the allowed return on equity for 2016 and 2017

306. The ROEs proposed by the parties are included in Table 11.

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368 Decision 2009-216, paragraphs 283 and 284.
369 Decision 2009-216, paragraph 200.
370 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 65.

Table 11. Summary of ROE recommendations

	Recommended by AltaLink/EPCOR[371] (Mr. Hevert)	Recommended by the Utilities[372] (Dr. Villadsen)	Recommended by the UCA[373] (Dr. Cleary)	Recommended by CAPP[374] (Dr. Booth)
	(%)			
2016	9.00 – 10.50	10.25	7.00	7.50
2017	9.00 – 10.50	10.25	7.00	7.50

307. AltaLink and EPCOR recommended an ROE in the range of 9.0 to 10.5 per cent, based on the expert evidence of Mr. Hevert. Mr. Hevert arrived at his recommended ROE range of 9.0 to 10.5 per cent, giving primary weight to his Canadian proxy group and his CAPM and risk premium model results.[375] Mr. Hevert noted his recommendation takes into consideration observable measures of investors' risk sentiments as well as current and expected capital market conditions in Canada and the U.S.

308. Mr. Hevert placed the least amount of weight on his DCF-based ROE estimates compared to his other estimates.[376] Mr. Hevert found that his DCF based estimates were relatively high compared to other metrics, including estimates of the overall market return.[377]

309. Dr. Villadsen, on behalf of the Utilities, recommended an allowed ROE in the range of 10.00 to 10.50 per cent, with 10.25 per cent as a reasonable point estimate.[378] Dr. Villadsen stated that this value was within the range of her three samples' estimates and supported by her Canadian utility sample before any consideration of financial risk. Dr. Villadsen testified that it was important to consider the ROE estimates using multiple models given the current market conditions.[379] Accordingly, Dr. Villadsen used DCF estimates, along with CAPM and risk premium estimates, to develop a range of reasonable ROE estimates.[380] Given the current challenges with the CAPM model, Dr. Villadsen placed a bit more emphasis on DCF.[381] Dr. Villadsen also noted that her recommendation fell into the upper half of her reasonable ROE range based on Mr. Buttke's views on current and expected capital market conditions, along with her own study of the required MERP in Canada being elevated relevant to historical levels.[382]

310. Dr. Booth, on behalf of CAPP, recommended an ROE of 7.50 per cent based on his risk premium and DCF estimates, concerns about economic interest rate forecasts and application of the "operation twist" adjustment.[383] This ROE recommendation was the same as his ROE recommendation in the 2013 GCOC proceeding. Dr. Booth noted that although there is objective evidence of a decline in interest rates since 2014, the long-term GOC bond yield has yet to hit

371 Transcript, Volume 11, page 1770 and page 1792.
372 Transcript, Volume 11, page 1829.
373 Transcript, Volume 12, page 2136.
374 Transcript, Volume 12, page 1989 and page 2030.
375 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 159.
376 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 92.
377 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 126.
378 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 84.
379 Transcript, Volume 7, page 1001.
380 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 83.
381 Transcript, Volume 7, page 1003.
382 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 83.
383 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 90.

the 3.80-4.00 per cent range, which he regarded as the minimum "average" yield for this stage of the business cycle.[384]

311. Dr. Booth indicated he generally places more weight on CAPM, using DCF and other methods as checks on his results, but this is not possible at the current point in time due to abnormally low real interest rates. Therefore, he indicated that he implicitly gave more weight to his DCF and other methods.[385] In discussing CAPM and DCF, Dr. Booth stated "[b]ut the DCF models, in my judgement, are giving higher estimates at the moment because they're right."[386]

312. Dr. Cleary, for the UCA, recommended an ROE of 7.0 per cent. In making this recommendation, he gave equal weight to his CAPM, DCF and BYPRPM estimates. He explained that he would normally rely more heavily on CAPM estimates due to CAPM's conceptual advantages. However, due to lower than typical CAPM estimates, he gave all three of his estimation methods equal weight. Dr. Cleary noted that although he gave equal weight to his DCF results, CAPM and BYPRPM are both more widely used than the DCF[387] models. To support this claim, Dr. Cleary cited studies stating that only 15 and 12 per cent of U.S. and Canadian chief financial officers, respectively, use DCF approaches.[388] Dr. Cleary noted that his results were reasonable compared to expected long-term market returns in the 7.0 to 9.0 per cent range, and the low-risk nature of regulated utilities.[389]

313. The CCA did not put forward an ROE recommendation. Rather, the CCA urged the Commission to make a "principle[d] decision" that would reduce the ROE.[390] In support of its position, the CCA pointed to historical data with respect to beta and MERP and noted that the utilities have continuously achieved ROEs higher than allowed returns since 2006.[391]

314. For the purposes of determining ROE in this decision, the Commission's point of departure is the allowed ROE established in the 2013 GCOC decision. From this starting point, the Commission has evaluated the evidence and argument in this proceeding to determine whether changes in the allowed ROE from the 2013 GCOC decision are warranted. To that end, the Commission generally considered the directional effect of elements of the evidence and argument in this proceeding on the allowed ROE from the 2013 GCOC decision.

315. The Commission's findings from the 2013 GCOC decision with respect to the allowed ROE are set out in Table 12 and explained in the subsequent paragraph.

[384] Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 90.
[385] Exhibit 20622-X0396, response to CAPP-AUC-2016APR12-006, PDF page 15.
[386] Transcript, Volume 7, page 1087.
[387] Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 64-65.
[388] Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 65.
[389] Exhibit 20622-X0306, evidence of Dr. Cleary, PDF pages 65-66.
[390] Transcript, Volume 12, page 2082.
[391] Transcript, Volume 12, page 2046.

Table 12. 2013 GCOC decision: Commission's CAPM, DCF and allowed ROE findings[392]

Risk-free rate	MERP	Beta	Flotation allowance	CAPM ROE	DCF ROE	Market professional ROE	Commission allowed ROE
(%)							
2.80 - 3.70	5.00 – 7.00	0.50 – 0.65	0.50	5.80 – 8.75	7.50 – 9.00	9.00	8.30

316. In addition, the Commission considered a number of other factors in the determination of the allowed ROE for 2013, 2014 and 2015. The Commission, in regard to some of the other factors:

(a) found that the risks in the financial markets observed since the 2011 GCOC proceeding had moderated and market conditions may not have been reflective of a typical risk-return relationship on which risk-premium models are based;[393]

(b) found the implied P/B ratio associated with the proposed purchase of AltaLink by Berkshire Hathaway Energy Co. was relevant and supported continuation of an ROE no higher than the Commission's allowed ROE of 8.75 per cent;[394]

(c) did not place significant weight on the BYPRPM test given the ample evidence of CAPM-based ROE estimates;[395]

(d) found that no adjustment was warranted to account for the application of the principles identified in Decision 2013-417[396] (Utility Asset Disposition (UAD) decision;[397]

(e) was not persuaded that the transition to performance-based regulation (PBR) for electric and gas distribution utilities had resulted in a change in risk profile that warranted any adjustments to the approved ROE, capital structure, or both;[398]

(f) found that the regulatory environment was not substantially less supportive than it was at the time of the 2011 GCOC proceeding, due to a number of factors.[399]

317. As noted above and in Section 6.1, the Commission has placed less weight on the parties' CAPM estimates of ROE in this proceeding compared to the parties' CAPM estimates of ROE in the 2013 GCOC proceeding, largely due to the Commission's finding that it could not identify, with any reasonable degree of confidence, a method that allows the Commission to narrow the range of betas recommended by the experts in this proceeding. Accordingly, the Commission has relied more heavily on other evidence that provides directional guidance with respect to changes in the expected utility equity returns, relative to the ROE determined in the 2013 GCOC decision.

392 Decision 2191-D01-2015, Table 2; paragraph 192; paragraph 239.
393 Decision 2191-D01-2015, paragraph 51.
394 Decision 2191-D01-2015, paragraph 223.
395 Decision 2191-D01-2015, paragraph 262.
396 Decision 2013-417: Utility Asset Disposition, Proceeding 20, Application 1566373-1, November 26, 2013.
397 Decision 2191-D01-2015, paragraph 351.
398 Decision 2191-D01-2015, paragraph 380.
399 Decision 2191-D01-2015, paragraph 398.

318. In this proceeding, the Commission was presented with evidence that both corporate credit spreads and utility credit spreads had widened since the 2013 GCOC proceeding. Specifically, utility credit spreads had widened by some 200 bps by early 2016.

319. The Commission examined credit spreads as a potential indicator of the required returns of equity investors because, as proposed by Mr. Hevert, equity investors are the residual claimants, and any expansion or change in credit spreads is a directional measure of a change in the cost of equity. To this point, Mr. Hevert argued that there is a related increase in expected return by utility equity investors, stating that:

> To the extent that we see an expansion of spreads or an expansion in the volatility of spreads, I think we can conclude that from the equity investors' perspective, because they do not have those same levels of protections because they are the residual claimant, they're last in line for cash flow; that any expansion or change that we see in credit spreads is a directional measure of the change in the cost of equity, but the change in the cost of equity could be more so.[400]

320. Similarly, in his written evidence Mr. Hevert stated:

> … although credit spreads are a general measure of risk perceptions, they are not a full measure of equity risk. Nonetheless, as a measure of directional change, there is little question that credit spreads have increased, suggesting some measure of increased risk perceptions among Canadian utility investors.[401]

321. The issue before the Commission with respect to this evidence is whether the widening of utility credit spreads provides evidence that there is a related increase in equity investors' required returns.

322. In order to conclude that the widening of utility credit spreads is indicative of a related increase in investors required returns, the Commission must determine whether the widening of utility credit spreads are a result of an increase in perceived risk on the part of utility bond investors. Experts advanced three possible explanations for the expansion in utility credit spreads.

323. Dr. Cleary and Dr. Villadsen attributed at least some of the higher credit spreads to slightly heightened risk aversion. Dr. Villadsen stated that "investors have been dramatically affected by the credit crisis and ongoing market volatility, so there are reasons to believe that their risk aversion remains elevated relative to pre-crisis periods."[402] Dr. Cleary pointed out that despite not being at the record highs experienced during the financial crisis, current credit spreads are still indicative of slightly heightened risk aversion.

324. Mr. Hevert noted that, consistent with the view that credit spreads are a barometer of business risk, credit spreads have moved somewhat in tandem with the VIXC. Recognizing that they may not be a full measure of equity risk, Mr. Hevert nonetheless concluded that "there is

400 Transcript, Volume 1, page 73.
401 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 42-43.
402 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 32.

little question that the increase in spreads suggests some measure of increased risk perception among Canadian utility investors."[403]

325. When answering the question "does this higher spread indicate increased risk for corporate bonds or increased risk aversion in Canada?" Dr. Booth responded "No."[404] He argued that higher credit spreads do not necessarily indicate increased risk for corporate bonds or increased risk aversion in Canada. Rather, the influx of foreign capital into the GOC segment of the Canadian bond market has pushed up prices, depressing yields and increasing spreads.[405] This would imply that there may be no increased risk for corporate credit investors. Dr. Booth went on to state "currently the market seems to be valuing similarly rated utility and non-utility A-rated debt the same."[406]

326. In addition to risk aversion and increased risk perceptions as possible reasons for the widening of credit spreads, Dr. Villadsen and Dr. Cleary provided evidence which supports Dr. Booth's view regarding the impact of monetary policy on credit spreads.[407]

327. In the Commission's view, there is no clear and objective measure on the record by which the Commission can determine which factor or factors explain the increased utility credit spreads, and accordingly it could be the result of a combination of factors. If there is no clear method to determine the cause for the increase in utility credit spreads, then the Commission cannot conclude that the widening of utility credit spreads indicates increased risk perceptions among Canadian utility bond investors and by extension, Canadian utility equity investors. Equally, the Commission cannot conclude that the widening of utility credit spreads does not indicate, at least in part, increased risk perceptions among utility bond and equity investors.

328. Given that there is insufficient evidence on the record of the proceeding to make a definitive finding that the increase in utility bond spreads is due to an increased risk perception or risk aversion on the behalf on utility bondholders, the Commission relies on corroborating evidence for the experts' proposed reasons for the widening utility credit spreads.

329. Dr. Cleary provided evidence that:

> Researchers at the Bank of Canada indicate that much of this increased spread is due to liquidity problems, but some still reflects increased risk premiums for even low risk companies like Canadian Utilities.[408]

330. Mr. Hevert and Dr. Villadsen provided evidence on the investor expectations of heightened market volatility, with reference to a number of market indicators. Dr. Villadsen observed that investors expect a higher risk premium during more volatile periods, even when investor risk aversion remains unchanged.[409] The evidence in Section 4 is that market volatility is higher today than at the time of the 2013 GCOC proceeding and the period leading up to that proceeding. The Commission notes that Mr. Hevert provided evidence that "credit spreads (as

[403] Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 42-43.
[404] Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 31.
[405] Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 31-32.
[406] Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 33.
[407] Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 22; Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 42.
[408] Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 42.
[409] Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 24.

measured by the broad Canadian A-Rated Utility Index) have moved somewhat in tandem with the VIXC."[410] Therefore, the Commission finds on the basis of this evidence that recent instability in estimators of investor perceptions of near-term market uncertainty, including the VIX and the VIXC, supports the views of Dr. Villadsen and Mr. Hevert that the increased utility credit spreads are explained, at least partially, by increased investor perceptions of risk.

331. The Commission notes the evidence of Dr. Cleary that "since stocks are riskier than bonds, we know that investors will require a higher return to invest in a firm's stocks than its bonds. The riskier the company, the greater the difference between these required returns (i.e., the greater the risk premium)."[411] It is a fundamental tenant of finance that if bond holders are compensated for increased risk then in turn, equity holders must also be compensated to bear additional risk.

332. Given the evidence that the increase in utility bond spreads is due, at least in part, to a perception of increased risk facing utility bond holders, and given that equity holders must also be compensated to bear that risk, the Commission concludes from the above findings that an increase in ROE is warranted in the 2016-2017 period. However, there remains uncertainty with respect to the timing and magnitude of the increase.

333. With respect to 2016, the Commission notes that the evidence in the proceeding has indicated that A-rated long term Canada bond yields have fallen since the last GCOC proceeding. This suggests that the risk free interest rate has fallen in Canada since the time of the last GCOC proceeding. When the Commission established the 8.3 per cent allowed ROE for 2013-2015, there was an assumed underlying relationship between the return required by utility equity investors and the risk-free rate, which was captured in the CAPM analysis in that proceeding. In this proceeding, the Commission has placed less weight on the underlying relationship between the return required by utility equity investors and the risk-free rate and more weight on the relationship between return required by utility bond holders and the. return required by equity investors.

334. The Commission notes that none of the parties have suggested that the implied relationship between the return required by utility bond holders and the return required by utility equity investors has changed since the last GCOC proceeding. The Commission agrees with Mr. Hevert when he states that "… although credit spreads are a general measure of risk perceptions, they are not a full measure of equity risk..." and considers it reasonable that the expected return on equity for utility investors is directionally related to the yield on utility bonds. Because the yields on utility bonds are lower now than they were during the time of the prior GCOC proceeding, due in part to lower rates of inflation and foreign investors pursuing, in Dr. Booth's words, a "walk to safety," the Commission considers that this evidence suggests that there is now downward pressure on the return required by equity holders, everything else equal.

335. However, given the Commissions finding above that utility bond holders are now facing more risk compared to what they were facing in the prior GCOC proceeding, as evidenced by the increase in utility credit spreads, and given the implied relationship between utility bond holders and equity investors, the Commission considers there is also upward pressure on the return required by utility equity holders, everything else equal.

410 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 42.
411 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 57.

336. Based on the fact that factors are occurring simultaneously, the Commission finds it is reasonable to consider these two effects to be offsetting. This finding comports with the evidence in Figure 5, which sets out the historic VIX and VIXC levels. Figure 5 demonstrates that, although market volatility in 2016 is greater than during the 2013-2015 period, market volatility has not reached the levels seen during 2008-2012 period, which was influenced by the great financial crisis. Therefore, although there is upward pressure on the required return of utility equity investors, there is insufficient evidence to conclude that the increase in required return is not offset by the effect on equity investors related to declining utility bond yields. As a result, it is the judgment of the Commission that a fair generic return on equity for the affected utilities is 8.30 per cent for 2016.

337. Based on the evidence in Section 4, which supports a finding that economic conditions are generally expected to improve in 2017, including an expected increase in interest rates, the Commission finds it reasonable that utility bond yields also will follow this trend. Therefore, the Commission finds that an increase in allowed return on equity is warranted for 2017.

338. Turning to the question of the magnitude of the increase in allowed ROE for 2017, having considered the expected growth in GDP by 2017 and the moderate forecast increase in interest rates, coupled with the Commission's finding that the DCF estimates for the utility market proffered by Dr. Villadsen and Mr. Hevert were overly optimistic and upwardly biased, and the Commission's finding that the risk premium component of Dr. Cleary's BYPRPM may need to be higher than he proposed, it is the judgment of the Commission that on balance, an increase in ROE for 2017 to 8.50 per cent, is reasonable.

339. The allowed ROE for 2017 of 8.50 per cent awarded in this decision will remain in place on an interim basis for 2018 and for subsequent years until changed by the Commission.

7 Capital structure matters

7.1 Overview

340. To satisfy the fair return standard, the Commission is required to determine deemed equity ratios (also referred to as capital structure) for each of the affected utilities. In this decision, the Commission has established an allowed ROE of 8.3 per cent for 2016 and 8.5 per cent for 2017 for all of the affected utilities on a final basis, with the exception of ATCO Electric Transmission, as explained in Section 8. The deemed equity ratio multiplied by debt and equity funded rate base and further multiplied by the allowed ROE must result in an overall fair return for equity investors. The Commission has adopted the approach of adjusting for differences in risk among each of the affected utilities by adjusting the deemed equity ratios. The Commission will make adjustments if required, to recognize changes in relative risk for each affected utility from the approved deemed equity ratios established in the 2013 GCOC decision.

341. This section of the decision determines the allowed deemed percentage of rate base (net of no-cost capital) supported by common equity as opposed to debt. Consistent with previous GCOC decisions, where preferred share capital is present, it has been considered by the Commission to be a substitute for a portion of the debt component of the capital structure. Whether or not a utility should use preferred shares in place of some of its debt is outside the scope of the present proceeding.

342. As noted in the 2009 GCOC decision, the 2011 GCOC decision and the 2013 GCOC decision, the return on investment-grade debt required by investors is lower than the return required on equity.[412] 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 the capital structure increases, everything else equal, a greater portion of the earnings from the operations of the firm are required to cover the increased interest costs on debt. Therefore, as the proportion of debt in the capital structure rises, everything else equal, both debt and equity investors will perceive an increase in risk. This is because if debt levels increase, debt holders will be more concerned that the debt obligations of the firm may not be met, and equity investors will be more concerned that there will be insufficient earnings from operations to cover both the debt obligations of the firm and to provide them with their expected return.

343. The risk to debt investors is 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 S&P and DBRS Limited (DBRS), assess the creditworthiness of individual firms[413] on the basis of, amongst other factors, various credit metrics.

344. Debt investors rely greatly, but not exclusively, on credit ratings. Indeed, ultimately the debt investors themselves assess the risk of investing in various debt instruments. The consensus judgment of debt investors is reflected in the credit spreads observed in the primary and secondary debt markets for individual debt issues and issuers, including utilities.

345. In establishing an approved deemed equity ratio for each affected utility, the Commission will review the factors it has historically reviewed in determining these figures. Among these factors are changes since the 2013 GCOC proceeding in general and company specific business risk (including supply risk, demand (or market) risk, competitive risk, operating risk and regulatory risk), credit metrics and market analysts' reports, actual debt issuances and other relevant factors like P/B ratios. The objective of this analysis, consistent with past decisions, is to ensure that a deemed equity ratio is established for each affected utility (with the possible exception of Lethbridge, Red Deer and TransAlta), that when combined with the allowed ROE established in this decision, will achieve target credit ratings in the A-range when assessed on a stand-alone basis.[414] In previous GCOC decisions, the Commission has recognized the importance of maintaining a credit rating in the A category for the affected utilities, which facilitates debt financing at optimal rates.

346. In performing its analysis, the Commission will first review the deemed equity ratio recommendations of each party in this proceeding. Next, it will review the evidence in respect of the credit metrics currently observed in the bond market as noted by credit rating agencies and market analysts in Canada, required by a typical pure-play regulated utility in order to maintain an A-range credit rating. The Commission will then evaluate, the credit metrics of the transmission utilities included in the affected utilities and the credit metrics of the distribution

[412] Decision 2009-216, paragraph 333; Decision 2011-474, paragraph 170; Decision 2191-D01-2015, paragraph 418.
[413] Exhibit 20622-X0109, PDF page 165.
[414] Decision 2009-216, paragraph 334; Decision 2011-474, paragraph 172; Decision 2191-D01-2015, paragraph 420.

utilities included in the affected utilities, based on the following significant financial parameters observed in Rule 005[415] filings and other evidence on the record of this proceeding: the embedded average debt rate, depreciation as a percentage of invested capital, income tax rate and the mid-year construction work in progress (CWIP) as a percentage of invested capital. Next, the Commission will review the evidence with respect to changes in risk impacting all the affected utilities since the 2013 GCOC proceeding. If required, the Commission will adjust the deemed equity ratios for all the affected utilities based on this generic business risk analysis. Finally, the Commission will consider the evidence in respect of the unique business risk of individual utilities and consider whether a further adjustment to the deemed equity ratios of any of these individual utilities is required to reflect a change in business risk since the 2013 GCOC proceeding.

7.2 Deemed equity ratios requested

347. Table 13 sets out the deemed equity ratios that were approved by the Commission in the 2013 GCOC decision and the deemed equity ratios recommended by the affected utilities and interveners in this proceeding.

[415] Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

Table 13. Deemed equity ratios approved in the 2013 GCOC decision and the deemed equity ratios recommended in this proceeding

	Last approved[416]	Recommended by the Utilities[417] Dr. Villadsen	Recommended by AltaLink/EPCOR[418] Mr. Hevert	Recommended by the UCA[419] Mr. Stauft	Recommended by CAPP[420] Dr. Booth	Recommended by Calgary[421] Dr. Booth
	(%)					
Transmission						
ATCO Electric Transmission	36	38		35		
AltaLink	36		40	35		
ENMAX Transmission	36	38		35		
EPCOR Transmission	36		38	35		
ATCO Pipelines	37	39		35	35	
Red Deer	36					
Lethbridge	36					
TransAlta	36					
Distribution						
ATCO Electric Distribution	38	40		37		
ENMAX Distribution	40	42		37		
EPCOR Distribution	40		42	37		
ATCO Gas	38	40		37		35
FortisAlberta	40	42		37		
AltaGas	42	44		41		

348. On behalf of the Utilities, Dr. Villadsen derived her recommended benchmark deemed equity ratio of 40 per cent from a three step analysis. First, she looked at the guidelines of the credit rating agencies as indicative of the criteria that the Utilities must meet to be A-range rated. Second, Dr. Villadsen considered the historical credit metrics of A-range rated Canadian utilities and investment grade U.S. utilities.[422] Finally, she forecast certain input parameters such as income tax rate, embedded average debt rate, depreciation rate and CWIP as a percentage of rate base, to derive a recommended benchmark equity ratio for the Utilities.

349. In making her final deemed equity ratio recommendations for the Utilities, Dr. Villadsen also considered the potential risks facing the affected utilities, as discussed by Dr. Carpenter and Mr. Buttke, and determined that the financial markets are more volatile than in the recent past.[423] In her view, this implied a deemed equity ratio that results in credit metrics closer to the middle rather than the low end of the benchmark range for credit metrics used by credit rating agencies.[424] Dr. Villadsen recommended that the Commission move to a base deemed equity ratio

416 Decision 2191-D01-2015, Table 10, paragraph 495.
417 Exhibit 20622-X0104, evidence of Dr. Villadsen, Figure 30, PDF page 85. Transcript, Volume 11, page 1829.
418 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 159. Transcript, Volume 11, page 1792.
419 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 5. Transcript, Volume 12, page 2132.
420 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 4. Transcript, Volume 12, page 2024.
421 Exhibit 20622-X0344, evidence of Mr. Johnson, PDF page 2. Exhibit 20622-X0345, evidence of Dr. Booth, PDF page 2. Transcript, Volume 12, page 1980.
422 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 70.
423 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 6.
424 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 5.

of 40 per cent for an average risk utility.[425] Noting that this base deemed equity ratio is 200 bps higher than the 38 per cent deemed equity ratio for an average risk utility approved in the 2013 GCOC decision, Dr. Villadsen recommended that the deemed equity ratio for each of the entities[426] comprising the Utilities be increased by 200 bps.[427]

350. Compared to the deemed equity ratios approved in the 2013 GCOC decision, Mr. Hevert, on behalf of AltaLink and EPCOR, recommended an increase of 400 bps for AltaLink and a 200 bps increase for both EPCOR Transmission and EPCOR Distribution. The 400 bps increase for AltaLink is composed of a 200 bps increase for non-taxability and a 200 bps increase for increased capital market and regulatory risks. The 200 bps increase for EPCOR Transmission and EPCOR Distribution is for increased capital market and regulatory risks. Mr. Hevert stated that the resulting 40 per cent deemed equity ratio for AltaLink would partially mitigate the risk of AltaLink's funds from operations (FFO)/debt ratio falling below 13 per cent.[428]

351. On behalf of CAPP and Calgary, Dr. Booth recommended a deemed equity ratio of 35 per cent for ATCO Pipelines[429] and ATCO Gas,[430] respectively. This was the same figure he recommended for ATCO Pipelines in the 2013 GCOC proceeding. Mr. Johnson concurred with Dr. Booth's recommended 35 per cent deemed equity ratio for ATCO Gas on the basis that the business risk for ATCO Gas is at the low end of the scale for natural gas and electric distribution utilities in Canada.[431]

352. Dr. Cleary recommended an overall decrease of 100 bps to the deemed equity ratios approved in the 2013 GCOC decision.[432] His recommendation was based on several factors. He testified that economic and capital market conditions are normalizing and, therefore, are far removed from the conditions that existed in 2009, when the Commission increased all of the affected utilities' deemed equity ratios by two per cent. He further noted that the affected utilities currently benefit from very low interest rates and, therefore, even lower costs for long-term borrowing, than during the 2013 GCOC proceeding.

353. In Mr. Stauft's opinion, an appropriate deemed equity ratio for an average risk utility is 37 per cent. He stated that at this level, the credit metrics for the average risk utility can be expected to be very strong relative to the standards traditionally applied by the Commission and S&P.[433] With respect to distribution utilities specifically, Mr. Stauft pointed to various factors to suggest that the currently approved 38 per cent deemed equity ratio for an average risk distribution utility is higher than necessary. He recommended a deemed equity ratio of 37 per cent be applied to all distribution utilities except AltaGas, which should be four per cent more at 41 per cent. Mr. Stauft explained his reasoning as follows:

> AltaGas has historically been given a 4% equity ratio premium over the large distributors, basically on the ground that it has more business risk. Dr. Cleary's EBIT [earnings before

425 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 77.
426 ATCO Electric Transmission, ATCO Electric Distribution, ATCO Gas, ATCO Pipelines, AltaGas, ENMAX Transmission, ENMAX Distribution, FortisAlberta.
427 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF pages 84-85.
428 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 149.
429 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 4.
430 Exhibit 20622-X0345, evidence of Dr. Booth, PDF page 2.
431 Exhibit 20622-X0344, evidence of Mr. Johnson, PDF page 2.
432 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 6.
433 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 69.

> interest and income taxes] variability analysis tends to confirm that, and I have no basis for saying that AltaGas's risk relative to the larger utilities has declined or that the traditional 4% premium is inappropriate.[434]

354. Using his recommended spread of 200 bps between the deemed equity ratios for transmission utilities and distribution utilities, Mr. Stauft submitted that the deemed equity ratio for all the transmission utilities, including ATCO Pipelines, be 35 per cent.[435]

7.3 Credit ratings and credit metric analysis

7.3.1 Financial ratios, capital structure and actual credit ratings

355. 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 debt principal, allowing the company to borrow at a lower interest rate.

356. Credit metrics (or financial ratios) are an important, although not the only, component that credit rating agencies consider when assessing the risk of any particular company and assigning a credit rating. As noted in the 2009 GCOC decision, the Commission has historically assessed three principal credit metrics:[436]

- EBIT coverage: This is referred to as an interest coverage ratio. In the Commission's credit metric model, it is calculated by grossing up the net income by the statutory income tax rate, adding the return on debt amount, and dividing the resulting figure by the sum of the return on debt amount and the interest on the CWIP balance, calculated using the deemed debt ratio and the embedded average debt rate.

- FFO coverage: This is also an interest coverage ratio. In the Commission's credit metric model, it is calculated by adding the return on debt amount, the net income and the depreciation collected and dividing the resulting figure by the sum of the return on debt amount and the interest on the CWIP balance, calculated using the deemed debt ratio and the embedded average debt rate. It is important to note that in the Commission's credit model, the interest expense associated with the CWIP balance is not included in the numerator because it is based on the assumption that there is no CWIP included in rate base.

- FFO/debt: S&P compares this payback ratio against benchmarks to derive the preliminary cash flow/leverage assessment for a company. S&P notes that this ratio is also useful in determining the relative ranking of the financial risk of companies.[437] In the Commission's credit metric model, it is calculated by adding the net income and the depreciation collected and dividing the resulting figure by the sum of the deemed mid-year debt for rate base and CWIP.

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[434] Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 63.
[435] Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 69.
[436] Decision 2009-216, paragraph 345.
[437] Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 736.

357. In the 2009 GCOC decision, the Commission observed the following minimum credit metrics to be associated with regulated utilities with an A-range credit rating:[438]

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

358. In the 2011 GCOC decision, the Commission noted that the position of the affected utilities with respect to the minimum credit metrics established in the 2009 GCOC decision was not explicitly stated.[439] In the 2013 GCOC decision, the Commission indicated that none of the parties provided updated evidence on the actual credit metrics associated with A-range credit ratings; or proposed changes to the ranges of the credit metrics established by the Commission in the 2009 GCOC decision.[440] In the 2013 GCOC decision, the Commission continued the use of the target credit metrics set out in the 2009 GCOC decision.[441]

359. In the 2009 GCOC decision, the 2011 GCOC decision and the 2013 GCOC decision, the Commission calculated the deemed equity ratios that were required for a typical pure-play regulated utility to attain the minimum credit metrics to maintain an A-range credit rating. In this decision, the Commission intended to use this same analysis as its starting point in evaluating credit metrics. However, it became evident over the course of the proceeding that a difference between the average depreciation rates for the distribution utilities and the transmission utilities had a significant effect on their resulting FFO/debt ratios. Because of these differences, the Commission determined it was necessary to develop separate credit metric calculations for distribution utilities and transmission utilities.

360. In this proceeding, parties emphasized the importance of the FFO/debt and the FFO coverage ratios, while downplaying the EBIT coverage ratio. Dr. Villadsen, for example, stated that credit rating agencies such as S&P and Moody's Investor Services (Moody's) focus on the two FFO ratios as opposed to EBIT coverage.[442] Similarly, Mr. Stauft submitted that the credit rating agencies pay virtually no attention to EBIT coverage. He commented that while interest coverage was the main credit metric constraint in the 2009 GCOC proceeding and the 2011 GCOC proceeding, the FFO/debt credit metric is presently a greater constraint for the affected utilities.[443] Mr. Hevert, AltaLink and Mr. Fetter made no recommendations regarding EBIT coverage or FFO coverage.

Mr. Hevert's comments on credit metrics

361. Mr. Hevert submitted that while credit metrics are an important part of the credit ratings determination process, they are only one part of a larger process which involves a comprehensive review of business and financial risks. Indeed, Mr. Hevert stated that both S&P and DBRS describe regulatory climate as critical to the bond/credit rating process. He pointed out that the

[438] Decision 2009-216, Table 12 and paragraphs 348, 354 and 356.
[439] Decision 2011-474, paragraph 189.
[440] Decision 2191-D01-2015, paragraph 438.
[441] Decision 2191-D01-2015, paragraph 439.
[442] Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 68.
[443] Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 57.

first two considerations of regulatory risk listed by DBRS in its October 2015 bond/credit rating methodology report are the deemed equity ratio and the allowed ROE.[444]

362. Mr. Hevert submitted that credit metrics do not determine the fair, investor-required rate of return because they are based on historical results and the allowed ROE, whereas the determination of the cost of capital is prospective in nature. He added that even pro forma credit metrics are not likely to fully reflect the incremental, residual risks faced by equity holders, or the returns they require to take on those risks.[445]

363. Mr. Hevert indicated that S&P may require FFO/debt ratios above 13 per cent and possibly 14 per cent for AltaLink (and similarly situated regulated utilities in Alberta) to address the risk of adverse credit rating changes.[446] Indeed, in what it described as an effort to mitigate the possibility of a credit downgrade to the "BBB" category, AltaLink stated that in its 2015-2016 GTA it requested an increase to its deemed equity ratio in order to ensure a minimum FFO/debt ratio of 13 per cent.[447]

Mr. Fetter's comments on credit metrics

364. In recognition of S&P's statements about the potential for a lower regulatory advantage assessment for the affected utilities (subsequently summarized in Section 7.4.1.1 and Section 7.4.1.2), Mr. Fetter stated that an FFO/debt ratio above 14 per cent would be necessary to maintain A category credit ratings to forestall a credit downgrade if an untoward negative financial event were to occur,[448] such as a downgrade of Alberta's regulatory advantage assessment by S&P.[449] An FFO/debt ratio of 13 per cent would meet both the "low volatility" and "medial volatility" scales used by S&P and be above the minimum benchmark used by the Commission. Mr. Fetter submitted that the Commission should set the FFO/debt ratio target for AltaLink and similarly situated utilities in Alberta at 13 per cent.[450]

AltaLink's comments on credit metrics

365. AltaLink submitted that its credit metrics have deteriorated relative to other A rated utilities since the 2009 GCOC decision, which in turn has increased the risk to its shareholders. It cited a credit report from S&P dated February 11, 2016 that showed AltaLink's actual FFO/debt ratio at 10.4 and the actual FFO coverage ratio at 4.06.[451] AltaLink stated that the 10.4 FFO/debt ratio is below the 11.1 per cent to 14.3 per cent benchmark established by the Commission in the 2009 GCOC decision. AltaLink commented that its FFO/adjusted debt ratio for the years 2012-2014 is among the lowest of all of the Canadian utilities referenced by Dr. Villadsen in her evidence.[452]

366. AltaLink also submitted that its credit metrics must be assessed on a standalone basis. AltaLink stated that Mr. Stauft's credit metric analysis is more representative of a generic utility and therefore not applicable to AltaLink. In particular, his analysis ignored AltaLink's specific

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444 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 151-154.
445 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 156-158.
446 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 43.
447 Exhibit 20622-X0140, evidence of AltaLink, PDF pages 8-9.
448 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 29.
449 Exhibit 20622-X0447, rebuttal evidence of Mr. Fetter, PDF page 10.
450 Exhibit 20622-X0447, rebuttal evidence of Mr. Fetter, PDF page 11.
451 This report is included as part of Exhibit 20622-X0162, PDF page 6.
452 Exhibit 20622-X0440, rebuttal evidence of AltaLink, PDF pages 7-12.

situation and the fact that AltaLink has the worst credit metrics of all the affected utilities. Based on its own data from 2013, 2014 and 2015, AltaLink submitted that it would require a much higher deemed equity ratio to meet the minimum credit ratio benchmarks set out by the Commission. Indeed, to achieve an FFO/debt ratio of 11.1 per cent, AltaLink submitted that the deemed equity ratios would have to have been above 44 per cent for 2013 and 2014, and above 45 per cent for 2015.[453]

Dr. Villadsen's comments on credit metrics

367. Dr. Villadsen compared the expectations for an A rating used by the Commission in the 2013 GCOC decision to the ratings used by DBRS, S&P and Moody's and the realized ratios for A-range rated utilities in Canada and the U.S. Her comparison is set out in Table 14.

Table 14. Credit ratio benchmarks for A-rating and realized ratios for A range utilities[454]

	EBIT coverage	FFO coverage	FFO/debt
Commission minimum	2.0	3.0	11.1% – 14.3%
DBRS	1.8 – 2.8		12.5% - 17.5 %
S&P			13.0% - 23.0%
Moody's		4.0 – 5.5	18.0% - 26.0%
Canadian utilities (DBRS average)	2.6		16.0%
Canadian utilities (DBRS median)	3.5		16.8%
U.S. utilities		5.0	28.6%

368. Dr. Villadsen commented that while the Commission has historically used total debt in calculating the FFO/debt ratio, credit rating agencies use adjusted debt as the denominator. She explained that the credit rating agencies consider leases and other items as "debt-like" and therefore add these to the total debt amount when they calculate FFO/debt ratios. Consequently, in her view, the Commission's FFO/debt ratios are overstated.[455] Mr. Fetter made the same observation.[456]

369. Dr. Villadsen also observed that the Commission's minimum levels for the three credit metrics are at or below the benchmarks of the credit rating agencies, and are below the realized ratios for A-range rated utilities. She stated that this comparison (as set out Table 14) should be considered by the Commission when it establishes minimum credit metrics.

370. Dr. Villadsen added that the Commission should consider whether the resulting return to investors is comparable to what they would receive if investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise. She suggested that the credit rating agencies assess their ratings continually and it is therefore important not to target historical or low-end benchmarks for credit ratios.[457]

371. In a similar vein, Dr. Villadsen submitted that the credit rating agencies base their ratings not only on observed metrics but also on forecast trends, especially potential risks facing the

453 Exhibit 20622-X0440, rebuttal evidence of AltaLink, PDF pages 14-15.
454 Source: Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF pages 71-73.
455 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 68.
456 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 10.
457 Source: Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF pages 71-73.

affected utilities. Noting the potential risks facing the affected utilities as discussed by Dr. Carpenter and Mr. Buttke, as well as the views expressed by credit rating agencies regarding the regulatory environment in Alberta, Dr. Villadsen stressed the need for greater financial flexibility to consistently achieve the minimum credit ratios.[458]

372. Dr. Villadsen recommended that the Commission, at a minimum, should seek to set credit metric benchmarks towards the middle of the DBRS range and well above the low end of the S&P range and the Moody's range. She recommended that the Commission adopt the following credit metric benchmarks:

- EBIT coverage of at least 2.5 times
- FFO coverage of 3.5 times to 4.0 times, preferably at the higher end
- FFO/debt ratio of at least 15 per cent[459]

373. Similar to what the Commission did in the 2013 GCOC decision, Dr. Villadsen conducted a sensitivity analysis illustrating the impact of a range of equity ratios on the three principal credit metrics using ROE amounts of 8.3 per cent and 10.0 per cent.[460] The input parameters she used are described in Section 7.3.2. Dr. Villadsen submitted that in order to be consistent with the benchmarks for an A-range rating, it is necessary for the deemed equity ratio to be 40 per cent if the allowed ROE is 10 per cent. She added that if the ROE is lower than 10 per cent, the deemed equity ratio would have to be higher in order to be consistent with the benchmarks for an A-range rating.[461]

Dr. Booth's comments on credit metrics

374. Dr. Booth placed the same emphasis on credit metrics as Mr. Hevert. He submitted that while interest coverage ratios are important, they do not over-ride the fair-return standard. He agreed with the British Columbia Utility Commission's statement from May 2012[462] that an A-category credit rating should be maintained but only to the extent that it can be maintained without going beyond what is required by the fair return standard.[463] Dr. Booth stated that credit rating agencies do not mechanically adjust credit ratings in response to changes in credit ratios.[464] Dr. Booth recommended that the Commission use the minimum of any rating agency guidelines and not rely on standards that are primarily used for rating riskier U.S. utilities.[465]

Mr. Stauft's comments on credit metrics

375. Mr. Stauft, like Dr. Villadsen, submitted that the Commission should consider and give weight to the formal quantitative credit measures applied by the credit rating agencies.[466] As summarized in Table 15 and described further below, he compared the benchmark ranges for credit ratios applied by S&P, DBRS and Moody's:

458 Source: Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 74.
459 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 74.
460 The specifics of Dr. Villadsen's calculations are shown in Exhibit 20622-X0105, Appendix B, Section V.
461 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF pages 74-76.
462 Dr. Booth noted this statement was included in a GCOC decision dated May 10, 2012 from the British Columbia Utilities Commission.
463 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 101.
464 Exhibit 20622-X0345, evidence of Dr. Booth, PDF pages 4-5.
465 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 102.
466 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF pages 43-44.

Table 15. Credit ratio benchmarks for A-rating discussed by Mr. Stauft

	EBITDA(1) coverage	Equity ratio	EBIT coverage	FFO coverage	FFO/debt
S&P – low volatility[467]	2.5 – 4.0			2.0 – 3.0	9.0% - 13.0%
S&P – medial volatility[468]					13.0% - 23.0%
DBRS – FRA A category[469] **(2)**		35.0% - 45.0%	1.8 – 2.8		12.5% - 17.5%
DBRS - average[470]		25.0% - 45.0%	1.5 – 2.8		10.0% - 17.5%
Moody's – A rating[471]		40.0% - 55.0%		4.0 – 5.0	18.0% - 26.0%
Moody's – Baa rating[472]		25.0% - 40.0%		2.8 – 4.0	11.0% - 18.0%
(1) Earnings before interest, income taxes, depreciation and amortization (EBITDA)					
(2) Financial risk assessment (FRA)					

376. Noting S&P's primary use of the FFO/debt ratio among the three credit metric ratios used by the Commission, Mr. Stauft indicated that the benchmark range associated with an A rating for S&P varies depending upon the volatility scale used by S&P. He observed that S&P applies its "low volatility scale," which has a benchmark range of nine to 13 per cent for the FFO/debt ratio, if the regulated utility has a regulatory advantage score of "strong." If a "medial volatility scale" is used, the resulting benchmark range is 13 to 23 per cent. Mr. Stauft submitted that S&P currently rates the regulatory advantage for utilities in Alberta as "strong."[473] Consequently, Mr. Stauft used the S&P "low volatility scale" benchmark of nine to 13 per cent for the FFO/debt ratio in his credit metric analysis. In contrast, Dr. Villadsen used the "medial volatility scale" benchmark of 13 to 23 per cent for the FFO/debt ratio in her credit metric analysis.

377. Mr. Stauft submitted that of the three credit ratings agencies, S&P's methodology is the most analogous to the Commission's in terms of how benchmark ranges are established for certain credit metrics in order to qualify for an A-range rating. Since S&P does not use EBIT coverage but rather EBITDA interest coverage, Mr. Stauft included that metric as well in his credit metric analysis. Mr. Stauft calculated the EBITDA ratio by adding depreciation and amortization to the numerator of the EBIT coverage ratio.[474]

378. Mr. Stauft stated that the FFO coverage ratio was similar to a supplementary coverage ratio that S&P describes as "FFO + interest / interest."[475]

379. Based on the results of his credit metric analysis,[476] Mr. Stauft concluded that S&P's minimum standards and ranges for its FFO/debt and EBITDA coverage are less onerous in terms of what is required to qualify for an A-range rating than the Commission's previously established

467 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 45.
468 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 45.
469 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 48.
470 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 48.
471 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 49.
472 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 49.
473 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF pages 44-45.
474 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 45.
475 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 45. As shown in Exhibit 20622-X0086, PDF page 113, S&P actually described it in their November 19, 2013 publication *Ratings Direct, Criteria | Corporates | General: Corporate Methodology* as FFO plus interest to cash interest.
476 The results are in Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 51, Table 2. Mr. Stauft's credit metric model is in Exhibit 20622-X0305.

standards. The results of his credit metric analysis indicated that the affected utilities would meet the minimum levels established by S&P for the FFO/debt ratio and the EBITDA coverage ratio with an ROE of 8.3 per cent and a 30 per cent deemed equity ratio.[477] This analysis supported his recommendation for a one per cent decrease in the deemed equity ratio for all the affected utilities.

380. In response to Mr. Stauft's evidence, Mr. Hevert submitted that a deemed equity ratio between 39 per cent and 40 per cent would be required to achieve an FFO/debt ratio of 13 per cent (where 13 per cent is the straddle point between S&P's low volatility and medial volatility scales) using Mr. Stauft's credit metric model. Based on the results of a sensitivity analysis he conducted using a depreciation rate of 4.5 per cent instead of the five per cent figure Mr. Stauft used, Mr. Hevert determined that Mr. Stauft's credit metric model is very sensitive to changes in assumptions. In his opinion, this demonstrates the risk of relying on a credit metric model.[478]

381. Mr. Stauft described the methodology used by DBRS to arrive at its credit ratings for regulated utilities, including how DBRS assesses business and financial risk and incorporates them into a credit rating. He stated that normally the business risk assessment (BRA) has greater weight than the FRA, and that the most important factor in determining the BRA is the quality of the regulatory regime.[479]

382. Mr. Stauft noted that DBRS has established "strong" credit metric benchmarks that must be met for a regulated utility to be in the A category for its FRA. However, based on his review of a DBRS study from January 2015[480] in which DBRS listed all of the rated companies along with their respective credit ratings and credit ratio judgements, Mr. Stauft observed that many of the A rated utilities did not receive "strong" credit metric assessments, but rather were assessed as having "average" credit metrics.[481]

383. Mr. Stauft noted that while Dr. Villadsen's recommendation was to set the minimum credit ratios at the middle of the DBRS range, her recommended minimum benchmark of 2.5 for the EBIT coverage ratio was above the middle of the DBRS range, which is 2.3. He further submitted that Dr. Villadsen's recommended base deemed equity ratio of 40 per cent will not satisfy all the minimum credit metrics she put forward, even with the use of an assumed ROE of 10 per cent. Mr. Stauft concluded that Dr. Villadsen's base deemed equity ratio recommendation is inconsistent with her credit metric ranges.[482]

384. Mr. Stauft reviewed the Moody's credit ratings methodology and concluded that, based on the benchmark credit ratings set out by Moody's for an A rating, it is difficult to see how any of the major regulated utilities in Canada would qualify for a credit rating of A from Moody's. Referencing credit rating reports for FortisAlberta issued by Moody's[483] and DBRS[484] in 2015,

[477] Exhibit 20622-X0303, evidence of Mr. Stauft, PDF pages 50-52.
[478] Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF pages 50-52.
[479] Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 47.
[480] The ratings Mr. Stauft referred to are included in Exhibit 20622-X0133, PDF page 95.
[481] Exhibit 20622-X0303, evidence of Mr. Stauft, PDF pages 47-49.
[482] Exhibit 20622-X0303, evidence of Mr. Stauft, PDF pages 64-65.
[483] Exhibit 20622-X0073, PDF page 1.
[484] Exhibit 20622-X0075, PDF page 1.

Mr. Stauft suggested that for Canadian utilities, it appears a credit rating of Baa from Moody's is functionally equivalent to an A-range credit rating from DBRS and S&P.[485]

Commission findings

385. In the absence of evidence comparing the overall cost of capital at different credit ratings in a protracted low interest rate environment, the Commission will, consistent with its approach in past GCOC decisions, award common equity ratios that are, on a stand-alone basis, consistent with credit ratings in the A category.

386. In this proceeding, parties provided evidence regarding the benchmarks associated with certain credit metrics used by various credit rating agencies. The Commission acknowledges the submissions of Mr. Hevert and Dr. Booth that credit metrics are only one part of the credit rating determination process. However, the Commission notes that both of these experts, as well as Dr. Villadsen and Mr. Stauft, submitted that credit metrics are important to credit rating agencies. Consequently, the Commission finds that it should consider these formal credit metrics. In doing so, the Commission is cognizant that the process of setting credit metrics required to maintain an A category credit rating for Alberta utilities is a function of market dynamics and credit agency/analyst analysis of macro-economic trends, Canadian utility industry specific variables and future investor expectations, applied to an assessment of the relative risk of the utility sector of the economy and perceptions of the regulatory environment.

387. Credit metrics reflect past market expectations as well as anticipated market expectations given an assessment of current economic conditions, the information and assumptions employed in conducting the analysis and judgment of relative risk. The element of judgement is reflected to some degree, in the differing credit metrics employed and the breadth of ranges used by various credit rating agencies and market analysts. Further, the application of utility sector credit metrics to a particular Alberta utility involves a further element of judgment on factors such as the Alberta regulatory climate.

388. From a practical perspective, however, credit metrics as established by credit rating agencies and market analysts and as applied to Alberta utilities, affect investor risk perceptions and consequently may affect market behaviour. Accordingly, despite the use of economic and business risk assumptions tempered by judgement embedded in the determination of credit metrics, the Commission considers the credit metrics reflected in credit rating and market analyst reports, as generally reflective of future expectations of utility debt and equity investors with respect to credit metric fundamentals. This observation is supported generally by a review of actual market behavior. Alberta utilities have generally had little difficulty in raising both debt and equity financing on satisfactory terms while maintaining an A category credit rating.

389. The benchmark FFO/debt ratio range used by S&P for a utility with a "strong" regulatory advantage score is 9 to 13 per cent.[486] The Alberta regulatory advantage is currently rated by S&P as "strong" with a trend of "negative."[487]

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485 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF pages 49-50.

486 This is confirmed by S&P in a publication issued by Standard & Poor's Ratings Services entitled *Ratings Direct: How Regulatory Advantage Scores Can Affect Ratings on Regulated Utilities*, dated April 23, 2015. The publication is in Exhibit 20622-X0133, beginning on PDF page 480. The information referred to by Mr. Stauft is on PDF page 483 of Exhibit 20622-X0133.

390. Even with the trend of "negative," the Commission notes AltaLink's credit rating report from S&P dated February 11, 2016[488] is assessed using S&P's "low volatility scale" benchmarks. As Mr. Stauft indicated, S&P only applies a "low volatility scale" when the regulatory advantage score is "strong." Similarly, FortisAlberta provided a credit rating report from S&P dated November 17, 2015.[489] As with the AltaLink report, a regulatory advantage score was not included, but the financial risk was also assessed using the "low volatility scale."

391. Dr. Villadsen commented that while the Commission has historically used total debt in calculating the FFO/debt ratio, credit rating agencies use adjusted debt as the denominator. However, the Commission is not convinced that the forecast credit metrics for AltaLink are materially affected by the adjustments made by S&P. Using the information provided by AltaLink,[490] the Commission recalculated the credit metric ratios excluding S&P's adjustments.[491] The resulting credit metrics are included in Table 16.

Table 16. Forecast credit metrics of AltaLink for 2016 and 2017 – with and without S&P adjustments[492]

	2016 forecast		2017 forecast	
	With S&P adjustments	Without S&P adjustments	With S&P adjustments	Without S&P adjustments
EBIT coverage	2.13	2.20	2.13	2.19
FFO coverage	3.85	4.01	3.73	3.84
FFO/debt	11.00%	11.20%	11.00%	10.80%
Debt/EBITDA	6.76	6.73	6.85	6.82

392. As is evident in the above table, any overstatement of forecast credit metrics is not material. For example, the 2017 forecast FFO/debt ratio using the Commission's credit metric model would be overstated by 0.20, which is less than two per cent of the adjusted value. Similarly, the 2016 forecast FFO/debt ratio would be overstated by 0.20, which is less than two per cent of the adjusted value. The Commission considers that differences in the FFO/debt ratio of one or two per cent do not materially affect the Commission's evaluation of forecast credit metrics.

393. Using a "low volatility scale," the credit metric benchmarks used by S&P for an A category credit rating are as follows:

- EBITDA coverage of 2.5 to 4.0

487 This is confirmed by S&P in a publication issued by Standard & Poor's Ratings Services entitled "Assessing Regulatory Advantage in Canada," dated April 21, 2015. The publication is in Exhibit 20622-X0128, beginning on PDF page 363. The regulatory advantage assessments are included on PDF page 371 of Exhibit 20622-X0128, and show the Alberta regulatory regime assessed as "strong" with a trend of "negative."

488 Exhibit 20622-X0162, beginning at PDF page 6.

489 Exhibit 20622-X0074, beginning at PDF page 1.

490 During this proceeding, Decision 3524-D01-2016 regarding AltaLink's 2015-2016 general tariff application was issued. Subsequent to the release of Decision 3524-D01-2016, parties were granted the opportunity to submit IRs to AltaLink on any possible implications that decision may have on this GCOC proceeding. During that IR stage, the Commission requested AltaLink to provide updated credit metric forecasts for 2016 and 2017 that incorporated the findings made in Decision 3524-D01-2016. The detailed calculation of these forecast credit metrics is included in Exhibit 20622-X0647.

491 The Commission removed the adjustments included on lines 32,33,34,39,46,47,51,52,53, 57,58 and 59.

492 These credit metrics were calculated by AltaLink using an ROE of 8.30 per cent and a deemed equity ratio of 36 per cent.

- FFO coverage of 2.0 to 3.0
- FFO/debt of 9.0 per cent to 13.0 per cent

394. Regarding the benchmarks used by DBRS, the Commission agrees with Mr. Stauft's observation that many utilities rated as A by DBRS did not receive credit metric assessments of 'strong,' even though the benchmarks utilized by DBRS for a "strong" credit metric assessment were the benchmarks referred to by Dr. Villadsen. This casts doubt on the use of the credit metric benchmarks issued by DBRS, and lends credibility to Mr. Stauft's statement that the BRA made by DBRS has greater weight than the FRA, when DBRS determines its overall credit rating. Mr. Stauft's statement is further supported by information issued by DBRS[493] and the fact that DBRS refers to the quality of the regulatory regime as being the most important factor in determining the BRA.[494]

395. In examining the credit metric benchmarks issued by Moody's, the Commission acknowledges Mr. Stauft's observation that it is difficult to see how any of the major regulated utilities in Canada could qualify for a credit rating of A from Moody's. Indeed, each of the three credit metric benchmarks recommended by Dr. Villadsen are below the Moody's minimums.

396. Accordingly, the Commission finds the credit metric benchmarks used by both DBRS and Moody's to be less informative than the S&P rankings in evaluating financial parameters necessary for an A credit rating.

397. Turning to the credit metric benchmarks recommended by Dr. Villadsen, the Commission agrees with Mr. Stauft that there are inconsistencies between her credit metric benchmarks and her recommended deemed equity ratio of 40 per cent for an average risk Alberta utility. Her credit metric sensitivity analysis indicated that at an approved ROE of 8.3 per cent, the deemed equity ratio required to reach the minimum level for all three of her recommended credit metric benchmarks is 47.5 per cent, with the constraining credit metric benchmark being the FFO/debt ratio, which she submitted was one of the key ratios.[495] Using an ROE of 10 per cent, which is the low end of the ROE range Dr. Villadsen recommended, the deemed equity ratio required in order to reach the minimum level for all three of her recommended credit metric benchmarks is 45 per cent, with the constraining credit metric benchmark again being the FFO/debt ratio.[496]

398. Using Dr. Villadsen's credit metric model[497] and her recommended deemed equity ratio of 40 per cent, the Commission calculated that an ROE of approximately 11.85 per cent would be required in order to satisfy Dr. Villadsen's recommended FFO/debt ratio minimum benchmark of at least 15 per cent. This result is inconsistent with Dr. Villadsen's recommended upper bound of 10.5 per cent for the allowed ROE. In addition, the Commission observes that the credit metric benchmarks employed by Dr. Villadsen are inconsistent with the currently "strong"

493 This is confirmed by DBRS in a publication entitled *Methodology: Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry*, dated October 2015. The publication is in Exhibit 20622-X0133, beginning on PDF page 307. The quote used by the Commission is from Exhibit 20622-X0133, PDF page 315.

494 This is confirmed by DBRS in a publication entitled *Methodology: Rating Companies in the Regulated Electric, Natural Gas and Water Utilities Industry*, dated October 2015. The publication is in Exhibit 20622-X0133, beginning on PDF page 307. The material referred to by the Commission is from Exhibit 20622-X0133, PDF page 312.

495 Exhibit 20622-X0104, evidence of Dr. Villadsen, Figure 26, PDF page 76.

496 Exhibit 20622-X0104, evidence of Dr. Villadsen, Figure 26, PDF page 76.

497 Dr. Villadsen's credit metric model is included in Exhibit 20622-X0120.

Alberta regulatory advantage assessment provided by S&P. Accordingly, the Commission does not accept Dr. Villadsen's recommended credit metric benchmarks.

399. In light of the difficulties with DBRS and Moody's benchmarks reviewed above, the Commission will place greater weight on S&P's credit metric benchmarks for FFO/debt and FFO coverage in evaluating the financial parameters necessary for an A credit rating. However, with regards to the EBIT coverage ratio, given that S&P does not calculate a standalone EBIT coverage ratio, the Commission will take guidance from the EBIT coverage ratio range used in the 2013 GCOC proceeding.

400. Mr. Stauft suggested that the affected utilities could meet the minimum credit metrics established by S&P with an ROE of 8.3 per cent and a deemed equity ratio of 30 per cent. The Commission is cognizant that this 30 per cent deemed equity ratio figure would result in credit metrics that fall at the low end of the S&P range and would be based on a "strong" S&P regulatory advantage rating, even though the S&P regulatory rating is currently on a negative trend. Accordingly, the Commission will be mindful of this when considering the S&P benchmarks.

7.3.2 Equity ratios associated with credit metrics

401. In the 2013 GCOC decision (Table 8), the Commission provided a sensitivity analysis to illustrate the effect of a range of equity ratios on the three principal credit metrics. The analysis was based on certain input parameters associated with the affected utilities.

402. In this proceeding, Dr. Villadsen[498] and Mr. Stauft[499] each prepared a sensitivity analysis based on the same parameters used by the Commission in its sensitivity analysis in the 2013 GCOC decision. The input values used by Dr. Villadsen and Mr. Stauft were the same as those used by the Commission in the 2013 GCOC decision, with the exception of the embedded average debt rate and the income tax rate.

403. Dr. Villadsen and Mr. Stauft both used an income tax rate of 27 per cent, which incorporates the increase in the Alberta corporate income tax rate. Dr. Villadsen used an embedded average debt rate of 5.2 per cent while Mr. Stauft used 4.8 per cent. In addition, Dr. Villadsen ran a separate analysis using an assumed ROE of 10 per cent.

404. Dr. Villadsen disagreed with the embedded average debt rate used by Mr. Stauft. She also submitted that Mr. Stauft's credit metric model was conceptually flawed because it provided inflated credit metrics. The flaw identified by Dr. Villadsen focused on how CWIP is financed. Mr. Stauft's credit metric model calculates interest costs on CWIP using the deemed debt ratio, which implies that there is a portion of CWIP that is financed by equity. Dr. Villadsen contended that this is not the case because the utility does not earn a return on the equity component of CWIP. Because CWIP is completely financed with debt, the interest costs associated with CWIP should be calculated on that basis. However, she stated that Mr. Stauft's credit metric model does not calculate interest costs in this way and as a result, understates interest costs and debt levels, which in turn overstates the interest coverage ratios and FFO/debt ratios.[500]

[498] Dr. Villadsen's credit metric model is included in Exhibit 20622-X0120.
[499] Mr. Stauft's credit metric model is included in Exhibit 20622-X0305.
[500] Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 76.

405. Additionally, Dr. Villadsen criticized Mr. Stauft's calculation of a weighted average mid-year debt rate of 4.8 per cent based on the 2014 Rule 005 reports for all the affected utilities. She submitted that the mid-year embedded average debt rate for ENMAX should be excluded from any such calculations because of ENMAX's ability to access lower than normal interest rate funds from the Alberta Capital Financing Authority. Dr. Villadsen stated that she based her embedded average debt rate of 5.2 per cent on the simple average of 5.22 and the median of 5.26 for the ATCO Utilities, AltaGas and FortisAlberta for 2014.[501]

Commission findings

406. The parameter values assumed by the parties in their credit metric calculations are summarized in Table 17, along with the values the Commission has elected to use in its updated calculations. The Commission's reasons for selecting the updated parameter values follow.

Table 17. Parameters for calculating credit metrics

Parameter	Parameter values applied in 2013 GCOC decision	Proposed by the Utilities[502]	Proposed by the UCA[503]	Parameter values applied in this decision – distribution utilities	Parameter values applied in this decision – transmission utilities
			(%)		
Embedded average debt rate	5.10	5.20	4.80	4.80	4.80
ROE	8.30	8.30 and 10.00	8.30	8.30	8.30
Income tax rate	25.00	27.00	27.00	27.00	27.00
Depreciation	5.00	5.00	5.00	5.75	4.10
Construction work in progress	5.00	5.00	5.00	3.78	5.00

407. 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 set out in the 2013 GCOC decision, the 2014 Rule 005 filings and the 2015 Rule 005 filings.

408. The ROE input parameter is common to all utilities, as is the income tax rate input parameter (non-taxable utilities are considered in Section 7.4.3.1). The Commission agrees with Dr. Villadsen and Mr. Stauft that the income tax rate used in the sensitivity analysis should be 27 per cent because this is the current combined federal and provincial statutory large corporation income tax rate for Alberta. The Commission has summarized the embedded average debt rates, depreciation rates and CWIP percentages for each affected utility in Table 18.

501 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF pages 76-77.
502 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 76.
503 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF pages 40-41.

Table 18. Embedded average debt rates, depreciation rates and CWIP percentages by utility

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 Electric – distribution				
2015 Rule 005	2,130,400	5.08	5.31	4.62
2014 Rule 005	1,948,600	5.21	5.21	7.04
2013 Rule 005	1,696,400	5.40	5.14	8.22
FortisAlberta – distribution				
2015 Rule 005	2,695,000	4.99	6.43	2.76
2014 Rule 005	2,499,400	5.22	6.77	2.52
2013 Rule 005	2,285,200	5.34	6.75	2.92
ENMAX – distribution				
2015 Rule 005	1,093,100	4.03	5.12	2.98
2014 Rule 005	995,900	4.24	5.06	5.09
2013 Rule 005	900,568	4.45	5.35	7.98
EPCOR – distribution				
2015 Rule 005	851,000	5.00	4.30	3.57
2014 Rule 005	738,300	5.30	4.34	2.78
2013 Rule 005	674,431	5.70	4.46	1.40
ATCO Gas – distribution				
2015 Rule 005	2,144,400	5.60	6.42	2.20
2014 Rule 005	1,997,700	5.90	6.39	2.12
2013 Rule 005	1,860,195	5.90	6.51	2.45
AltaGas – distribution				
2015 Rule 005	244,500	4.71	4.90	2.69
2014 Rule 005	215,800	4.90	5.12	1.48
2013 Rule 005	195,732	5.08	5.25	1.05
AltaLink – transmission				
2015 Rule 005	5,257,400	4.11	4.50	3.49
2014 Rule 005	5,110,500	4.10	3.37	-1.20
2013 Rule 005	3,592,600	3.90	3.82	36.73
ATCO Electric – transmission				
2015 Rule 005	5,197,900	4.72	2.67	1.40
2014 Rule 005	4,630,200	4.84	2.83	1.54
2013 Rule 005	3,640,600	5.02	2.90	34.00
ENMAX – transmission				
2015 Rule 005	392,200	4.03	3.86	5.82
2014 Rule 005	323,500	4.24	3.72	13.13
2013 Rule 005	251,667	4.45	3.73	18.62
EPCOR – transmission				
2015 Rule 005	657,700	4.93	3.40	2.50
2014 Rule 005	624,300	4.88	3.32	3.18
2013 Rule 005	471,067	4.78	3.59	15.53
ATCO Pipelines – transmission				
2015 Rule 005	1,083,300	5.29	5.14	11.04
2014 Rule 005	956,600	5.50	5.34	8.62
2013 Rule 005	868,417	5.64	5.42	7.28
Simple average				
2015 Rule 005		**4.77**	**4.73**	**3.92**
2014 Rule 005		**4.94**	**4.68**	**4.21**
2013 Rule 005		**5.06**	**4.81**	**12.38**

409. In Table 19 below, the Commission presents additional calculations based on the information presented in Table 18. There is no simple average or weighted average for gas

transmission utilities presented separately in Table 19 because there is only one gas transmission utility; i.e., ATCO Pipelines.

Table 19. Additional analysis of information included in Table 18

Utility	Debt cost per cent	Depreciation as a percentage of invested capital	Mid-year CWIP as a percentage of invested capital
Simple average – overall			
2015 Rule 005	4.77	4.73	3.92
2014 Rule 005	4.94	4.68	4.21
2013 Rule 005	5.06	4.81	12.38
Weighted average - overall			
2015 Rule 005		4.58	3.24
2014 Rule 005		4.39	2.35
2013 Rule 005		4.67	18.71
Simple average – distribution utilities			
2015 Rule 005	4.90	5.41	3.14
2014 Rule 005	5.13	5.49	3.50
2013 Rule 005	5.31	5.58	4.00
Weighted average – distribution utilities			
2015 Rule 005		5.77	3.16
2014 Rule 005		5.86	3.77
2013 Rule 005		5.93	4.40
Simple average – transmission utilities			
2015 Rule 005	4.62	3.91	4.85
2014 Rule 005	4.71	3.71	5.06
2013 Rule 005	4.76	3.89	22.43
Weighted average – transmission utilities			
2015 Rule 005		3.72	3.30
2014 Rule 005		3.32	1.33
2013 Rule 005		3.58	31.05
Simple average – electric distribution utilities			
2015 Rule 005	4.78	5.29	3.48
2014 Rule 005	4.99	5.35	4.36
2013 Rule 005	5.22	5.43	5.13
Weighted average – electric distribution utilities			
2015 Rule 005		5.60	3.48
2014 Rule 005		5.72	4.39
2013 Rule 005		5.76	5.17
Simple average – gas distribution utilities			
2015 Rule 005	5.15	5.66	2.44
2014 Rule 005	5.40	5.76	1.80
2013 Rule 005	5.49	5.88	1.75
Weighted average – gas distribution utilities			
2015 Rule 005		6.26	2.25
2014 Rule 005		6.27	2.06
2013 Rule 005		6.39	2.32
Simple average – electric transmission utilities			
2015 Rule 005	4.45	3.61	3.30
2014 Rule 005	4.51	3.31	4.16
2013 Rule 005	4.54	3.51	26.22
Weighted average – electric transmission utilities			
2015 Rule 005		3.59	2.57
2014 Rule 005		3.14	0.68
2013 Rule 005		3.38	33.65

410. For the purpose of this decision, the Commission calculated the credit metrics using the same definitions as set out in the 2013 GCOC decision and was able to verify the outputs calculated by Mr. Stauft and reported in Table 1 of his evidence.[504] Dr. Villadsen argued that Mr. Stauft's credit metric model has a conceptual flaw. The Commission does not agree. The Commission used Mr. Stauft's parameter values in its own credit metric model and was able to replicate the outputs calculated by Mr. Stauft.

411. In contrast, using Dr. Villadsen's parameter values in its own credit metric model, the Commission was unable to replicate the outputs calculated by Dr. Villadsen and reported in Figure 26 of her evidence.[505] The reason for the differences between the outputs calculated using Dr. Villadsen's credit metric model and the outputs calculated using the Commission's credit metric model is in the treatment of the debt amounts and interest costs associated with CWIP. Dr. Villadsen calculates her CWIP debt amount and resulting interest costs by including a value of 100 per cent for CWIP financed by debt, whereas, the Commission's credit metric model calculates the CWIP debt amount and resulting interest costs by including the deemed debt ratio percentage for CWIP financed by debt.

412. Dr. Villadsen submitted her calculations are correct because the utility does not earn a return on the equity component of CWIP. While the Commission agrees with Dr. Villadsen that under normal circumstances CWIP is not included in rate base and, therefore, the utility does not earn a direct return on the equity component of CWIP, the Commission notes that Dr. Villadsen does not account for the fact that the utility is permitted to include an amount for allowance for funds used during construction (AFUDC) in its CWIP balances before these balances are capitalized to rate base. The AFUDC amount is generally calculated on the mid-year CWIP balance using the weighted average cost of capital. The weighted average cost of capital includes an equity component, so the utility accrues a return on the equity component of CWIP. Consequently, the Commission finds that there is no conceptual flaw in its credit metric model.

413. In its credit metric calculations, the Commission adopted the following five parameters: ROE value, embedded average debt rate, income tax rate, depreciation as a percentage of invested capital and mid-year CWIP as a percentage of invested capital.

ROE value

414. The Commission has applied an ROE value of 8.3 per cent in its credit metric calculations, consistent with its findings in Section 6.7.

Embedded average debt rate

415. The Commission notes that the only difference between the parameter values used by Dr. Villadsen and Mr. Stauft is the value for the embedded average debt rate. Dr. Villadsen used a figure of 5.2 per cent while Mr. Stauft used 4.8 per cent. The value used in the 2013 GCOC decision was 5.1 per cent, and this is the same as the simple average for all of the utilities based on their 2013 Rule 005 reports, which is reported in Table 18.

416. The simple average of the embedded average debt rates is 4.9 per cent based on the 2014 Rule 005 reports, and 4.8 per cent based on the 2015 Rule 005 reports. Mr. Stauft's weighted average, based on the 2014 Rule 005 reports, is 4.8 per cent. These figures demonstrate that the

504 Table 1 of Mr. Stauft's evidence is in Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 42.
505 Figure 26 of Dr. Villadsen's evidence is in Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 76.

embedded average debt rate is declining, which is to be expected as the affected utilities continue to retire debt with higher interest rates and replace it with lower cost debt. The Commission considers that the 5.2 per cent figure used by Dr. Villadsen, which is greater than the 5.1 per cent figure used by the Commission in the 2013 GCOC decision, is contrary to the reduction in the simple average of the embedded average debt rates since 2013.

417. The Commission is not prepared to use current interest rates, as recommended by Dr. Booth, rather than embedded average debt rates. Using current debt rates as proposed by Dr. Booth would ignore the mix of historical debt securities and associated rates that make up the accumulated debt for the utilities.

418. Accordingly, the Commission finds that the use of 4.8 per cent for the embedded average debt rate is reasonable. This figure is between the simple average for the distribution utilities and the transmission utilities based on the 2015 Rule 005 reports. Given that the affected utilities should continue to retire higher interest debt and replace it with lower interest debt, the Commission considers the use of 4.8 per cent to be conservative.

Income tax rate

419. As mentioned above, the Commission agrees with Dr. Villadsen and Mr. Stauft that the income tax rate used in the credit metric calculations should be 27 per cent.

Depreciation as a percentage of invested capital

420. The amount of depreciation collected through rates is included in the calculation of the FFO component of the FFO/debt ratio. The information in Table 18 demonstrates a notable difference in depreciation rates between the distribution utilities and the transmission utilities. Both the simple average and the weighted average depreciation rates for the distribution utilities are greater in each of the years 2013, 2014 and 2015 than the corresponding rates for the transmission utilities. This supports AltaLink's submission that Mr. Stauft's credit metric analysis, which is more representative of a generic utility, ignores AltaLink's specific situation.

421. Based on the difference in the average depreciation rates for distribution utilities and transmission utilities, the Commission finds it is necessary to develop separate credit metric ratio calculations.

422. The weighted average depreciation rate as a percentage of invested capital for the distribution utilities based on the 2015 Rule 005 reports is 5.77 per cent, as shown in Table 19. For simplicity, the Commission will round this to 5.75 per cent. This figure is between the weighted average depreciation rates based on the 2015 Rule 005 reports for the electric distribution utilities (with a figure of 5.60 per cent) and the gas distribution utilities (with a figure of 6.26 per cent). The Commission notes that the adoption of 5.75 per cent provides for a conservative estimate of the depreciation component in the credit metric calculations.

423. The weighted average depreciation rate as a percentage of invested capital for the transmission utilities based on the 2015 Rule 005 reports is 3.72 per cent, as shown in Table 19. This is an increase of 40 bps from the 3.32 per cent figure based on the 2014 Rule 005 reports. The individual utility results in Table 16 show that the depreciation rate for AltaLink increased from 3.37 per cent in 2014 to 4.50 per cent in 2015, while the depreciation rate for ATCO Electric Transmission decreased from 2.83 per cent to 2.67 per cent. As explained by AltaLink in

its 2015-2016 GTA, its depreciation rate is increasing because of the commencement of collecting depreciation on the large capital projects AltaLink has recently added to rate base.[506]

424. In the case of ATCO Electric Transmission, the Commission is aware that the actual in-service date for the Eastern Alberta Transmission Line (EATL) capital project was December 18, 2015.[507] The EATL project cost of $1.76 billion[508] was added to rate base in 2015 but, because of the late in-service date, no depreciation for 2015 for the EATL project was included in the 2015 Rule 005 information.[509] Once depreciation commences on the EATL project, the average depreciation rate for ATCO Electric Transmission will increase. Given the 40 bps increase in the weighted average depreciation rate for 2015 for the transmission utilities, primarily related to AltaLink's significant capital program, the Commission expects the weighted average depreciation rate as a percentage of invested capital for 2016 will also increase by approximately 40 bps because of ATCO Electric Transmission's significant capital program. The Commission will, therefore, use an average depreciation rate of 4.1 per cent[510] in its credit metric ratio calculations for the transmission utilities.

Mid-year CWIP as a percentage of invested capital

425. The Commission notes that the rate used for the CWIP parameter does not significantly affect the three credit metrics relied on by the Commission. For example, based on the parameters used in the Commission's credit metric calculations in the 2013 GCOC decision, at an equity ratio of 38 per cent, a change in the CWIP rate of 1.00 results in a 0.1 change in the FFO/debt ratio. However, the Commission considers that it is still important that the rate used for the CWIP parameter reflect the expected value.

426. Using the weighted average values for 2013, 2014 and 2015 for the distribution utilities from Table 19, the Commission calculated the resulting simple average of 3.78 per cent.[511] The Commission will use 3.78 per cent as the CWIP rate for distribution utilities in its credit metric calculations in this proceeding.

427. With the release of the recent AltaLink decision (Decision 3524-D01-2016), the Commission notes that the CWIP in rate base credit support mechanism was reversed with an effective date of January 1, 2013. Concurrently, ATCO Electric Transmission's recent GTA decision (Decision 20272-D01-2016) suspended CWIP in rate base for 2017. Consequently, the Commission must consider that the historic CWIP data from the Rule 005 filings does not reflect current circumstances or future CWIP averages to be used in credit metric calculations for the transmission utilities.

428. In determining the CWIP parameter value to use for transmission utilities, the evidence from Mr. Lomore, on behalf of AltaLink, suggested that CWIP balances would be declining in

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506 Decision 3524-D01-2016: AltaLink Management Ltd., 2015-2016 General Tariff Application, Proceeding 3524, Application 1611000-1, May 9, 2016,Table 15 and paragraph 240.

507 Decision 20272-D01-2016: ATCO Electric Ltd., 2015-2017 Transmission General Tariff Application, Proceeding 20272, August 22, 2016, Table 37.

508 Decision 20272-D01-2016Table 37.

509 Decision 20272-D01-2016, paragraphs 403-404.

510 The 3.72 per cent is the weighted average for 2015, plus 0.40 per cent results in a figure of 4.12 per cent. To be conservative, the Commission has used a figure of 4.10 per cent.

511 Calculated as follows: (4.40+3.77+3.16)/3 = 3.78.

2015 and 2016.[512] The evidence shows that AltaLink's forecast capital additions are expected to be greater than the forecast capital expenditures in both 2016 and 2017, which would lead to a reduction in the forecast CWIP balance of AltaLink for each of these years.[513] The Commission observes that given the completion of recent large capital programs by certain transmission utilities, future mid-year CWIP balances will constitute a comparatively smaller percentage of the current value of invested capital.

429. The Commission notes that CWIP for transmission utilities is generally higher than CWIP for distribution utilities because of the larger capital cost projects undertaken by the transmission utilities. The Commission used a 5.00 per cent value for CWIP in the 2013 GCOC decision and notes that Dr. Villadsen and Mr. Stauft both used 5.00 per cent as their CWIP values in this proceeding. In light of the anomalies in the transmission utilities' CWIP percentages discussed above, the Commission will retain the CWIP rate of 5.00 per cent for transmission utilities in this proceeding.

430. Based on the credit metric parameters discussed above, the Commission has updated its credit metrics calculations at various equity ratios from the calculations last set out in the 2013 GCOC decision. To address the impact of zero income tax on credit metrics, the Commission has also provided credit metric calculations at various equity ratios which reflect an income tax rate of zero. The revised calculations are set out in Table 20, Table 21, Table 22 and Table 23.

Table 20. Credit metrics compared to equity ratios – Commission calculations – distribution utilities – income tax rate of 27 per cent

	EBIT coverage		FFO coverage		FFO/debt %	
Equity ratio	2013 GCOC decision, Table 8	2016	2013 GCOC decision, Table 8	2016	2013 GCOC decision, Table 8	2016
30%	1.8	1.9	3.0	3.3	10.2	11.3
31%	1.9	2.0	3.0	3.4	10.5	11.6
32%	1.9	2.0	3.1	3.4	10.7	11.9
33%	2.0	2.1	3.1	3.5	11.0	12.2
34%	2.0	2.1	3.2	3.6	11.3	12.5
35%	2.1	2.2	3.2	3.6	11.6	12.8
36%	2.1	2.2	3.3	3.7	11.9	13.2
37%	2.2	2.3	3.3	3.8	12.2	13.5
38%	2.2	2.4	3.4	3.8	12.5	13.8
39%	2.3	2.4	3.5	3.9	12.9	14.2
40%	2.3	2.5	3.5	4.0	13.2	14.6
41%	2.4	2.5	3.6	4.1	13.6	14.9
42%	2.4	2.6	3.7	4.2	13.9	15.3
43%	2.5	2.7	3.8	4.2	14.3	15.8
44%	2.6	2.8	3.8	4.3	14.7	16.2
45%	2.6	2.8	3.9	4.4	15.1	16.6

512 Transcript, Volume 3, page 397.
513 This information is in Exhibit 20622-X0647, lines 74-75.

Table 21. Credit metrics compared to equity ratios – Commission calculations – distribution utilities – income tax rate of zero

Equity ratio	EBIT coverage 2016 non-taxable	FFO coverage 2016 non-taxable	FFO/debt % 2016 non-taxable
30%	1.7	3.3	11.3
31%	1.7	3.4	11.6
32%	1.7	3.4	11.9
33%	1.8	3.5	12.2
34%	1.8	3.6	12.5
35%	1.9	3.6	12.8
36%	1.9	3.7	13.2
37%	1.9	3.8	13.5
38%	2.0	3.8	13.8
39%	2.0	3.9	14.2
40%	2.1	4.0	14.6
41%	2.1	4.1	14.9
42%	2.2	4.2	15.3
43%	2.2	4.2	15.8
44%	2.3	4.3	16.2
45%	2.3	4.4	16.6

Table 22. Credit metrics compared to equity ratios – Commission calculations – transmission utilities – income tax rate of 27 per cent

	EBIT coverage		FFO coverage		FFO/debt %	
Equity ratio	2013 GCOC decision, Table 8	2016	2013 GCOC decision, Table 8	2016	2013 GCOC decision, Table 8	2016
30%	1.8	1.9	3.0	2.8	10.2	9.0
31%	1.9	2.0	3.0	2.9	10.5	9.2
32%	1.9	2.0	3.1	2.9	10.7	9.5
33%	2.0	2.1	3.1	3.0	11.0	9.7
34%	2.0	2.1	3.2	3.0	11.3	10.0
35%	2.1	2.2	3.2	3.1	11.6	10.3
36%	2.1	2.2	3.3	3.1	11.9	10.5
37%	2.2	2.3	3.3	3.2	12.2	10.8
38%	2.2	2.3	3.4	3.3	12.5	11.1
39%	2.3	2.4	3.5	3.3	12.9	11.5
40%	2.3	2.5	3.5	3.4	13.2	11.8
41%	2.4	2.5	3.6	3.5	13.6	12.1
42%	2.4	2.6	3.7	3.5	13.9	12.5
43%	2.5	2.7	3.8	3.6	14.3	12.8
44%	2.6	2.7	3.8	3.7	14.7	13.2
45%	2.6	2.8	3.9	3.8	15.1	13.6

Table 23. Credit metrics compared to equity ratios – Commission calculations – transmission utilities – income tax rate of zero

	EBIT coverage	FFO coverage	FFO/debt %
Equity ratio	2016 non-taxable	2016 non-taxable	2016 non-taxable
30%	1.7	2.8	9.0
31%	1.7	2.9	9.2
32%	1.7	2.9	9.5
33%	1.8	3.0	9.7
34%	1.8	3.0	10.0
35%	1.8	3.1	10.3
36%	1.9	3.1	10.5
37%	1.9	3.2	10.8
38%	2.0	3.3	11.1
39%	2.0	3.3	11.5
40%	2.1	3.4	11.8
41%	2.1	3.5	12.1
42%	2.1	3.5	12.5
43%	2.2	3.6	12.8
44%	2.2	3.7	13.2
45%	2.3	3.8	13.6

431. The Commission has applied the above calculations in light of the credit metrics findings of the Commission in Section 7.3.1 above and observes that the credit rating metrics required for an Alberta utility to achieve a credit rating in the A category have changed since they were last observed in the 2009 GCOC proceeding. Table 24 sets out the guidelines established by the Commission in this section to achieve a credit rating in the A category which assumes a credit rating assessment of "strong" for the Alberta regulatory environment. The guidelines do not take into account potential adjustments to the deemed equity ratios that may be necessary in the Commission's judgement to take account of the current trend of "negative" noted by credit rating agencies and in particular by S&P.

Table 24. Commission guidelines for equity ratios to achieve a credit rating in the A category

Credit metric guideline	2013 GCOC decision	2016 distribution utilities – income tax rate of 27 per cent	2016 distribution utilities – income tax rate of zero per cent	2016 transmission utilities – income tax rate of 27 per cent	2016 transmission utilities – income tax rate of zero per cent
		(%)			
2.0 EBIT coverage (2013 and 2016)	33	31	38	31	38
2.0-3.0 FFO coverage (2016)	n/a	Both below 30	Both below 30	Below 30 to 33	Below 30 to 33
3.0 FFO coverage (2013)	33	n/a	n/a	n/a	n/a
9.0-13.0 FFO/debt ratio (2016)	n/a	Below 30 to 36	Below 30 to 36	30 to 44	30 to 44
11.1-14.3 FFO/debt ratio (2013)	34 to 43	n/a	n/a	n/a	n/a

432. In the 2013 GCOC decision, the minimum deemed equity ratio awarded to a distribution utility was 38 per cent. In that decision, the Commission considered this value to be sufficient to attain an A category credit rating for an average risk distribution utility. The credit metric analysis calculations for the distribution utilities shown in Table 20 and Table 21 demonstrates that, as a result of updating the parameters of the Commission's credit metric calculations in this proceeding, a decrease in the deemed equity ratio for distribution utilities may be warranted.

433. The calculations in Table 20, Table 21, Table 22 and Table 23, when applied to the credit metric guidelines in Table 24 demonstrate that, absent differences in business risk, the continued perpetuation of the historical gap in equity ratios between the higher equity ratio awarded to distribution utilities and the lower equity ratio awarded to transmission utilities is no longer warranted.

7.4 Business risk analysis

434. In this section of the decision, the Commission considers the evidence dealing with business risk from both a generic perspective impacting all Alberta utilities and a company specific perspective. In conducting this analysis, the Commission will consider whether any generic business risk factors impacting all the affected utilities, or utilities by sector, require the Commission to make directional adjustments to the deemed equity ratios that would otherwise result from the credit metric calculations alone. Next the Commission will consider whether any utility specific business risk factors require the Commission to make a utility-specific deemed equity ratio adjustment.

7.4.1 Generic business risks

435. In this section of the decision, the Commission considers the evidence on generic business risk impacting all Alberta utilities.

436. Dr. Carpenter defined business risk as "the underlying risks inherent in a particular company's operations." He added that while business risk is "a somewhat subjective concept, and there is more than one way of structuring an analysis of business risk," an approach that is commonly taken is to consider five elements of business risk: supply risk, demand (or market) risk, competitive risk, operating risk and regulatory risk. Mr. Stauft and Mr. Johnson also referred to these five elements of business risk in their evidence.

437. Dr. Carpenter assessed the business risk of the Utilities in 2016 and 2017 relative to the business risk of the Utilities in the past. He particularly focussed on Dr. Villadsen's sample of natural gas LDCs. His analysis also focussed on the electricity distribution function, which he noted the Commission had used as a benchmark in prior proceedings.

438. Although Dr. Carpenter noted that while the overall decline in the level of economic activity in Alberta may increase demand risk through its influence on growth customer numbers, the Utilities did not face significant competition, supply, demand or operating risk. Accordingly, his evidence focused on regulatory risk, which is summarized in sections 7.4.1.1, 7.4.1.2 and 7.4.1.3 that follow.

439. Mr. Hevert submitted that although the direct effects of the 2008-2009 credit crisis may be somewhat removed in time, the increasingly volatile current capital market is a factor that should be reflected in the deemed equity ratios for AltaLink and EPCOR. Based on his analysis of regulatory risk, which is summarized in sections 7.4.1.1, 7.4.1.2 and 7.4.1.3 that follow, Mr. Hevert stated that the level of perceived regulatory risk has increased since 2013.

440. Dr. Cleary described business risk as some variation of factors that cause uncertainty, or volatility, in operating income. In his opinion, most experts would agree with this description. Dr. Cleary used a coefficient of variation (CV) of the EBIT/sales ratio to quantify the level of business risk of the affected utilities.

441. Dr. Cleary concluded that the affected utilities have low business risk, as demonstrated by their low earnings volatility, their ability to generate high operating profit margins, and their ability to grow operating earnings. In his view, this low risk supported a 100 bps "across the board" reduction in deemed equity ratios. Dr. Cleary reached this conclusion by examining the historical allowed ROEs of the affected utilities, by calculating the CV of the EBIT/sales ratio and the CV of ROE of the affected utilities and comparing them to U.S. and other Canadian utilities; and by analyzing the median annual percentage EBIT growth of the affected utilities and comparing them to U.S. and other Canadian utilities.

442. In assessing business risk, Dr. Cleary examined the ability of the affected utilities to earn their allowed ROEs on a consistent basis from 2005-2014. The yearly figures illustrated that the affected utilities earned average and median ROEs above the allowed ROE in all years except 2005, when the average ROE was 0.18 per cent below the allowed ROE. In his submission, this consistent overearning indicated that the affected utilities operate in an environment with low overall business risk.

443. Mr. Hevert disagreed with Dr. Cleary's use of EBIT/sales as a measure of risk. Instead of quantifying volatility based on the CV (EBIT/sales) calculation that Dr. Cleary used, Mr. Hevert stated that the CV of net operating income (NOI) was a more appropriate measure of business risk because income taxes are an operating expense for utility companies. Mr. Hevert stated that the CV (NOI), together with the CV of earned ROE, draws a more accurate picture of risk. Mr. Hevert submitted that the average of the CV (NOI) and the CV (ROE) shows that all sample groups considered by the parties in this proceeding are relevant in deriving an ROE for the affected utilities.

444. Dr. Carpenter also criticized Dr. Cleary's evidence regarding business risk. He stated that Dr. Cleary's evidence was not consistent with the framework of Dr. Carpenter for analyzing risk because it only focused on the regulatory risk element of fundamental risk. Dr. Carpenter also

submitted that Dr. Cleary's variability risk analysis is flawed because it is based on historical information that does not capture variability in investor returns and is not forward looking.

445. Dr. Carpenter further submitted that Dr. Cleary's definition of business risk is not particularly helpful in determining how to analyze risk in a forward-looking sense. He noted that Dr. Cleary's focus on historical accounting-based earnings variability fails to inform the factors identified by Mr. Hevert in his definition of business risk, such as service territory economic growth, customer mix and concentration, capital intensity and operating leverage and regulatory risk.

446. Based on the foregoing, Dr. Carpenter concluded that Dr. Cleary's quantitative analysis of business risk is seriously flawed both conceptually and empirically. In his view, the Commission should not rely on Dr. Cleary's analysis in reaching a conclusion about the business risk of the affected utilities.

447. Mr. Stauft listed the five elements of business risk generally assessed by regulators, which were also listed by Dr. Carpenter and Mr. Johnson in their evidence. While he agreed that to some extent this categorization is useful, he stated that in the modern era, and especially for the affected utilities, the primary driver of both short-term and long-term business risk is the regulatory regime. Mr. Stauft submitted that supply risk, market risk and operational risk are very low for the affected utilities, and more importantly, these risks stabilize over time.

7.4.1.1 Impact of the Commission's utility asset disposition decision

448. In the UAD decision the Commission reviewed the legislation and related court decisions. It found that customers are responsible for the net book value of utility assets that are taken out of utility service as the result of an "ordinary retirement" before the original cost of the assets have been recovered from customers through the depreciation expense included in rates. On the other hand, utility shareholders, as owners of the assets, are responsible for the net book value of utility assets that are taken out of utility service as the result of an "extraordinary retirement" before the original cost of the assets has been recovered from customers through the depreciation expense included in rates. This symmetrical relationship was described at paragraph 333 of the UAD decision as follows:

> 333. … The courts have now clarified the matter, stating that all proceeds and losses on all utility assets are for the account of the shareholders, as the sole owners of the utility assets. As property owner, the utility can expect compensation from customers in respect of its asset only for so long as those assets are used (as determined on a reasonable basis) to provide service to customers. Whatever the perspective, the property law principles of ownership must be applied symmetrically to all utility assets.

449. The meaning of "ordinary retirement" and "extraordinary retirement" were referred to in the UAD decision at paragraph 304 as follows:

> 304. … The UCAGU [Uniform Classification of Accounts for Gas Utilities, Alberta Regulation 546/63] in Section 8 states that "ordinary retirements result from causes reasonably assumed to have been contemplated in prior depreciation provisions, and normally may be expected to occur when plant reaches the end of its expected service life." The UCAGU also makes provision for "extraordinary retirements" defined as retirements "from causes not reasonably assumed to have been anticipated or contemplated in prior depreciation or amortization provisions." Under-recovery or

> over-recovery of capital investment on ordinary retirements are for the account of customers under the amortization of reserve differences described above. Under-recovery or over-recovery of capital investment on extraordinary retirements (as is the case with assets disposed of outside of the ordinary course of business or moved to a non-utility account) are for the account of the utility. The treatment of retirements for electric utilities is to the same effect under the USA [Uniform System of Accounts] Electric Plant Instructions. [footnotes omitted]

450. What would constitute an "extraordinary retirement" was further explained at paragraph 327 of the UAD decision where the Commission stated the following:

> 327. … 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. [footnotes omitted]

451. In this proceeding, AltaLink submitted that the regulatory risk component of business risk has increased materially for utilities in Alberta because of the Commission's findings in the UAD decision that "extraordinary retirements" may result in utility assets being removed from rate base without the ability to recover the remaining net book value of those assets from ratepayers. AltaLink added that this result is unprecedented in North America.[514]

452. Mr. Fetter, on behalf of AltaLink, submitted that the regulatory environment is the most important qualitative component of a utility's credit rating. He added that a constructive regulatory environment is critical if a regulated utility is to be assigned a credit rating at the A level.[515] He indicated that the views of the credit rating agencies and equity and debt analysts about the regulatory support provided by the Commission have moved in a negative direction since the issuance of the 2013 GCOC decision and the UAD decision, the dismissal of the appeal of both decisions by the Alberta Court of Appeal and the subsequent refusal by the Supreme Court of Canada to grant leave to appeal.[516]

453. Mr. Fetter also stated that a reason for the change in the views of the credit rating agencies and equity and debt analysts is a belief that the Commission has "created the risk that shareholders will bear stranded asset losses, notwithstanding the absence of any imprudent behavior on the part of utility management."[517] Mr. Fetter submitted that the manner in which the UAD decision is implemented will affect how the regulatory climate in Alberta will be viewed by investors and credit rating agencies in the future.[518]

514 Exhibit 20622-X0124, evidence of AltaLink, PDF page 2.
515 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 5.
516 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 5.
517 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF pages 5-6.
518 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 6.

454. Dr. Carpenter submitted that the main effect of the UAD decision is uncertainty about future treatment of the costs of stranded assets, and this aspect is relevant for analyzing business risk. He described stranded assets as those that were prudently added to a utility's rate base in the past, but which, as a result of external factors such as technological developments, no longer provided a valuable service to customers. Dr. Carpenter stated that investors in the equity of regulated utilities would consider an important part of the regulatory regime bargain, which permits utilities to access capital at relatively low cost in exchange for dedicating assets to public utility service, includes the expectation that the costs of stranded assets would be permitted to be recovered through the utility's rates, absent a finding of imprudence by the utility's regulator.[519] Dr. Carpenter submitted that the UAD decision calls into question this aspect of the regulatory bargain, and signals that in the future the Commission may determine that investors, not customers, should be at risk for the costs of stranded assets.[520] He added that this creates a new stranded asset risk[521] for which investors would require compensation.[522]

455. Dr. Carpenter submitted that the UAD decision has an effect on business risk for 2016 and 2017 for the affected utilities and added that if there were to be significant disallowances in the future, the result would be a further significant increase in business risk.[523] He stated that this increased business risk requires an increase in allowed returns.[524]

456. Dr. Carpenter further stated that the Commission's approach to stranded assets described in the UAD decision, as well as Decision 2014-297[525] (Slave Lake decision) and the possible wholesale retirement of the majority of existing electro-mechanical and automated meter reading meters on EPCOR Distribution's system, highlights a difference of approach in relation to the recovery of prudently incurred investments, relative to other Canadian and U.S. jurisdictions.[526]

457. Dr. Carpenter submitted that the test for cost recovery in most jurisdictions is prudence, and prudently incurred costs will be eligible for cost recovery. He added that in the UAD decision, the Commission has departed from the prudence standard for cost recovery.[527] Dr. Carpenter indicated that generally, asset utilization risk and the risk of extraordinary obsolescence is borne by customers. In his view, if it becomes clear that investors, rather than customers, are to bear these risks, investors will require a higher return as compensation.[528]

458. Dr. Carpenter referred to the Commission's decision on an application from ATCO Gas to recover certain costs related to the southern Alberta floods of 2013.[529] He noted in that decision, the Commission distinguished ATCO Gas's application from the Slave Lake decision and approved the Z factor cost for recovery in customer rates. Dr. Carpenter submitted this

519 Exhibit 20622-X0489, rebuttal evidence of Dr. Carpenter, PDF pages 24-25.
520 Exhibit 20622-X0489, rebuttal evidence of Dr. Carpenter, PDF page 25.
521 Exhibit 20622-X0121, evidence of Dr. Carpenter, PDF page 6.
522 Exhibit 20622-X0489, rebuttal evidence of Dr. Carpenter, PDF page 26.
523 Exhibit 20622-X0121, evidence of Dr. Carpenter, PDF page 7.
524 Exhibit 20622-X0121, evidence of Dr. Carpenter, PDF page 37.
525 Decision 2014-297 (Errata): ATCO Electric Ltd, 2012 Distribution Deferral Accounts and Annual Filing for Adjustment Balances, Proceeding 2682, Application 1609719-1, October 29, 2014. Errata issued January 8, 2005.
526 Exhibit 20622-X0121, evidence of Dr. Carpenter, PDF page 30.
527 Exhibit 20622-X0121, evidence of Dr. Carpenter, PDF page 31.
528 Exhibit 20622-X0121, evidence of Dr. Carpenter, PDF page 34.
529 Decision 2738-D01-2016: ATCO Gas and Pipelines Ltd., Z Factor Application for Recovery of 2013 Southern Alberta Flood Costs, Proceeding 2738, March 16, 2016.

difference in treatment introduces further ambiguity as to what circumstances will be considered to be an extraordinary retirement.[530] He stated this would indicate to an equity investor that there remains considerable case-by-case discretion in the Commission's application of the UAD decision.

459. Dr. Booth submitted that ATCO Pipelines has limited exposure to any UAD risk. He noted ATCO Pipelines' confirmation that, as part of its review of the assets forming the "Alberta System,"[531] it did not find any assets that were not used and useful. Dr. Booth added that the $700 million urban pipeline replacement capital project of ATCO Pipelines, which creates a new pipeline system ringing Edmonton and Calgary, implies a reduction in operational risk, as the integrity of a new high pressure pipeline would be greater than that of the pipeline it replaces.[532]

460. Dr. Booth agreed with comments from DBRS that UAD disallowances are potentially "low probability/high impact events."[533] He added that an unfavourable UAD decision alone would not affect a credit rating because DBRS would assess the magnitude on a case-by-case basis when such an event materializes.[534]

461. Dr. Booth submitted that when serious risks do arise for regulated utilities in Canada, it is extremely rare for these regulated utilities not to ask their regulator for some reallocation of costs to keep the shareholders whole. He expects a review will occur if any serious problems arise that cast doubt on ATCO Pipelines' ability to earn its allowed ROE.[535]

462. Dr. Booth stated that regulatory risk has not increased for ATCO Gas. He added that he has never seen a Canadian utility hurt by PBR, as it mainly offers upside potential to the allowed ROE.[536] Dr. Booth judged there to be minimal stranded asset risk for ATCO Gas. He proposed that if stranded asset risk ever becomes material, the regulatory dynamic will ensure that rates remain fair and reasonable and every effort will be taken to protect the shareholders' opportunity to earn a fair ROE.[537]

463. Mr. Johnson stated that in the UAD decision, the Commission confirmed that the utilities in Alberta have an equivalent opportunity to enhance their ROE by selling capital assets that are no longer required to provide utility service. He submitted that this additional return opportunity offsets potential losses when the utility has not adequately depreciated an asset that is deemed to be no longer needed or used and useful.[538]

464. Mr. Thygesen disagreed with Dr. Carpenter's assertion that the UAD risk was "created by the original appeal of the *Stores Block*[[539]] decision." In Mr. Thygesen's view, unless the

530 Exhibit 20622-X0489, rebuttal evidence of Dr. Carpenter, PDF page 27.
531 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 97.
532 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 97.
533 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 98.
534 Exhibit 20622-X0242, evidence of Dr. Booth, PDF page 98.
535 Exhibit 20622-X0242, evidence of Dr. Booth, PDF pages 98-99.
536 Exhibit 20622-X0345, evidence of Dr. Booth, PDF page 14.
537 Exhibit 20622-X0345, evidence of Dr. Booth, PDF page 16.
538 Exhibit 20622-X0344, evidence of Mr. Johnson, PDF pages 5-6.
539 *ATCO Gas & Pipelines Ltd. v Alberta (Energy & Utilities Board)*, 2006 SCC 4, [2006] 1 S.C.R. 140 (*Stores Block).*

legislation is changed, the Commission has no option with respect to how it treats assets no longer used for utility service.[540]

465. Mr. Thygesen submitted that the simplest solution to any UAD risk would be to amend the legislation.[541] He added that this would “greatly reassure the credit markets” that positive steps are being taken “to eliminate what the utilities have advised credit markets are major concerns.”[542]

466. Dr. Cleary submitted that despite quotes from credit rating agency reports suggesting that the implications of the UAD decision are a big risk facing the utilities in Alberta, these same utilities continue to be rated “excellent” with respect to business risk by S&P, while DBRS reports show low business risk as the number one strength of the affected utilities.[543] He added the UAD decision also presents the possibility that gains will accrue to shareholders.[544]

467. Mr. Stauft’s general response to the claims that the regulatory environment in Alberta has deteriorated as a result of the risk associated with the UAD decision is that they are overstated. He stated that the UAD decision cannot reasonably be expected to have any significant effect on the utilities or their financial affairs.[545] In his view, the UAD decision simply extended the risk-bearing principle beyond the narrow range of cases where it benefits the utilities, to utility assets in general, where sometimes it does not benefit the utilities. He stated that while it is likely true that the treatment of extraordinary retirements that arose out of the UAD decision is unusual, so is the treatment of surplus real estate that arose out of *Stores Block*. Mr. Stauft commented that the logical alternative to the UAD decision structure is one in which all post-retirement risks are allocated to customers rather than the affected utilities.[546]

468. Mr. Stauft submitted that the amounts at risk for both customers and the affected utilities in terms of potential UAD-related disallowances and windfall profits are trivial relative to the revenues and assets of the affected utilities. Mr. Stauft referred to the 2013 floods in southern Alberta, described as the greatest natural disaster in Alberta’s history, and he stated that so far they have cost the affected utilities in Alberta nothing. He also commented that the Slave Lake fire destroyed half of a sizable town, and that it cost ATCO Electric Distribution only approximately $400,000.[547] He noted that the affected utilities achieved gains of a few million dollars through the disposition of utility assets and that there is the potential for several million more:

> A list of those gains was provided in response to an undertaking in the 2013 GCOC, and they added up to gains of a few million dollars. In addition, I understand that there have been subsequent applications for approvals of dispositions of real estate by Fortis [FortisAlberta] and ATCO Gas that could end up netting those utilities several millions of dollars.[548] [footnote omitted]

540 Exhibit 20622-X0343, evidence of Mr. Thygesen, PDF pages 20-21.
541 Exhibit 20622-X0343, evidence of Mr. Thygesen, PDF page 23.
542 Exhibit 20622-X0343, evidence of Mr. Thygesen, PDF page 24.
543 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 67.
544 Exhibit 20622-X0306, evidence of Dr. Cleary, PDF page 68.
545 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 29.
546 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 30.
547 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 32.
548 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 31.

469. Mr. Stauft concluded that it appears the affected utilities have gained more than they have lost under the principles laid down by the courts and reflected in the UAD decision through the dispositions of surplus real estate.

470. Mr. Stauft indicated that while most of the discussion around the UAD decision is with respect to natural disasters, there is also the potential for stranded assets that result from industry restructuring, which normally involves unbundling integrated utility services into separate services, and from the introduction of competition. He submitted that the utility industry in Alberta is completely unbundled with the sole exception of AltaGas' merchant service. Mr. Stauft added that none of the affected utilities are subject to meaningful competition.[549]

471. Mr. Stauft submitted that in the abstract, the idea of making the affected utilities solely responsible for absorbing stranded costs may be unusual and alarming for credit rating agencies and financial analysts. However, if there is no reasonable possibility of material stranded costs ever materializing in the Alberta utility industry, the idea does not matter.[550]

472. AltaLink countered that it faces significant UAD-related risks, arising from the potential for extraordinary retirements and the forced removal from rate base of assets not used or required to be used to provide service. It submitted that unlike a utility with lands acquired at a minimal historical cost, AltaLink does not have the same potential for land sales that may result in large gains that would offset corresponding losses from an extraordinary retirement. AltaLink noted it has had one sale of an asset outside of the ordinary course of business since its inception, with a resulting gain of $1.1 million. It submitted that the potential upside benefit is negligible compared to the relative downside risk.[551]

473. Mr. Fetter stated that Mr. Thygesen's evidence that the Commission's UAD policy was mandated by the *Stores Block* decision is irrelevant.[552] Mr. Fetter submitted the relevant considerations are that the Commission's UAD decision has created new and unique risks that should be factored into this proceeding.[553]

474. Mr. Fetter submitted that the extent of damages to the affected utilities from events likely to be included under the Commission's UAD decision, such as weather, terrorism, or other disasters, go far beyond weakening credit metrics. He stated they "reach a level of worrying about a utility's ongoing financial viability."[554] Mr. Fetter submitted that while all utilities face these threats, the difference for the affected utilities is that compensation to cover damages from these risks would not apply under the principles reviewed in the UAD decision. He added because of this, non-recovery of such losses tied to ordinary activities of the affected utilities should be factored into this GCOC proceeding.[555]

475. Mr. Fetter disagreed with Mr. Stauft's opinion that there is symmetry within the UAD decision. He noted that the net gains on dispositions outside the ordinary course of business since the *Stores Block* decision amount to $3.718 million for EPCOR and $1.1 million for AltaLink.

549 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF pages 33-34.
550 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 34.
551 Exhibit 20622-X0440, rebuttal evidence of AltaLink, PDF pages 19-20.
552 Exhibit 20622-X0447, rebuttal evidence of Mr. Fetter, PDF page 4.
553 Exhibit 20622-X0447, rebuttal evidence of Mr. Fetter, PDF page 4.
554 Exhibit 20622-X0447, rebuttal evidence of Mr. Fetter, PDF page 6.
555 Exhibit 20622-X0447, rebuttal evidence of Mr. Fetter, PDF page 9.

Mr. Fetter doubted that any utility executive would seek to take on all of the downside risks associated with the UAD decision in return for such small net gains.[556]

476. Mr. Buttke submitted it is unclear to the markets how the Commission will implement the UAD decision in the future and because of that, there is risk for which investors will expect to be compensated.[557]

477. Mr. Buttke referenced a UAD "stress case" that was prepared by DBRS. In this stress case, DBRS assumed that a utility with rate base of $5 billion and an equity component of 36 per cent experiences an extraordinary event in which $500 million of rate base costs are impaired and the Commission finds that the loss is for the account of shareholders. DBRS stated in order to remain aligned with the deemed regulatory structure, the shareholder is required to inject $500 million of equity. DBRS also assumed the destroyed assets (which had been recently built) are rebuilt for $500 million and placed into rate base.[558]

478. Using the DBRS stress case, Mr. Buttke noted that from a bondholder's point of view, leverage rises from 64 per cent to 71.1 per cent, while the asset is being rebuilt and until it is placed into rate base, which may take a significant amount of time. Mr. Buttke submitted it is unlikely that credit spreads would stay unchanged during this timeframe. He added that issuers would be left with an asset/liability gap in their optimal debt structure and the utility would suffer higher funding costs than necessary for an asset not in its rate base as the existing term debt would not be able to be called without a significant penalty via the "make whole call."[559] He also indicated that equity investors would suffer a permanent dilution of their equity stake, with these investors' ROE being reduced from 8.3 per cent to 6.5 per cent.[560]

7.4.1.2 Risk of credit rating downgrade

479. AltaLink stated that the deterioration in the regulatory environment in Alberta has become an increasing source of concern for AltaLink's debt investors, debt analysts[561] and credit rating agencies.[562] It pointed out that S&P has placed Alberta's regulatory advantage assessment on "negative trend." AltaLink submitted that if S&P downgrades Alberta's regulatory advantage assessment, many, if not all, of the affected utilities could face a ratings downgrade if they are deemed to have an insufficient FFO/debt ratio.[563]

480. Referring to an S&P report from August 26, 2015,[564] AltaLink indicated that S&P has made it clear that any substantial disallowance by the AUC, whether related to stranded asset risk or some other matter, would likely change S&P's view on Alberta's regulatory assessment,

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556 Exhibit 20622-X0447, rebuttal evidence of Mr. Fetter, PDF page 10.
557 Exhibit 20622-X0449, rebuttal evidence of Mr. Buttke, PDF page 54.
558 Exhibit 20622-X0449, rebuttal evidence of Mr. Buttke, PDF pages 54-55.
559 Exhibit 20622-X0449, rebuttal evidence of Mr. Buttke, PDF page 55.
560 Exhibit 20622-X0449, rebuttal evidence of Mr. Buttke, PDF page 56.
561 AltaLink included material from DBRS, Bank of Montreal, Scotiabank and Royal Bank of Canada (RBC) Capital Markets which commented on the 2013 GCOC decision report that commented on the UAD decision and the Slave Lake decision. This material is included in Exhibit 20622-X0124, evidence of AltaLink, PDF pages 7-8.
562 AltaLink included material from a DBRS report that commented on the UAD decision and the Slave Lake decision. This material is included in Exhibit 20622-X0124, evidence of AltaLink, PDF pages 5-6.
563 Exhibit 20622-X0124, evidence of AltaLink, PDF page 2.
564 S&P report titled Are Recent Regulated Utility Downgrades A Sign of Erosion In The Canadian Utility Sector Outlook. This report can be found in Exhibit 20622-X0133, PDF page 443.

resulting in a credit rating downgrade for those utilities in Alberta whose FFO/debt ratio was below the absolute minimum of 13 per cent and perhaps below an even higher threshold.[565]

481. AltaLink stated that credit rating downgrades tend to last for years and cannot be resolved in the immediate aftermath. It added that it must take proactive steps to mitigate the risk of a credit downgrade because the effect on ratepayers is too high. AltaLink pointed out that a credit rating downgrade not only affects debt rates, but also access to debt markets. It stated that entities with a "BBB" credit rating "do not have the ability to raise capital from the term debt markets whenever they desire."[566]

482. AltaLink referred to its 2012-2013 direct assigned capital deferral account application,[567] which was being processed by the Commission when AltaLink submitted its evidence in this proceeding. AltaLink indicated that certain interveners in that proceeding were proposing disallowances of up to $300 million. It added that it would be a "watershed moment" for credit rating agencies if AltaLink was denied recovery of significantly incurred costs.[568] AltaLink submitted that the established history in Alberta of negligible, if any, disallowances is fundamental to the assessment of the Alberta regulatory regime by both S&P and DBRS.[569]

483. AltaLink referred to its inability to issue its planned $500 million of medium-term notes on June 25, 2015, as a consequence of the concerns from debt investors, debt analysts and credit rating agencies. It was only able to issue $350 million, and only after offering a five bps concession to investors.[570] AltaLink indicated that since March 31, 2014, both its 10-year and 30-year credit spreads have moved significantly higher, and in its view, these increased credit spreads are an indication of heightened credit risk.[571]

484. Mr. Hevert indicated that chief among the business risks currently facing AltaLink and EPCOR are those associated with regulation.[572] Similar to what AltaLink did in its evidence, Mr. Hevert included a number of quotes from credit rating agencies and analysts regarding the 2013 GCOC decision and the UAD decision.[573] Mr. Hevert stated that although it is difficult to assess the risks associated with these decisions, such difficulty does not mean that those risks are unimportant to either debt or equity investors.[574] He also submitted that credit rating agencies and analysts view the regulatory climate in Alberta as having deteriorated since the 2013 GCOC decision and the UAD decision were issued. Mr. Hevert added that these changes in perceptions indicate increased regulatory risk for all the affected utilities, including AltaLink and EPCOR.[575]

485. Mr. Hevert also mentioned the downgrade of the province of Alberta's long-term credit ratings from "stable" to "negative" by Moody's on January 18, 2016. While he acknowledged that the downgrade by Moody's was not directed at the regulatory environment in Alberta, he

565 Exhibit 20622-X0124, evidence of AltaLink, PDF page 12.
566 Exhibit 20622-X0124, evidence of AltaLink, PDF page 9.
567 Proceeding 3585. Decision 3585-D03-2016: AltaLink Management Ltd., 2012 and 2013 Deferral Accounts Reconciliation Application, Proceeding 3585, Application 1611090-1, June 6, 2016.
568 Exhibit 20622-X0124, evidence of AltaLink, PDF page 13.
569 Exhibit 20622-X0124, evidence of AltaLink, PDF page 13.
570 Exhibit 20622-X0124, evidence of AltaLink, PDF page 3.
571 Exhibit 20622-X0124, evidence of AltaLink, PDF page 14.
572 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 103.
573 These quotes can be found in Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 104-116.
574 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 111.
575 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 114.

stated that it indicates how the deteriorating financial conditions of the province of Alberta are increasing the risk to the province's economy. Mr. Hevert added that this increased macroeconomic risk will increase the operating risks and possibly the financial positions of all firms operating in Alberta.[576]

486. Mr. Fetter commented that a utility's credit ratings have a significant effect on the ability of the utility to raise capital on a timely basis and at reasonable terms.[577] He added that a strong credit profile is important for AltaLink, EPCOR and the other affected utilities due to ongoing significant levels of capital investment.[578]

487. Mr. Fetter stated that the commentaries from the financial community show a changing regulatory environment in Alberta.[579] Referencing excerpts from various commentaries on AltaLink and AltaLink Investments L.P. from DBRS and S&P from May 2012 to December 2014,[580] Mr. Fetter submitted that these were years of steady-state positive assessments of utility regulation in Alberta.[581] He added that beginning in 2015, this positive view began to change as the credit rating agencies considered the potential ramifications of the UAD decision and the 2013 GCOC decision.[582]

488. Mr. Fetter pointed out that phrases such as "deteriorating" and "recent unsettling decisions in Alberta" are included in credit rating reports issued since early 2015.[583] He also referred to DBRS changing its trend on FortisAlberta's ratings from "positive" to "stable" in late 2015.[584] Mr. Fetter acknowledged that in early 2016, S&P summed up the same supportive view of regulation in Alberta, but also noted that S&P continued to point to a potential ratings downside if prudently incurred but stranded costs were to be disallowed at a material level.[585] He pointed out that while the Slave Lake decision effect of $400,000 was relatively small, his belief is that when decisions with greater financial effect occur in the future, the reaction will be much louder and more urgent.[586]

489. Mr. Fetter indicated that the credit rating agencies seem to be waiting for the Commission to issue a significantly negative decision related to UAD.[587] Unlike the credit rating agencies, equity and debt analysts have reacted strongly to the Commission's UAD decision.[588] Some of the debt and equity analyst reports in Mr. Fetter's evidence indicate that credit ratings and interest rate spreads could widen for the affected utilities.[589] For example, in a report dated March 13, 2015, Scotiabank stated:

> We think the potential impact on bondholders of the UAD decision … is simple. Higher risk means higher spreads. …Going forward, this would mean higher borrowing costs for

576 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 122-123.
577 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 7.
578 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 8.
579 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 15.
580 These references can be found in Exhibit 20622-X0089, evidence of Mr. Fetter, PDF pages 16-18.
581 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 18.
582 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 18.
583 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF pages 19-20.
584 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 20.
585 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 20.
586 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 33.
587 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 21.
588 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 21.
589 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF pages 21-25.

> Alberta utilities. …we think it would likely, over time, become material, say, 10 to 20 bps, for Alberta utilities, compared to other provincial jurisdictions. We think the spread widening would become even more than 10 to 20 bps if this risk were to be crystalized by the real-life occurrence of a material adverse event.…[590]

490. Similarly, RBC Capital Markets stated in a report dated September 18, 2015 that:

> We think the current 10-20 bp long bond spread discount between Alberta regulated utility issuers (AltaLink LP, CU Inc, EPCOR Utilities Inc and FortisAlberta Inc) and peers in other jurisdictions is warranted and should persist given continued uncertainty of the province's regulatory framework.[591]

491. Mr. Fetter indicated that S&P has placed Alberta's "strong" regulatory advantage assessment on a negative trend and S&P has stated that it will continue to assess regulatory developments in Alberta.[592] He added that a weakening regulatory advantage assessment from S&P would result in targets for the FFO/debt ratio being raised from the nine to 13 per cent, corresponding to the Commission's previously established target range of 11.1 per cent to 14.3 per cent for the FFO/debt ratio range, to a 13 to 23 per cent range. Mr. Fetter stated that EPCOR's current target range is 13 to 23 per cent for its FFO/debt ratio.[593] Mr. Fetter provided evidence that a turnaround from any credit rating downgrade is almost always measured in years.[594]

492. Mr. Fetter strongly urged the Commission not to make the occurrence of a credit rating downgrade a trigger for an after-the-fact response.[595]

493. Mr. Fetter described the core principle underlying S&P's ratings philosophy for regulated utilities as a cost-of-service methodology based upon a prudency standard that allows for full cost recovery with negligible disallowances. He stated that DBRS also subscribes to this standard. As a result, Mr. Fetter concluded that, even though there have been no major negative ratings event following the UAD decision and the 2013 GCOC decision, he expects that if a more positive direction does not come out of this 2016 GCOC proceeding, a major negative ratings event will eventually occur. Mr. Fetter submitted that the universal credit ratings philosophy cannot be accepting of a major disallowance relating to the cost of assets prudently constructed and utilized to provide customers with utility service, but rendered unusable through no fault of the utility involved.[596]

494. Mr. Fetter stated his view that the scrutiny of the financial community will not be relaxed until greater clarity on UAD is obtained. He recommended that the Commission authorize ROE and equity ratio determinations in this proceeding that allow for an FFO/debt credit metric above 14 per cent. He added his view that a 14 per cent FFO/debt level should secure the A ratings of all of the affected utilities.[597]

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590 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 22.
591 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 24.
592 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 26.
593 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 28.
594 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF pages 30-33.
595 Decision 20456-D01-2016.
596 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 35.
597 Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 36.

495. Mr. Buttke stated that this decision will be monitored closely by market participants in light of the market's reaction to the 2013 GCOC decision and the ongoing potential litigation relating to clarification of the principles discussed in the UAD decision. Similar to Mr. Fetter, Mr. Buttke noted that credit rating agencies have cited the regulatory environment in Alberta as a factor in some recent negative ratings actions. Mr. Buttke indicated that while some have chosen a "wait and see" approach, all have specifically pointed to the current and future Commission proceedings and the UAD-related cases as key data points.[598]

496. Mr. Buttke submitted that markets have raised the relative cost of funding for the Utilities' regulated entities relative to their Canadian peers in light of increased regulatory risk, and will be looking to this 2016 GCOC decision, as well as others, to determine whether additional pricing adjustments need to be made.[599]

497. Mr. Buttke stated that the market is already pricing in some probability of S&P downgrading their assessment of the regulatory environment in Alberta.[600] He added that both S&P and DBRS have cited decisions of the Commission, among other factors, in revising ratings outlooks for certain utility companies in Alberta.[601] Mr. Buttke indicated that numerous banks have commented that the UAD decision is a clear credit negative in that it creates an unquantifiable risk that must be offset in part by higher investor returns.[602] He added that the lower ROE and reduced deemed equity ratios approved in the 2013 GCOC decision, as well as regulatory lag, have been raised as areas of concern by debt and equity analysts.[603]

498. Mr. Buttke submitted that the lowering of the deemed equity ratios in the 2013 GCOC decision is a concern to investors because it implies that the Commission deems the risk of operating a utility in Alberta is decreasing, while the market believes that the risk is increasing based on the UAD decision and the transition to PBR, among other factors. He added that for bondholders, a lower allowed ROE on a lower deemed equity ratio is detrimental to debt coverage ratios monitored by the credit rating agencies.[604]

499. Mr. Buttke stated that S&P's regulatory advantage assessment determination has a significant effect on S&P's view of a utility's financial risk. Consequently, a utility with a weaker regulatory advantage assessment would have to have a significantly stronger financial profile in order to obtain or maintain an A stand-alone credit rating.[605]

500. Mr. Buttke submitted that analysts have noted a widening of the Utilities' debt spreads relative to peers since the release of the UAD decision and the 2013 GCOC decision.[606] Mr. Buttke stated that in addition to pricing, the most important reason for regulated utilities in Canada to maintain an A credit rating is to maintain dependable market access in almost all

598 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 6.
599 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 6.
600 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF pages 32-33.
601 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 34.
602 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 35.
603 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 35.
604 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 37.
605 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 41.
606 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 45.

market conditions at a reasonable price. He added that this allows the Utilities more flexibility to fund at the most opportune times.[607]

501. Mr. Stauft noted that the negative comments about the UAD decision have not been accompanied by actual credit rating downgrades. He submitted that it is unreasonable to believe that the UAD decision or the 2013 GCOC decision reflect any meaningful deterioration in the Alberta regulatory environment, or that they have materially increased regulatory or business risk for the affected utilities.[608]

7.4.1.3 Regulatory lag

502. AltaLink referred to the reduced allowed ROE and deemed equity ratios resulting from the 2013 GCOC decision, which was issued in 2015, and the impacts associated with regulatory lag.[609]

503. Mr. Hevert stated that AltaLink and EPCOR face financial uncertainty related to regulatory lag.[610] He defined regulatory lag as "… the length of time between the investment of funds on the part of a utility, and the recovery of those funds through rates."[611] Mr. Hevert pointed out that the greater the capital expenditures made by a utility, the larger is the magnitude of the effect on the utility's cash flows from regulatory lag, and the longer the regulatory lag, the greater is the risk faced by the utility due to financial uncertainty. He added that Moody's considers timely cost recovery as an important determinant of credit quality.[612] Mr. Hevert listed a number of regulatory proceedings applicable to either AltaLink, EPCOR or both where regulatory lag was a concern. In his view, the regulatory lag associated with these proceedings ranges from one-year to over four years.[613]

504. Mr. Stauft submitted that the "main reason the 2013 GCOC decision was somewhat out of phase was that the Commission wanted to ensure that the utilities and other parties had an adequate opportunity to address PBR-related and UAD-related issues in [that proceeding].[614] He stated that there is no reason to expect this timing issue to arise again because the delays that were experienced in the 2013 GCOC proceeding are not an intrinsic feature of the Alberta regulatory system.[615]

7.4.1.4 Other generic business risk considerations

505. Mr. Hevert referred to two other risks that, although difficult to quantify with respect to timing and eventual effect, may have significant implications for utility operations going forward. These risks are the risk of load reduction (as high load customers assess the economics of "behind the fence" generation) as well as the risk of the development of distributed generation (which could disrupt the utility business model).[616]

607 Exhibit 20622-X0126, evidence of Mr. Buttke, PDF page 48.
608 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF pages 35-36.
609 Exhibit 20622-X0124, evidence of AltaLink, PDF page 2.
610 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 122.
611 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 119.
612 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 119.
613 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 120-122.
614 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 30.
615 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 30.
616 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 123.

506. AltaLink also referred to the significant amount of customer contributions on its books, which have grown from $31.3 million in 2002 to a forecast amount of $580 million in 2017. It submitted the Commission has previously acknowledged that the management of customer contributions and consequent reductions to rate base, contribute to business risk.[617] AltaLink stated that this risk was not considered by any of the intervener experts.

507. Mr. Johnson stated that regulatory risk in Alberta has not increased. In particular, he submitted that the implementation of a PBR regime has not increased the regulatory risk or business risk of ATCO Gas. Mr. Johnson referred to the actual ROEs earned by ATCO Gas in 2013 of 11.86 per cent and in 2014 of 10.95 per cent which were 3.56 per cent and 2.65 per cent, respectively, over the allowed ROE approved by the Commission in the 2013 GCOC decision.[618]

Commission findings

508. Dr. Cleary attempted to mathematically quantify the business risk of the affected utilities using a CV of the EBIT/sales ratio. The Commission continues to consider, as it did in the following quote from Decision 2004-052[619] (2004 GCOC decision), that judgement is a critical component of determining the fair return for utilities.

> The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board [Alberta Energy and Utilities Board] considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk.[620]

509. With respect to the UAD decision, the affected utilities submitted in this proceeding, as they did in the 2013 GCOC proceeding, that the UAD decision has resulted in incremental business risk to utility investors which should be compensated through higher returns.

510. In the 2013 GCOC decision, the Commission considered the *Stores Block* line of cases starting in 2006, which were reviewed in the UAD decision, and found 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 that decision."[621] However, it determined that no adjustment to the allowed ROE or deemed equity ratios was warranted because the series of court decisions reviewed in the UAD decision had provided consistent signals to the market on the risks and benefits associated with the ownership of utility property over a period of time with no perceptible impact to objective market measures. The Commission further noted in the 2013 GCOC decision:

> 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….

617 Exhibit 20622-X0440, rebuttal evidence of AltaLink, PDF page 20.
618 Exhibit 20622-X0344, evidence of Mr. Johnson, PDF pages 4-5.
619 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 2, 2004.
620 Decision 2004-052, page 35.
621 Decision 2191-D01-2015, paragraph 334.

511. The Commission found no supporting evidence of a perceived greater degree of risk arising from the *Stores Block* line of cases effecting the ability of the affected utilities to raise debt capital at reasonable rates, as demonstrated by the then recent history of credit spreads for the affected utilities. In addition, credit rating reports available at that time did not indicate any changes to ratings for the affected utilities arising from the alleged increase in business risk.[622]

512. In the 2013 GCOC decision, the Commission also found that a conclusion on incremental risk to utility investors could not be determined because "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."[623]

513. Finally, the Commission found the limitation of utility shareholder risk to occurrences of an "extraordinary retirement" as mitigating against an adjustment to ROE or to the equity ratio.

514. In this proceeding, the Commission again received evidence and argument on the implications of the *Stores Block* line of cases reviewed in the UAD decision and subsequent related Commission decisions on the risk perception of utility investors and its effect on the allowed ROE or deemed equity ratios, or both, for the affected utilities.

515. The Commission has considered events since the 2013 GCOC decision, particularly as they relate to the UAD decision. The Commission accepts the view of Dr. Carpenter that the main issue is the impact of the UAD decision and subsequent decisions on perceived investor uncertainty about the future regulatory treatment of undepreciated capital costs associated with assets impacted by an extraordinary retirement. A perceived increase in the regulatory risk component of business risk may suggest additional shareholder regulated returns are warranted.

516. Some parties referred to the Commission's decision in respect of the ATCO Gas request to recover costs arising from the 2013 flood in southern Alberta as providing support to the affected utilities and adding greater clarity on what the Commission would consider to be an extraordinary retirement, thereby reducing perceived business risk. Dr. Carpenter, however, asserted that the Commission's approval of PBR Z factor treatment for the ATCO Gas flood damages, as distinguished from the Commission's Slave Lake decision where recovery was denied on the basis of an extraordinary retirement occasioned by a fire, introduced further ambiguity rather than clarity as to what circumstances will be considered to be an extraordinary retirement by the Commission and therefore for the shareholders' account.

517. AltaLink's evidence indicated that S&P has placed Alberta's "strong" regulatory advantage assessment on "negative trend" and that any substantial disallowance by the AUC, whether related to stranded asset risk or some other matter, would likely change S&P's view on Alberta's regulatory assessment. Mr. Fetter submitted that phrases such as "deteriorating" and "recent unsettling decisions in Alberta" have been included in credit rating reports issued since early 2015 following the 2013 GCOC decision and the UAD decision. Although, as Mr. Stauft pointed out, there have been no actual credit downgrades, Mr. Fetter suggested that the credit rating agencies seem to be waiting for further clarity from the Commission or a significantly negative decision related to UAD. He also provided evidence that equity and debt analysts have reacted strongly to the Commission's UAD decision. Some of the debt and equity analyst reports

622 Decision 2191-D01-2015, paragraphs 335-338.
623 Decision 2191-D01-2015, paragraph 346.

in Mr. Fetter's evidence indicate that credit ratings and interest rate spreads could widen for the affected utilities. For example, as noted above, he referred to a report dated March 13, 2015, where Scotiabank stated:

> We think the potential impact on bondholders of the UAD decision … is simple. Higher risk means higher spreads. …Going forward, this would mean higher borrowing costs for Alberta utilities. …we think it would likely, over time, become material, say, 10 to 20 bps, for Alberta utilities, compared to other provincial jurisdictions. We think the spread widening would become even more than 10 to 20 bps if this risk were to be crystalized by the real-life occurrence of a material adverse event. …[624]

518. Mr. Fetter's view was also supported by Mr. Hevert, who included a number of quotes from credit rating agencies and analysts regarding the negative impact of the 2013 GCOC decision and the UAD decision, and Mr. Buttke, who provided evidence indicating that analysts have noted a widening of the Utilities' debt spreads relative to peers since the release of the UAD decision and the 2013 GCOC decision. Mr. Buttke additionally submitted that markets have raised the relative cost of funding for the Utilities' regulated entities relative to their Canadian peers in light of increased regulatory risk. This evidence supports the view that uncertainty with respect to the interpretation and application by the Commission of the principles espoused in the UAD decision to certain utility stranded assets, among other matters, results, in the words of Mr. Buttke, in an "unquantifiable risk which must be offset in part by higher investor returns."[625]

519. Given that the Commission determines the application of the UAD decision on a case-by-case basis, the Commission accepts the assertion of Mr. Buttke that it is unclear to the markets how the Commission will implement the UAD decision in the future, resulting directionally in some amount of increased business risk for which investors will seek compensation.

520. Based on the foregoing, the Commission finds that the evidence on the record of the proceeding is sufficient to confirm that some amount of upward pressure on the return expectations of investors has occurred since the 2013 GCOC decision due to an increase in perceived business risk of the affected utilities. The evidence supports the view that this perception arises, in part, from investor uncertainty about how the Commission will continue to interpret and apply *Stores Block* principles as reviewed in the UAD decision and in particular, the parameters of an "extraordinary retirement" to future case-by-case examples of assets unexpectedly being removed from utility service prior to the full recovery of their undepreciated capital costs.

521. The above discussion has focused on perceived changes in investor perceptions of investment in the affected utilities since the release of the 2013 GCOC decision arising from potential shareholder exposure to losses from an "extraordinary retirement" of utility assets prior to the cost of prudently acquired assets being fully depreciated. Investor perceptions have been evolving since the 2013 GCOC decision, in part, as a result of the principles laid out in the *Stores Block* decision and subsequent Court of Appeal decisions, as reviewed by the Commission in the UAD decision. The evidence of the Utilities suggested that the regulatory risk component of business risk has increased as a result of these developments. In particular, the uncertainties associated with the interpretation and application by the Commission of the definition of an

[624] Exhibit 20622-X0089, evidence of Mr. Fetter, PDF page 22.
[625] Exhibit 20622-X0132, PDF page 35.

"extraordinary retirement" in future circumstances creates a marked unknown future potential risk for investors. Interveners highlighted the corresponding enhanced earning opportunities that the affected utilities have by selling capital assets that are no longer required to provide utility service and the trivial nature of disallowances to date. Interveners argued that the facts to date illustrate that gains on sales should at least offset losses due to extraordinary retirements. Therefore, they argued that no additional allowed returns should be awarded because no changes have occurred since the 2013 GCOC proceeding. After reviewing the evidence, the Commission determined above that directionally, regulatory risk for investors in Alberta utilities has increased by some incremental but unquantifiable amount as a result of the *Stores Block*-UAD line of decisions.

522. An alternate hypothesis can also be advanced which is directionally consistent with the above Commission findings. This alternative hypothesis is based on the premise that the enhanced earning opportunities for investors has diminished since the 2013 GCOC proceeding because a substantial portion of the utility assets, which might be disposed of without impacting service and which could result in gains for utilities shareholders, will have been identified and sold since the 2006 *Stores Block* decision. Although there was limited evidence presented in this proceeding on realized and potential future opportunities for gains due to selling capital assets compared to the evidence submitted in the 2013 GCOC proceeding, if the alternative hypothesis is correct, then the affected utilities may have fewer gains on asset sales going forward to offset potential losses arising upon an extraordinary retirement. If this proposition is accurate, it directionally supports an increase in perceived investor risk.

523. With respect to the others matters raised by parties arguing that business risk has increased for the affected utilities, the Commission has considered the impact of credit metrics, including the FFO/debt ratio, in Section 8.3 of this decision. The Commission notes, however, that notwithstanding the finding above that investor uncertainty with respect to the interpretation and application of the principles discussed in the UAD decision has resulted in some amount of upward pressure on the return expectations of investors since the time of the 2013 GCOC decision, there is no evidence on the record of this proceeding that any of the affected utilities are facing a credit rating downgrade in the foreseeable future.

524. The Commission agrees with Mr. Stauft's observation that the regulatory lag associated with the 2013 GCOC decision related to requests for adjournments by the parties and other adjournments or delays to allow parties to comment on the implications of PBR, capital trackers, the UAD decision and Proceeding 2682 (relating to ATCO Electric's 2012 distribution deferral accounts and annual filing for adjustment balances application). The Commission does not consider regulatory delay to be a material factor at the present time.

7.4.2 Business risk utility sector analysis

525. 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 (EBIT) and, hence, determines the capacity for a business to be financed with debt as opposed to equity.

526. In the 2009 GCOC decision, 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).[626]

527. In the 2011 GCOC decision, the Commission reaffirmed many of its previous findings with respect to the business risk attributable to the various utility sectors. 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 effect of its integration agreement with NOVA Gas Transmission Ltd. (NGTL).

528. In this proceeding, Mr. Stauft indicated that if the existing two per cent adder to the deemed equity ratios for non-taxability and the existing two per cent adder to the deemed equity ratios for credit metric relief related to large capital programs are eliminated, as he has recommended, this would result in the difference between the equity ratio of distribution utilities and the equity ratio of transmission utilities being four per cent. He questioned whether this difference reasonably reflects relevant risk differences between distribution and transmission utilities under current market and utility circumstances.

529. Mr. Stauft stated that while the generally held belief that transmission utilities have less business risk than distribution utilities is intuitively sound, differences in this risk are difficult to quantify and moreover it is not clear why whatever difference exists implies a 400 bps deemed equity ratio spread. He submitted that based on the differences in regulation between transmission utilities and distribution utilities, it is still reasonable to believe that transmission utilities have less business risk than distribution utilities. Mr. Stauft indicated that based on Dr. Cleary's analysis of EBIT volatility, there is no discernible pattern of distribution utilities having more EBIT volatility than transmission utilities.

530. Regarding other factors that are relevant to the spread between the deemed equity ratios for transmission and distribution utilities, Mr. Stauft stated there appears to be a pattern of transmission utilities having lower effective depreciation rates than distribution utilities. He commented that all else equal, this undermines the credit metrics for transmission utilities and makes it more difficult for them to achieve credit metric levels at a given deemed equity ratio. Mr. Stauft submitted this suggests that transmission utilities may require higher deemed equity ratios. Mr. Stauft indicated it would be reasonable for the Commission to reduce the traditional four per cent difference in deemed equity ratios between distribution utilities and transmission utilities to two per cent.

531. In the 2013 GCOC proceeding, the distribution utilities suggested their risk had increased because of the implementation of PBR. They submitted that their earnings volatility may increase under PBR, as compared to the cost-of-service regime. In this proceeding, Mr. Thygesen presented information on earnings volatility which included the actual ROEs of the distribution utilities for the years 2013 and 2014. The actual ROE information for 2015 was also submitted during the proceeding. The approved 2012 going in ROE was 8.75 per cent, and the subsequent approved ROE for 2013, 2014 and 2015 was 8.3 per cent.

626 Decision 2009-216, paragraphs 370-371.

Views of the Commission

532. Mr. Stauft submitted that if the historic two per cent adder for non-taxability is discounted, it is still reasonable to believe that transmission utilities have less business risk than distribution utilities because of the differences in regulation between transmission utilities and distribution utilities and the apparent pattern of transmission utilities having lower effective depreciation rates than distribution utilities, He argued, however, that a two per cent differential would be sufficient to reflect the differences in risk, rather than the four per cent difference in deemed equity ratios between distribution utilities and transmission utilities that the Commission has previously awarded.

533. The historic two per cent adder for non-taxability addressed by Mr. Stauft is discussed in Section 7.4.3.1. With respect to the remainder of Mr. Stauft's argument, the Commission notes that its credit metric calculations do not support the continuation of a 400 bps difference in the awarded deemed equity ratios based on financial risk. It is also unclear that a difference of any amount remains warranted using only a credit metric financial risk analysis. From a business risk perspective, the Commission agrees that there are differences in rate regulation (for example: PBR versus cost-of-service rate regulation) and depreciation rate differences between transmission and distribution utilities, and other business risk differences, such as the method of recovery of fixed costs, although this is somewhat mitigated for the gas distribution utilities under PBR which accounts for actual changes in customer usage. Accordingly, the Commission will balance the financial risks as examined in the credit metric calculations and business risks including utility sector business risks, in arriving at its final deemed equity ratio determinations.

534. In the 2013 GCOC proceeding, evidence was introduced with respect to earnings volatility of distribution utilities as a result of PBR. The Commission was not persuaded that the cost of capital was higher under PBR than under traditional cost-of-service regulation. Consequently, it found that there was no evidence to conclude there was appreciably more risk under a PBR regime. In support of this statement, the Commission noted all but one of the ROEs earned in 2013 for the distribution utilities based on their Rule 005 submissions were higher than the 2013 interim ROE level and the approved level embedded in the 2012 going in rates.

535. In this proceeding, Mr. Thygesen presented information which included the actual ROEs of the distribution utilities for the years 2013 and 2014. The actual ROE information for 2015 was also submitted during the proceeding. The approved 2012 going in ROE was 8.75 per cent, and the subsequent approved ROE for 2013, 2014 and 2015 was 8.3 per cent. The Commission observes that with the exception of ENMAX Distribution, whose actual ROEs in 2013, 2014 and 2015 were all lower than the approved ROEs for those years, and AltaGas in 2015, whose actual ROE was 6.16 per cent, each of the remaining actual ROEs were in excess of the approved ROEs. Furthermore, in the majority of the cases the actual ROEs exceeded the approved ROE's by more than 100 bps. This is confirmed by a statement made by DBRS in a credit rating report it issued on December 16, 2015 for FortisAlberta, in which DBRS stated:

> FortisAlberta's low business risk is supported by the following factors: (a) the Company is a regulated electric distributor, with no exposure to commodity price risk; (b) the regulatory system in Alberta under the Performance Based Regulation (PBR) framework (January 2013 through 2017) is viewed as reasonable, providing the opportunity for the Company to earn a return above the allowed ROE; (c) the Company has a sizable customer base to provide good scale to better achieve the productivity factor set in the

PBR formula; and (d) the risk of actual operating costs exceeding the forecasted amount under the cost of service methodology is eliminated.[627]

536. The information discussed above supports the Commission's conclusion in the 2013 GCOC decision that there is no appreciable increase in earnings volatility risk under PBR.

7.4.3 Company specific equity ratio adjustments

537. In this section the Commission will review the company specific business risk evidence.

7.4.3.1 Adjustment for non-taxable status

538. Dr. Villadsen recommended that the Commission's policy in past GCOC proceedings of adding two per cent equity to non-income taxpaying utilities should be continued in this proceeding.[628] She described the economic justification for this policy as being all else equal, the earnings volatility of a non-income taxpaying utility is higher than that for a regular income taxpaying utility.[629] This is because the income tax authority does not take any risk in respect of the non-income tax paying utility, and investors bear all of the risk in the pre-income tax returns. Dr. Villadsen submitted that this increased earnings volatility should be recognized through an increase in the equity ratio of a non-income tax paying utility.[630]

539. Dr. Villadsen stated that the EBIT value for a non-income tax paying utility, all else being equal, is lower than those of an income tax paying utility. In order for the non-income tax paying utility to have the same EBIT interest coverage ratio as an income tax paying utility, all else being equal, the non-income tax paying utility will require a larger deemed equity ratio.[631]

540. Using her credit metric model input parameters, Dr. Villadsen submitted that a two per cent increase in the deemed equity ratio for non-income tax paying utilities is below that required to offset the difference in EBIT interest coverage ratios between non-income tax paying and income tax paying utilities.[632] She stated that based on her credit metric model analysis, the deemed equity ratio would need to be increased by 780 bps to equalize the EBIT interest coverage ratio between the non-income tax paying and income tax paying utilities.[633] Even with a deemed equity increase of 780 bps, Dr. Villadsen stated that the corresponding revenue requirement for the non-income tax paying utility would remain lower than the revenue requirement for the income tax paying utility.[634]

541. Mr. Hevert submitted that the 200 bps uplift for non-taxability for both the transmission and distribution operations of EPCOR approved as part of their equity ratios in the 2013 GCOC decision should also be continued.[635]

542. Mr. Hevert submitted that the Commission has consistently found that non-taxability has the effect of increasing volatility and decreasing interest coverage ratios, thereby adding risk

627 Exhibit 20622-X0075, PDF page 2.
628 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 82.
629 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 78.
630 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF pages 78-79.
631 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 79.
632 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 80.
633 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 81.
634 Exhibit 20622-X0104, evidence of Dr. Villadsen, PDF page 82.
635 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 148.

from the debt holder's perspective. He added that non-taxability results in lower pre-tax interest coverage ratios compared to taxable entities, all else remaining equal. Mr. Hevert stated that because financial leverage concentrates risk on equity holders, variations in pre-tax returns have a proportionately greater effect on the earned ROE, and therefore on equity investors.[636]

543. Referring to relevant portions of the 2009 GCOC decision, the 2011 GCOC decision and the 2013 GCOC decision,[637] Mr. Hevert stated that the Commission has consistently applied a 200 bps uplift to the deemed equity ratios to provide some measure of mitigation for the risks associated with non-taxable status.[638]

544. Based on AltaLink's 2015-2016 GTA, in which AltaLink indicated it expects to be in a non-taxable position for 2016 and the foreseeable future, Mr. Hevert submitted that the 200 bps uplift for non-taxability should be applied to AltaLink's deemed equity ratio.[639]

545. Mr. Stauft described the background to the issues around the use of a 200 bps adder to the deemed equity ratio for non-taxable status. He noted this was introduced in the 2004 GCOC proceeding, and was originally only applicable to the ENMAX and EPCOR utilities. Mr. Stauft indicated that in the 2009 GCOC decision, the principle was expanded to include FortisAlberta, which at the time was expected to be de facto non-taxable for a considerable period. Mr. Stauft stated the original rationale for the 200 bps adder in the 2004 GCOC decision was that being non-taxable increases the volatility of a utility's earnings, and thus increases business risk. He added that in the 2009 GCOC decision, when the Commission introduced its credit metric calculations in their current form, the Commission observed that non-taxability also reduces the EBIT interest coverage ratio.[640]

546. Mr. Stauft stated while he understands the arithmetic regarding the EBIT coverage ratio and earnings volatility underlying the non-taxable status of a utility, the question for the Commission is whether these theoretical costs to the affected utilities are significant enough to justify the compensation they receive for them through the 200 bps adder to their deemed equity ratios. Mr. Stauft submitted that they are not, because the costs involved are trivial, and the compensation is far out of proportion to any actual harm the utilities suffer as a result of being non-taxable.[641]

547. Mr. Stauft commented that the Commission's policy of the 200 bps adder appears to be that if a utility is completely exempt from income tax, or expects to be non-taxable for several years, then the 200 bps adder applies. He submitted that most of the taxable utilities are taxed at effective levels that are far below the statutory income tax rate. Mr. Stauft stated that in 2014 the effective income tax rate for ATCO Pipelines was 2.3 per cent and the effective income tax rate for AltaGas Utilities was four per cent. He added that although effective income tax rates vary considerably from year-to-year, most of the taxable utilities obtain little of the alleged benefit of

636 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF page 145.
637 The portions of the three decisions that Mr. Hevert included in his evidence are in Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 145-147.
638 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 145-147.
639 Exhibit 20622-X0082, evidence of Mr. Hevert, PDF pages 147-148.
640 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 52.
641 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 53.

taxability much of the time. He concluded that the practical difference between being taxable and non-taxable is likely very small on average.[642]

548. Mr. Stauft commented that if ATCO Pipelines, for example, changes from being taxable at 2.3 per cent in 2014 to being non-taxable in 2016, it would in theory become entitled to a 200 bps deemed equity ratio increase, even though the actual income tax position of ATCO Pipelines would not have changed materially.[643]

549. Mr. Stauft submitted that for the de facto non-taxable utilities the short run solution for cash-flow or credit metric issues is to allow those utilities to utilize a normalized or future income tax (FIT) methodology to pre-collect its FIT obligations. He stated that the end result of this is simply a shift in the timing of the collection of income taxes from customers, and there is no significant change in the total cost burden that customers bear in the long run. Mr. Stauft submitted that a 200 bps addition to the deemed equity ratio is an outright cost to customers, plus in the long run customers will also pay all of the income taxes anyway. He commented that if the de facto non-taxable utilities do not apply for FIT, it is because their credit metrics are not a genuine problem.[644]

550. Mr. Stauft stated that the cost to customers of a 200 bps increase to the deemed common equity of a utility is in the range of 0.2 per cent, or 20 bps, in additional ROE.[645]

551. With respect to credit metrics, Mr. Stauft noted that non-taxability only affects the EBIT interest coverage ratio. He stated that in his base case credit model, reducing the income tax rate to zero increases the deemed equity ratio needed to meet a target of 2.0 for the EBIT interest coverage ratio from 31 per cent to 38 per cent. Mr. Stauft indicated that at a 35 per cent deemed equity ratio, the EBIT interest coverage ratio is 1.84 and increasing the deemed equity ratio by 200 bps to 37 per cent increases the EBIT interest coverage ratio to 1.92. Mr. Stauft submitted that these effects do not have any practical real world impact on the creditworthiness of a non-taxable utility from the perspective of the credit rating agencies. Mr. Stauft stated he is not aware of any credit agency rating reports that even mention non-taxability.[646]

552. Mr. Stauft submitted that the credit rating agencies pay virtually no attention to EBIT coverage ratios. While DBRS lists it as a criterion, the lower bound is 1.8 and that is below what is implied by a zero income tax rate in Mr. Stauft's base case credit metric model at a 35 per cent deemed equity ratio. Mr. Stauft stated that the EBITDA metric used by S&P is not a constraint. Mr. Stauft commented that while interest coverage was the main credit metric constraint in the 2009 GCOC proceeding and the 2011 GCOC proceeding, it is not the real credit metric challenge for the affected utilities now. He submitted the real constraint is now FFO/debt.[647]

553. With respect to the earnings variability arguments offered by Dr. Villadsen and Mr. Hevert, Mr. Stauft contended those arguments only make sense if a utility's earnings are variable. Mr. Stauft submitted the earnings and cash flow variability for the affected utilities is so small that the practical cost impact of non-taxability on utility shareholders is virtually nil, and

642 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 53.
643 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF pages 53-54.
644 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 54.
645 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 55.
646 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 56.
647 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 57.

certainly not a reasonable justification for the additional 20 bps of ROE that the 200 bps deemed equity ratio adder imposes on customers.[648]

554. Mr. Stauft analyzed the variability of the actual ROEs of the affected utilities over the 2005-2014 time period.[649] Based on his analysis. Mr. Stauft submitted the variability of the actual earnings of the affected utilities is very small. He noted the standard deviation of the ROE for the 2005-2014 time period for most of the affected utilities is less than two per cent, and added that for three of the affected utilities the standard deviation of the ROE for the 2005-2014 time period is less than one per cent.[650]

555. Mr. Stauft concluded that the Commission should discontinue the practice of awarding a 200 bps deemed equity ratio adder for non-taxable utilities. He reiterated the recommended use of FIT for de facto non-taxable utilities and submitted that for the affected utilities, the actual credit metrics and actual earnings variability are such that the true actual cost of being non-taxable is essentially zero.[651]

556. Mr. Hevert disagreed with Mr. Stauft's recommendation to remove the 200 bps uplift to the deemed equity ratios for non-taxable utilities. He stated that without some adjustment such as the 200 bps uplift, non-taxable utilities would have lower interest coverage ratios and face greater risk than their taxable peers.[652] Mr. Hevert submitted that there is little question that non-taxability reduces interest coverage and increases earnings volatility.[653]

557. Countering Mr. Stauft's claim that the effective income tax rates for the affected utilities are far below the statutory rate, Mr. Hevert noted that AltaLink's effective income tax rate in 2014 was approximately 26 per cent. He added that for the years 2005-2014, the average effective tax rate for AltaLink was approximately 25 per cent. Mr. Hevert submitted that Mr. Stauft's claim regarding effective income tax rates does not apply to AltaLink.[654]

558. While Mr. Hevert agreed with Mr. Stauft that credit rating agencies typically review cash flow based measures of interest coverage, he commented that does not mean that the EBIT coverage ratio is not meaningful to investors. He noted in the U.S. the Securities and Exchange Commission requires utility companies to provide five years of fixed charge coverage ratios as part of their annual reporting, and because this disclosure is required, it can be reasonably assumed that measures of fixed charge coverage, such as EBIT/interest, are important to investors.[655]

559. Dr. Villadsen calculated the minimum deemed equity ratios for which a generic utility in Alberta would meet the Commission's EBIT coverage benchmark of 2.0, as well as her recommended benchmark of 2.5. Based on her calculations, she submitted a generic non-taxable utility in Alberta would require a deemed equity ratio of at least 41 per cent to meet the Commission's threshold EBIT coverage benchmark, and would require a deemed equity ratio of 51 per cent to meet her recommended EBIT coverage benchmark. Dr. Villadsen stated that the

648 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 58.
649 This analysis is in Exhibit 20622-X0305.
650 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 58.
651 Exhibit 20622-X0303, evidence of Mr. Stauft, PDF pages 59-60.
652 Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF page 57.
653 Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF page 58.
654 Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF pages 59-60.
655 Exhibit 20622-X0443, rebuttal evidence of Mr. Hevert, PDF page 60.

deemed equity ratio adder required to restore a given EBIT coverage ratio when moving from an income tax rate of 27 per cent to an income tax rate of zero per cent would be 800 bps. This indicates the 200 bps adder granted to non-taxable entities in the past should be maintained if not increased.[656]

560. Dr. Villadsen submitted customers benefit when a utility is tax exempt because of the fact that no income taxes are paid by the utility and therefore all else equal, customers' rates under a tax exempt utility will be lower than customers' rates under a taxable utility. She submitted transitioning from the flow-through methodology for income taxes to the FIT methodology is not trivial, and this change should only be contemplated if it were expected to be in place for a longer period.[657]

Commission findings

561. With respect to the issue of an adjustment to the deemed equity ratios for any of the affected utilities that are not paying income tax, the Commission must determine whether the deemed equity ratios associated with an A credit rating resulting from the Commission's credit market calculations are sufficient to provide these utilities with a fair return when the unique business risks arising from the fact that the utilities are not paying income tax are considered. Historically, tax-exempt or de facto non-taxable utilities have been awarded a 200 bps deemed equity ratio premium primarily because of the business risk associated with higher earnings volatility which may impact the ability of the utility to meet the credit metrics necessary to maintain an A category rating. The Commission notes the testimony of Dr. Villadsen when she commented on the need for the 200 bps deemed equity ratio premium for non-taxable or tax-exempt utilities:

> Q. So my question is why should customers of these utilities have to provide an additional 2 percent equity thickness for companies that have gone 7 or 11 years earning more than the fair return as determined by this Commission?
> A. DR. VILLADSEN: I don't think that's what we are addressing here. What we are addressing here is whether -- what the return should be, first and foremost; and, secondary, because these entities that are nontaxable or tax exempt, simply just don't pay taxes, are more volatile, the possibility that they will have a return that is lower or higher than what we actually would expect is simply just more exaggerated because taxes serve as a buffer. Therefore, the volatility is higher. We know volatility is linked to risk, and that's why we accept the 2 percent. This is especially linked to the simple fact that equity thickness is fairly low here in Alberta. So that there's a good possibility that nontaxable entities might end up in an EBIT coverage ratio that's lower than what is accepted. And that's what we are trying to prevent.[658]

562. As observed in Table 21, Table 23, and Table 24, a deemed equity ratio of at least 37 per cent for both distribution and transmission utilities that do not pay income tax at the allowed 2016 ROE of 8.3 per cent will achieve results which closely approximate the Commission's credit metric guideline of 2.0 for the EBIT coverage ratio. Using the 2017 allowed ROE of 8.5 per cent the EBIT credit metric guideline is achieved for the distribution utilities that do not currently pay income tax and moves within 0.06 of the guideline for the transmission utilities that do not currently pay income tax. In the Commission's view, these results support a finding

656 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF pages 78-79.
657 Exhibit 20622-X0457, rebuttal evidence of Dr. Villadsen, PDF page 86.
658 Transcript, Volume 7, pages 947-948.

that the concern over earnings volatility in relation to the EBIT coverage ratio discussed by Dr. Villadsen is sufficiently addressed for both distribution and transmission utilities that are not presently paying income tax without adding an additional 200 bps deemed equity ratio premium.

563. Although the EBIT coverage ratio is important for utilities that presently do not pay income tax, the Commission agrees with parties that the most important of the three credit metrics to focus on in this proceeding is the FFO/debt ratio. The Commission notes that the income-tax status, whether it is being tax-exempt or de facto non-taxable, does not impact the FFO/debt ratio. The Commission considers the 37 per cent equity ratio, in connection with the approved ROE of 8.3 per cent, addresses this credit metric guideline for the transmission utilities. This focus on the FFO/debt ratio is a continuation of the Commission's statements regarding this credit metric in its recent decision on ATCO Electric Transmission's 2015-2017 GTA, in which the Commission stated:

> 1307. On the basis of the foregoing, the Commission concludes that the FFO/debt ratio is an important, if not the most important, metric that is evaluated in the assessment of a regulated utility's creditworthiness.[659]

564. The resulting FFO coverage ratio at a 37 per cent deemed equity ratio is 3.2 for the transmission utilities, as set out in Table 22. The resulting FFO coverage ratio at a 37 per cent deemed equity ratio is 3.8 for the distribution utilities, as set out in Table 20. Both of these are above the Commission's guideline for this ratio of 3.0.

7.4.3.2 AltaLink and ATCO Electric Transmission deemed equity ratio premium for large capital programs

565. As a result of the 2011 GCOC decision, and the 2013 GCOC decision, AltaLink and ATCO Electric Transmission were awarded, in addition to other credit metric support approved in their general rate applications, a 200 bps deemed equity ratio premium to reflect the incremental business risks associated with their then current large capital programs. In this proceeding, parties differed on the merit of continuing with the additional premium.

566. Mr. Stauft submitted that the 200 bps deemed equity ratio premium for the large transmission utilities "is no longer required, because those large capital programs have largely been completed"[660] and that the "related specific credit metric concerns that motivated those adjustments have now ended."[661]

567. AltaLink disagreed that the capital programs and related specific credit metric concerns considered in the 2009 and 2011 GCOC proceedings had been eliminated. AltaLink indicated that work in connection with its large capital programs had not yet been completed with capital expenditures for the years 2016 and 2017 in the approximate range of $550 million and $600 million respectively. AltaLink indicated that its credit metrics had not recovered to the levels of its utility peer group therefore relief was required in the form of an increased deemed equity ratio.[662]

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[659] Decision 20272-D01-2016, paragraph 1307.
[660] Exhibit 20622-X0303, evidence of Mr. Stauft, PDF page 5.
[661] Exhibit 20622-X0303, evidence of Mr. Stauft, PDF pages 61-62.
[662] Exhibit 20622-X0440, rebuttal evidence of AltaLink, PDF page 22.

568. AltaLink also noted that the amount of its customer contributions continues to increase each year. Customer contributions have increased from the $31.3 million in 2002 to a forecasted amount of $580 million in 2017. AltaLink argued that this increasing level of customer contributions results in under-compensation to the utility.

569. In support of an increased equity ratio, Mr. Hevert submitted that the common financing practice of "maturity matching" provided a perspective on capital structure, and supported his recommended deemed equity ratios for AltaLink and EPCOR. This practice involves matching the lives of the capital assets being financed with the maturity of the securities issued to finance those capital assets in order to minimize exposure to changes in the cost of capital. Applying this perspective to AltaLink, Mr. Hevert commented that AltaLink's existing long-term debt is reasonably staggered with no requirement to refinance a significant portion of it within the near-term. He indicated that AltaLink has extended the weighted average maturity of its long-term debt while reducing the risks associated with refinancing multiple maturing debt within a compressed time period.

570. Mr. Hevert stated that adding equity to the capital structure also extends the weighted average life of long-term liabilities and mitigates incremental refinancing risk, whereas adding long-term debt to the capital structure increases incremental refinancing risk. However, it is the equity investors that are exposed to refinancing risk associated with long-term debt, even if it is the case that this risk may be some time in the future, because equity is perpetual in nature.

571. Based on an assumption that maturity matching represents a prudent financing strategy, Mr. Hevert submitted that maintaining a deemed equity ratio of 36 per cent for AltaLink "would provide few options but to issue a greater proportion of long-term debt with longer-dated maturities." He expressed his concern that this would increase AltaLink's refinancing risk, and if the refinancing was to occur in a contracted credit availability period, it would increase long-term debt rates. In addition, Mr. Hevert submitted that because these refinancing risks are long-term in nature, it is unclear whether they would be fully reflected in near-term, pro forma credit metrics.

572. Mr. Hevert disagreed with Mr. Stauft's recommendation to remove the 200 bps adder to the deemed equity ratio for large capital programs. Focusing his attention on internal funds, which he defined as the sum of net income and depreciation and amortization, Mr. Hevert noted that for the 2013-2014 period AltaLink's total capital requirement was approximately $3.77 billion and its internal funds was approximately $591 million, which equates to 16 per cent. Consequently, AltaLink was heavily dependent upon external financing to fund its capital needs.

573. Dr. Villadsen disagreed with Mr. Stauft's recommendation to eliminate the 200 bps adder for the large capital programs. She submitted adding and subtracting based on one off issues is not the right approach to determine the capital structure. Dr. Villadsen stated it is the totality of the risk going forward that needs to be considered, yet neither Mr. Stauft nor Dr. Cleary's volatility analysis does so. She noted that the large capital program is ongoing for ATCO Electric Transmission, albeit at a lower rate, and mentioned that the magnitude of the contributions in aid of construction has not been evaluated.

Commission findings

574. The Commission considers that the AltaLink and ATCO Electric Transmission deemed equity ratio premium for large capital programs is primarily an issue of financial credit metrics,

regardless of whether the capital programs have been substantially completed. The Commission agrees with AltaLink that its credit metrics have not recovered to an extent that a downward adjustment to the deemed equity ratio can be considered as a result of the substantial completion of the large capital programs.

575. In Section 7.4.3.1, the Commission considered that a deemed equity ratio of at least 37 per cent, in connection with the approved ROE of 8.3 per cent, addressed the Commission's FFO/debt and FFO coverage credit metric guidelines for the transmission utilities. It also approximated the Commission's EBIT credit metric guideline for transmission utilities who do not presently pay income tax. The 8.5 per cent ROE in 2017 will further enhance all credit metrics.

576. Consistent with its previous practice, the Commission in this proceeding has not considered the preferred shares issued by ATCO Electric in setting the deemed equity ratio for either the distribution or transmission divisions of ATCO Electric. The preferred share mechanism, like the subordinated debt mechanism approved by the Commission in AltaLink's recent GTA decision,[663] may have a positive effect on customers and utility shareholders by potentially lowering overall debt and equity costs.

577. In Decision 20272-D01-2016, the recent ATCO Electric Transmission 2015-2017 GTA decision, the Commission approved the continuation of the collection of federal FIT in 2016 and 2017, and the continuation of CWIP in rate base in 2016, but not in 2017. This will support the FFO/debt ratio for ATCO Electric Transmission for 2016 and 2017. As subsequently discussed in Section 8 of this decision, the Commission will determine the final capital structure for 2016 and 2017 for ATCO Electric Transmission in a separate process.

578. Regarding Mr. Hevert's proposition that AltaLink would face refinancing risk if it was not awarded a higher deemed equity component because long-term debt in future years could be issued at substantially higher interest rates, the Commission finds that the interest component on any financing is flowed directly through to ratepayers and therefore AltaLink shareholders would not be exposed to any interest rate volatility.

7.4.3.3 ATCO Pipelines and ATCO Gas

579. Dr. Booth concluded that the business risk of ATCO Pipelines is minimal since it is a cost-of-service pipeline. In support of this conclusion, Dr. Booth noted that although commodity prices have dropped since 2014, the Western Canadian Sedimentary Basin (WCSB) continues to be prolific with estimated reserves of over 100 years. He added that NGTL sits on top of the enormous reserves in the WCSB with significant recent and planned infrastructure expansion, particularly in North East British Columbia. Since ATCO Pipelines' revenue requirement is completely recovered as a charge included in NGTL's revenue requirement, Dr. Booth saw no change in ATCO Pipelines' ability to recover its revenue requirement since the 2013 GCOC proceeding.

580. He added that in the short run, ATCO Pipelines' revenue requirement is paid by NGTL similar to the treatment of electric transmission operator charges. Dr. Booth stated that the probability of ATCO Pipelines not earning its ROE for operating reasons is extremely low due to

[663] Decision 3524-D01-2016: AltaLink Management Ltd., 2015-2016 General Tariff Application, Proceeding 3524, Application 1611000-1, May 9, 2016, paragraph 879.

the history of over-earning by ATCO Pipelines. While there may be minimal long run recovery risk due to competition and supply, Dr. Booth indicated that this risk is likely smaller than in 2011 and 2014. Further, and to emphasize this point, Dr. Booth stated that ATCO Pipelines must, by definition, have lower risk than NGTL.

581. Dr. Booth stated that the only risks faced by ATCO Pipelines are that the Commission will not approve ATCO Pipelines' revenue requirement, which is a risk that all utilities face, or that NGTL does not pay ATCO Pipelines. With respect to this latter eventuality, Dr. Booth noted ATCO Pipelines' statement that it would enforce its contractual right to recover such payments from NGTL.

582. Dr. Carpenter submitted Dr. Booth had not demonstrated that the business risk of ATCO Pipelines has decreased relative to the 2013 GCOC proceeding. While Dr. Carpenter agreed that the integration of NGTL and ATCO Pipelines decreased the competitive risk of ATCO Pipelines, he stated that this does not mean that any of the supply risk, market risk and competitive risks faced by NGTL are irrelevant to ATCO Pipelines. Dr. Carpenter further submitted that NGTL's recent expansion plans into the shale gas areas of Northeast British Columbia and Northern Alberta means that NGTL's supply and competitive risks are increasing, not decreasing.

583. With respect to ATCO Gas, Dr. Booth recommended a deemed equity ratio of 35 per cent. In support of his recommendation, he submitted that there has been no increase in the business risk of ATCO Gas since 2003. Dr. Booth submitted that if anything, the business risk of ATCO Gas has decreased because it has exited the retail market, which reduces its exposure to commodity prices. While ATCO Gas is now exposed to heating demand from residential and commercial customers, which makes the actual ROE sensitive to weather, Dr. Booth noted that this exposure was largely removed by the establishment of a weather deferral account. Furthermore, Dr. Booth submitted that natural gas has a significant cost advantage over propane, electricity and heating oil in the residential space heating and water heating markets. As a result, natural gas residential users have increased by an average of 100,000 users a year for the past 10 years.[664]

584. Dr. Booth submitted that if ATCO Gas ever has any financing problems, the Commission should deem a higher preferred share component rather than increase the allowed ROE or deemed equity ratio. He added that this will support any target bond ratings without rewarding the common shareholders.

585. Mr. Johnson submitted that ATCO Gas has minimal supply risks because it is a pure distribution utility with no retail function and therefore different from most other natural gas distribution utilities in Canada and the U.S. that are distributors and/or retailers. With respect to demand or market risk, Mr. Johnson stated that ATCO Gas has captured most of the market for natural gas in Alberta, and because natural gas is the predominant heating fuel in Alberta, ATCO Gas has minimal market risk. He further submitted that ATCO Gas has minimal competition for markets because it has either franchises or by-laws with most of the municipalities in which it has facilities, which provide ATCO Gas with exclusivity.

586. Mr. Stauft submitted that the business risk for ATCO Pipelines is comparable to that of the electricity transmission utilities and therefore the deemed equity ratios should be the same.

[664] Exhibit 20622-X0345, evidence of Dr. Booth, PDF page 10.

He noted that ATCO Pipelines has zero revenue risk and it also has higher effective depreciation rates than the electricity transmission utilities.

Commission findings

587. ATCO Gas and ATCO Pipelines did not request company specific adjustments to their deemed equity ratios from what was approved in the 2013 GCOC decision. Both utilities requested a 200 bps increase to their deemed equity ratios to reflect the incremental business risks identified by Dr. Carpenter and Mr. Buttke for the Utilities and to improve credit metrics in accordance with Dr. Villadsen's recommendations.

588. The Commission has addressed the incremental business risk and credit metric arguments raised by the Utilities in Section 7.4.1.4 and Section 7.4.3.1.

589. With respect to ATCO Gas, the Commission notes Dr. Booth's submission supporting a company specific equity reduction of 300 bps that the business risk of ATCO Gas has decreased because it has exited the retail market, which reduces its exposure to commodity prices. While ATCO Gas is now exposed to heating demand from residential and commercial customers, which makes the actual ROE sensitive to weather, Dr. Booth noted that this exposure was largely removed by the establishment of a weather deferral account. He also noted that natural gas has a significant cost advantage over propane, electricity, and heating oil in the residential space heating and water heating markets. Dr. Booth also noted that even with Alberta's economy, "… on the gas side, ATCO Gas, I don't see a significant drop in demand for gas from consumers."[665]

590. Mr. Johnson submitted that ATCO Gas has minimal supply risks because it is a pure distribution utility with no retail function and has minimal market risk.

591. The Commission does not consider that the company specific business risks for ATCO Gas have materially changed since the 2013 GCOC decision. The Commission notes that ATCO Gas continues to be rate regulated under the PBR revenue per customer cap approach and continues to reconcile its weather deferral account on a periodic basis. Accordingly, the Commission finds that no company specific business risk adjustment is required for ATCO Gas.

592. With respect to ATCO Pipelines, Dr. Booth concluded that while there may be minimal long run recovery risk due to competition and supply, this risk is likely smaller than it was in 2011 and 2014. In addition, ATCO Pipelines overall business risk is minimal because its revenue requirement is completely recovered as a charge included in NGTL's revenue requirement.

593. Dr. Booth further stated that the only risks faced by ATCO Pipelines are that the Commission will not approve ATCO Pipelines' revenue requirement, which is a risk that all utilities face, or that NGTL does not pay ATCO Pipelines.

594. Mr. Stauft noted that ATCO Pipelines has zero revenue risk and it also has higher effective depreciation rates than the electricity transmission utilities.

595. The Commission has not been persuaded by the evidence that the company specific business risks for ATCO Pipelines have materially changed since the 2013 GCOC decision. Accordingly, the Commission finds that no company specific business risk adjustment is required for ATCO Pipelines.

665 Transcript, Volume 9, page 1316.

7.4.3.4 AltaGas Utilities Inc.

596. Given the relatively small size of AltaGas relative to the other distribution utilities, Dr. Villadsen, as well as Dr. Cleary and Mr. Stauft, recommended that the deemed equity ratio of AltaGas continue to be set at 400 bps higher than the deemed equity ratio of the average distribution utility. Mr. Stauft submitted that there was no basis to alter this 400 bps difference, and noted that Dr. Cleary's EBIT variability calculations actually confirm this difference.

Commission findings

597. The Commission accepts the evidence of Dr. Villadsen, Dr. Cleary and Mr. Stauft, that the recommended deemed equity ratio of AltaGas should be 400 bps higher than the deemed equity ratio of the average distribution utility, reflecting that the business risk of AltaGas relative to other distribution utilities has remained constant since the 2013 GCOC proceeding.

7.4.3.5 Actual capital structure of ENMAX Power Corporation

598. In the 2013 GCOC decision, ENMAX Transmission was awarded a deemed debt/equity ratio of 64/36 and ENMAX Distribution was awarded a deemed debt/equity ratio of 60/40 for 2013, 2014, and 2015. ENMAX's Rule 005 reports do not separate capital structure information for transmission and distribution. Using ENMAX's 2015 Rule 005 reports, which includes information for the 2013 calendar year, the deemed debt/equity ratio, on a combined distribution/transmission basis, based on mid-year invested capital would be 61/39.[666]

599. In its 2015 Rule 005 filing, which includes information for the 2013 calendar year, ENMAX's actual debt/equity ratio on a combined distribution/transmission basis was 57/43 at 2013 year-end. ENMAX operated on a combined distribution/transmission basis with actual equity that was 400 bps higher than the 2013 GCOC deemed equity amount on a year-end basis.

600. In its 2015 Rule 005 filing for the 2014 calendar year, ENMAX's actual debt/equity ratio on a combined distribution/transmission basis was 60/40 at 2014 year-end. ENMAX operated on a combined distribution/transmission basis with actual equity that was 100 bps higher than the 2013 GCOC deemed equity amount on a year-end basis.

601. In its 2016 Rule 005 filing for the 2015 calendar year, ENMAX's actual debt/equity ratio on a combined distribution/transmission basis was 66/34 at 2015 year-end.[667] ENMAX operated on a combined distribution/transmission basis with actual equity that was 500 bps lower than the 2013 GCOC deemed equity amount on a year-end basis.

602. Information set out in ENMAX's Rule 005 filings indicates that the combined distribution and transmission year-end plant in service increased by approximately 30 per cent, or $350 million, between 2013 and 2015. The actual equity over the same period decreased by approximately 10 per cent, or $60 million.[668]

[666] The 2015 Rule 005 reports for the 2014 calendar year can be found in Exhibit 20622-X0056.
[667] The 2016 Rule 005 reports for the 2015 calendar year can be found in Exhibit 20622-X0570 and Exhibit 20622-X0571.
[668] These figures were derived from the information included in the 2015 Rule 005 reports for the 2014 calendar year, and the 2016 Rule 005 reports for the 2015 calendar year.

603. On March 27, 2015, ENMAX filed an application, proceeding 20294, with the Commission seeking approval to issue debt. As part of that same application, ENMAX included the following:

> EPC also seeks Commission approval to maintain an actual capital structure that may differ from the deemed capital structure approved by the Commission from time to time. EPC will continue to set its rates based on its approved capital structure.[669]

604. ENMAX elaborated on its position in its debt application in the following IR response:

> EPC's application was intended to seek approval from the AUC that would allow EPC the flexibility to consider maintaining a different actual capital structure from the approved deemed capital structure approved in Decision 2191-D01-2015. As EPC would continue to use the approved deemed capital structure for rate setting purposes and funds would continue to be borrowed using the Alberta Capital Finance Authority ("ACFA") mechanism there would be no impact on rate payers if this flexibility was approved by the AUC.
>
> …
>
> However, to be clear, EPC is not willing to risk its ROE in return for the requested flexibility. Consequently, if the Commission is of the view that EPC must maintain an actual capital structure that is consistent with the approved deemed capital structure in order to be permitted a reasonable opportunity to earn the approved generic ROE, EPC will do so.[670]

605. In its decision on ENMAX's debt application, the Commission addressed ENMAX's request regarding capital structure flexibility as follows:

> 29. EPC's request involves a method to obtain a utilities return that has not been evaluated or considered in the generic cost of capital proceedings, which are the proceedings designed to consider questions of deemed capital structure and ROE, the most recent being the 2013 Generic Cost of Capital proceeding. The Commission is not able to fully evaluate and consider EPC's request given the limited scope of information in this debt application. Therefore, the Commission will not consider EPC's request to maintain an actual capital structure that may differ from the deemed capital structure in this application and instead, should EPC wish to pursue this request, it is directed to bring forward this aspect of its application to the next generic cost of capital proceeding, where it can be considered in the full context of setting a capital structure and ROE.[671]

606. In the present proceeding, ENMAX co-sponsored the Utilities expert evidence. ENMAX did not file any standalone, company specific evidence, although it did file IR responses, including the responses originally filed in proceeding 20294. During the oral hearing in this proceeding, ENMAX did not present any company witnesses. Commission counsel asked the witness panel for the Utilities, consisting of Dr. Villadsen, Dr. Carpenter and Mr. Buttke, if any of them knew whether ENMAX intended to pursue the request to maintain an actual capital structure that may differ from the deemed capital structure first raised in Proceeding 20294, as

669 Exhibit 20622-X0173, PDF page 2
670 Exhibit 20622-X0173, PDF page 3
671 Decision 20294-D01-2015: ENMAX Power Corporation, 2015 Application to Issue Debt, Proceeding 20294, May 29, 2015, paragraph 29.

part of the 2016 GCOC proceeding. Each of the three witnesses responded that they did not know.[672]

607. In his oral argument, Mr. Wood, counsel for ENMAX, made the following submission regarding this issue:

> ENMAX’s actual capital structure was the subject of some discussion during the hearing. For example, Mr. Finn asked Dr. Villadsen whether she was able to say whether ENMAX intended to pursue the request that it made in its 2015 debt application for the flexibility to maintain an actual capital structure different from its deemed capital structure. Dr. Villadsen said that she didn't know, as did Dr. Carpenter. ENMAX does not intend to pursue that request, as ENMAX stated in its response to information request AUC-EPC-FEB18-001b. "However, to be clear, EPC is not willing to risk its ROE in return for the requested flexibility. Consequently, if the Commission is of the view that EPC must maintain an actual capital structure that is consistent with the approved deemed capital structure in order to be permitted a reasonable opportunity to earn the approved generic ROE, EPC will do so." Now, ENMAX acknowledges that its actual capital structure has diverged from the deemed capital structure in 2015 as a result of a couple of factors, but ENMAX is committed to bringing its actual capital structure in line with the approved capital structure by the end of 2016 and would accept a condition to that effect in the Commission's 2016 generic cost of capital decision. ENMAX's request in this proceeding is for an approved deemed equity thickness of 38 percent for transmission and 42 percent for distribution. To be clear, ENMAX does not request that its deemed capital structure be adjusted to conform to its current actual capital structure. Rather, it will commit to adjusting its actual capital structure to conform to the approved deemed capital structure.[673]

Commission findings

608. In this proceeding, ENMAX requested a deemed debt/equity ratio of 58/42 for distribution and 62/38 for transmission. As clarified by its counsel, ENMAX was no longer seeking approval to allow its actual capital structure to diverge from the requested deemed capital structure, as it had previously requested in Proceeding 20294.

609. It is evident from the review of ENMAX’s Rule 005 filings above, that ENMAX operated at above the approved deemed equity level on a combined distribution/transmission basis in 2013 by 400 bps and by 100 bps in 2014. In 2015, ENMAX was able to operate on a combined distribution/transmission year-end basis at 500 bps lower than the approved deemed equity level. It would appear, based on the IR responses filed in proceeding 20294, that operating at higher or lower equity levels for some period of time does not significantly impact either the availability of debt financing or the cost of debt to ENMAX. Actual 2015 year-end equity levels are similarly significantly lower than the deemed equity level requested by ENMAX in the present proceeding for 2016 and 2017.

610. A fair return is determined by the Commission as a component of just and reasonable rates; rates that must be just and reasonable, both for the utility and for its customers. The total return, which is a function of ROE and capital structure applied to rate base, should not be higher, nor lower than what is fair based on the evidence before the Commission at a given time.

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672 Transcript, Volume 5, page 704.
673 Transcript, Volume 11, pages 1898-1900.

In *Northwestern Utilities v the City of Edmonton* [1929] S.C.R. 186; [1929] 2 DLR 4 (*NUL 1929*), the Supreme Court of Canada found at page 192:

> The duty of the Board was to fix fair and reasonable rates: rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. 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 investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise

611. One possible conclusion that can be drawn from ENMAX's 2015 actual Rule 005 report results and the request of ENMAX to allow the utility to operate at different actual capital structure levels than the approved deemed levels, is that the deemed equity components determined in the 2013 GCOC decision for ENMAX's distribution and transmission functions, are higher than required to ensure that the utility is provided with a reasonable opportunity to earn a fair return. In determining a fair return for ENMAX in this proceeding, the Commission must consider whether the equity component of the capital structure should reflect the actual year-end equity levels reported in its Rule 005 filings in respect of the 2015 calendar year. However, there is insufficient evidence on the record of this proceeding to make a determination with respect to this issue. Further, ENMAX was not provided with an opportunity to fully address this issue. Accordingly, the Commission will set an interim capital structure for the distribution and transmission functions of ENMAX for 2016 and 2017 equal to the capital structure determined for EPCOR Distribution and EPCOR Transmission in this proceeding as a placeholder. The Commission directs ENMAX to submit a compliance filing prior to December 1, 2016, to determine the final capital structure for its distribution and transmission functions for 2016 and 2017. The compliance filing will address the application of the fair return standard, insofar as it relates to the setting of capital structure, particularly in light of recent actual capital structures and the guidance of the Supreme Court of Canada that the determination of a fair return is linked to the amount of capital actually invested in an enterprise. The generic ROE established by the Commission in this decision for 2016 and 2017 will apply on a final basis to ENMAX Distribution and ENMAX Transmission.

7.5 Determination of Commission-approved deemed equity ratios

612. In the 2013 GCOC decision, the Commission's starting point was an average risk utility. That average risk utility was awarded a 38 per cent deemed equity ratio. Each utility was compared to the average risk utility and the deemed equity ratios were determined by the Commission based on the evidence after the application of the Commission's judgement. As a result the deemed equity ratios determined by the Commission in the 2013 GCOC decision are set out in Table 25.

Table 25. Deemed equity ratios from the 2013 GCOC decision

	Last approved (%)
Electricity and natural gas transmission	
AltaLink	36
ATCO Electric Transmission	36
ATCO Pipelines	37
ENMAX Transmission	36
EPCOR Transmission	36
Lethbridge	36
Red Deer	36
TransAlta	36
Electric and gas distribution	
AltaGas	42
ATCO Electric Distribution	38
ATCO Gas	38
ENMAX Distribution	40
EPCOR Distribution	40
FortisAlberta	40

613. In this proceeding, the Commission started with a review of credit metrics as an indication of the financial risk of the affected utilities, then considered generic business risks, sector specific business risks, and finally, company specific business risks in evaluating the deemed equity ratios for the affected utilities.

614. In its credit metric review, the Commission revised its previously established credit metric guidelines, in light of changes in the applicable financial parameters and changes in credit metrics required for a credit rating in the A category.

615. Based on the information in Table 20 and Table 22, the Commission notes that an average distribution utility and an average transmission utility would meet all the credit metric guidelines of the Commission, with an ROE of 8.3 per cent, at a deemed equity ratio of 31 per cent. For both an average distribution and transmission utility that does not currently pay tax, they would both meet the FFO/debt and FFO coverage credit metric guidelines of the Commission, with an ROE of 8.3 per cent, at a deemed equity ratio of 30 per cent. The Commission's EBIT credit metric guideline would be met with a 38 per cent deemed equity ratio at an ROE of 8.3 per cent for those affected utilities which currently do not pay tax.

616. The Commission's finding following a review of generic business risk, including risks associated with the UAD decision, demonstrated a directional increase in generic business risk for all utilities, supporting an across-the-board increase to the deemed equity ratios.

617. In its distribution/transmission utility sector business risk analysis, the Commission found that a continuation of a 400 bps difference in the awarded equity ratios for an average distribution utility when compared to an average transmission utility, was not required after consideration of the Commission's credit metric guidelines. However, the Commission found that there continued to be differences in business risks between transmission and distribution

utilities. Accordingly, the Commission determined that it must balance the financial risks, as examined in the credit metric calculations, and the different business risks of the distribution and transmission utility sectors, in arriving at its final deemed equity ratio determinations.

618. The Commission applied its judgement to determine the deemed equity ratios for the affected utilities, prior to any company specific adjustments, after a consideration of the following factors:

- The results of the Commission's credit metric calculations.
- The current assessment of the regulatory environment in Alberta as trending "negative" by credit rating agencies, in particular S&P.
- The Commission's findings of a directional increase in generic business risk, mainly due to concerns with the principles reflected in the UAD decision.
- The Commission's utility sector analysis.

619. As a result of this analysis, the Commission has determined, subject to company specific adjustments, that a deemed equity ratio of 37 per cent for both distribution and transmission utilities, including those which pay tax and those which currently do not pay tax, satisfies the fair return standard required when combined with an 8.3 per cent allowed ROE for 2016, and an 8.5 per cent allowed ROE for 2017, and will enable the affected utilities to maintain a credit rating in the A category.

620. The Commission found that company specific adjustments were not required to the 37 per cent deemed equity ratio for the average distribution utility and the average transmission utility for:

- utilities that currently do not pay income tax
- the large capital build program of AltaLink
- ATCO Pipelines and ATCO Gas

621. The Commission found that a 400 bps company specific upward adjustment to the 37 per cent deemed equity ratio for the average distribution utility was warranted for AltaGas. The Commission also established placeholders for ENMAX Transmission and ENMAX Distribution and for ATCO Electric Transmission.

622. Based on the above, the Commission finds that the 2016 and 2017 deemed equity ratios set out in Table 26 for the affected utilities (other than placeholders established for ENMAX Transmission, ENMAX Distribution and ATCO Electric Transmission), when multiplied by the debt and equity funded portion of rate base, and further multiplied by the 8.3 per cent allowed ROE for 2016 (8.5 per cent allowed ROE for 2017), will result in a return for the affected utilities that satisfies the requirements of the fair return standard, and will enable them to maintain a credit rating in the A category.

Table 26. Commission-approved deemed equity ratios

	2016-2017 approved	Last approved	Change in approved common equity ratio
	(%)		
Electricity and natural gas transmission			
AltaLink	37	36	+1
ATCO Electric Transmission*	37	36	+1
ATCO Pipelines	37	37	0
ENMAX Transmission*	37	36	+1
EPCOR Transmission	37	36	+1
Lethbridge	37	36	+1
Red Deer	37	36	+1
TransAlta	37	36	+1
Electric and gas distribution			
AltaGas	41	42	-1
ATCO Electric Distribution	37	38	-1
ATCO Gas	37	38	-1
ENMAX Distribution*	37	40	-3
EPCOR Distribution	37	40	-3
FortisAlberta	37	40	-3
* approved on a placeholder basis			

623. The approved deemed equity ratios awarded in this decision will remain in place on an interim basis for 2018 and for subsequent years until changed by the Commission.

8 ATCO Electric Transmission compliance filing

624. The Commission noted at the beginning of this proceeding that a decision on ATCO Electric Transmission's 2015-2017 GTA[674] would not be issued before the close of record for this 2016 GCOC proceeding. The Commission set out the following process in order to accommodate parties with respect to the potential impacts of ATCO Electric Transmission's 2015-2017 GTA on submissions filed in this proceeding:

- All parties taking part in the 2016 GCOC will participate according to the provided schedule. ATCO Electric Transmission will participate as a constituent of the Alberta Utilities group in the normal course and tender evidence on both return on equity (ROE) and deemed capital structure as part of that group.

- The Commission's final decision in respect of the 2016 GCOC will, absent extraordinary intervening circumstances, approve final ROE and deemed capital structure values for all affected utilities except ATCO Electric Transmission.

- The Commission's final decision in respect of the 2016 GCOC will approve both an ROE and deemed capital structure for ATCO Electric Transmission on an interim

674 Proceeding 20272.

basis, pending consideration of any relevant information obtained from the results of the company's GTA.

- Once the Commission and parties have had an opportunity to assess what, if any, effect the outcome of the ATCO Electric Transmission GTA should have on its interim GCOC values, its allowed ROE and deemed equity ratio will either be confirmed as final for the test period, or alternatively, varied. The Commission will determine whether such confirmation or variation will be preceded by additional process steps at a later date, once the information has been obtained.[675]

625. Decision 20272-D01-2016[676] on ATCO Electric Transmission's 2015-2017 GTA was issued on August 22, 2016. The Commission directs ATCO Electric Transmission, in a compliance filing to this decision filed on or before 4 p.m. on December 1, 2016, to provide submissions on the impact, if any, of the findings and directions of the Commission in Decision 20272-D01-2016 on the allowed ROE and deemed equity ratio approved for it on a placeholder basis for 2016 and 2017 in this 2016 GCOC decision. Following ATCO Electric's submissions, the Commission will determine what process steps, if any, are required to finalize the ATCO Electric Transmission placeholders.

9 Implementation of generic cost of capital decision findings

626. Any affected utility that has a Commission-approved revenue requirement under cost-of-service regulation for 2016 and subsequent years was required to use ROE and deemed equity ratio placeholders until values for these could be approved by the Commission on a final basis. The Commission directs these utilities to apply by November 9, 2016, to adjust their respective revenue requirements for 2016 and subsequent years, to reflect the final or interim allowed ROE and final or interim approved deemed equity ratios 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). The Commission directs any utilities under cost-of-service regulation who do not have Commission-approved revenue requirements for 2016 and 2017 to incorporate the allowed ROE and approved deemed equity ratios as set out in this decision as part of their revenue requirement application(s) for these years.

627. The Commission confirms that the allowed ROE and deemed equity ratios approved in this decision may be used in the calculation of certain flow-through items, where required (e.g., in treatment of deferral accounts that use weighted average cost of capital for the calculation of carrying charges). The Commission also confirms that the 2016-2017 allowed ROE and approved deemed 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,[677] 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

675 Exhibit 20622-X0041.
676 Decision 20272-D01-2016: ATCO Electric Ltd., 2015-2017 Transmission General Tariff Application, Proceeding 20272, August 22, 2016.
677 Decision 2013-435: Distribution Performance-Based Regulation, 2013 Capital Tracker Applications, AltaGas Utilities Inc., ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution & Transmission Inc. and FortisAlberta Inc., Proceeding 2131, Application 1608827-1, December 6, 2013.

requirement calculations based on forecast or actual capital additions for the identified project or program for the PBR year. In Decision 3434-D01-2015,[678] the Commission determined that revenue requirement calculations in the second component of the accounting test should be based on the allowed ROE and approved deemed equity ratios for that year.[679]

[678] 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.

[679] Decision 3434-D01-2015, paragraph 70.

10 Order

628. It is hereby ordered that:

(1) The final allowed return on equity for AltaGas Utilities Inc., AltaLink Management Ltd., the distribution operations of ATCO Electric Ltd., ATCO Gas, ATCO Pipelines, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., FortisAlberta Inc., the transmission operations of the City of Lethbridge, the transmission operations of the City of Red Deer, and certain electricity transmission assets of TransAlta Corporation, is set at 8.3 per cent for 2016 and 8.5 per cent for 2017.

(2) The final approved deemed equity ratios for AltaGas Utilities Inc., AltaLink Management Ltd., the distribution operations of ATCO Electric Ltd., ATCO Gas, ATCO Pipelines, EPCOR Distribution & Transmission Inc., FortisAlberta Inc., the transmission operations of the City of Lethbridge, the transmission operations of the City of Red Deer, and certain electricity transmission assets of TransAlta Corporation, are as set out in the table below.

(3) The allowed return on equity of 8.5 per cent for 2017, and the approved deemed equity ratios set out in the table below, are approved on an interim basis for 2018, and for each subsequent year thereafter, unless otherwise directed by the Commission.

(4) AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd., ATCO Gas, ATCO Pipelines, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., FortisAlberta Inc., the City of Lethbridge, the City of Red Deer and TransAlta Corporation are to apply to adjust their rates to implement the findings of this decision, as directed in Section 9.

(5) The allowed return on equity of 8.3 per cent for 2016 and 8.5 per cent for 2017, and the deemed equity ratio of 37 per cent, are approved as placeholders for the transmission operations of ATCO Electric Ltd.

(6) The deemed equity ratio of 37 per cent is approved as a placeholder for the distribution and transmission operations of ENMAX Power Corporation.

(7) In addition to the separate applications directed in order (4) above, ENMAX Power Corporation and ATCO Electric Ltd. are to additionally submit compliance filings, as directed in Section 7.4.3.5 and Section 8 respectively.

	2016-2017 approved (%)
Deemed equity ratios	
Electricity and natural gas transmission	
AltaLink	37
ATCO Electric Transmission*	37
ATCO Pipelines	37
ENMAX Transmission*	37
EPCOR Transmission	37
Lethbridge	37
Red Deer	37
TransAlta	37
Electricity and natural gas distribution	
AltaGas	41
ATCO Electric Distribution	37
ATCO Gas	37
ENMAX Distribution*	37
EPCOR Distribution	37
FortisAlberta	37
* approved on a placeholder basis	

Dated on October 7, 2016.

Alberta Utilities Commission

(original signed by)

Mark Kolesar
Vice-Chair

(original signed by)

Bill Lyttle
Commission Member

(original signed by)

Henry van Egteren
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) **Company name of counsel or representative**
AltaGas Utilities Inc. (AltaGas)
AltaLink Management Ltd. (AltaLink) Borden, Ladner Gervais LLP
EPCOR Distribution & Transmission Inc. (EPCOR) Fasken Martineau Dumoulin LLP
ENMAX Power Corporation (ENMAX) Torys LLP
Canadian Association of Petroleum Producers (CAPP) Lawson Lundell Barristers & Solicitors
ATCO Gas Bennett Jones
ATCO Electric Ltd. (ATCO Electric)
ATCO Pipelines
FortisAlberta Inc. (FortisAlberta)
Consumers' Coalition of Alberta (CCA)
Office of the Utilities Consumer Advocate (UCA) Reynolds, Mirth, Richards & Farmer LLP
The City of Calgary McLennan Ross Barristers & Solicitors
Industrial Power Consumers Association of Alberta (IPCAA)

Alberta Utilities Commission Commission panel M. Kolesar, Vice-Chair B. Lyttle, Commission Member H. van Egteren, Commission Member Commission staff B. McNulty (Associate general counsel) R. Finn (Commission counsel)* M. Peden (Commission counsel) D. Mitchell O. Vasetsky C. Strasser C. Malayney * participated until July 18, 2016

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative	Witnesses
The Utilities: AltaGas Utilities Inc., ATCO Utilities, ENMAX Power Corporation and FortisAlberta Inc. L. Smith, QC T. Dalgleish, QC B. Ho L. Cusano D. Wood N. McKenzie	B. Villadsen P. Carpenter R. Buttke
AltaGas Utilities Inc. (AltaGas) N. McKenzie	
AltaLink Management Ltd. (AltaLink) and EPCOR Distribution & Transmission Inc. (EPCOR) R. Block, QC J. Liteplo	D. Koch C. Lomore R. Hevert S. Fetter
AltaLink Management Ltd. (AltaLink) R. Block, QC	
ATCO Utilities: ATCO Electric Ltd., ATCO Gas and Pipelines Ltd. L. Smith, QC	
ENMAX Power Corporation (ENMAX) L. Cusano D. Wood	
EPCOR Distribution & Transmission Inc. (EPCOR) J. Liteplo	
FortisAlberta Inc. (FortisAlberta) T. Dalgleish, QC B. Ho	
The City of Calgary (Calgary) D. Evanchuk	L. Booth H. Johnson
Canadian Association of Petroleum Producers (CAPP) L. Manning N. Schultz	L. Booth
Consumers' Coalition of Alberta (CCA) J. Wachowich, QC S. Gibbons	J. Thygesen
Office of the Utilities Consumer Advocate (UCA) T. Shipley B. Schwanak R. McCreary	S. Cleary M. Stauft

Alberta Utilities Commission

Commission panel
M. Kolesar, Vice-Chair
B. Lyttle, Commission Member
H. van Egteren, Commission Member

Commission staff
R. Finn (Commission counsel)
M. Peden (Commission counsel)
D. Mitchell
O. Vasetsky
C. Malayney
C. Strasser

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. One possible conclusion that can be drawn from ENMAX's 2015 actual Rule 005 report results and the request of ENMAX to allow the utility to operate at different actual capital structure levels than the approved deemed levels, is that the deemed equity components determined in the 2013 GCOC decision for ENMAX's distribution and transmission functions, are higher than required to ensure that the utility is provided with a reasonable opportunity to earn a fair return. In determining a fair return for ENMAX in this proceeding, the Commission must consider whether the equity component of the capital structure should reflect the actual year-end equity levels reported in its Rule 005 filings in respect of the 2015 calendar year. However, there is insufficient evidence on the record of this proceeding to make a determination with respect to this issue. Further, ENMAX was not provided with an opportunity to fully address this issue. Accordingly, the Commission will set an interim capital structure for the distribution and transmission functions of ENMAX for 2016 and 2017 equal to the capital structure determined for EPCOR Distribution and EPCOR Transmission in this proceeding as a placeholder. The Commission directs ENMAX to submit a compliance filing prior to December 1, 2016, to determine the final capital structure for its distribution and transmission functions for 2016 and 2017. The compliance filing will address the application of the fair return standard, insofar as it relates to the setting of capital structure, particularly in light of recent actual capital structures and the guidance of the Supreme Court of Canada that the determination of a fair return is linked to the amount of capital actually invested in an enterprise. The generic ROE established by the Commission in this decision for 2016 and 2017 will apply on a final basis to ENMAX Distribution and ENMAX Transmission. .... Paragraph 611

2. Decision 20272-D01-2016 on ATCO Electric Transmission's 2015-2017 GTA was issued on August 22, 2016. The Commission directs ATCO Electric Transmission, in a compliance filing to this decision filed on or before 4 p.m. on December 1, 2016, to provide submissions on the impact, if any, of the findings and directions of the Commission in Decision 20272-D01-2016 on the allowed ROE and deemed equity ratio approved for it on a placeholder basis for 2016 and 2017 in this 2016 GCOC decision. Following ATCO Electric's submissions, the Commission will determine what process steps, if any, are required to finalize the ATCO Electric Transmission placeholders. .... Paragraph 625

3. Any affected utility that has a Commission-approved revenue requirement under cost-of-service regulation for 2016 and subsequent years was required to use ROE and deemed equity ratio placeholders until values for these could be approved by the Commission on a final basis. The Commission directs these utilities to apply by November 9, 2016, to adjust their respective revenue requirements for 2016 and subsequent years, to reflect the final or interim allowed ROE and final or interim approved deemed equity ratios 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). The Commission directs any utilities under cost-of-

service regulation who do not have Commission-approved revenue requirements for 2016 and 2017 to incorporate the allowed ROE and approved deemed equity ratios as set out in this decision as part of their revenue requirement application(s) for these years. .... Paragraph 626

Appendix 4 – Abbreviations

Abbreviation	Name in full
2004 GCOC decision	Decision 2004-052, Generic Cost of Capital
2009 GCOC decision	Decision 2009-216, 2009 Generic Cost of Capital
2011 GCOC decision	Decision 2011-474, 2011 Generic Cost of Capital
2013 GCOC decision	Decision 2191-D01-2015, 2013 Generic Cost of Capital
AFUDC	allowance for funds used during construction
AltaGas	AltaGas Utilities Inc.
AltaLink	AltaLink Management Ltd.
ARCH	autoregressive conditional heteroscedasticity
ATCO Electric	ATCO Electric Ltd.
BEIR	break-even inflation rate
BMO	BMO Bank of Montreal
Board	Alberta Energy and Utilities Board
bps	basis points
BRA	business risk assessment
BYPRPM	bond yield plus risk premium model
CAD	Canadian dollar
CAD/USD	Canadian dollar to the United States dollar
Calgary	The City of Calgary
CAPM	capital asset pricing model
CAPP	Canadian Association of Petroleum Producers
CCA	Consumers’ Coalition of Alberta
CIBC	Canadian Imperial Bank of Commerce
CV	coefficient of variation
CWIP	construction work in progress
DBRS	DBRS Limited
DCF	discounted cash flow
EATL	Eastern Alberta Transmission Line
EBIT	earnings before interest and income taxes
EBITDA	earnings before interest, income taxes, depreciation and amortization
ECAPM	empirical capital asset pricing model
ENMAX	ENMAX Power Corporation
EPCOR	EPCOR Distribution & Transmission Inc.
EPS	earnings per share
FFO	funds from operations
FIT	future income tax
FortisAlberta	FortisAlberta Inc.
FRA	financial risk assessment
GARCH	generalized form of ARCH
GCOC	generic cost of capital
GDP	gross domestic product
GOC	Government of Canada
GTA	general tariff application
IR	information request

Abbreviation	Name in full
IBES	Institutional Brokers' Estimate System
KCFSI	Kansas City Financial Stress Index
LDC	local distribution companies
Lethbridge	City of Lethbridge
MERP	market equity risk premium
Moody's	Moody's Investor Services
MRP	market risk premium
NGTL	NOVA Gas Transmission Ltd.
NOI	net operating income
P/B	price-to-book
PBR	performance-based regulation
PRPM	predictive risk premium model
QE	quantitative easing
RBC	Royal Bank of Canada
Red Deer	City of Red Deer
ROE	return on equity
S&P	Standard & Poor's
Scotiabank	Bank of Nova Scotia
Slave Lake decision	Decision 2014-297 (Errata), ATCO Electric Ltd, 2012 Distribution Deferral Accounts and Annual Filing for Adjustment Balances
SML	Security market line
TD	Toronto-Dominion Bank
the ATCO Utilities	ATCO Electric Ltd., and ATCO Gas and Pipelines Ltd.
the Fed	the Federal Reserve System
the Utilities	AltaGas Utilities Inc., the ATCO Utilities, ENMAX Power Corporation and FortisAlberta Inc.
TransAlta	TransAlta Corporation
TSX	Toronto Stock Exchange
U.K.	United Kingdom
U.S.	United States
UAD	utility asset disposition
UAD decision	Decision 2013-417, Utility Asset Disposition
UCA	Office of the Utilities Consumer Advocate
USD	U.S. dollar or United States dollar
VIX	30-day implied volatility of the S&P index (representing the stock market in the U.S.)
VIXC	30-day implied volatility of the S&P/TSX 60 index (representing the stock market in Canada)
VVIX	traded index of the expected volatility of the VIX
WCSB	Western Canadian Sedimentary Basin