Aurizon Network 2016 Access Undertaking

Aspects of the WACC

PREPARED FOR

Aurizon Network for Submission to the Queensland Competition Authority

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Unless otherwise defined in this report, capitalized terms used in this report have the meaning given in the Queensland Competition Authority "Final Decision: Aurizon Network 2014 Access Undertaking – Volume IV – Maximum Allowable Revenue," April 2016.

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I. Introduction and Summary

A. Introduction

In support of Aurizon Network's submission to the Queensland Competition Authority (QCA) for the 2016 Access Undertaking (UT-5) commencing July 1, 2017, the Brattle Group has been asked to provide a report detailing its expert opinion on issues related to the appropriate allowed rate of return, in the form of the weighted average cost of capital (WACC), for Aurizon Network. In particular, we present and support our recommendations for determining certain of the parameters necessary to estimate the cost of equity capital using the Capital Asset Pricing Model (CAPM):

- the risk-free rate of interest;
- the Market Risk Premium (MRP); and
- the unlevered or assets beta.

With respect to the risk-free interest rate, we address several issues central to performing a CAPM estimate of the cost of equity for setting rates over the UT-5 period. We consider how investment horizon relates to the maturity of the government bond selected as the risk-free asset. We also present our views on how normalization techniques and interest rate forecasts can inform what risk-free rate will best represent expected returns during the relevant period.

As concerns the Market Risk Premium, we summarize the various methods traditionally considered by the QCA and other regulators to estimate the MRP, and discuss their relative merits in context of current economic and capital market conditions and the goals of the QCA's regulation. We present evidence concerning the relationship of the current MRP to historical average levels, and how this evidence informs our recommendation. Additionally, we emphasize the importance of considering the MRP and risk-free rate jointly and ensuring that the inputs chosen are logically and empirically consistent when implementing the CAPM.

Finally, consistent with the approach relied on by the QCA in the UT-4 Decision, our beta recommendations arise from statistical measurements of betas[1] for sample groups of publicly traded comparator companies that we view as representative of Aurizon Network's systematic business risk. We provide comprehensive discussions of key business risk characteristics of the sample groups and how they compare to Aurizon's business, and use this comparison to inform our interpretation of our estimates.

B. Summary

It is our view that the risk-free rate is best estimated using a long-term government bond such as the 10-year government bond yield. Because the current yield on government bond yields are unusually low and the spread to corporate bonds have widened, it is likely that the risk-free rate will increase over the regulatory period. We note that practitioners and regulators in other jurisdictions have relied on forecasted or normalized risk-free rates in recognition of these circumstances. We also note that there is a relationship between the risk-free rate and the Market Risk Premium (MRP) because

- the maturity of the risk-free rate must be consistent with the maturity of bonds over which the MRP is estimated;
- an increase in the spread between corporate bond yields and risk-free government bond yields indicates an increase in the premium investors require to hold assets that are not riskless; and
- the expected market return does not increase / decrease by 100 basis points when the risk-free rate increases / decreases by 100 percent; rather, movements in the expected market return is directionally aligned with but proportionately smaller than movements in the risk-free rate.

It is therefore necessary to consider aspects (e.g., maturity) of the risk-free rate and the MRP jointly.

As for the market risk premium we recommend that the QCA consider both historical and forward-looking data. In line with academic and practitioner texts, we suggest that the historical MRP is determined using as long a period as possible given the available data using the arithmetic average. We further recommend that a forward-looking method takes into account cash flows rather than dividends. Specifically, we find the reliance on only 50 years

1 As discussed below, we estimate betas using historical equity returns, which are then unlevered at the companies' market-value capital structures to control for differences in financial risk and provide an estimate of the *asset beta*, that is representative of the systematic business risk associated with Aurizon Network's assets.

of data for the Ibbotson method problematic, when there clearly are longer series available for calculation. We therefore recommend that the longest, reliable series be used – e.g., the Credit Suisse series which consider 1900 to 2015. We further recommend that the QCA looks to the Wright method, which combines historical observations on the real MRP with a forward look on inflation. Finally, we suggest that the QCA considers a commercial forecast of the MRP such as Bloomberg's, which is based on a discounted earnings model, where growth rates converge to the GDP growth. As for the Dividend Discount Model previously used, we note that it inherently provides a downward biased estimate as it ignores cash flows other than dividends and also ignores option values. Finally, we recommend against the Siegel method and survey methodologies for reasons explored below.

We estimate the MRP using each of the three recommended methods (Ibbotson, Wright, and Bloomberg forecast) and consider the impact of imputation credits. We find a midpoint MRP estimate of 7.7 percent when imputation credits are considered and 7.5 percent when imputation credits are not considered. Based on these calculations, we recommend an MRP of 7.7 percent for use in the WACC determination.[2]

We estimate that an appropriate asset beta for Aurizon Network falls in the range of 0.55 to 0.65. To determine this estimate, we rely on 5-year weekly equity returns regressed on market returns using CAPM for a sample of comparable companies from the freight rail, pipeline, electric utility, natural gas distribution, and water utility industries. We then unlever these equity betas using the Conine formula to report average and median asset betas by industry sample. We narrowed down this range by excluding industries that we find risks to be less comparable to those of Aurizon, specifically the electric distribution utilities and the U.S. Class 1 Freight Rail. We believe that the sample of natural gas and liquids pipeline transmission companies face risk most comparable to those of Aurizon Network due to the transmission of energy commodities for wholesale customers and their cost of service regulations, and therefore recommend the beta range of 0.55 to 0.65 based on this sample of firms.

We also evaluated betas by industry portfolios, rather than individual companies, and on varying time scales. We find that the portfolio betas align with our asset beta estimates and that 5-year weekly data strikes the right balance between statistical precision from longer periods of more data while also reflecting the current systematic risk dynamics.

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[2] The calculation uses a gamma of 0.25 and need to be adjusted should gamma be deemed higher or lower.

As a result of our estimation, we consider the midpoint of our range of 0.55 to 0.65; namely 0.60 to be a reasonable estimate for Aurizon Network as of today.

II. WACC Parameters

In Aurizon's UT-4, the QCA's final decision has a post-tax nominal (vanilla) WACC of 7.17 percent consisting of a cost of equity of 8.41 percent, a cost of debt of 6.15 percent and a benchmark capital structure of 55 percent gearing.[3] In UT-4 the cost of equity was determined using the Sharpe-Lintner Capital Asset Pricing Model (CAPM)[4] with the following inputs.[5]

Metric	Value	Description
Risk-free Rate	3.21%	4-year Commonwealth Government bond yields
Market Risk Premium	6.5%	Ibbotson, Siegel, Survey, and Cornell methods
Asset Beta	0.45	
Debt Beta	0.12	Precedence from prior decisions
Debt to Value	55%	Assumption
Equity Beta	0.8	Unlevering and relevering with taxes and debt beta
Imputation Credits, γ	0.47	

Debt Beta based on UT-3 proceeding. [6]

Fundamentally, the cost of capital represents an opportunity cost for investors; by undertaking one particular investment, the investor foregoes the return she might earn on some other investment of equivalent risk. At the time of the investment, however, the returns (and risks) of such foregone opportunities are unknown. The cost of capital therefore represents the expected return that a rational investor would require to make her indifferent between investments that are expected to have equivalent risk profiles. To precisely measure the cost of capital thus requires precise knowledge of market expectations for risk and return across the universe of tradable risky assets. But clearly, it is impossible to ever "know" these expectations. Even after the fact, realized returns and risk measurements are only point

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3 Queensland Competition Authority, "Final Decision: Aurizon Network 2014 Access Undertaking – Volume IV – Maximum Allowable Revenue," April 2016 (UT-4 Decision), p. 201.

4 Past decisions have considered using versions of the Black CAPM, which takes the empirical observation that the market security line is too steep into consideration. See, for example, UT-4 Decision, p. 265.

5 UT-4 Decision pp. 201-202.

6 Queensland Competition Authority, "Draft Decision: Aurizon Network 2014 Draft Access Undertaking – Maximum Allowable Revenue," September 2014 (UT-4 Draft Decision), p. 239.

observations from the distribution of outcomes that were possible at the time of the investment. The best one can do is to estimate the parameters relating to the cost of capital using the techniques of modern finance.

In the following, we discuss the determination of the risk-free rate, the market risk premium and beta as well as whether there are variations of the CAPM that may merit consideration.

III. Risk-Free Rate

A. Horizon of the Risk-Free Rate

The CAPM can be estimated using a short-term or long-term version of the risk-free rate and a comparable term of the MRP. However, it has become common for practitioners and many regulators to use the long-term version. For example, the Economic Regulatory Authority of Western Australia (ERA) in its recent review of the WACC for railroads relied on a 10-year risk-free rate[7] as did the Australian Energy Regulator's (AER) decision on AGN's access arrangement.[8,9] The Australian Competition Tribunal's (ACT) decision on Ausgrid, Endeavor, and Essential Energy's appeal did not contest the AER's choice of risk free rate:

> In relation to the risk free rate, the AER was satisfied that the yields on Commonwealth government securities with a 10 year term to maturity represented a widely accepted proxy for the risk free rate. That is not contentious.[10]

Looking elsewhere, the Alberta Utilities Commission, the British Columbia Utilities Commission, and the Ontario Energy Board in Canada all use a long-term (e.g., 30-years)

7 Review of the method for estimating the Weighted Average Cost of Capital for the Regulated Railway Networks, Final Decision, ERA, 18 September 2015, Section 7.5 Final Decision, p. 56.

8 Final Decision Australian Gas Networks Access Arrangement 2016 to 2021, Attachment 3 – Rate of return, AER, May 2016, Section 3.4.1, page 3-42.

9 Other maturities have also been used in Australian regulatory proceedings.

10 Australian Competition Tribunal, Applications by Public Interest Advocacy Centre Ltd and Ausgrid [2016] ACompT 1, 26 February 2016, p. 190

government bond as a reference for the risk-free rate.[11] In the U.S., the Surface Transportation Board uses the 20-year government bond.[12] The British regulator, Ofgem, along with the Italian energy regulatory, *Autorità per l'energia elettrica il gas e il sistema idrico* (AEEGSI), use 10-year government bond yield.[13] It is common practice among U.S. state regulators to use risk-free rate of 20-30 year maturity although the practice is much less documented.

In summation, most regulatory jurisdictions that we are familiar with rely on a long-term government bond as the risk-free rate. The reasons for this include:

1. long-term government rates, which are commonly used to measure the risk-free rate, are less influenced by monetary policy than are short-term rates;
2. regulated assets are long-lived;
3. equity investments have a perpetual horizon, representing a claim on cash flows generated by the company's assets in perpetuity; and
4. the Market Risk Premium (MRP) is often measured relative to a long-term government bond.

Because monetary policy influences short-term government bonds more than long-term bonds, the shorter bonds tend to fluctuate more than long-term rates during times of substantial government or central bank policy. This can be seen in Figure 1 below, which looks at the standard deviation of the four-year and the 10-year Australian Government bond yield normalized by the yield.[14]

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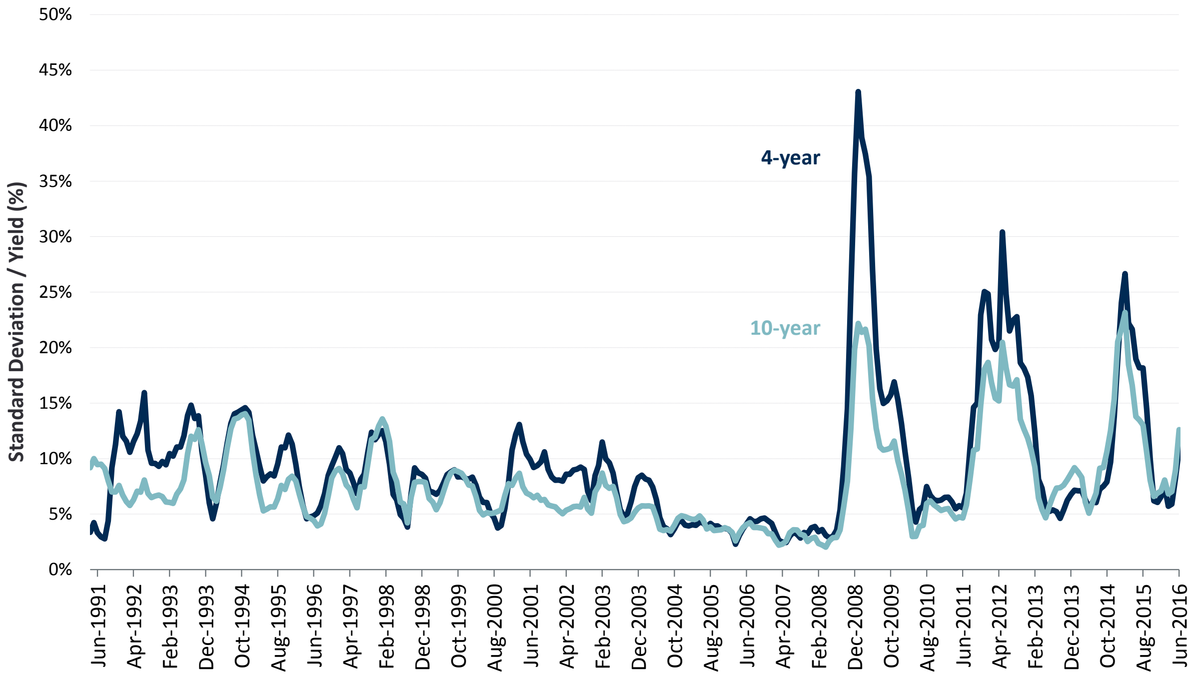
[11] The difference between Canada and the U.S. seems to be that while the Canadian government has consistently issued 30-year bonds, the 30-year government bond was abandoned in the U.S. from August 2001 to February 2006, so that a long series of consistent data is not available. Sources: Alberta Utilities Commission, "Decision 2191-D01-2015," March 23, 2015, para 92-93; British Columbia Utilities Commission, "FortisBC Energy Inc. Application for it Common Equity Component and Return on Equity for 2016," August 10, 2016, pp. 59-60; Ontario Energy Board Staff Report, "EB-2009-0084: Review of the Cost of Capital for Ontario's Regulated Utilities," January 14, 2016, p. 3.

[12] Surface Transportation Board, "Decision STB Ex Parte No. 664: Methodology to be Employed in Determining the Railroad Industry's Cost of Capital," January 17, 2008, p. 7;

[13] Ofgem "Final Decision, Decision on our methodology for assessing the equity market return for the purpose of setting RIIO-ED1 price controls," February 17, 2014; AEEGSI, "Decision 583/2015/R," December 2015. We understand that the Dutch regulator and other European regulators also rely on the 10-year government bond as the risk-free asset.

[14] The standard deviation is calculated using the most recent 12 month at each data point.

Figure 1
Standard Deviation to Level of Risk-Free Australian Government Rates



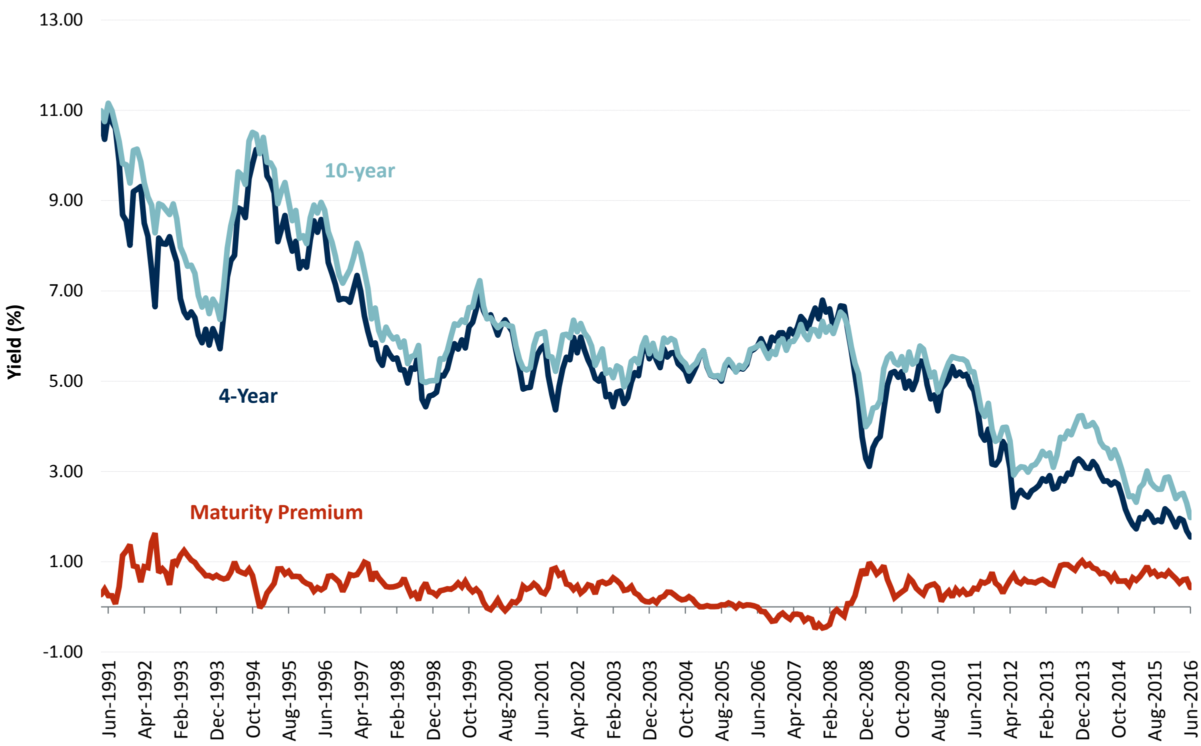
Source: Bloomberg

Regardless of which version is implemented (a longer or shorter term) it is imperative that the risk-free rate used in the CAPM calculation and that used in the determination of the MRP are consistent. If the maturity of the risk-free rate that is used in the CAPM differs from the risk-free rate over which the market risk premium was determined, the cost of equity and the WACC will be biased. Specifically, if the risk-free rate used in the CAPM has a shorter maturity than the risk-free rate used to assess the MRP, the estimated WACC is too low.[15] Such a bias will result in an inaccurate decision, which may impact the regulated entity's return and plausibly its ability to attract capital.

The magnitude of the bias on the estimated cost of equity and hence the WACC depends on the maturity premium, which is the premium that investors require to hold debt instruments for a longer period; e.g., 10 years rather than 4 years. Looking at recent yields on 4-year and 10-year Government of Australia bonds, it is evident that the maturity premium is positive by a non-trivial amount and has increased in recent years.

15 Dr. Martin Lally, "Review of Submissions on the MRP and the Risk-Free Rate," submitted to the QCA, 12 June 2015, pp. 35-37. Dr. Lally acknowledged that there was a mismatch, but argued that the impact on the estimated cost of equity would not be material, see pp. 39-41. We disagree.

Figure 2: Yield on 4-Year and 10-Year Government Bonds



Source: Bloomberg

Figure 2 above shows the yield on Australian 4-year and 10-year government bonds since 1991 along with the maturity premium. A simple calculation of the average maturity premium shows that while it differs across periods, it has usually been 40-60 basis points. While the maturity premium at the end of June 2016 was 43 basis points, the average maturity premium was 45 basis points from 1991 to today, 35 basis points from 2000 to today, and 66 basis points over the last five years.[16] Thus, it is imperative that the maturity of the risk-free rate used in the CAPM and to determine the MRP are consistent or that an adjustment is made for the maturity premium.[17]

16 Source: Bloomberg data using monthly data from March 1991 through June 2016 (Series: GACGB4 and GACGB10).

17 An argument can be made for calculating the maturity premium over the same period as the MRP is calculated over. As we recommend calculating the historical MRP over as long a period as we have reliable data for, we would prefer to calculate the maturity premium over as long a period as we have data for. We do not have access to as long a series for the maturity premium as for the MRP, so we recommend using a long-term government bond that is consistent in maturity term with the MRP relied upon; i.e., 10 years. However, should the QCA maintain the reliance on a 4-year risk-free rate we propose to upward adjust the MRP by the maturity premium discussed (45 basis points using the longest period we have available).

One reason given for using a long-term risk-free rate to estimate cost of equity is that equity can be viewed as a long-term claim on the firm's assets, and therefore the relevant 'alternative risk-free investment' is a long-term bond.[18] Regulated rates are set periodically.

The UT-4 Decision notes that the QCA consider it important that the Net Present Value (NPV) of the regulated firm's cash flow over the life of the asset equals its initial investment—the $NPV = 0$ Principle.[19] This proposition was originally developed by Marshall et al. 1981,[20] who showed investors would expect zero economic profit *over the life of the project*.

Clearly, the Aurizon Network's assets are long-lived and the expected life is certainly longer than four years. Schmalense 1989[21] extended the NPV-0 Principle to hold for shorter periods when the firm faces *no cash flow risk, asset value risk and if it is financed 100% by equity*. Further, the 2014 Draft Decision[22] notes Lally's work on including additional risk sources such as operating cost and demand risk and further notes that his work shows that asset revaluations can be dealt with through risk allowances. The results require a periodic reset of the regulated price.[23] We note two problems with these results. First, it requires that any asset revaluation is handled through risk allowances, which is a difficult requirement as it adds to the number of items that needs to be estimated. Further, the current regulatory entity (i.e, the QCA) and its members cannot *ex ante* bind future regulators to grant risk allowances should an asset need revaluation. Second, the result requires the regulated price to be reset periodically, which plausibly will be obtainable in the current regulatory environment but may not be in the future. Therefore, it seems that the NPV-0 Principle over a 4-year horizon is only truly feasible if the risk of stranded assets or substantial asset

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18 See, for example, *2016 Valuation Handbook- Guide to Cost of Capital, Market Results Through 2015*, Duff & Phelps, (Hoboken, New Jersey: John Wiley & Sons, Inc.), 2015, pp. 3-1, 3-2.

19 UT-4 Decision p. 6. We include the cost of capital as a cost here.

20 Marshall, W, Yawitz, J & Greenberg, E 1981, "Optimal Regulation Under Uncertainty", *Journal of Finance*, vol. 36, pp. 909-921.

21 Schmalensee, R 1989, "An Expository Note on Depreciation and Profitability Under Rate-of-Return Regulation", *Journal of Regulatory Economics*, pp. 293-298.

22 Queensland Competition Authority, "Draft Decision: Aurizon Network 2014 Draft Access Undertaking – Maximum Allowable Revenue," September 2014 (2014 Draft Decision).

23 2014 Draft Decision p. 195.

revaluations is minimal. In the case of Aurizon, where certain customers are primarily coal shippers and certain lines serve specific mines, there certainly is some risk of stranding.[24]

In summary, the NPV-0 proposition is appropriate for the life of the regulated asset but the strong assumptions used to derive the results for the regulatory period, makes it of little to no assistance in determining the horizon of the risk-free rate.

As discussed above, (a) the NPV-0 proposition does not help us determine the horizon of the risk-free rate, (b) data on the MRP are commonly calculated over a 10-year government bond in Australia, (c) longer term government bonds are less susceptible to monetary policy and hence less volatile than short-term bonds. Therefore, there are multiple benefits to using long-term government bonds and we do not see the NPV-0 proposition as an argument. We find that a straightforward way to avoid biasing the estimated cost of equity through an inconsistent use of the risk-free rate in the CAPM calculation and in the MRP determination is to rely on the 10-year government bond.

As the textbook of Pratt and Grabowski notes[25]

> In valuing "going-concern" businesses and long-term investments made by businesses, practitioners generally use long-term U.S. government bonds as the risk-free security …

And

> Many financial analysts today use the 20-year U.S. government bond yield to maturity as the risk-free rate as of the effective date of the valuation because:
>
> - It most closely matches the often-assumed perpetual lifetime horizon of an equity investment.
> - The longest-term yield to maturity fluctuate considerably less than short-term yields to maturity and thus are less likely to introduce unwarranted short-term distortions into the cost of capital.

We further note that texts such as Duff & Phelps' Valuation Handbook recommend using a long-term risk-free rate to estimate the cost of equity because equity is a long-term claim on

24 While the current regulatory regime re-allocates any otherwise stranded costs to other shippers, this may not be feasible if the magnitude of the stranded asset cost becomes unmanageable. Therefore, the risk exists.

25 Shannon P. Pratt & Roger J. Grabowski, "*Cost of Capital in Litigation: Applications and Examples*," Wiley 2011, p. 28.

the company's assets and therefore the relevant 'alternative risk-free investment' is a long-term bond.[26]

Further, infrastructure companies such as Aurizon—as well those we consider relevant to our beta estimation analysis—rely primarily on long-term financing. Equity is inherently infinite and the magnitude of long-term debt by far outweighs the short-term debt among these infrastructure companies.

As noted above other Australian regulators such as the AER, ERA (rail) and IPART use the 10-year risk-free rate as do Canadian, U.S. and several European regulators.[27] Because a mismatch of the risk-free rate and the term relied upon in the MRP determination can have a material impact on the cost of equity estimate, it is important to ensure there is no discrepancy between the maturity of the term of the risk-free rate and the term of the MRP.[28]

B. Forecasted Risk-Free Rate

As the Maximum Allowable Revenue for Aurizon will be determined for the period FY2018-FY2021, the WACC should reflect the cost of capital that is expected to be in place during that period. Therefore, the risk-free rate, the MRP, and the beta should ideally be forward looking.

Because the risk-free rate is expected to change (increase) over the next year or years, a forecasted risk-free rate may be appropriate. Looking to the most recent forecasts made by large Australian banks, we find that they consistently expect the yield on 10-year government bonds to remain similar or increase above the recent yield of approximately 2.1%[29] over the next 12-18 months. Examples are summarized in Figure 3 below.

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26 *2016 Valuation Handbook- Guide to Cost of Capital*, Market Results Through 2015, Duff & Phelps, (Hoboken, New Jersey: John Wiley & Sons, Inc.), 2015, pp. 3-1, 3-2.

27 For example, the U.S. Surface Transportation Board uses a 20-year government bond (consistent with the MRP relied upon by the regulator).

28 Ibbotson as well as the Credit Suisse data calculates the historical MRP over long term bonds with a maturity of no less than 10 years.

29 Average of the 10-year Australian government bond measured over the 20 trading dates ending 30 June 2016.

Figure 3: Forecasts on the 10-Year Government Bond Yield[30]

Source	Forecast	Forecast is for (date)
NAB	2.00%	Sept. 2017
Commonwealth Bank	2.60%	Dec. 2017
Westpac Weekly	2.45%	Sept. 2017

Moreover, at the time these forecasts were made (in late July and August, 2016), the Australian 10-year Government bond yield was trading at or near historic lows in the 1.8-1.9 percent range, from which it has since rebounded.[31] In other words, these financial institutions forecast that the yield on the Australian 10-year bond will not remain at the low levels observed in recent months, but are expected to increase by a non-trivial amount over the next 12-18 months. This means that the CAPM-based estimate for the cost of equity would be higher based on market expectations than if based on recently prevailing measures of the 10-year yield.

Because risk-free rates are expected to increase, it is imperative that the relied upon risk-free rate is not downward biased. As the short-term risk-free rate commonly is more affected by monetary policy this is an additional reason to rely on a long-term (e.g., 10-year) risk-free rate.

In many jurisdictions in North America, it is common to look to the expected risk-free rate. For example, Canadian jurisdictions commonly look at the Consensus Forecast for the 10-year government bond yield and add a maturity premium (to match the MRP, which is calculated over a 20-30 year government bond).[32] Similarly, several state regulators in the U.S. (e.g.,

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30 http://www.nab.com.au/business/international-and-foreign-exchange/financial-markets/interest-rate-forecast, updated August 23, 2016.

https://www.commbank.com.au/content/dam/commbank/corporate/research/publications/economics/forecasts-economic-financial/2016/050816-Forecasts.pdf

https://www.westpac.com.au/docs/pdf/aw/economics-research/WestpacWeekly.pdf, week beginning July 25, 2016.

31 The Australian 10-year yield was at 1.913 percent on July 25 when the cited Westpac forecast was issued, 1.870 percent on the August 5 issue date of the Commonwealth Bank forecast, and 1.848 percent on August 23 when NAB issued its forecast.

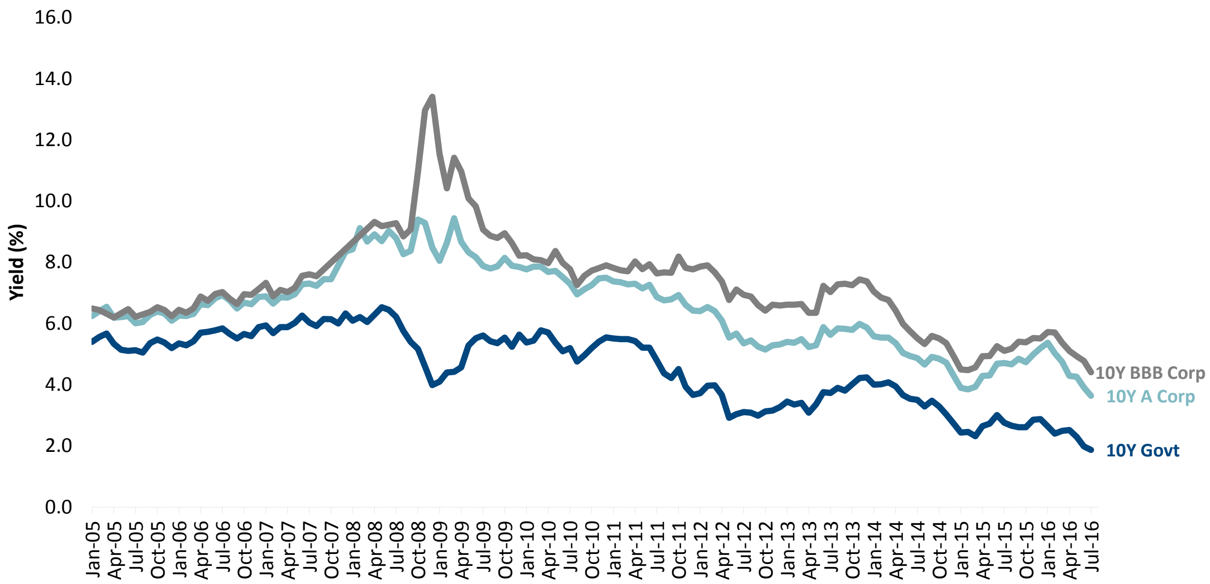
32 Alberta Utilities Commission, "Decision 2191-D01-2015," March 23, 2015, paragraph 93; British Columbia Utilities Board, "Generic Cost of Capital Proceeding (Stage 1): Decision," May 10, 2014, pp. 59-60, Ontario Energy Board Staff Report, "EB-2009-084," January 14, 2016.

Massachusetts, Michigan, Wisconsin, add others) have accepted the use of forecasted risk-free rate.[33]

C. Normalizing the Risk-Free Rate

Figure 4 below shows the yield on BBB and A rated corporate bonds as well as on 10-year government bonds – all of 10-year maturity. It is evident from the chart that the difference between government bond yields and corporate yields widened dramatically around the financial crisis of 2008-09 and has remained high relative to the level prior to the financial crisis. It is also evident that the spread between A or BBB rated corporate bond widened and have remained higher than prior to the financial crisis.

Figure 4: Australian 10-Year Government and Corporate Bond Yields



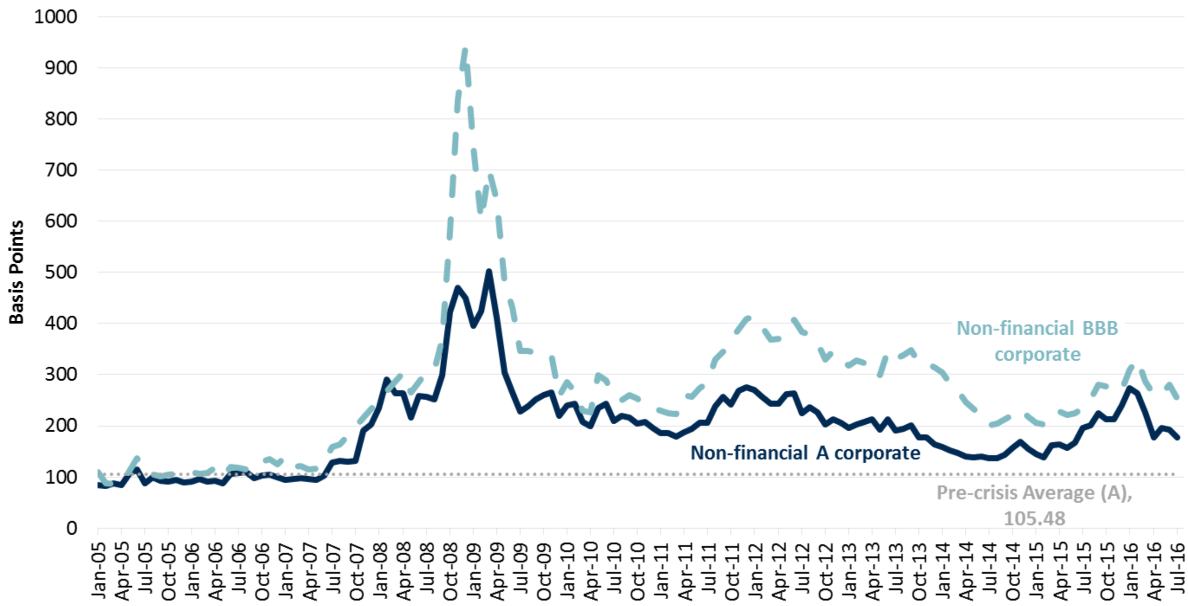
Source for corporate yields: http://www.rba.gov.au/statistics/tables/
Source for government yields: Bloomberg

To further illustrate the phenomena, Figure 5 below shows the spreads between the corporate bond yields and the government bond yield. Prior to the financial crisis, the spread between A rated corporate bonds was a bit above 105 basis points, but the spread now stands at close to 200 basis points. Put differently, the relationship between corporate and government bonds has changed.

33 U.S. state regulators rarely have a specific estimation methodology and therefore the merely accept or reject evidence.

The spread between corporate and risk-free government bond yields matter because it is an indication that either (i) government bond yields are suppressed by monetary policy and / or (ii) the risk premium investors require to invest in assets other than risk-free government bonds has increased.

Figure 5: Australian 10-Year Corporate Bond Yield Spreads



Source: http://www.rba.gov.au/statistics/tables/

Regardless of the interpretation, it has implications for the determination of the cost of equity – either the risk-free rate is too low relative to a normal benchmark and / or the Market Risk Premium (MRP) is too low. There are two ways in which analysts can approach this problem – the risk-free rate can be normalized by adding a portion of the increase in the spread to the risk-free rate that is used in the CAPM or the current impact on the MRP can be considered. Both approaches have been used. For example, the practitioner data that are available from Duff & Phelps calculate the cost of equity capital using a normalized risk-free rate[34] as did the British Columbia Utilities Commission as late as August of this year,[35] while the Alberta Utility Commission has preferred to recognize an increase in the MRP.[36]

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34 www.duffandphelps.com/CostofCapital

35 British Columbia Utilities Commission, "Decision and Order G-129-16," August 10, 2016, pp. 59-60.

36 Alberta Utilities Commission, "Decision 2191-D01-2015," March 23, 2015, para 86. British Columbia Utilities Commission, "Decision and Order G-129-16," August 10, 2016, pp. 59-60.

If the QCA were to normalize the risk-free rate it would require adding the increase in yield spread to the current rate on the risk-free government bond. In the case of the 10-year government bond, the increase in the yield spread is 70-90 basis points.

D. Recommendation

We recommend that the risk-free rate is based on a long-term government bond and given that rates are expected to be in effect for four years starting in 2017 and given the expected increase in interest rates, we caution against using the very low current interest rates without considering (a) the likely development in interest rates going forward and (b) the relationship between interest rates and the risk premium required to invest in equity. Notably, the market risk premium is inversely related to the risk-free rate, so a currently low interest rate is associated with a high MRP. We therefore recommend that the current risk-free rate (approximately 2.1 percent for 10-year Australian government bonds averaged over 20 trading dates ending 30 June 2016) be combined with an MRP that takes into account the currently elevated spread between corporate bond yields and government bond yields as illustrated above.

IV. Market Risk Premium

The market risk premium is inherently a forward-looking measure that changes with economic conditions and investors risk aversion. Thus, the expected market risk premium may differ from the current market risk premium and from the recent history. For perspective, it is important to recognize that the ERA has recently adopted MRP values in the range of 7.3 to 7.4 percent and concluded that the Ibbotson arithmetic MRP was a "lower bound" on estimates on the MRP. [37]

Looking to the methods that the QCA in the recent past has relied upon, we discuss the following key items:

- Methods most recently used by the QCA: Ibbotson, Siegel, Surveys, and Forecast

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37 Review of the method for estimating the Weighted Average Cost of Capital for the Regulated Railway Networks, Final Decision, ERA, 18 September 2015, Section 7.5 Final Decision, pp.139-140. See pp. 136-145 for a more detailed discussion of the Ibbotson method and other estimation methods. Final Decision on Proposed Revisions to the Access Arrangement for the Goldfields Gas Pipeline, Submitted by Goldfields Gas Transmission Pty Ltd, amended 21 July 2016, pp. 221-222, 230.

- Other Methods: e.g., Wright and Cash-Flow or Income-based forecasts

We conclude this section with our recommendations.

A. Using historical data – Ibbotson and Siegel

If a historical estimate of the MRP is used, it should be estimated using an arithmetic average, as long a period as possible given the availability of reliable data and as only the income return of a bond is truly risk free, so ideally the MRP should be measured over the income return.

Looking to specific measures of the historical MRP for Australia and elsewhere, we summarize key estimates of the MRP in Figure 6 below.

Figure 6: Historical MRP Data[38]

	Australia	World	US	Estimation Period
Credit Suisse	6.6%	4.4%	6.4%	1900-2015
Duff & Phelps	n/a	n/a	7.0%	1926-2014
Credit Suisse Real	5.8%	4.1%	5.8%	1926-2015

The Credit Suisse measure used above reports the average arithmetic total return on the local market index minus the total return on the long-term government bond.[39] Duff & Phelps follow the strict Ibbotson methodology, which calculated the MRP as the difference between total market returns and income returns. Finally, the Credit Suisse Real measure is determined as the real return on equities vs. the real return on long-term bonds. We emphasize that the market risk premium, like the cost of capital itself, is a forward-looking concept. In principle, it is the premium above the risk-free rate that investors can expect to

38 Sources: *Credit Suisse Global Investment Return Sourcebook 2016* (Credit Suisse 2016) and Duff & Phelps, "*2015 International Valuation Handbook*" (Duff & Phelps 2015). We note that while Credit Suisse reports data for Australia back to 1900, Duff and Phelps only carries data back to 1970 for Australia, which is too short a period for MRP estimation purposes. For the shorter period of 1970 to 2014, Duff & Phelps report an MRP of 4.0% for Australia, whereas the same text report 6.9% for Australia using 1975 to 2014.

39 Credit Suisse 2016, p. 61 notes that they currently use total returns and bonds with 10 or more years to maturity.

earn by investing in a value-weighted portfolio of all risky investments in the market.[40] As emphasized by, for example, Ibbotson, the only truly risk-free part of the bond return is the income return, so that ideally a historical MRP should be measured over the income return – the Ibbotson approach.[41]

Neither the Credit Suisse nor the Duff & Phelps measures include an adjustment for the imputation credit in Australia. However, the dividend imputation tax system was not introduced in Australia until 1987, so the majority of data comprised in the Credit Suisse measure would be unaffected by imputation credits. Only a quarter of the years in Credit Suisse's estimation period would have imputation credits, therefore decreasing the overall effect on the MRP. Imputation credits would have more impact on the Duff & Phelps data for Australia given its shorter estimation period.

Looking to Figure 6, we note that the Australian MRP data from Credit Suisse are consistent with the U.S. data from Credit Suisse. We also note that the relatively short time period used by Duff & Phelps for Australia (see footnote 38) inherently makes the data less reliable than those of other sources. For example, sustained inflation above 10%[42] and significant downturns in Australian equity markets[43] caused by the oil crisis in the early- and mid-1970s have a large impact in decreasing the MRP cited by Duff & Phelps to lower values than other sources with longer series of historical data.

Clearly, current investor expectations are not reflected in 50 years of data but rather in today's markets, so the question is how best to measure current investor expectations. MBA texts such as Ross et. al and practitioner emphasize the use of as long a data series as possible,[44] where data are reliable, because as Ciacchino & Lesser observe "history tends to

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40 We note that Credit Suisse have used data from a variety of maturities back in time depending on data availability. Current practice is to use Australian Government bonds "with ten or more years to maturity." Credit Suisse 2016 p. 61.

41 Morningstar / Ibbotson, "*Ibbotson SBBI 2015 Classic Yearbook*," (Ibbotson 2015), pp. 153.

42 http://www.rba.gov.au/publications/bulletin/2008/jun/pdf/bu-0608-3.pdf, p. 21.

43 https://www.finsia.com/docs/default-source/jassa-new/jassa-2006/3_2006_equity_returns.pdf?sfvrsn=6

44 The MBA text of Professors Stephen A. Ross, Randolph W. Westerfield, and Jeffrey F. Jaffe, "*Corporate Finance*," 10th edition, 2013 (Ross et al. 2013), p. 326 recommend using a long period to estimate the MRP as does the practitioner text of Morningstar / Ibbotson, "*Ibbotson SBBI 2015 Classic Yearbook*," (Ibbotson 2015), pp. 153-154.

repeat itself, for good or ill, arbitrary exclusions of certain historic years 'because they can never occur again' strikes us as either naïve, or an exercise in wishful thinking."[45]

Thus, we have Ibbotson methodology data from Duff and Phelps for Australia back to only 1970, which is short for the purpose of determining the forward-looking MRP. Credit Suisse in turn reports an Australian MRP based on historical return data, but uses detailed information back to 1900. Because the Credit Suisse data has a long history and is widely available, we recommend it be used as a source for historical arithmetic average MRP. Thus, our historical average MRP for Australia over long-term bonds is 6.6% (without accounting for imputation credits). We note that the real MRP can only be used if adjusted for the expected inflation as discussed in the Wright method below.

As mentioned above, the Credit Suisse method has not been adjusted for imputation credits. We follow the argument of Lally (2008) Equation 1 in order to solve for the MRP inclusive of the value of imputation credits.[46] We then average the MRP inclusive of imputation credits, weighted by the number of years in the historical data period during which Australia had the dividend imputation tax system, with the value excluding imputation credits. We find the adjusted historical average MRP for Australia to be 6.8%.[47] It is important to note, however, that caution is required when applying the historical average MRP to CAPM estimation of the cost of equity. This is because the historical average is only a valid forecast of the current and expected future risk premium when economic conditions are themselves "average" relative to the historical estimation period. If economic conditions are instead unusual compared to the historical period—for example as embodied by the current very low interest rate environment—the historical average estimate may represent a biased (in this case downwardly) forecast of the expected MRP. Therefore, analysts consider additional information apply explicit methods to provide a more accurate estimate of the MRP, rather than relying solely on the historical average. We address forward-looking MRP measures below.

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[45] Leonardo R. Giacchino and Jonathan A. Lesser, "*Principles of Utility Corporate Finance*," Public Utilities Report, Inc., 2011, p. 236.

[46] Lally, M. "Relationship between franking credits and the market risk premium: a comment". *Accounting and Finance* (2008).

[47] See Appendix A for details on imputation credit adjustment.

1. Siegel

The QCA has in past decisions relied on the Siegel method, which adjusts the Ibbotson estimated MRP by adding the real bond return back and subtracting the expected real bond return in each historical year. Thus, it attempts to adjust for unexpected inflation.

There are several issues with the Siegel procedure. It is not widely recognized or used among practitioners or regulators,[48] and it is not clear that the method has merits today.

Outside of Australia and New Zealand, we know of no regulator, who has considered the Siegel method and within Australia, the AER and ERA has not used it in recent decision.[49] The ERA in its recent rail WACC decision relied on the Ibbotson method, the Wright approach and a forward-looking estimate. The method is not mentioned in the AER's recent decision on the Australian Gas Networks.[50] Looking through standard MBA textbooks such as Brealey, Myers & Allen (2008), Ross, Westerfield & Jaffe (2013), Berk & DeMarzo (2014), we found no mentioning of the Siegel method. [51] Similarly, we looked at practitioner texts such as Duff & Phelps (2015) and Pratt & Grabowski (2011) without finding any mentioning of the method.[52]

The method was derived for the period 1940-1990, which was characterized by industrial development and periods of very high inflation. Because a long historical period is favored to determine the historical arithmetic MRP, it would be important to repeat the study using data from the last 25 plus years. It is not clear that an economy characterized by growth in the service and information industries is similar to that of the 1940s through the 1980s, which relied much more heavily on manufacturing. While Dr. Lally in 2014 argued that the low

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48 See, for example, QCA, "Draft Decision: Aurizon Network 2014 Draft Access Undertaking – Maximum Allowable Revenue," September 2014, p. 230.

49 Review of the method for estimating the Weighted Average Cost of Capital for the Regulated Railway Networks, Final Decision, ERA, 18 September 2015, Section 7.5 Final Decision.

50 Australian Energy Regulator, "Final Decision: Australian Gas Networks Access Arrangement 2016 to 2021," Attachment 3 – Rate of Return, May 2016.

51 Richard A. Brealey, Stewart C. Myers and Franklin Allen, "*Principles of Corporate Finance*," 9th edition, 2008; Stephen A. Ross, Randolph W. Westerfield, and Jeffrey F. Jaffe, "*Corporate Finance*," 10th Edition, 2013; Jonathan Berk and Peter DeMarzo, "*Corporate Finance*," 3rd Edition, 2014;

52 Duff & Phelps, "*2015 International Valuation Handbook: Guide to Cost of Capital*," 2015 and Shannon P. Pratt and Roger J Grabowski, "*Cost of Capital in Litigation*," Wiley 2011.

inflation period was accompanied by real bond return in the range of 3.5 percent,[53] the analysis by Dr. Lally did not address the fundamental question of whether the relationship post-1990 remains the same. For example, markets have become substantially more integrated since 1990, so that an analysis based solely on Australian data may not be applicable. Without such a study, we recommend against the use of the Siegel method. We have not seen an updated study and note that neither the UT-4 Decision nor the report of the QCA's expert, Dr. Lally, cited an updated version of the Siegel study.[54]

We also note that the comparison to the Wright method, which we discuss below, is misguided. The Wright method determines the real market return using realized historical data for real returns and uses a forecasted inflation to estimate a forward-looking nominal return, whereas the Siegel method relies on the difference between ex post realized and ex ante expected returns on bonds. Hence, it makes an adjustment to use ex ante expected rather than ex post realized inflation. This makes it imperative—if relying on the Siegel method—to demonstrate that market expectations regarding the relationship between return and inflation are similar today as they were in 1940-1990. The Wright method relies on realized historical real return and on *current* inflation expectations.

For the reasons discussed above, we recommend that the QCA eliminates the Siegel method from consideration.

Having observed the best estimate of the historical MRP, we observe that there are many reasons why the MRP changes over time and recent academic studies have found that the MRP post the financial crisis is higher than prior to the financial crisis. The next section addresses this issue.

B. Forecasted MRP and Cornell Method

There are many models that attempt to forecast the MRP using a variety of discounted dividend (or cash flow) models. Such models depend on the initial dividend or cash flow yield and growth rate assumptions. The Cornell method, for example, looks at dividends rather than cash flows, so to the extent that there are cash flows other than dividends that accrue to shareholders, the model will underestimate the MRP. If growth rate assumptions

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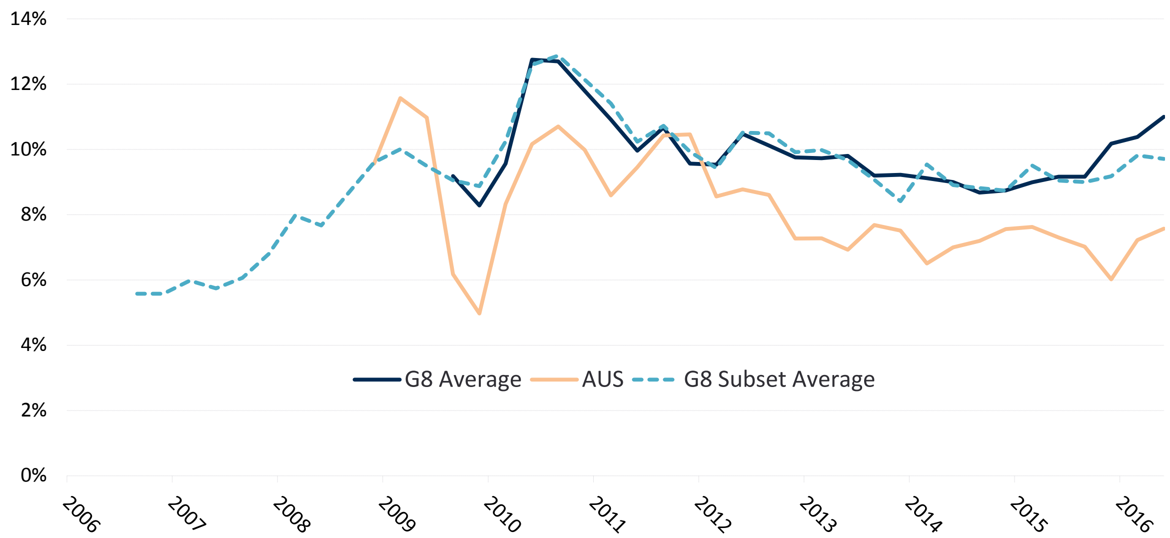
53 Martin Lally, "Review of Submissions to the QCA on the MRP, Risk-Free Rate and Gamma," March 2014, pp. 11-12.

54 Martin Lally, "Review of Submissions on the MRP and the Risk-Free Rate," 12 June 2015, pp. 27-33 and pp. 35-41.

are over or under estimated, the MRP will be over or underestimated. Because share buybacks are a vehicle for companies to distribute cash to shareholders, we recommend that a cash flow based model or a model that explicitly accounts for share buybacks is applied.[55] As discussed above, we prefer a model that is widely available. One such model provided by Bloomberg, which bases its forecast on normalized cash flow before extraordinary items (e.g., a 3-year average), uses the company specific growth rate for the first few years and then converges the growth rate to the GDP growth rate.

Bloomberg currently forecasts an MRP for Australia of 7.6 percent, while the forecast for the G8 is higher and the U.S. forecast is also 7.6 percent.[56] The Bloomberg forecast does not include the value of imputation credits. We find a forecasted MRP of 8.6% when adjusting for imputation credits.[57]

Figure 7: Bloomberg's Forecasted Australian and Average G8 MRP



Source: Bloomberg

We oberve that the Bloomberg forecasted MRP is more volatile than a dividend discount model with a substantial amount of volatility occurring around the financial crisis. However, we consider the ability of the model to capture current market conditions as a strength rather than a weakness and especially so if it is used as one of several models – thus the variations

55 While Australian firms do not engage as much in share buybacks as firms in some other countries, we discuss the plausible impact later in this section.

56 The G8 subset excludes Germany, Italy, and Russia as Bloomberg does not have data for these countries before 2009.

57 See Appendix A for details on calculation.

are modified. Importantly, the forecasted MRP for the G8 has been well above the historical level since the financial crisis and while we do not have data on Australia prior to 2009, the pattern post 2009 has been similar to that of the G8.

Regarding the details of Bloomberg's implementation of the forecasted MRP, we note that it relies on a normalized cash flow rather than dividends and a payout ratio rather than dividends and growth rates converges to the GDP growth rate over a period of 8-15 years with mature companies being in the lower range and start-ups being in the longer range.[58] Thus, the convergence to GDP growth is faster for established companies and longer for growth companies. Because the model relies on a version of cash flow rather than dividends, it accounts for all cash flow that is distributed to shareholders – contrary to a dividend discount model, which implicitly assumes that dividends are the only source of cash for shareholders. Further, a discounted cash flow model or DDM does not consider any option values that may be inherent in stocks. Therefore, such model tends to underestimate the MRP.[59] In 2014, Professor Lally assessed that the effect of share repurchases was approximately 50 basis points, but also argued that such repurchases would reduce the growth rate going forward.[60] We disagree. Assuming the discounted cash flow model with net share repurchases is estimated on a per share bases, analysts that provide company-specific or GDP growth rate forecasts will presumably know the announced share repurchases (issuances) in the same manner as do investors – such activities are commonly disclosed in financial reports or through press releases. Therefore, analysts will consider the impact, if any, on the growth rate they provide and any adjustment for this issue will double-deduct the effect. Thus, the impact of not accounting for share buybacks is not trivial. An analysis of the dividend and share-buyback yield at the ASX 200 is consistent with an approximately 50 basis points additional yield created by share buybacks.[61] If relying on the dividend discount model for the MRP, upward 50 basis points needs to be added to the estimated MRP.

We believe the Bloomberg forecast, which is based on normalized cash flow and a convergence to GDP growth provides a reasonable estimate of the current MRP. The data in Figure 7 above is consistent with the findings of, for example, a recent analysis by Duarte

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58 Bloomberg data.

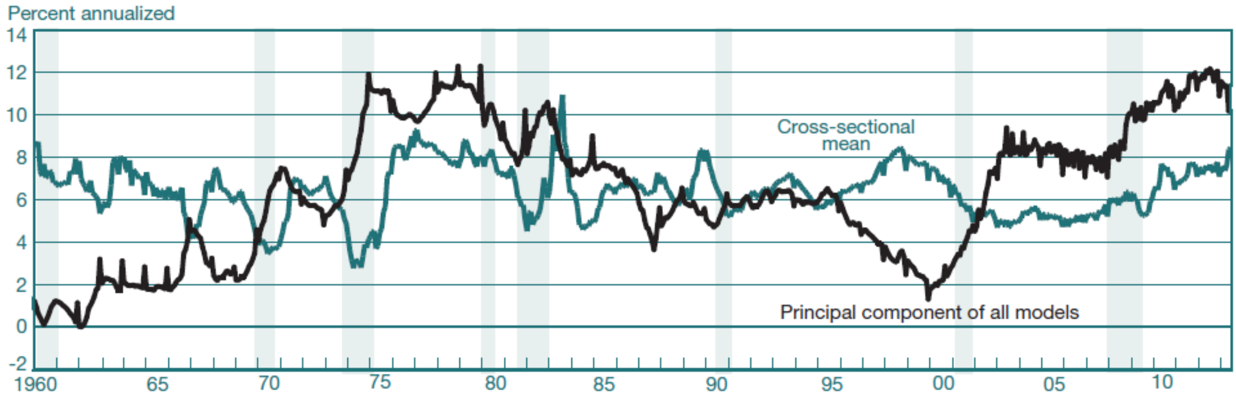
59 We note that a model that account for, for example, share repurchases need to consider repurchases net of new issuances, where the issuer obtain cash from shareholders.

60 Dr. Martin Lally, "Review of Submissions on the MRP and Risk-Free Rate," 12 June 2015, p. 40.

61 Bloomberg data.

Rosa of the Federal Reserve of New York,[62] who summarized many of the models used to estimate the MRP. The authors estimated 20 models each year from 1960 through 2013 and found, consistent with the literature, that the MRP was very low in the early 2000s, but that it since has increased dramatically and the results in the U.S. are generally consistent with the Bloomberg data. The results of Duarte and Rosa are illustrated in Figure 8 below, which replicates Chart 3 from their paper.[63]

Figure 8: Replication of Chart 3 from Duarte & Rosa 2014: One-Year Ahead MRP (U.S)



It is clear from Figure 8 above, that the MRP consistently has been elevated relative to its historical average since the financial crisis of 2008-09 and remains elevated.

Looking next to the impact of the elevation in yield spread shown in Figure 5, we notice a substantial increase in this spread, so that investors require a higher premium for holding assets that are not risk-free than they have in the past. Using the data depicted in Figure 5, we calculate the elevation in yield spread relative to prior to the financial crisis for June and July 2016. The results are shown in Figure 9 below.

Figure 9: Elevation in Corporate Yield Spread Relative to Pre-Crisis Norm

	A rated	BBB rated
June 2016	87 bps	175 bps
July 2016	71 bps	148 bps

[62] Fernando Duarte and Carlo Rosa, "The Equity Risk Premium: A Review of Models," Federal Reserve Bank of New York, 2015 (Duarte & Rosa 2015).

[63] Duarte & Rosa 2015, Chart 3.

The implications of the yield spread being elevated is that investors require a higher return on investment grade utility debt relative to the return on Australian Government bonds than they did before the crisis and ensuing economic turmoil. If the required return on investment grade bonds is elevated, clearly the required return on equity is also elevated relative to what is available on government bonds.

This information can be used to provide a quantitative benchmark for the implied increase in MRP based on a paper by Edwin J. Elton, et al., which documents that the yield spread on corporate bonds is normally a combination of a default premium, a tax premium, and a systematic risk premium.[64] Of these components, it is the systematic risk premium that likely explains the vast majority of the yield spread increase. In other words, unless the risk-free rate is underestimated as described above, the market equity risk premium has increased relative to its "normal" level.[65] Therefore, we consider a scenario allocating part of the approximately 70-85 bps increase in A-rated utility spreads to an increase in the MRP (which drives the increase in systematic risk premium on A-rated debt). This is conservative as we use the lowest figure in the table above.

Assuming a beta of 0.12 for A-rated debt[66] means that an increase in the MRP of one percentage point translates into a 0.12 percentage point increase in the risk premium on A-rated debt (i.e., 0.12 (beta) times 1 percentage point (increase in MRP) = 0.12 percentage point increase in yield spread). An elevation of 71-87 bps in the yield spread relative to its historical norm is therefore consistent with an increase in the MRP of upward 5.9 – 7.2 percentage points ($calculated\ as\ \frac{0.71\%}{0.12} = 5.9\%\ and\ \frac{0.87\%}{0.12} = 7.2\%$). We consider this evidence as confirmation that the current MRP in Australia is elevated by a non-trivial amount relative to its historical norm.

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64 "Explaining the Rate Spread on Corporate Bonds," Edwin J. Elton, Martin J. Gruber, Deepak Agarwal, and Christopher Mann, *The Journal of Finance*, February 2001, pp. 247-277.

65 In theory, some of the increase in yield spread for A range rated debt may be due to an increase in default risk, but the increase in default risk for A range rated debt is undoubtedly very small because utilities with A range rated debt have a low default risk. This means that the vast majority—if not all—of the increase in A rated yield spreads is due to a combination of the increased systematic risk premium and the downward pressure on the yields of government debt. Although there is no increase in the tax premium discussed in the Elton et al. paper due to coupon payments, there may be some increase due to a small tax effect resulting from the probability of increased capital gains taxes when the debt matures.

66 UT-4 Decision pp. 201-202.

Looking to our forecasted MRP results, Bloomberg indicates an MRP of 7.6 percent, while the increase in yield spread indicates the MRP is elevated by 5.9 to 7.2 percent. Because we prefer data that are widely available, we recommend that the Bloomberg estimate of 7.6 percent be included as part of the MRP estimate.

C. Surveys

Surveys, such as those produced by Fernandez et al.,[67] that ask broad samples of academics, company managers, and other finance practitioners to cite their estimate of the MRP suffer from several methodological deficiencies as a source for inputs to the CAPM. For one thing, these surveys cannot be independently replicated, the variation in the provided answers is large, and depending on the country, the number and composition of the professionals who provide input to the survey may be limited. Additionally, there is commonly no information provided about whether the responses represent the respondents' estimates of the long-term, short-term, or some other horizon risk premium. Because the 10-year government bond often is used as a reference for long-term government bonds in Australia, while Canada and the U.S. commonly rely on 20 or 30-year bonds, a participant may cite the premium over a 20-30 year bond and have it interpreted as being over a 10-year bond, resulting in a biased estimate.

In the most recent survey by Fernandez, Australian contributors are listed as, on average, using an MRP of 6.0%, but the standard deviation is 1.6%, which indicate a fairly wide range of estimates; from approximately 3–9 percent (assuming a normal distribution). Further, no information is available about the composition of the Australian respondents or the purpose for which they use the MRP. For example, if it is for teaching purposes, a rounded figure is often used whereas the applicable MRP changes over time. For these reasons we urge extreme caution in using survey results to inform the MRP input for CAPM estimates of the cost of equity. Unlike expert reports by investment professionals or other valuation experts that present data and analysis to support their recommended estimates of the MRP, surveys are neither transparent nor easily evaluated for relevance to the implementation at hand. Hence it is our view that survey results should not be relied upon when determining the MRP.

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[67] Pablo Fernandez, Alberto Ortiz, and Isabel Fernandez Acín, "Market Risk Premium used in 71 countries in 2016: a survey with 6,932 answers," IESE Business School, May 9, 2016.

D. Wright Method

The Wright method has been suggested as an alternative to one or more of the methods currently used by the QCA. The Wright method essentially estimates the return on the market rather than the market risk premium and, as the Australian Energy Regulator (AER) has noted,

> The Wright approach results in significantly more stable estimates of the expected return on equity when compared to the implementation of the Sharpe–Lintner CAPM (using our foundation model approach).[68]

In recommending that the Wright method be considered, the AER observed that the stability of the estimates is desirable given that network assets are long-lived. We agree with the AER, and also recognize some other advantages of using the Wright method, especially relative to application of the other approaches based on adjusted historical data (such as the Siegel method). By averaging historical market returns rather than historical risk premiums, it mitigates the issue of potential mismatch between historical average and forward-looking interest rate conditions. Additionally, the focus on historical *real* rather than nominal returns controls for large differences in the rate of inflation over time and its effect on interest rates and risk premiums. For these reasons, we use the Wright method part of our MRP recommendation.

The Wright approach assumes that the relationship between the real risk-free rate and the real MRP is perfectly negatively correlated. The method calculates the forward-looking MRP using the following steps:

- Step 1: Estimate the real return on the market each year over a specified historical time period

$$R_m^{real}(t) = \frac{1+R_m^{nominal}(t)}{1+Inflation(t)} - 1$$

- Step 2: Determine the average $\overline{R_m}^{real}$, over the entire period
- Step 3: Use the forecasted inflation rate, $E[inflation]$, to determine the expected nominal return on the market:

$$E[R_m^{nominal}] = (1 + \overline{R_m}^{real}) \times (1 + E[inflation]) - 1$$

- Step 4: Use the expected nominal return on the market along with a measure of the risk-free rate to determine the forward-looking expected MRP.

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[68] Australian Energy Regulator, "Better Regulation: Explanatory Statement – Rate of Return Guideline (Appendices)," December 2013, p. 35.

$$E[\text{MRP}] = E[R_m^{nominal}] - r_f$$

The Wright approach uses historical data to determine the real MRP but applies a forward-looking inflation rate to determine the MRP. Thus, the method implicitly assumes that real returns will behave as they have historically, but inflation need not do the same. Using the Wright method, historical average real returns are predictive of future real returns, such that future nominal returns are best forecast by applying current inflation expectations to the historical average real return. However, unlike these methods, the Wright approach does not consider future growth, but relies exclusively on the forecasted inflation rate. An advantage of this approach is that it makes the MRP relatively stable, but a disadvantage is that it fails to recognize variations in investor expectations.

Looking to the current estimates, we note that the real return on the Australian market has been approximately 8.3 percent since 1900,[69] while the forecasted inflation is approximately 1.8 to 2.1 percent[70] for a forecasted nominal return on the market of approximately 10.2 to 10.6 percent. As the current yield on 10-year government bonds is approximately 2.1%, the Wright method estimates an MRP of 8.1 to 8.6 percent and is thus consistent with the forecasted MRP discussed in Section IV.B. Looking to the average of these two estimates, we arrive at a Wright MRP estimate of about 8.3 percent without imputation credits, or 8.6% after adjusting for imputation credits.[71]

E. Horizon of the Risk-Free Rate and MRP Should Match

If the MRP is estimated over a 10-year government bond, then the risk-free rate should also have a 10-year maturity or a maturity premium should be applied. For example, if a 4-year government bond yield is used as the risk-free rate and the MRP is estimated over a 10-year government bond (Dimson, Marsh and Staunton and Ibbotson use 10 or more years to maturity, while Bloomberg uses 10 years), then the expected maturity premium between a 10-year and a 4-year government bond yield should be added to the MRP. As noted above, the maturity premium has historically ranged from 0.45% over the period 1991-2016 (June)

69 *Credit Suisse Global Investment Return Sourcebook 2016*

70 WestpacWeekly, July 2016 and CBA Forecast, August 2016.

71 See Appendix A for details on calculation.

to currently 0.58%. Other periods exhibit slightly higher or lower maturity premia. Thus, if a historical MRP over long-term government bonds is used along with a 4-year risk-free rate, then it is necessary to add 0.45 – 0.58 percent to the MRP to ensure consistency.

We note that this calculation takes into account the comments of the QCA's consultant, Dr. Lally, who looked to as long as possible a period for estimating the maturity premium in the UT-4 proceeding.[72] Dr. Lally further suggests that there could be a term structure for the market return, so that the expected market return would be higher if defined over a 10-year horizon rather than a 4-year horizon.[73] While this may be true, the historical MRP used in the Ibbotson and Siegel approach are based on historical observations that average realized excess returns over periods of one year. Thus, this observation seems to be applicable for forecasted MRP estimates rather than MRP estimates based on historical observations.

We note that the estimates listed in Figure 6 are over a government bond with a maturity of **at least** 10 years for Australia, so that our determination of the maturity premium (using 10-year government bonds) may be conservative.

The following example illustrates this point using a beta of one for simplicity and also assumes the current spread and the historical spread between 4-year and 10-year government bonds is 0.58 percent. Using slightly different spreads will show the same pattern although the final numbers would differ slightly.

Example:

Assumptions:	4-year risk–free rate:	1.81%	
	10-year risk-free rate:	2.39%	
	MPR over 10-year bonds:	7.50%	
	MRP over 4-year bonds:	8.08%	
	Beta:	1.00	(for simplicity)

If we assume, without implications, that the above measures are accurate, then we obtain the following estimates for the cost of equity.[74]

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72 Dr. Martin Lally, "Review of Submissions on the MRP and the Risk-free Rate," submitted to the QCA and dated 12 June 2015, p. 36.

73 *Ibid.*, p. 34-35.

74 We note that the number in Figure 10 are for illustrative purposes only and while the example use realistic figures, no consideration has been given to capital structure, imputation credits, or any other necessary adjustments.

Figure 10: Illustration of Matching the Horizon of the MRP and Risk-free Rate

RFR / MRP horizon	RFR	Beta	MRP	Estimated COE
4 / 4	1.81%	1	8.08%	**9.89%**
4 / 10	1.81%	1	7.50%	9.31%
10 / 4	2.39%	1	8.08%	10.47%
10 / 10	2.39%	1	7.50%	**9.89%**

As the example shows, if the 4-year risk-free rate is used with a 10-year MRP, the estimated cost of equity is downward biased and if the 10-year risk-free rate is used with a 4-year MRP, then the estimated cost of equity is upward biased.

As the historical MRP is often reported over 10 or 20-year government bonds or over 30 or 90-day government bills, a theoretically correct implementation as is customary in many regulatory jurisdictions is to implement the CAPM using a *comparable* risk-free rate.[75] It is also possible to adjust the MRP for the difference in maturity by adding an appropriate maturity premium. Notably, if the QCA seek to use a 4-year risk-free rate, then it becomes necessary to add a maturity premium of 0.45 – 0.58 percent.

F. Recommendation on MRP

It is imperative that the horizon of the risk-free rate and the MRP match and we recommend a long-term; e.g., 10-year maturity be used for both as that ensures consistency, avoid shorter-term rates that are more susceptible to monetary policy, and also take the long-lived nature of Aurizon's assets into account.

Based on our research, we find that the historical MRP for Australia is 6.6%, while the forecasted MRP is approximately 7.6 percent (ignoring imputation credits). We observe that the MRP has been elevated above the historical MRP for an extended period of time, so that the currently forecasted MRP cannot be dismissed as being too volatile. The Wright method similarly finds an MRP in the range of 7.9 to 8.3 percent and thus affirms the elevated nature

75 The Australian Energy Regulatory has recently relied on the 10-year risk-free rate (See, AER, "Explanatory Statement: Rate of Return Guidelines," December 2013, p. 73). The U.S. Surface Transportation Board uses a 20-year risk-free rate to match Ibbotson's reported long-term historical MRP (see Surface Transportation Board, "Decision Docket No. EP-558 (Sub-No. 17)," issued July 31, 2014, p. 7).

of the current MRP. We also observe that the elevated yield spread supports and MRP in excess of its historical average.

We further observe that any MRP forecast that relies exclusively on a dividend discount model applied to the market necessarily underestimated the MRP because companies distribute cash to shareholders through means other than dividends and because the DDM does not include option values. While the magnitude of this underestimation is challenging to pinpoint, we believe, as discussed above that the impact on growth rates is already included and that the current estimates using the Cornell dividend discount method needs to be upward adjusted by at least 50 basis points.

The most recent survey of Fernandez indicates an MRP of 6.0 percent with a standard deviation of 1.6% for a range of about 3 to 9 percent. However, as explained above, we do not recommend relying on results reported by the Fernandez survey or similar surveys.

Thus, the bulk of the measures indicate that the current MRP is elevated relative to its historical average, which is consistent with recent academic research. We therefore believe the current MRP is in the range of 7¼ percent to 7¾ percent. In the interest of transparency, we recommend that the QCA determine the MRP as the midpoint of the range comprising the Credit Suisse arithmetic average, the Wright method, and the Bloomberg forecasted MRP. Our recommendation is based on our preference for publicly available data that are transparent. We also favor arithmetic averages that are calculated over very long periods as does the academic literature, which leads us to have a preference for the Credit Suisse data back to 1900 instead of a shorter period. We do not endorse methods that cannot be replicated (e.g., the Fernandez survey) and recommend that any forecasted MRP (i) be based on cash flows rather than dividends and (ii) come from reputable data provider. These recommendations are intended to make the determination less controversial. In this instance our MRP recommendation, shown both before and after adjusting for imputation credits, is calculated as follows:[76]

[76] Rounding all data to the nearest decimal.

Figure 11: Recommendation for Market Risk Premium

Method	MRP, before imputation credit adjustment	MRP, after imputation credit adjustment
	[1]	[2]
Credit Suisse	6.6%	6.8%
Wright	8.3%	8.6%
Bloomberg	7.6%	8.6%
Average	**7.5%**	**8.0%**
Midpoint	**7.5%**	**7.7%**

Based on the discussion and calculation above, we recommend that the QCA uses a MRP of 7.7 percent including imputation credits. Our recommendation balances the inclusion of the Ibbotson method, which is purely historical, a discounted cash flow, which is purely forward-looking, and the Wright method, which relies on historical data and forecasted inflation. Thus, it balances the historical and forward looking methodologies.

V. Beta

A. Approach to Estimating Equity Beta

When the cost of equity capital is estimated using the Capital Asset Pricing Model (CAPM), the systematic risk of the equity investment is embodied in the beta (β) parameter, such that the return required by investors varies in direct proportion to beta, which measures the tendency of investment returns to co-vary with returns on a diversified portfolio of all risky investments in the market. The modern finance theory underpinning the CAPM and other cost of capital models posits that investors must be compensated for greater systematic risk in the form of greater expected return, since they cannot avoid that risk through diversification.

The equity beta used to determine Aurizon Network's cost of equity should reflect *forward looking* expectations of its systematic risk, and can therefore not be known with certainty. Nor can Aurizon Network's historical beta be measured directly, since it does not itself have publicly traded stock whose returns can be compared to market returns. Therefore, our approach (which is consistent with that accepted by the QCA in past proceedings including the UT-4) is to estimate betas based on historical returns of publicly traded companies with risk characteristics comparable to those of Aurizon Network, and use these estimates to infer a beta reflective of Aurizon Network's systematic risk.

Two categories of risk must be considered when estimating equity beta based on historical stock returns: business risk and financial risk. *Business risk* is manifested in the tendency for the cash flows generated by a firm's business operations (and employing the firm's assets) to covary with market returns. *Financial risk* derives from the effect of a firm's financing on the returns to its equity holders: due to the fixed nature of debt obligations, increasing the proportion of the firm's assets that are financed by debt magnifies the variability of cash flows available to equity holders, relative to the cash flows generated by the firm's assets. In short, increased financial leverage increases the systematic risk of equity.

Drawing on the theoretical work of Professors Franco Modigliani, Merton Miller, Robert S. Hamada,[77] and others, modern finance has developed methods of isolating and adjusting for the effect of leverage (or gearing) on the risk of (and commensurate required return on) equity. The QCA has in the past relied on the Conine formula for *unlevering* equity betas measured for publicly traded comparable companies—and therefore reflecting the financial risk associated with gearing of those companies—to obtain *unlevered* or *asset* betas, which effectively isolate the business risk associated with the cash flows generated by those companies' assets.[78] We consider the Conine formula appropriate and follow the QCA's past approach.

Given the Conine unlevering and relevering formulas to adjust for differences in financial risk, the key considerations of our analysis are (1) selecting samples of publicly traded companies that can be expected to have similar business risk to Aurizon Network, and (2) employing appropriate statistical estimation techniques to determine the range of betas most likely to predict systematic risk going forward. In pursuit of the first objective, we select industry-based samples of comparable companies based on analysis of comparability in industry risk characteristics. As for the second objective, estimate the betas for the selected companies and analyze the effects of various estimation windows and sampling frequencies on stability and statistical precision of historical beta estimates. We also consider the influence of changing capital market conditions those estimates.

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77 Modigliani, F.; Miller, M. "The Cost of Capital, Corporation Finance and the Theory of Investment". *American Economic Review*, 1958. Hamada, Robert S. "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stocks". *The Journal of Finance*, May 1972.

78 The asset beta considered representative of Aurizon Network's business risk is then *relevered* at the regulatory capital structure determined for Aurizon Network.

B. Comparable Companies

1. Industry-based Samples

Since Aurizon Network does not itself have publicly traded stock, it is not possible to estimate its beta directly. Nor are we aware of any publicly traded pure play[79] "below rail" coal network operator—in Australia or anywhere else—that represent obviously similar investment opportunities for investors In the absence of such "perfect comparators" we take an approach similar to the framework relied on by the QCA in the UT-4 proceeding. Specifically, we construct samples of publicly traded companies from industry groups that possess characteristics relevant to the systematic business risk of Aurizon Network. Informed by context from the UT-4 Decision, [80] we selected samples from the following industries:

- Freight Rail Transportation
- North American Pipelines
- Regulated Distribution Utilities, including
  - U.S. electric companies
  - U.S. natural gas local distribution companies (gas LDCs)
  - U.S. water utility companies

We include the freight rail transportation companies because their operations are obviously similar to those of Aurizon Network. The North American Pipeline industry shares many features with Aurizon Network in that pipelines in the U.S. and Canada (i) are open access providers of transportation services, (ii) are subject to cost-based economic regulation, (iii) tend to have a limited set of corporate customers that often (or always in the case of U.S. natural gas pipelines) sign long term contracts, and (iv) serve customers whose commercial operations involve exposure to commodity markets. The regulated distribution utilities are included in part because they operate fully regulated infrastructure and also because the UT-4 decision relied on such comparables, although we find them to be of lower risk than Aurizon Network.

A brief discussion of our sample selection process follows, along with high level descriptions of the final samples. More detailed information about the business segments of the comparator North American pipeline and freight rail transportation companies is included in the samples is contained in Appendices C and D, respectively.

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79 Pure play refers to a company that focuses on a particular product or activity.

80 See further discussion in Section V.C. below

2. Selection of Sample Companies

a. *Company Screening Criteria*

In selecting the members of our industry samples, we began with industry groups defined by *Bloomberg* and *Value Line*, Our initial groups of potential comparators consisted of publicly traded companies within each of the comparable industries: pipelines, electric utilities, gas LDCs, water utilities, and rail freight companies. We started with large initial groups and eliminated companies from each group based on additional screening criteria designed to eliminate potential sources of bias in the beta estimates.

These criteria aimed to exclude companies that experienced events during the beta estimation period that might affect their stock price dramatically and "artificially", such that the resulting equity returns may not have reliably reflected underlying systematic risk of their business operations (as influenced by their financial leverage). Accordingly, we required that over a five year study period ending on the date of the analysis, the sample companies have no dividend cuts and no significant merger activity.[81] We also generally required that each of the sample companies had at least one investment grade credit rating from one of the three major rating agencies and a market capitalization greater than USD$500 million as of the latest quarter of available financial data.

b. *Freight Rail Sample*

The companies in our freight rail sample were selected to reflect operating characteristics particular to the freight rail transportation business, with an emphasis on exposure to bulk commodity shipping. Consequently, we eliminated companies whose business descriptions or segmented financial data (sourced from Bloomberg and company annual reports) indicated that they had substantial exposure to other businesses, such as passenger rail or non-rail intermodal freight transportation. Among the ten companies included in our final sample, revenue from bulk commodity haulage as a percentage of total company revenue ranges from approximately 30% to 80%, with an average of 42%.[82] One company, Daqin Railway Co., Ltd. (Daqin), is included in our railway sample despite not having any official credit rating; Daqin

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81 While we exercised judgement in determining what constituted "significant" merger activity, we screened for any companies that participated in any mergers or acquisitions that had a deal value greater than 25% of its market capitalization at the time of the deal.

82 In accordance with the most common classifications of "bulk" freight used in 2015 company annual reports, we include coal, agricultural products, fertilizers, metals, and minerals in our "bulk" category when calculating bulk haulage revenue as a percentage of total revenue.

derives an especially high proportion (79%) of its total revenues from coal haulage, making it the most comparable railroad to Aurizon Network in terms of commodity segmentation, and warranting its inclusion in the final sample group.

c. North American Pipeline Sample

The comparators in the Pipeline sample are selected from among the public companies included in *Value Line's* "Pipeline MLP" and "Oil & Gas Distribution" industry groups. In addition to applying the screening criteria discussed above, we analyzed business descriptions and segmented financial data from the firms' annual reports, and eliminated any companies that were not primarily or substantially engaged in regulated transmission of natural gas, crude oil, petroleum products, or natural gas liquids.[83] Our full Pipeline sample contains four U.S. publicly-traded partnerships with between approximately 50% and 80% of their plant assets dedicated to regulated natural gas transmission and six U.S. publicly-traded partnerships with between approximately 40% and 90% of their plant assets dedicated to operation of regulated "liquids" pipelines.[84] As discussed further in Section V.C below, U.S. pipeline regulation treats natural gas and liquids pipelines somewhat differently; therefore, we constructed "Natural Gas" and "Liquids" subsamples (with 4 and 6 members, respectively) to see whether any differences in asset beta were evident. The sample's characteristics are discussed further in Section V.C.3 and Appendix C provides detailed information about the individual companies in this sample.

Additionally, the full Pipeline sample contains one publicly traded partnership (ONEOK Partners L.P.) with approximately 40% of its net plant assets dedicated to regulated pipeline operations, divided between natural gas and natural gas liquids pipelines, and two Canadian corporations (Enbridge Inc. and TransCanada Corp.), each with approximately 75% of its assets dedicated to regulated natural gas and oil pipeline operations.[85]

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83 Regulation in the context of North American pipelines refers to cost-based regulation of transportation rates by the U.S. Federal Energy Regulatory Commission (FERC) and/or the Canadian National Energy Board (NEB). See further discussion below in Section V.C.

84 In the pipeline industry, the terms "liquids pipeline" or "oil pipeline" can be broadly applied to pipelines that transmit crude oil, petroleum products, or natural gas liquids.

85 The NEB regulates Canadian oil and natural gas pipelines under substantially the same framework, so while TransCanada Corp operates more natural gas pipelines and Enbridge Inc. more oil pipelines, we did not include them in the Natural Gas and Liquids subsamples. Also, we felt ONEOK did not fit naturally into either of the Natural Gas or Liquids subsamples.

d. U.S. Regulated Distribution Utility Samples

In selecting samples representative of the distribution utility industry, we focused on well-established industry classifications from *Value Line* for U.S. Electric, Natural Gas, and Water utilities. In addition to applying the screening criteria described above, we required that members of our distribution utility proxy groups have at least 50% of their assets dedicated to provision or utility service under cost of service regulation. In recognition of subtle differences in the nature of these three varieties of distribution businesses and our knowledge of the industry compositions, we constructed three separate samples:

1. A group of 27 electric utilities, all with more than 50% of their assets under regulation, but several providing regulated or unregulated power generation as well as distribution;
2. A group of nine water utilities, all with over 80% of their assets dedicated to regulated water distribution service.[86]
3. A group of six natural gas LDCs, with between approximately 65% and 90% of their assets dedicated to regulated local distribution of natural gas.

These samples are familiar to us from our work in North American utility rate cases. We note that owing to its higher share of unregulated activity and inclusion of some vertically integrated electric utilities (i.e., those that generate as well as distribute electricity), the Electric sample is less directly representative of distribution network business characteristics than the Water and Gas LDC samples.

C. Risk Characteristics and Comparability of Industry Samples

1. Context of the UT-4 Decision

In the UT-4 Decision, the QCA adopted the view expressed by its consultant (Incenta) that regulated energy and water utility companies are the most appropriate comparators for Aurizon Network, and endorsed Incenta's point estimate for Aurizon Network's asset beta of

86 The nine company membership of the Water utility sample has been very stable over time. It several very large and geographically diversified companies, as well as several smaller companies, two of which have market capitalizations below our standard $500 million threshold. However, we include these companies, since they are comparable investments in the publicly traded water peer group.

0.42, based on estimates performed for an international sample of those companies.[87] The QCA ultimately decided to maintain the UT-3 asset beta of 0.45,[88] citing the consistency of that value "with the observed betas for a relevant comparator group of energy businesses (noting [the QCA] rejected coal companies and railroads as appropriate comparators),"[89] and noting that it is "well within the reasonable range of 0.35 to 0.49 identified by Incenta."[90] Incenta considered a 0.35 asset beta estimated for the Dalrymple Bay Coal Terminal to represent a lower bound for the reasonable range, and its 0.49 asset beta estimate for a sample of publicly traded toll road companies to represent an upper bound.[91]

In determining that energy and water utility companies were the most relevant comparators for Aurizon Network (and in electing not to consider beta estimates for U.S. Class 1 railroads) in the UT-4 proceeding, the QCA and its consultant compared potential comparable industries to Aurizon Network with respect to certain business risk characteristics. Our interpretation of the decision documents and the 2014 Incenta Beta Report is that the QCA's determination gave primary emphasis to issues of revenue risk as influenced by regulatory regimes and their interactions with underlying industry economics. Incenta argued that the application of a revenue cap with periodic cost reviews "buffers" Aurizon Network against variability in revenue that would otherwise result from short-term fluctuations in demand for its "below rail" service (i.e., access to its coal rail infrastructure), concluding that the presence of cost of service regulation was a key criterion for selecting comparable industries. Incenta argued that energy and water utilities face cost of service regulation, while regulation of the U.S. Class 1 railroads by the Surface Transportation Board is limited to certain segments of the industry (e.g., shipment of coal and other bulk commodities) and imposes looser constraints on revenue.[92] We note that North American pipelines are regulated under cost of service as is some aspects of railroad transportation.

87 UT-4 Decision, p 249, referencing 2014 Draft Decision, p. 252-253. See also "Review of Regulatory Capital Structure and Asset / Equity beta for Aurizon Network and response to stakeholder comments," submitted the QCA by Incenta Economic Consulting in April 2014 (2014 Incenta Beta Report), p. 7.

88 UT-4 Decision, pp. 266-268. See also 2014 Draft Decision, p. 253-254.

89 UT-4 Decision, p. 266

90 2014 Draft Decision, p. 253.

91 2014 Incenta Beta Report, p. 7.

92 UT-4 Decision, p. 248. See also 2014 Incenta Beta Report, pp. 40-41.

Similarly, Incenta highlighted the presence of long-term contracts for access to the Central Queensland Coal Network (CQCN), arguing that contract cover provides "substantial confidence" that Aurizon will recover regulated revenues.[93] It suggested that because (according to securities analysts) the U.S. Class 1 railroads generally have shorter term shipment contracts than Aurizon Network, their revenue risk is not mitigated to the same degree by contract cover.[94] Again, North American pipelines often have long-term contracts with shippers.

Our own consideration of business risk comparability for sample selection is informed by the context of the UT-4 Decision. We agree with the QCA that revenue risk (manifested in the expected adequacy and volatility of revenue) is a relevant consideration for comparability, and that it is influenced by business characteristics including regulatory framework and contracting. However, we believe that additional characteristics—such as supply risk, demand risk, operating risk, and stranding risk—represent important considerations when evaluating the systematic business risk of commodity transportation infrastructure networks. Consequently, we draw somewhat different conclusions about the most relevant comparable industries for estimating Aurizon Network's asset beta.

2. Energy and Water Distribution

Fundamentally, electric, natural gas, and water distribution utilities have two business characteristics in common with Aurizon Network: (1) they operate infrastructure networks dedicated to transportation of a commodity, and (2) the rates they charge are generally subject to cost of service regulation. However, they also differ fundamentally from Aurizon Network on two important dimensions:

- Nature of customer base
- Elasticity of demand for service

First, energy and water distribution utilities serve large populations of *retail* customers—end users of the commodity—in their franchise service territories, while Aurizon Network's customers are corporate entities that access its network to transport coal from supply regions to downstream distribution channels. In addition, many publicly traded firms in the energy and water distribution business operate multiple regulated utility operating companies in

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93 2014 Incenta Beta Report, p. 32.

94 2014 Incenta Beta Report, p. 9.

geographically diverse regions;[95] this contrasts with Aurizon Network's dedicated operation of the CQCN. The diffuse and geographically diverse nature of the customer base for energy and water distribution companies serves to mitigate their demand risk, since changes in usage by any individual customer has relatively little impact on overall system revenue. And while Aurizon Network's take or pay contract arrangements does help to reduce its own demand risk, the potential for declining revenue from the gradual roll-off of contracts is likely high relative to the potential for similar usage declines among distribution utility customer bases numbering in the hundreds of thousands or millions.[96]

Second, distribution utilities benefit from relatively inelastic demand for their service. This is due in part to the features of their customer bases (as discussed above), and in part to the lack of substitutes for their service to those customers. In general, retail end users have limited opportunities to substitute away from the commodity being delivered, and the local distribution utility has a natural monopoly preventing entry of alternative suppliers of distribution service.[97] In contrast, demand for access to Aurizon Network's infrastructure fundamentally depends on the ability of its customers to profit from transporting coal from and to the nodes of that network. That in turn depends on regional and global demand for Queensland coal supplies, as well as the price of those supplies. Given the recent and ongoing shifts in global energy markets, demand for Queensland coal is likely more price-elastic and variable than the demand for electric, natural gas, and water distribution service provided by energy networks. And while regulation and contract cover may reduce Aurizon Network's exposure to demand risk in the short-term, those forces cannot eliminate such risks entirely.

In our judgement, while energy and water distribution utilities may provide useful information for estimating Aurizon Network's asset beta, they are not ideal comparators.

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95 We note this is especially true for the companies in our Electric sample, the majority of which operate utilities in multiple locations and some of which operate both electric and gas utilities in certain regulatory jurisdictions. It is also true for some of the larger firms in the Water and Gas LDC samples.

96 We note that diffusion of distribution customer bases may also reduce operating risk, since repair, maintenance, and even expansion expenditures can be undertaken in smaller chunks, reducing operating leverage relative to transmission networks with proportionately more infrastructure on a per customer basis.

97 One noted exception to this is electricity generation from distributed solar photovoltaic installations, which in has reduced end-users' usage of grid-distributed electricity in certain locations. However, distributed generation currently does not eliminate retail customers' need to be connected to the grid, and in many jurisdictions, revenue decoupling mechanisms reduce the utility's risk from declining volume.

While they are comparable to Aurizon Network in that they are subject to cost of service regulation, they face inelastic demand from large and diffuse customer bases—characteristics that lower their systematic business risk relative to that of Aurizon Network. Consequently we view the asset beta estimates from our samples of North American electric utility companies, natural gas local distribution companies, and water distribution utilities as being lower than what is reasonable for Aurizon's asset beta.

3. North American Pipelines

For the reasons stated above, we find regulated energy and water distribution utilities are not ideal comparators for Aurizon Network. However, at least in North America, companies dedicated to the *transmission* of energy commodities have relevant business characteristics that are more directly comparable to the operation of a coal rail network. Indeed, natural gas and oil pipelines perform better in the precise dimensions of comparability on which distribution utilities fail.[98] In contrast to distribution networks, pipelines serve relatively small and concentrated groups of corporate customers, and pipeline companies are often geographically focused.[99] And while demand for retail natural gas distribution service has few substitutes and is therefore highly inelastic, "wholesale" demand for natural gas (or oil or petroleum products) supplied along a specific route can be responsive to broader regional supply and demand forces. Shippers on the pipeline are in the business of providing the commodity to large industrial customers, downstream marketers, power plants, local distribution companies, or storage facilities and they usually do not have competitively priced transportation alternatives along a given route.[100] Furthermore, especially since the explosion of North American oil and natural gas production over the last half-decade, demand for pipeline transportation services has become increasingly reliable and insensitive to commodity prices. However, if dynamics shift in supply markets or downstream demand centers, over time a given pipeline's customers may shift their demand to alternative routes.

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[98] While long range of transmission of electricity is also comparable in relevant dimensions influencing business risk, we are only aware of one "pure-play" public electric transmission company in the U.S.: ITC Holdings, Inc. Thus, we do not consider electric transmission as a separate industry comparable.

[99] It is our understanding that this feature also distinguishes North American pipelines form their Australian counterparts, which serve retail customers and have geographic diversity in their service markets. For example, APA Group has gas transmission and distribution network across the nation.

[100] For oil and petroleum products, barge, truck, and rail alternatives are generally significantly more expensive than pipeline transportation; for natural gas, the pipeline advantage is even more pronounced.

In terms of these market features, pipeline transmission networks are more comparable to Aurizon Network than are utility distribution networks.

North American pipelines provide service under cost based regulation by the U.S. Federal Energy Regulatory Commission (FERC), the Canadian National Energy Board (NEB), and (in the case of intra-state pipelines) certain state regulatory bodies. Furthermore, long-term capacity reservation contracts are a central feature of the North American pipeline industry, just as they are for Aurizon Network's below rail coal service. As regulation and contract cover were given primary consideration by the QCA and its consultant, we offer the following discussion of these features as they apply to the North American pipeline industry.

a. Cost of Service Regulation

In the United States, the Federal Energy Regulatory Commission (FERC) regulates the transportation rates of both natural gas and oil pipelines, but does so under two somewhat different frameworks. Natural gas pipelines are regulated under the Natural Gas Act, which requires that rates charged for interstate pipeline services be "just and reasonable."[101] FERC describes its regulatory framework for natural gas pipelines as follows.

> Setting just and reasonable rates requires a balancing of equities between the interests of the pipeline and its ratepayers. The basic methodology we use to establish just and reasonable rates is cost-of-serve ratemaking. Under cost-of-service ratemaking, rates are designed based on a pipeline's cost of providing service including an opportunity for the pipeline to earn a reasonable return on its investment.[102]

As is the case for many state regulated U.S. distribution utilities, natural gas pipelines are not required to undergo rate reviews on a fixed schedule. However, pipelines must make a so-called "Section 4" cost of service filing whenever it wishes to increase its rates. Additionally, the regulator has discretion to initiate a rate review at any time, of its own accord or at the behest of the pipeline's customers.

> [FERC] also has authority under Section 5 of the NGA to require prospective changes in the rates charged by a pipeline when it can be demonstrated that the rates are no longer just and reasonable. The Commission can initiate a Section 5 proceeding on its own motion or upon complaint from an interested party.[103]

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101 https://www.law.cornell.edu/uscode/text/15/717c

102 http://www.ferc.gov/industries/gas/gen-info/rate-filings.asp

103 http://www.ferc.gov/industries/gas/gen-info/rate-filings.asp

The current regulatory scheme for natural gas pipelines was established in 1992, when FERC issued Order No. 636,[104] which required natural gas pipeline operators to unbundle their transportation and sales / marketing services, and provide "open access" transportation services to any customer willing to reserve capacity.[105] This unbundled structure is analogous to the separation of "below rail" and "above rail" services for Australian freight rail operators. Additionally, Order No. 636 mandated that natural gas pipeline transportation rates be designed on a "straight-fixed variable" basis, meaning that all of the pipeline's fixed costs including the return of and on invested capital are recovered in a capacity reservation charge, which the customer pays regardless of the volume of commodity actually transported. This form of rate design mitigates revenue risk from fluctuating flows, and mitigates stranding risk.[106]

FERC applies the same "just and reasonable" standard to transportation rates for interstate oil and petroleum products pipelines. However, its approach differs somewhat. Liquids pipeline rates are capped at a ceiling established by application of an annual index designed to track changes in pipeline industry costs. The index is determined by periodic FERC reviews comparing changes in oil pipeline companies' per-unit cost of service over time, and is held in a fixed differential to a general measure of inflation (the Producer Price Index or PPI) in between reviews. [107] Oil pipelines are also required to file annual statements of their total jurisdictional cost of service, using the same cost of service methodology applied by FERC to set initial rates for new pipeline service, or in complaint proceedings initiated by the pipeline's customers.[108]

In Canada, the NEB also applies a "just and reasonable" standard to tolls and tariffs for natural gas and oil pipelines. It establishes just and reasonable tolls through either uncontested settlements between the pipeline and its shippers, or through cost of service proceedings initiated by a contested toll change or a complaint against existing tolls. According to the NEB,

> Under this cost-of-service approach, a pipeline company's tolls are set so investors can recover costs and earn a reasonable return on their investment.

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104 http://www.ferc.gov/legal/maj-ord-reg/land-docs/rm91-11-000.txt

105 http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/ferc636.html

106 http://www.eia.gov/oil_gas/natural_gas/analysis_publications/ngmajorleg/keyferc.html

107 http://www.ferc.gov/industries/oil/gen-info/pipeline-index.asp

108 http://www.ferc.gov/docs-filing/forms/form-6/overview.asp. See Order No. 572 and Opinion No. 154-B.

To set tolls, most companies forecast their cost of service and throughput for a forward test year(s). The cost of service is made up of operating expenses, depreciation, return on capital, and income and other taxes. We allow a pipeline company the opportunity to earn an approved rate of return.

In determining the rate of return, we consider whether:

- the pipeline can attract capital on reasonable terms and conditions
- the allowed return is comparable to the return available to other companies of similar risk
- the financial integrity of the regulated pipeline will be maintained[109]

b. Contracting

With respect to Canadian pipeline operations, the NEB distinguishes between "contract carrier" natural gas pipelines—which require that customers contract for service—and "common carrier" oil pipelines, which historically provided service to all customers, but notes that "some oil pipelines are now requiring long-term take-or-pay agreements for a portion of the pipeline's capacity, before construction begins."[110] This is very much the case in the U.S., where major liquids pipeline expansion projects are now routinely mostly or fully-subscribed under long term capacity reservation (i.e., take or pay) contracts before the project enters service (or even begins construction). FERC evaluates and approves (or denies) these arrangements via a Petition for Declaratory Order (PDO).[111]

For FERC regulated natural gas pipelines, there is a convenient data source enabling us to actually quantify contract cover in the U.S. natural gas pipeline industry. FERC requires natural gas pipelines to submit an "index of customers" on a quarterly basis, listing the duration and contracted capacity for all firm transportation contracts on its system.[112] Using this data, were able to estimate the average, median, and aggregate levels of contract cover for U.S. natural gas pipelines at 5, 10, and 15 years from the present. The results, presented in Figure 12 below, demonstrate the prevalence of long-term take or pay contracts in the natural

109 https://www.neb-one.gc.ca/bts/whwr/rspnsblt/trffctlltrff-eng.html#s5

110 https://www.neb-one.gc.ca/bts/whwr/rspnsblt/trffctlltrff-eng.html#s4

111 For examples of several PDO's for expansion projects involving committed shippers signing long term contracts, see http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13966011, Appendix L.

112 http://www.ferc.gov/docs-filing/forms/form-549b/data.asp

gas pipeline industry—with more the three quarters of capacity under contract for at least 5-years, and half still under contract at 15 years out.[113]

[113] For tractability, we focused our contract cover analysis on the 33 pipelines listed in Figure 12, which together account for more than 80% of total net utility plant and more than 75% of total operating profit for all pipelines contained in the index of customers database.

Figure 12
Age Discounted Contract Cover
For 33 Largest U.S. Natural Gas Pipelines by Net Utility Plant

Pipeline System	5-Year Contract Cover	10-Year Contract Cover	15-Year Contract Cover
Transwestern Pipeline Company, LLC	100%	100%	100%
Gulfstream Natural Gas System, LLC	99%	93%	89%
Ruby Pipeline, LLC	91%	69%	56%
Equitrans, LP	91%	81%	70%
ETC Tiger Pipeline, LLC	90%	69%	61%
Northwest Pipeline, LLC	90%	74%	64%
Florida Gas Transmission Company, LLC	90%	76%	67%
Rockies Express Pipeline LLC	87%	75%	70%
Transcontinental Gas Pipe Line Company, LLC	86%	80%	73%
Southeast Supply Header, LLC	86%	61%	50%
Dominion Transmission, Inc	75%	55%	46%
Texas Eastern Transmission, LP	72%	61%	54%
Gulf South Pipeline Company, LP	71%	56%	46%
National Fuel Gas Supply Corporation	71%	58%	51%
ANR Pipeline Company	69%	61%	57%
Tennessee Gas Pipeline Company, LLC	68%	57%	50%
Millennium Pipeline Company, LLC	68%	52%	42%
Dominion Cove Point LNG, LP	68%	53%	43%
Columbia Gas Transmission, LLC	68%	53%	44%
Northern Natural Gas Company	67%	54%	46%
Algonquin Gas Transmission, LLC	66%	53%	48%
Colorado Interstate Gas Company, LLC	65%	53%	45%
Gulf Crossing Pipeline Company, LLC	63%	42%	35%
El Paso Natural Gas Company, LLC	61%	50%	43%
Texas Gas Transmission, LLC	59%	41%	34%
Alliance Pipeline, LP	55%	36%	29%
Southern Natural Gas Company, LLC	52%	43%	38%
Panhandle Eastern Pipe Line Company, LP	50%	40%	35%
Northern Border Pipeline Company	50%	33%	27%
Midcontinent Express Pipeline, LLC	49%	30%	24%
Enable Gas Transmission, LLC	47%	32%	26%
Kern River Gas Transmission Company	46%	39%	35%
Natural Gas Pipeline Company of America, LLC	30%	22%	19%
Average	70%	56%	49%
Median	68%	54%	46%
Aggregate	68%	55%	48%

Source: The Brattle Group. Data from Q3 2016 Index of Customers via SNL Energy (accessed 08/24/2016).
Note: Ratios calculated as discounted contracted capacity divided by discounted maximum capacity. Period terms begin on January 1, 2017. Maximum capacity is calculated as the maximum daily contracted capacity on the pipeline, from the beginning of the quarter (July 1, 2016) onward, multiplied by 365.25 days per year. A discount rate of ten percent is used. Pipelines are ranked by 5-year contact cover.

In light of this evidence, we feel comfortable that the pipelines operated by the companies in our North American Pipeline sample have substantial contract cover over relatively long time horizons, suggesting a high degree of comparability to Aurizon Network. For the companies in our Natural Gas Pipeline subsample, and for TransCanada Corp, we can be confident that a very high proportion of capacity is contracted in the near-term, with possibly more than 50% remaining contracted 15 years out.

c. Conclusion

The cost-based regulation and long-term capacity contract features of the North American pipeline industry serve to buffer revenue variability in the manner identified by the QCA and Incenta with respect to Aurizon Network. Although the specific flavors of cost-based rate design applied to regulated natural gas and oil pipelines by FERC and the NEB are not perfectly analogous to the QCA's regulation of Aurizon Network, we note that in the UT-4 Decision, the QCA found that "while cost-based regulation will reduce a firm's systematic risk, variations in the specific form of cost-based regulation, including additional regulatory mechanisms, are unlikely to be reflected in observed measures of systematic risk." In accordance with this view, any difference in the asset beta of regulated pipeline companies compared to regulated distribution utilities is likely to be explained by structural differences between the transmission and distribution businesses.

Importantly, as described above, pipelines are more like Aurizon Network than are distribution utilities in terms of market structure and operational characteristics. Ultimately, unlike regulation of distribution utilities, pipeline transmission rate regulation and contract cover operate on a business construct that is analogous to Aurizon Network's operation of the CQCN: commercial customers pay for network access to transport a commodity along a fixed route that is generally up-stream of the retail end-use market. Consequently, we consider the North American pipeline industry the most relevant point of comparison for determining Aurizon Network's asset beta.

4. Freight Rail Transportation

It is our view that certain aspects of operating a rail network dedicated to freight transportation are best captured by consideration of comparators that operate in that line of business. Patterns of cash flows related to operating expenses, maintenance and expansion capital expenditures, and working capital balances for freight rail companies are, put simply, likely to be most comparable to those of other freight rail companies. Therefore, as described in Section V.B above, we have constructed a global sample of publicly traded freight rail companies with substantial portions of their revenue coming from shipment of bulk commodities, such as coal and agricultural products.

We are mindful the that QCA has in the past declined to consider beta evidence based on U.S. Class 1 railroads, owing to concerns about the diversity of their customers and traffic, the nature of the regulation they face, and the apparently shorter duration of contracts for their services relative to Aurizon Network. Therefore, we have expanded our sample to incorporate a variety of *non*-U.S. Class 1 freight rail companies with greater diversity in business characteristics and consider separately a non-US Class 1 freight rail sample. This sample includes two Canadian railroads, which face price regulation for shipments of Western grain[114] that is stricter than what the U.S. Class 1 railroads face for regulated bulk commodity shipping.[115] It includes Australian traded firm Aurizon Holdings Limited, as well as Genessee and Wyoming Inc., all of which have both below rail and above rail operations in Australia. Finally, it includes Daqin Railway Co. Ltd., which is close to a pure play operator of a coal railway in Northern China; Daqin's prices are fixed by the Chinese government, and 45% of its sales come from its top 5 clients, which are coal producers in Shanxi Province and Inner Mongolia. Obviously, none of these companies is directly comparable to Aurizon Network in every aspect; however, we view them as broadly reflecting the operating characteristics of the bulk commodity freight rail business, and as adding context to asset beta estimates for the U.S. Class 1 railroads.

D. Beta Estimation Parameters

1. Individual Company and Industry Portfolio Betas

For each company in each sample, we estimate its equity beta from Bloomberg, using a custom formula to specify the estimation parameters. These "raw" historical equity beta estimates are calculated using an ordinary least squares (OLS) regression of the company's historical total stock returns on the historical total returns of the corresponding local market index.[116] Total stock returns comprise price appreciation as well as proceeds from dividends, which are assumed to be reinvested and compounded into the return. We specify the frequency of the data as well as the horizon over which the beta is to be estimated (e.g., weekly using five years of data). Having estimated the company equity beta, we applied the Conine formula to unlever each company's Bloomberg raw equity beta estimate (as described in Section V.D.4 below). Finally, for each sample we compute the means and medians of the resulting individual asset betas. We also compute the average and median asset betas for

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114 https://www.otc-cta.gc.ca/eng/western-grain-maximum-revenue-entitlement-program.

115 See for example, http://business.financialpost.com/fp-comment/political-meddling-is-putting-canadas-rail-network-at-risk-right-when-we-need-it-most.

116 For example, U.S. company betas are measured against the S&P 500 Index; betas of Canadian companies traded on the Toronto Stock Exchange are measured against the S&P/TSX Composite Index; and Australian company betas are measured relative to the S&P/ASX 200 index.

certain subsamples, including U.S. Class 1 and non-U.S. Class 1 railroads within the Freight Rail sample as well as Natural Gas and Liquids subsample results within the Pipelines sample.

In additional to individual company beta estimates, we estimated betas for each industry sample based on the excess total returns to a value-weighted portfolio of the companies in the sample.[117] We constructed the series of industry portfolio returns by weighting each company's returns in each period by its share of the total sample market capitalization.[118] The portfolio returns for each industry sample (and certain subsamples) were then regressed (using OLS) against the returns for a single representative market index.[119] [120]

We considered portfolio betas for two reasons. First, they provide slightly different information relative to averages and medians of individual betas. While the latter statistics measure the central tendency giving equal weight to each company, the portfolio returns reflect a "composite" of all the sample companies, weighted by their contribution to total market value. It therefore provides an estimate of the systematic risk of the industry as a whole, placing more emphasis on larger companies.

Second, portfolio betas can generally be measured with greater statistical precision than individual company estimates. This is because idiosyncratic variability in individual company returns (i.e., stock movements that are specific to that company and not correlated with those of other sample companies) tends to be "diversified away" in the construction of a portfolio, such that less estimation error occurs in the regression. For example, the standard errors of the 5-year weekly individual company betas for the North American Pipeline sample range from 0.07 to 0.16 with a median of 0.12 compared to 0.07 for the corresponding Pipeline sample portfolio beta.[121]

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117 The excess total return is the total return minus the return on a government bill.

118 The companies are re-weighted within the portfolio for each period of returns sampled; the weights are computed based on the market capitalizations at the start of each period.

119 Given the prevalence of North American and especially U.S. companies in the samples, the S&P 500 index was used as the market index for the portfolio beta estimates, with individual company total returns and market capitalizations being converted to U.S. dollars before weighting them to form the portfolio returns.

120 Technically, we performed the OLS regression using excess returns, by computing the portfolio and market index returns less returns on a short-term risk-free government bond.

121 Standard error is a measure of the uncertainty of a statistical estimate. A smaller standard error indicates that the estimated parameter (in this case beta) is estimated with greater precision.

Given their higher statistical precision and composite approach to measuring the covariance of industry returns with the market, the portfolio betas complement the sample averages and medians, which treat each company's beta as an (equally weighted) independent observation of industry-specific systematic business risk. Additionally, the sample portfolios are convenient for plotting the evolution of industry betas over time, and evaluating the statistical properties of beta estimates derived using different return frequencies and / or estimation windows.

2. Return Frequency: Weekly vs. Monthly Betas

The periodicity or frequency with which returns are sampled for beta estimation is a matter worthy of some discussion. Academic and regulatory applications commonly rely on betas computed using weekly or monthly returns over a period of two to five years.[122] For example, Bloomberg's default setting for beta uses two-years of weekly returns in the OLS regression, while *Value Line* uses five years of weekly returns.

In deciding which frequency to rely on, the key considerations are accuracy and statistical precision. With shorter (i.e., weekly or daily) return sampling frequencies, there is some concern about stocks of smaller companies that are not often traded. If these stocks are infrequently traded, their returns may not vary much at weekly resolution, creating the potential for a downward bias in the betas.[123] However, for the majority of the companies in our samples, low weekly trading volume is unlikely to be a concern, and in fact the weekly betas are in most cases actually slightly higher than the monthly estimates.

With regard to statistical precision, there is a clear advantage to using weekly returns: more observations are possible over a given estimation window. While a 5-year monthly beta is based on 60 observations, a weekly beta estimated over the same time period uses of 260 data points, allowing more precise estimation of the beta parameter. This effect is illustrated in Figure 13 below for the Pipeline sample portfolio betas. Rolling point estimates are plotted, along with "error bars" showing a range of one standard error on either side of the estimate.[124] Clearly, use of weekly data provides more confidence in the precision of the estimate.

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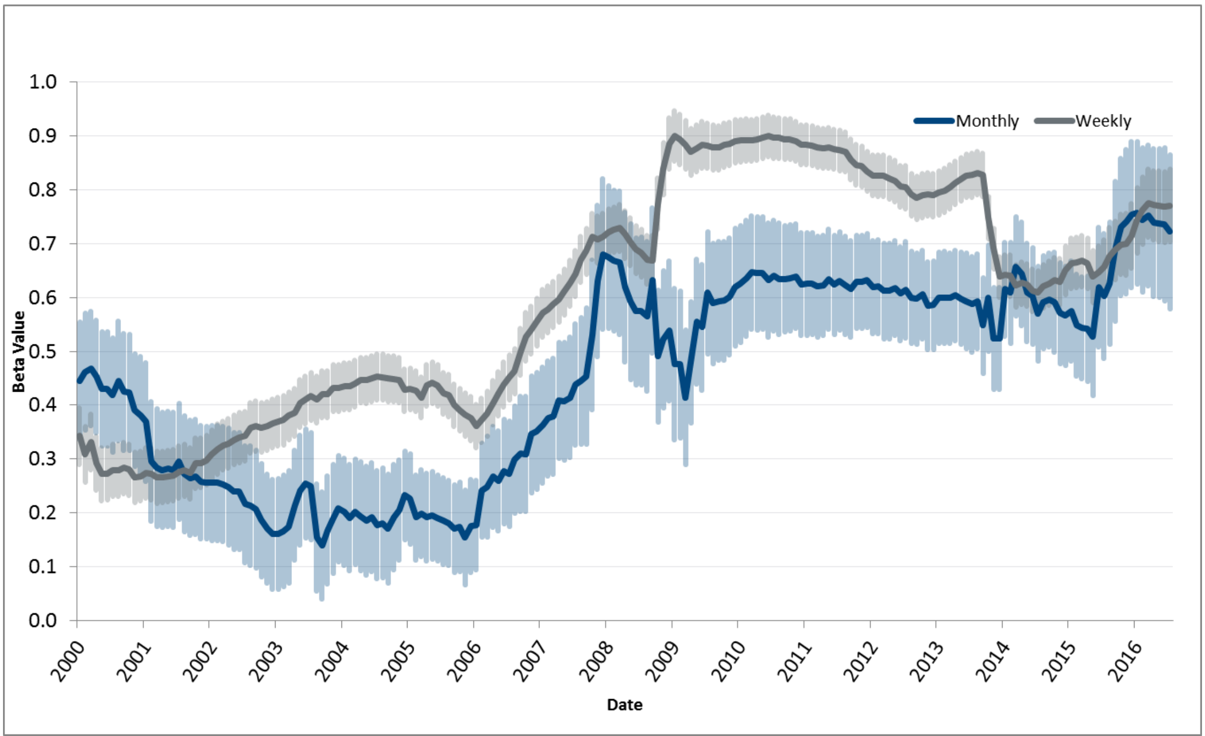
122 Jonathan Berk and Peter DeMarzo, "*Corporate Finance*," 3rd edition, 2014, p. 407.

123 The downward bias is caused by the infrequently traded stock price moving much less frequently than the market, which included many more frequently traded companies.

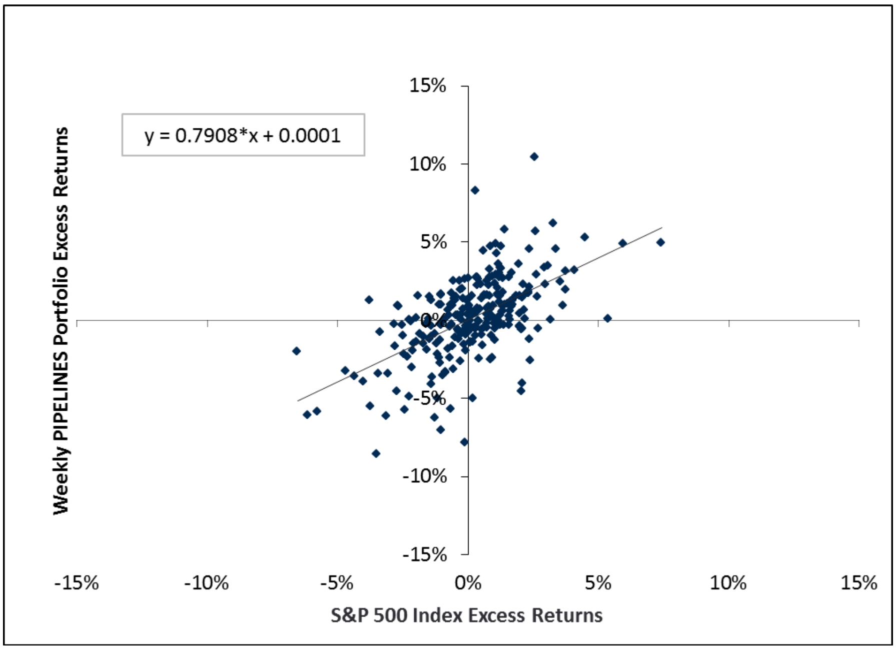
124 Under the assumptions of OLS regression analysis, there is approximately 68% probability that the "true" beta falls within this range.

Figure 13
Rolling 5-Year Pipeline Sample Portfolio
Raw Equity Beta Estimates with Error Bars

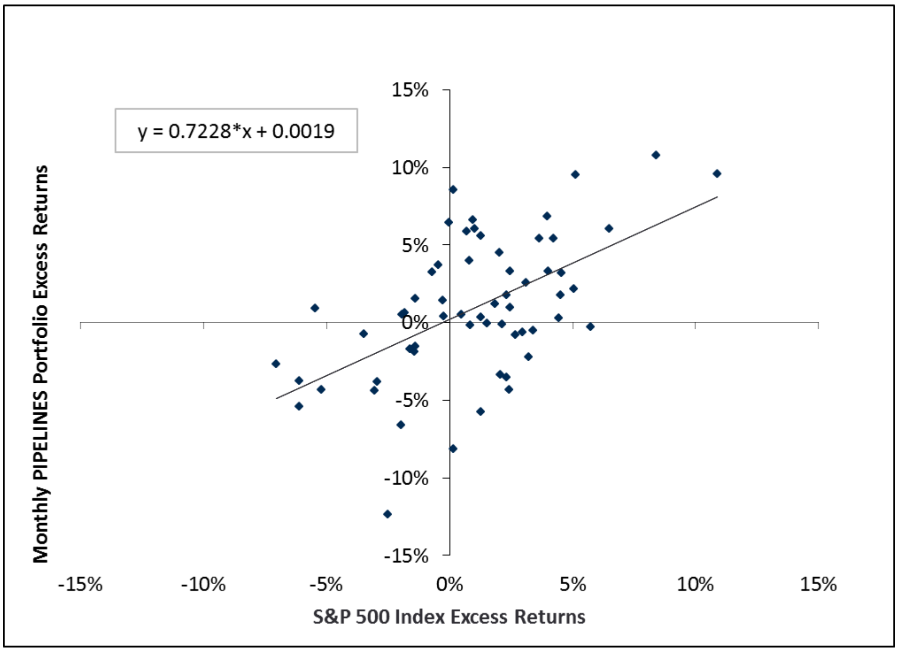


Another way to evaluate the relative statistical merits of weekly versus monthly betas is by looking at how well the regression "fits" the returns data. Consider, for example, the scatterplots in Figure 14 below. It is clear from the graphs in Panel B that the relationship between the monthly market index and the Pipeline portfolio returns does not provide a particularly good fit to that data. By contrast, the weekly data in Panel A are more closely grouped along the regression line representing the relationship between market and industry portfolio returns.

Figure 14
Pipeline Sample Portfolio Raw Equity Beta as of August 2016
Panel A – Weekly Returns



Panel B – Monthly Returns

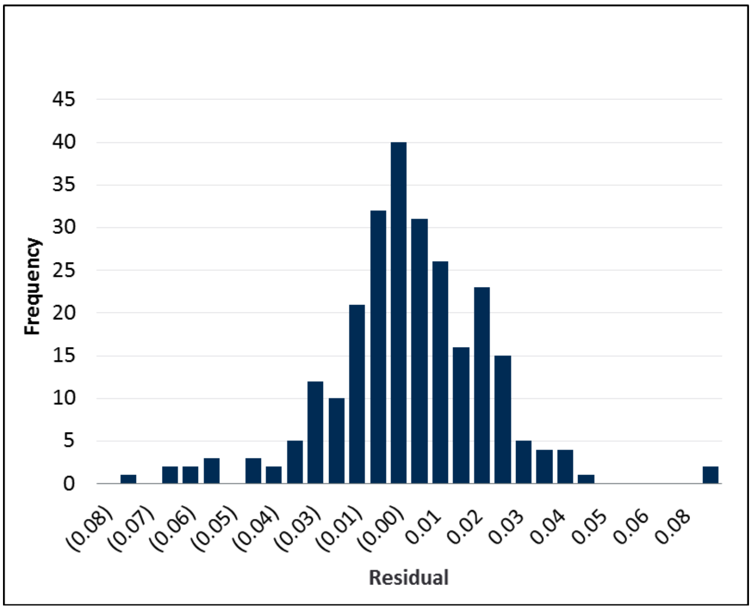


This discrepancy in the "goodness of fit" between the monthly and weekly beta regressions can be quantified in terms of a Normalized Root Mean Square Error (NRMSE), which measures the degree to which the data points diverge from the regression line, relative to the degree of dispersion in the raw data.[125] A lower NRMSE corresponds to a better "goodness of fit". For the Pipeline sample the plots depicted below show an NRMSE of 0.163 for the monthly beta, versus only 0.111 for the weekly beta. Thus, the weekly beta clearly has a better fit.

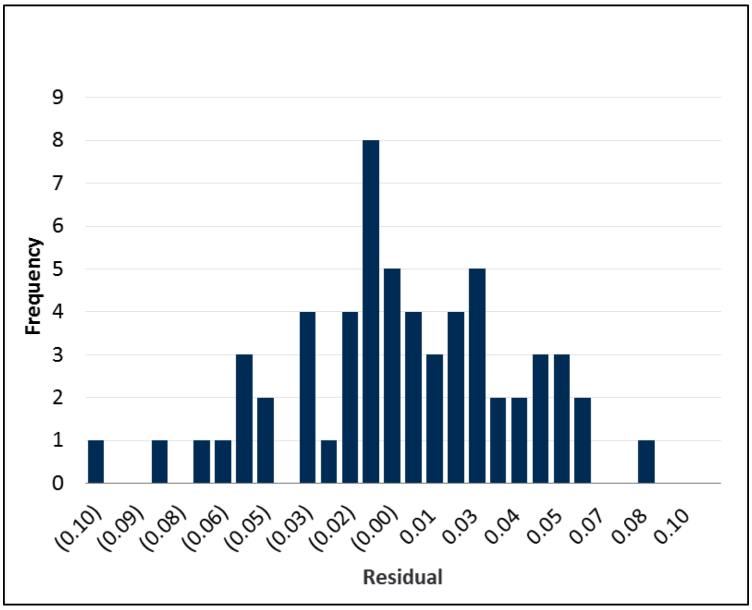
Further insights can be gained by plotting the regression errors themselves. According to the assumptions underlying OLS regression, the so-called residuals—represented graphically the vertical distances of the data points from the regression line—should follow a bell-curve shaped normal distribution. As can be seen below for the Pipeline sample portfolio results shown in Figure 15, this is not the case. However, the residuals from the regression that relies on weekly data is much closer to being symmetric and shaped like a bell curve than are the residual errors that result from the monthly regression. Put differently, the weekly regression exhibit residuals that are closer to being normally distributed.

[125] Specifically, the root mean square error (RMSE) is the square root of the sum of the squared vertical distances of each point from the regression line. To "normalize" the RMSE, we scale it by the range (i.e., difference of maximum and minimum values) of the portfolio excess return.

Figure 15
Histogram of Regression Residuals for
Pipeline Sample Portfolio Raw Equity Beta as of August 2016
Panel A – Weekly Returns



Panel B – Monthly Returns



Similar graphical and statistical comparisons of beta regression fit weekly and monthly return data for the other samples reveals similar results, with weekly beta estimates uniformly reflecting a better fit to the data than monthly estimates.[126] This effect is especially pronounced for the U.S. Utility samples (Electric, Natural Gas, and Water), indicating that

126 See Appendix E for scatterplots, histograms, NRMSE statistics, and intercept t-statistics comparing weekly and monthly regressions for the other sample portfolios.

weekly returns provide substantially better statistical beta estimates than monthly returns for those samples. We therefore rely on weekly beta estimates to inform our conclusions regarding the systematic business risk of the comparator companies in our industry samples.

3. Length of Estimation Window

As mentioned above, statistical precision of beta estimates improves with the use of more data points. In addition to sampling returns at weekly—rather than monthly—resolution, another way to incorporate more observations into the estimate is to use a longer estimation window. There is a trade-off inherent in this decision, however, since longer estimation windows reach back further in time, and therefore incorporate more non-current information. Because systematic risk changes over time, utilizing historical returns over a very long period may yield a beta estimate that is not predictive of systematic risk going forward. Conversely, if too short an estimation window is used, the estimate may be too sensitive to temporary capital market conditions, which again may not provide meaningful information about systematic risk going forward.

To illustrate this balancing act, we have plotted a time series of beta estimates estimated over rolling 3- and 5-year periods. The plot for the Pipeline sample portfolio is shown in Figure 16 below. In our opinion, this plot (and others like it for the other samples) suggests two important takeaways.[127] First, industry betas are non-stationary and can be influenced by capital market conditions such as the global financial crisis of 2008-2009 and the ensuing recession. Second, betas estimated over shorter periods respond to changing conditions in a more volatile fashion, since events like the financial crisis enter and exit the estimation window more frequently and abruptly.

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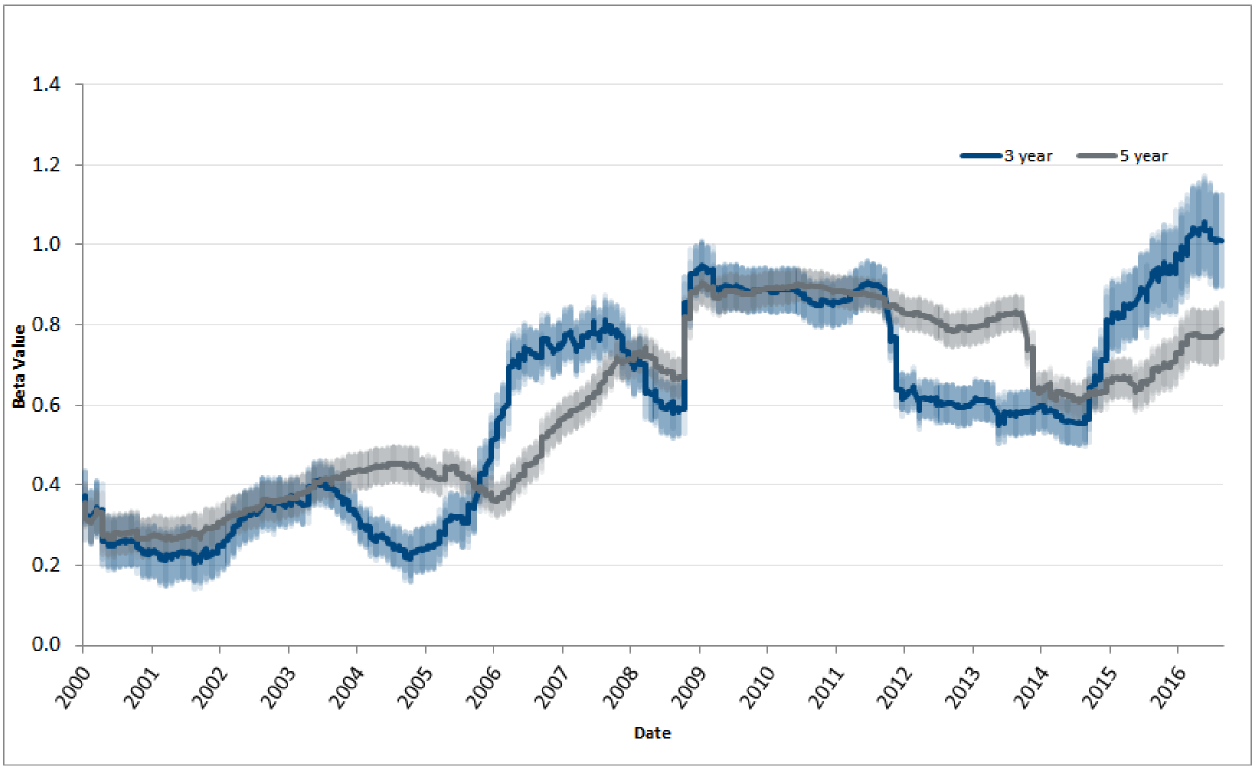
[127] See Appendix F for plots of rolling 3- and 5-yr weekly portfolio betas for the other samples and subsamples.

Figure 16
Rolling 3- and 5-Year Pipeline Portfolio
Raw Equity Weekly Beta Estimates with Error Bars



It is important to note that changing capital market conditions can (and do) affect the systematic risk of a company or industry, *even if the underlying business risk characteristics of the industry remain unchanged*. As the markets change, a given category of investments (e.g., an industry) can take on different roles in a diversified portfolio, making it more or less risky *relative to the market*, even if its specific risk characteristics have not changed in an absolute sense. For example, consider the "tech bubble" that affected U.S. stock markets in the early 2000s. Using data from this period, betas for utilities (and many industries) were especially low, reflecting that they exhibited less systematic risk as part of a market portfolio with volatile returns dominated by tech stocks. Conversely, during the financial crisis of 2009, many utility stocks became *more* correlated with the market as investors sought security amidst turmoil; consequently, such stocks exhibited higher systematic risk at that time. When using historical data to estimate beta for purposes of estimating forward-looking systematic risk, we believe it is unwise to take the view that systematic risk is constant. Rather, the cost of capital analyst should consider how well a beta estimated using data from a particular historical period is likely to *predict* the systematic risk of that investment going forward.

Based on our observation of how 3- and 5-year betas have recently evolved for the industries we studied, we believe a 5-year estimation window strikes the right balance for this proceeding. A 5-year window, allows real and permanent changes in systematic risk to influence the beta estimates without overreacting to temporary shifts in capital markets. We also note that five years avoid is a short enough period that we need not rely on data from the height of the financial crisis of 2008-09.

Conversely, for the selected samples, the shorter estimation window (e.g., 3 years) is quite volatile and only the Pipelines appear to have changed in a substantial manner over the past few years (see Appendix F for a comparison of 3 and 5 year betas for all industries). A longer window (e.g., ten years), includes the financial crisis, which severely impacted financial markets worldwide, and generally may have information that may not be representative of the true systematic risk going forward. For example, the outlook for the energy industry was much different 10 years ago than it is today.

4. Parameters for Unlevering Betas

In accordance with the QCA's former decisions that focus on the asset beta, we unlever raw equity betas for each company in the industry sample groups using the standard Conine formula to arrive at their asset betas. Other parameters needed for the Conine formula include a debt beta, average proportions of the company's common equity, preferred equity, and debt over the relevant time period, as well as a representative tax rate for each company. To comply with the UT-4 Draft Decision, we employ a debt beta of 0.12 for all companies. We calculate the average capital structure proportions for either the past three of five years using Q2 balance sheet data from Bloomberg and verified by S&P Capital IQ. In regard to tax rates, we rely on the representative statutory rate combined with any state or provincial rates for each company's country of incorporation.[128]

Although we use a corporate tax rate when unlevering all company betas, in reality, our sample of U.S. pipeline master limited partnerships (MLPs) are exempt from directly paying a corporate income tax. These MLPs pass their tax deduction for interest payments through to their partners, who benefit from the deduction on their personal tax returns. In this way, our Conine adjustment may misrepresent the marginal tax rate relevant for valuing the interest tax shields for these MLPs, since in reality it depends on the tax rates of the partners.

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[128] 30% for Australia; 25% for China; 39.1% for the United States, which includes the federal 35% rate plus the average rate among the states; 26.5% for Canada, which includes the 15% statutory rate plus an 11.5% provincial rate approximated based on the locations of our Canadian sample companies.

However, we believe any imprecision inherent in our use of corporate tax rates when unlevering betas for MLPs is unlikely to have a material effect on the results.[129]

E. Results and Recommendation

The asset beta estimates for our industry samples are summarized below in Figure 17. We rely on the Unlevered 5-year Historical Betas based on weekly observations for the increased statistical precision, but also present the 3-year Historical Betas for comparison.[130] The 5-year data suggests a range of asset betas from 0.4 to 1.1. We believe the asset betas associated with U.S. Electric, Gas LDC, and Water distribution utility networks are lower than what is representative for Aurizon Network's equity, with the Electric sample being the least comparable. In addition, we find that the U.S. Class 1 Rail subsample has higher risk than Aurizon Network. This excludes the two end points of our sample and narrows our range. Considering the regulated water and natural gas distribution utilities at the low end and the non-US Class 1 Freight Rail subsample at the high end, we find a range of 0.45 to 0.85. For the reasons stated in Section V.C above, we believe the North American Pipeline sample is the most directly comparable to Aurizon Network for purposes of determining a representative asset beta.[131] It is therefore our view that a range of 0.55 to 0.65 is reasonable, and that the midpoint of 0.6 represents the best point estimate of Aurizon Network's asset beta.

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129 To put a boundary on the potential magnitude of any impact, we also calculate asset betas assuming 0% tax rate for the U.S. MLPs. The average asset beta for the full sample is 0.08 higher when using the corporate tax rate (0.84) compared to when assuming a tax rate of zero (0.76). However, the actual impact cannot be anywhere near this large, since MLP partners *do* in fact pay taxes, and in some cases may face tax rates *larger* than the corporate tax rate. Indeed, it is not even clear whether our use of corporate tax rates serves to raise or lower the assets beta estimates relative to a more precise calculation.

130 Asset Betas based on 10 years of weekly returns and unlevered using the past five years of capital structure data are presented in Appendix G.

131 We note that the asset beta results for our Liquids Pipeline subsample exceed those of the Natural Gas Pipeline subsample by approximately 0.1. Although a slightly lower beta for natural gas pipelines is consistent with the facts that they are generally subject to tighter cost based regulation and *may* have a higher degree of contracted capacity than liquids pipelines (though the latter cannot be known since oil pipelines do not report an index of contract customers), it is not possible to say for certain based on the small size of the subsamples. We rely primarily on the full sample results, which include the two Canadian corporate pipeline companies and the "mixed" pipeline MLP ONEOK Partners as well as the members of the Liquids and Natural Gas subsamples.

Figure 17
Industry Sample Assets Betas
Estimated Using 3- and 5-years of Historical Weekly Returns

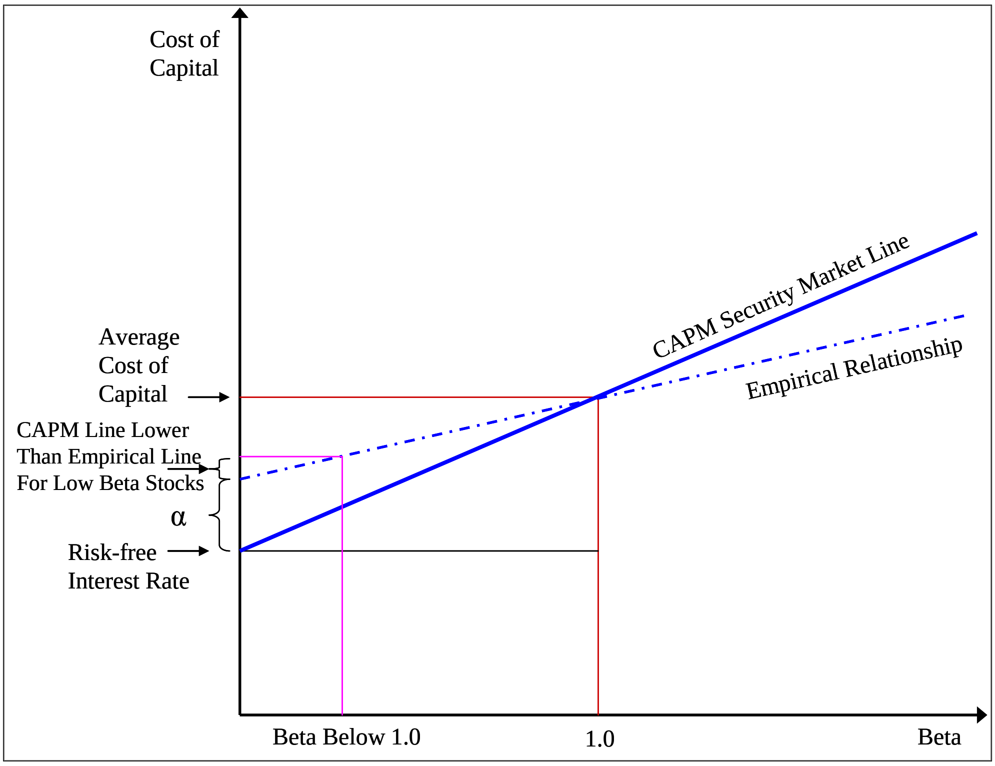
	Unlevered 5-yr Historical Beta			Unlevered 3-yr Historical Beta		
Sample Group	Average	Median	Portfolio	Average	Median	Portfolio
[1]	[2]	[3]	[4]	[5]	[6]	[7]
Rail Freight Sample	0.96	0.99	0.94	0.92	0.95	0.96
U.S. Class 1 Subsample	1.11	1.07	1.04	1.03	1.01	0.99
Non U.S. Class 1 Subsample	0.85	0.76	0.78	0.85	0.82	0.88
Pipeline Sample	0.61	0.58	0.62	0.84	0.80	0.79
Natural Gas Subsample	0.55	0.56	0.56	0.78	0.78	0.75
Liquids Subsample	0.66	0.67	0.66	0.90	0.86	0.85
Electric Sample	0.39	0.38	0.35	0.34	0.32	0.31
Gas LDC Sample	0.46	0.46	0.45	0.37	0.36	0.36
Water Utility Sample	0.44	0.46	0.35	0.43	0.44	0.31

Sources and Notes:
Analysis of Bloomberg data by The Brattle Group

VI.CAPM Challenges

Perhaps the most fundamental challenge to the CAPM has been the consistent empirical observation that the low beta stocks have higher average returns than predicted by the CAPM, and high beta stocks lower average returns – that is, the empirical estimates seem to require a flattening of the so-called Security Market Line. This observation is illustrated in Figure 18 below and our statistical estimation of betas for portfolios, shown in Appendix E, confirmed that the observed excess portfolio returns (portfolio return less then risk-free rate) were higher than predicted by the CAPM (i.e., beta times the excess market return), as evidenced by the positive intercepts on the scatter-plots.

Figure 18: CAPM Empirical Challenge



The extent that this is valid, it suggests that cost of capital for regulated companies, which often have a beta less than one, will be underestimated by the traditional CAPM.[132]

A. Empirical Tests of the CAPM

Papers by Black, Jensen and Scholes (1972) and Fama and MacBeth (1972) were among the first to identify this issue.[133] Although the realized market returns demonstrated a remarkable linearity in the CAPM beta, as predicted by CAPM, the empirical version of the SML was pivoted around beta = 1.0, i.e., the intercept was higher and the slope less steep than predicted by theory. Several subsequent studies confirmed the robustness of this result and proposed explanations revolving around market frictions, such as different borrowing and

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132 Implementing a long-run version of the CAPM which uses (annualized) long-horizon returns (e.g., with long bond rates as risk-free rate) generally produces a flatter SML than obtained by using short-rates, due to the general presence of an upward sloping yield curve. While this partially compensates for the empirically observed flattening, it is not sufficient to explain all of the observed flattening of the SML. That is, even implementations that utilize a long-run risk-free interest rate require a further, albeit smaller, adjustment to match the empirical SML.

133 F. Black, M.C. Jensen, and M. Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," *Studies in the Theory of Capital Markets*, Praeger Publishers, 1972, pp. 79-121 and E.F. Fama and J.D. MacBeth, "Risk, Returns and Equilibrium: Empirical Tests," *Journal of Political Economy* 81 (3), 1972, pp. 607-636.

lending rates, and the role of taxes.[134] Nevertheless, the empirical evidence suggested significant movement in the SML, often flattening, to the point that Fama and French (1992) found a zero slope in the empirical SML.[135] Fama and French suggested that factors other than the risk relative to the market, such as size and book-to-market value ratios (among others) were significant in explaining the SML. A string of papers followed the initial work that has culminated into the model now known as the Fama-French model. Although this empirical challenge has motivated important and interesting work, alternatives to using the CAPM remain hotly debated by many.

The Empirical CAPM (ECAPM) is one way of correcting for the empirical flattening of the SML. Specifically, the ECAPM directly adjusts the CAPM SML by a parameter, alpha, that can be controlled for sensitivities, etc. Formally, the ECAPM relation is given by

$$r_s = r_f + \alpha + \beta_s \times (MRP - \alpha)$$

where α is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are as defined above. The alpha adjustment has the effect of increasing the intercept but reducing the slope of the SML, which results in a security market line that more closely matches the results of empirical tests as seen in Figure 18.

In general, the academic literature has estimated a fairly wide range of alpha parameters, ranging from 1 percent to as much as 7 percent.[136] While this may seem very large, much of the variation between studies arises from differences in methodology and time periods so that the alpha estimates are not strictly comparable.

There are many alternative models that attempt to account for the empirical regularity. Among them, the most commonly used model is the so-called Fama-French model, which explains stock market returns by adding explanatory risk factors to the CAPM model. Fama & French (1997) found that in addition to the (1) excess return on the market, (2) the return

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[134] Appendix H contains a list of additional articles documenting this result.

[135] E.F. Fama and K.R. French, "The Cross-Section of Expected Returns," *Journal of Finance* 47, 1992, pp. 427-465.

[136] Much of the academic literature estimating alpha dates back to the 1980s and prior to that. Appendix H provides an explanation of how to estimate the alpha parameter and also lists relevant academic research. Attention in this area has since turned to the Fama-French multifactor model, which attempts to explicitly capture the empirical pivot of the SML as a function of additional pricing factors (i.e., book-to-market ratios, price-to-earnings ratio, and size).

on small-firm stocks less the return on large-firm stocks (the size factor) and (3) the return on high book-to-market-ratio stocks less the return on low book-to-market-ratio stocks helped explain empirical regularities.[137] Notice that the Fama-French model is an alternative to the ECAPM – one should not employ a Fama-French model with an alpha adjustment. Indeed, one way of thinking about the Fama-French approach is as a way of explaining the estimated alpha adjustment observed in the SML.

Appendix H summarizes the empirical results of tests of the CAPM, including their estimates of the "alpha" parameter necessary to improve the accuracy of the CAPM's predictions of realized returns.

The key take-away from this section is that the standard CAPM implementations may be under estimating the cost of equity for entities that have a beta below one. In a regulatory setting, this implies that ECAPM estimates should inform the allowed rate of return when the regulated entity has a beta less than one, or at least that regulators should recognize the downward bias inherent in standard CAPM estimates under those circumstances when setting the allowed return.[138]

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137 E.F. Fama and K.R. French, "Industry Costs of Equity," Journal of Financial Economics 43, 1997, pp. 153-193.

138 We note that some regulatory commissions in the U.S. (e.g., the Mississippi Public Service Commission) use the ECAPM as one model in their determination of the allowed return on equity.

APPENDIX A: Calculation of Imputation Credit Adjustment

Table A-1
Imputation Credit Adjustment for Credit Suisse MRP

Risk-free Rate	[1]	2.1%
Corporate Tax Rate	[2]	30%
Gamma	[3]	0.25
MRP Excluding Imputation Credits	[4]	6.6%
MRP Including Imputation Credits	[5]	7.5%
Estimation Period Start	[6]	1900
Estimation Period End	[7]	2015
Imputation Credit Begun	[8]	1987
Average MRP Including Imputation Credits	[9]	6.8%

Sources and Notes:
[1]: Current yield on 10-year Canadian Government Bond
[2]: Assumed 30% Australian Tax Rate
[3]: The Brattle Group
[4]: Credit Suisse Historical MRP for Australia
[5]: MRP adjusted to included imputation credits, dervied from Lally (2008) Eq. 1
[6]: Credit Suisse Historical MRP for Australia, data start year
[7]: Credit Suisse Historical MRP for Australia, data end year
[8]: Australia implemented Imputation Credit tax system
[9]: Average MRP weighted by years

Table A-2
Imputation Credit Adjustment for Bloomberg Forecasted MRP

Risk-free Rate	[1]	2.1%
Corporate Tax Rate	[2]	30%
Gamma	[3]	0.25
MRP Excluding Imputation Credits	[4]	7.6%
MRP Including Imputation Credits	[5]	8.6%

Sources and Notes:
[1]: Current yield on 10-year Canadian Government Bond
[2]: Assumed 30% Australian Tax Rate
[3]: The Brattle Group
[4]: Bloomberg MRP Forecast for Australia, excluding imputation credits
[5]: MRP adjusted to included imputation credits, dervied from Lally (2008) Eq. 1

Table A-3
Imputation Credits for Wright Method MRP

Risk-free Rate	[1]	2.1%
Corporate Tax Rate	[2]	30%
Gamma	[3]	0.25
MRP Excluding Imputation Credits	[4]	8.1%
MRP Including Imputation Credits	[5]	9.2%
Estimation Period Start	[6]	1900
Estimation Period End	[7]	2015
Imputation Credit Begun	[8]	1987
Average MRP Including Imputation Credits	[9]	8.4%

Sources and Notes:
[1]: Current yield on 10-year Canadian Government Bond
[2]: Assumed 30% Australian Tax Rate
[3]: The Brattle Group
[4]: MRP from Wright Method based on The Brattle Group Analysis.
[5]: MRP adjusted to included imputation credits, dervied from Lally (2008) Eq. 1
[6]: Credit Suisse Historical MRP for Australia, data start year
[7]: Credit Suisse Historical MRP for Australia, data end year
[8]: Australia implemented Imputation Credit tax system
[9]: Average MRP weighted by years

APPENDIX B: List of Sample Companies

Freight Rail Transportation Sample

U.S. Class 1 Railroads:
CSX Corporation
Kansas City Southern
Norfolk Southern Corporation
Union Pacific Railroad Corporation

Non U.S. Class 1 Railroads:
Asciano Limited
Aurizon Holdings Ltd.
Canadian National Railway Company
Canadian Pacific Railway Limited
Daqin Railway Co., Ltd.
Genesee & Wyoming

North American Pipelines

Natural Gas:
Boardwalk Pipeline Partners L.P.
EQT Midstream Partners L.P.
Spectra Energy Partners L.P.
TC Pipelines LP

Liquids:
Buckeye Partners L.P.
Enbridge Energy Partners L.P.
Enterprise Products Partners L.P.
Magellan Midstream Partners L.P.
Plains All American Pipeline L.P.
Sunoco Logistics Partners L.P.

Mixed:
ONEOK Partners L.P.
Enbridge Inc.
TransCanada Corp

Gas LDC Sample

Atmos Energy Corp.
New Jersey Resources Corp.
Northwest Nat. Gas Co.
South Jersey Industries Inc.
Southwest Gas Corp.
WGL Holdings Inc.

Electric Sample

ALLETE
Alliant Energy
American Elec. Power
Ameren Corp.
CenterPoint Energy
CMS Energy Corp.
Consolidated Edison
Dominion Resources
DTE Energy
Edison International
El Paso Electric
Entergy Corp.
Great Plains Energy
IDACORP Inc.
MGE Energy
NextEra Energy
OGE Energy
Otter Tail Corp.
PG&E Corp.
Pinnacle West Capital
Portland General
Public Serv. Enterprise
SCANA Corp.
Sempra Energy
Vectren Corp.
Westar Energy
Xcel Energy Inc.

Water Utility Sample

American States Water Co
American Water Works Co Inc.
Aqua America Inc.
Artesian Resources Corp
California Water Service Group
Connecticut Water Service Inc.
Middlesex Water Co
SJW Corp
York Water Co

Source: The Brattle Group.

APPENDIX C: Description of Pipeline Sample Companies

Company	Segment Information from 2015 Finanancial Statements	Regulatory Information from 2015 Financial Statements
Boardwalk Pipeline	"The Partnership operates in one reportable segment - the operation of interstate natural gas and NGLs pipeline systems including integrated storage facilities. This segment consists of interstate natural gas pipeline systems which originate in the Gulf Coast region, Oklahoma and Arkansas and extend north and east through the Midwestern states of Tennessee, Kentucky, Illinois, Indiana and Ohio and NGLs pipelines and storage facilities in Louisiana and Texas." (54)	"Federal Energy Regulatory Commission. FERC regulates our natural gas operating subsidiaries under the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978. FERC regulates, among other things, the rates and charges for the transportation and storage of natural gas in interstate commerce and the extension, enlargement or abandonment of facilities under its jurisdiction." (10) "The maximum rates that may be charged by our operating subsidiaries that operate under FERC's jurisdiction for all aspects of the natural gas transportation services they provide are established through FERC's cost-of-service rate-making process." (10)
Buckeye Partners L.P.	"In December 2015, we realigned our reportable segments into three reportable segments as a result of changes in our organizational structure and renamed one of our reportable segments. Our three reportable segments are: Domestic Pipelines & Terminals (formerly known as Pipelines & Terminals), Global Marine Terminals and Merchant Services." (1) "The Domestic Pipelines & Terminals segment owns and operates approximately 6,000 miles of pipeline located primarily in the northeastern and upper midwestern portions of the United States, and services approximately 110 delivery locations. This segment transports liquid petroleum products, including gasoline, jet fuel, diesel fuel, heating oil and kerosene, from major supply sources to terminals and airports located within end-use markets. The pipelines within this segment also transport other refined petroleum products, such as propane and butane, refinery feedstock and blending components, as well as crude oil. The segment also includes 117 active terminals that provide bulk storage and throughput services with respect to liquid petroleum products and renewable fuels, including ethanol, and have an aggregate storage capacity of over 55 million barrels." (3)	Several pipelines owned by BPL are subject to rate regulation by FERC. See page 13 of BPL's 2015 10K. "BPLC, Wood River, BPL Transportation, Buckeye Linden Pipe Line Company LLC ("Buckeye Linden") and NORCO operate pipelines subject to the regulatory jurisdiction of the Federal Energy Regulatory Commission ("FERC") under the Interstate Commerce Act, the Energy Policy Act of 1992 and the Department of Energy Organization Act. FERC regulations require that interstate oil pipeline rates be posted publicly and that these rates be "just and reasonable" and not unduly discriminatory."
Enbridge Energy Partners L.P.		"The FERC regulates the interstate pipeline transportation of crude oil, petroleum products, and other liquids such as NGLs, collectively called "petroleum pipelines" or "liquids pipelines." Our Lakehead, North Dakota, Bakken and Ozark systems are our primary interstate common carrier liquids pipelines subject to regulation by the FERC under the Interstate Commerce Act, or ICA, the Energy Policy Act of 1992, or EP Act, and rules and orders promulgated thereunder." (15) "The ICA gives the FERC the authority to regulate the rates we can charge for service on interstate common carrier pipelines. The ICA requires, among other things, that such rates be "just and reasonable" and that they not be unduly discriminatory or unduly preferential to certain shippers." (15)
Enterprise Products Partners, LP	"Our historical operations are reported under five business segments: (i) NGL Pipelines & Services, (ii) Crude Oil Pipelines & Services, (iii) Natural Gas Pipelines & Services, (iv) Petrochemical & Refined Products Services and (v) Offshore Pipelines & Services." (F-40)	"Certain of our NGL, petroleum products and crude oil pipeline systems are interstate common carriers subject to regulation by the FERC under the Interstate Commerce Act ("ICA")…"The ICA prescribes that the interstate rates we charge for transportation on these interstate liquids pipelines must be just and reasonable, and that the rules applied to our services not unduly discriminate against or confer any undue preference upon any shipper." (31)

Continued on next page

Company	Segment Information from 2015 Finanancial Statements	Regulatory Information from 2015 Financial Statements
EQT Midstream Partners LP	Segments: Transmission and Storage, and Gathering System "As of December 31, 2015, EQM's transmission and storage system included an approximately 700-mile FERC-regulated interstate pipeline that connects to five interstate pipelines and multiple distribution companies. The transmission system is supported by 14 associated natural gas storage reservoirs..." (7) "Through a lease with EQT, EQM also operates the AVC facilities, which include an approximately 200-mile FERC-regulated interstate pipeline that interconnects with EQM's transmission and storage system." (7) "As of December 31, 2015, EQM's gathering system included approximately 185 miles of high pressure gathering lines with approximately 1.4 Bcf of total firm gathering capacity and multiple interconnect points with EQM's transmission and storage system. EQM's gathering system also included 1,500 miles of FERC-regulated low pressure gathering lines." (10)	"The FERC regulates the rates and charges for transmission and storage in interstate commerce. Under the NGA, rates charged by interstate pipelines must be just and reasonable. The FERC's cost-of-service regulations generally limit the recourse rates for transmission and storage services to the cost of providing service plus a reasonable rate of return. In each rate case, the FERC must approve service costs, the allocation of costs, the allowed rate of return on capital investment, rate design and other rate factors." (14)
Magellan Midstream	Segments didn't change in 2015 - Refined Products, Crude Oil, and Marine Storage "We are principally engaged in the transportation, storage and distribution of refined petroleum products and crude oil. As of December 31, 2015, our asset portfolio, including the assets of our joint ventures, consisted of: • our refined products segment, comprised of our 9,500-mile refined products pipeline system with 52 terminals as well as 28 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system; • our crude oil segment, comprised of approximately 1,700 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 22 million barrels, of which 14 million are used for leased storage; and • our marine storage segment, consisting of five marine terminals located along coastal waterways with an aggregate storage capacity of approximately 26 million barrels." (1)	Our refined products pipeline system's interstate common carrier pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act, the Energy Policy Act of 1992 and rules and orders promulgated pursuant thereto. FERC regulation requires that interstate pipeline rates, including rates for all petroleum products, be filed with the FERC and posted publicly and that these rates be nondiscriminatory and "just and reasonable" when taking into account our cost of service. (12)
ONEOK Partners L.P.	Business segments: Natural Gas Gathering and Processing, Natural Gas Liquids, Nautral Gas Pipelines (8) "Our Natural Gas Pipelines segment provides transportation and storage services to end users through its wholly owned assets and its 50 percent ownership in Northern Border Pipeline." (14) Also have intrastate pipelines, mostly in Oklahoma (14)	"Our interstate pipelines are regulated by the FERC and are located in North Dakota, Minnesota, Wisconsin, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas and New Mexico." (14) "Under the Natural Gas Act, which is applicable to interstate natural gas pipelines, and the Interstate Commerce Act, which is applicable to crude oil and natural gas liquids pipelines, our interstate transportation rates, which are regulated by the FERC, must be just and reasonable and not unduly discriminatory." (30)
Plains All Amer. Pipe.	"We own and operate midstream energy infrastructure and provide logistics services for crude oil, natural gas liquids ("NGL"), natural gas and refined products. We own an extensive network of pipeline transportation, terminalling, storage, and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. Our business activities are conducted through three operating segments: Transportation, Facilities and Supply and Logistics." (4) "Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems, trucks and barges." (18)	"**General Interstate Regulation:** Our interstate common carrier liquids pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act ("ICA"). The ICA requires that tariff rates for liquids pipelines, which include both crude oil pipelines and refined products pipelines, be just and reasonable and non-discriminatory." (41) "**Canadian Regulation**. Our Canadian pipeline assets are subject to regulation by the NEB and by provincial authorities, such as the AER. With respect to a pipeline over which it has jurisdiction, the relevant regulatory authority has the power, upon application by a third party, to determine the rates we are allowed to charge for transportation on, and set other terms of access to, such pipeline. In such circumstances, if the relevant regulatory authority determines that the applicable terms and conditions of service are not just and reasonable, the regulatory authority can impose conditions it considers appropriate." (41)

Continued on next page

Company	Segment Information from 2015 Finanancial Statements	Regulatory Information from 2015 Financial Statements
Spectra Energy Partners LP	"Spectra Energy Partners, LP, through its subsidiaries and equity affiliates, is engaged in the transmission, storage and gathering of natural gas, and the transportation and storage of crude oil, through interstate pipeline systems in the United States and Canada with over 15,000 miles of transmission and transportation pipelines and the storage of natural gas in underground facilities with aggregate working gas storage capacity of approximately 170 billion cubic feet (Bcf)." (4) Segments: US Transmission and Liquids (5) "Our U.S. Transmission business primarily provides transmission, storage, and gathering of natural gas for customers in various regions of the northeastern and southeastern United States. Our pipeline systems consist of approximately 14,000 miles of pipelines with eight primary transmission systems..." (5) "Our Liquids business provides transportation and storage of crude oil for customers in central United States and Canada. Our Liquids pipeline system consists of Express-Platte." (14)	"Most of U.S. Transmission's pipeline and storage operations are regulated by the FERC and are subject to the jurisdiction of various federal, state and local environmental agencies." (5) "Most of Liquids' pipeline and storage operations are regulated by the FERC and the NEB, and are subject to the jurisdiction of various federal, state and local environmental agencies." (14)
Sunoco Logistics Part.	"The updated reporting segments are: Crude Oil, Natural Gas Liquids and Refined Products." (2) "The Crude Oil segment provides transportation, terminalling and acquisition and marketing services to crude oil markets throughout the southwest, midwest and northeastern United States. Included within the segment isapproximately 5,900 miles of crude oil trunk and gathering pipelines in the southwest and midwest United States and equity ownership interests in three crude oil pipelines." (2) "The Natural Gas Liquids segment transports, stores, and executes acquisition and marketing activities utilizing a complementary network of pipelines, storage and blending facilities, and strategic off-take locations that provide access to multiple NGLs markets. The segment contains approximately 900 miles of NGLs pipelines, primarily related to our Mariner systems located in the northeast and southwest United States." (2) "The Refined Products segment provides transportation and terminalling services, through the use of approximately 1,800 miles of refined products pipelines and approximately 40 active refined products marketing terminals." (3)	"**General Interstate Regulation** Interstate common carrier pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act, the Energy Policy Act of 1992, and related rules and orders. The Interstate Commerce Act requires that tariff rates for petroleum pipelines be "just and reasonable" and not unduly discriminatory." (17) Also subject to intrastate regulation.
TC PipeLines LP	"We have four wholly-owned pipelines and equity ownership interests in three natural gas interstate pipeline systems that are collectively designed to transport approximately 9.1 billion cubic feet per day of natural gas from producing regions and import facilities to market hubs and consuming markets primarily in the Western, Midwestern and Eastern U.S. All of our pipeline systems are operated by subsidiaries of TransCanada." (11)	"Interstate natural gas pipelines are regulated by FERC. FERC approves the construction of new pipeline facilities and regulates aspects of our business including the maxiumum rates that we are allowed to be charged." (9)
Enbridge Inc.	"Enbridge Inc. is a publicy traded energy transportation and distribution company. Enbridge conducts its business through five business segments: Liquids Pipelines; Gas Distribution, Gas Pipelines and Processing; Green Power and Transmission; and Energy Services." (10) "Liquids Pipelines consists of common carrier and contract crude oil, natural gas liquids (NGL) and refined products pipelines and terminals in Canada and the United States..." (10) "Gas Pipelines and Processing consists of investments in natural gas pipelines and gathering and processing facilities. Investments in natural gas pipelines include the Company's interests in the Alliance Pipeline, the Vector Pipeline (Vector) and transmission and gathering pipelines in the Gulf of Mexico. Investments in natural gas processing include the Company's interest in Aux Sable, a natural gas extraction and fractionation business located near the terminus of the Alliance Pipeline, Canadian Midstream assets located in northeast British Columbia and northwest Alberta and United States Midstream assets located primarily in Texas and Oklahoma." (10)	"Certain of the Company's businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Alberta Energy Regulator, the New Brunswick Energy and Utilities Board (EUB) and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers." (13) Enbridge Inc. itself is not regulated as a 'Group 1' pipeline by the NEB. However, Enbridge Pipelines Inc. is regulated as a Group 1. See: https://www.neb-one.gc.ca/bts/whwr/cmpnsrgltdbnb-eng.html
TransCanada Corp.	Segments didn't change in 2015 - Natural Gas Pipelines, Liquids Pipelines, and Energy "The Natural Gas Pipelines segment consists of the Company's investments in 67,300 km (41,900 miles) of regulated natural gas pipelines and 250 Bcf of regulated natural gas storage facilities." (127) "The Liquids Pipelines segment consists of 4,247 km (2,639 miles) of wholly-owned and operated crude oil pipeline systems which connect Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas." (127)	"In Canada, regulated natural gas pipelines and liquids pipelines are subject to the authority of the National Energy Board (NEB). In the U.S., natural gas pipelines, liquids pipelines and regulated natural gas storage assets are subject to the authority of the Federal Energy Regulatory Commission (FERC). In Mexico, natural gas pipelines are subject to the authority of the Energy Regulatory Commission (CRE). The Company's Canadian, U.S. and Mexican natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls." (128) The following entities are regulated as "Group 1" pipelines by the NEB: TransCanada Keystone Pipeline Ltd., and TransCanada Pipelines Ltd. See: https://www.neb-one.gc.ca/bts/whwr/cmpnsrgltdbnb-eng.html

Selected Information from Buckeye Partners 2015 Form 10-K
Note 25 - Business Segments

	December 31, 2015	December 31, 2014
Total Assets:		
Domestic Pipelines & Terminals (1)	$ 3,498,883	$ 3,357,410
Global Marine Terminals (2)	4,500,705	4,239,792
Merchant Services	369,693	468,518
Total assets	$ 8,369,281	$ 8,065,720

(1) All equity investments are included in the assets of the Domestic Pipelines & Terminals segment.

(2) The Global Marine Terminals segment's long-lived assets consist of property, plant and equipment, goodwill, intangible assets and other non-current assets. Total tangible long-lived assets located in our international locations were $1,506.2 million and $1,520.8 million for the years ended December 31, 2015 and 2014, respectively.

Source:

Buckeye Partners SEC 2015 Form 10-K, Note 25, Page 114

Selected Information from Buckeye Partners 2015 Form 10-K
Note 25 - Business Segments

9. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following at the dates indicated (in thousands):

	Estimated Useful Lives (Years)	December 31, 2015	December 31, 2014
Land	N/A	$ 669,130	$ 655,847
Rights-of-way	(1)	107,293	104,754
Buildings and leasehold improvements	13-50	235,872	364,704
Jetties, subsea pipeline and docks	20-50	629,677	485,523
Gas storage facility	25-50	2,349	2,229
Pipelines and terminals	7-50	4,616,080	4,306,472
Vehicles, equipment and office furnishings	3-20	117,494	103,253
Processing facilities	30-50	557,853	—
Construction in progress	N/A	141,153	445,165
Total property, plant and equipment		7,076,901	6,467,947
Less: Accumulated depreciation		(874,820)	(732,160)
Total property, plant and equipment, net		$ 6,202,081	$ 5,735,787

(1) Rights-of-way assets are depreciated over the useful life of the related pipeline assets.

Depreciation expense was $158.7 million, $148.4 million and $122.7 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Source:
Buckeye Partners SEC 2015 Form 10-K, Note 9, Page 87

Selected Information from Magellan Midstream Partners L.P. 2015 Form 10-K
Item 1 - Business

Our refined products segment accounted for the following percentages of our consolidated revenue, operating margin and total assets:

	Year Ended December 31,		
	2013	2014	2015
Percent of consolidated revenue	80%	77%	73%
Percent of consolidated operating margin	71%	68%	61%
Percent of consolidated total assets	59%	52%	50%

Our crude oil segment accounted for the following percentages of our consolidated revenue, operating margin and total assets:

	Year Ended December 31,		
	2013	2014	2015
Percent of consolidated revenue	11%	15%	19%
Percent of consolidated operating margin	18%	23%	30%
Percent of consolidated total assets	26%	35%	38%

Our marine storage segment accounted for the following percentages of our consolidated revenue, operating margin and total assets:

	Year Ended December 31,		
	2013	2014	2015
Percent of consolidated revenue	9%	8%	8%
Percent of consolidated operating margin	11%	9%	9%
Percent of consolidated total assets	13%	12%	11%

Source:
Magellan Midstream Partners L.P. 2015 Form 10K, Item 1, pages 2-11

9. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	2015	2014
(millions of Canadian dollars)			
Liquids Pipelines[1]			
Pipeline	2.7%	**31,092**	22,007
Pumping equipment, buildings, tanks and other	3.1%	**14,319**	12,230
Land and right-of-way	2.4%	**1,221**	1,077
Under construction	-	**6,002**	7,449
		52,634	42,763
Accumulated depreciation		**(8,233)**	(6,655)
		44,401	36,108
Gas Distribution			
Gas mains, services and other	3.0%	**8,819**	8,427
Land and right-of-way	1.0%	**85**	84
Under construction	-	**902**	352
		9,806	8,863
Accumulated depreciation		**(2,379)**	(2,256)
		7,427	6,607
Gas Pipelines and Processing			
Pipeline	2.7%	**3,557**	2,888
Compressors, meters and other operating equipment	3.4%	**3,864**	2,957
Processing and treating plants	2.5%	**869**	599
Pumping equipment, buildings, tanks and other	5.0%	**275**	246
Land and right-of-way	2.3%	**680**	511
Under construction	-	**956**	1,204
		10,201	8,405
Accumulated depreciation		**(2,003)**	(1,505)
		8,198	6,900
Green Power and Transmission			
Wind turbines, solar panels and other	4.1%	**4,311**	3,829
Power transmission	1.8%	**387**	368
Land and right-of-way	4.2%	**45**	28
Under construction	-	**51**	210
		4,794	4,435
Accumulated depreciation		**(600)**	(404)
		4,194	4,031
Energy Services			
Pumping equipment and other	3.4%	**34**	26
Under construction	-	**-**	5
		34	31
Accumulated depreciation		**(13)**	(9)
		21	22
Eliminations and Other			
Vehicles, office furniture, equipment and other	6.1%	**331**	306
		331	306
Accumulated depreciation		**(138)**	(144)
		193	162
		64,434	53,830

1 *In July 2014, $62 million of Property, plant and equipment was disposed as part of the sale of a 35% equity interest in the Southern Access Extension Project. The remaining balance of $136 million in Property, plant and equipment was reclassified to Long-term investments (Note 11).*

Depreciation expense for the year ended December 31, 2015 was $1,852 million (2014 - $1,461 million).

Source:
Enbridge Inc 2015 Amended Consolidated Financial Statements, Note 9, page 31

Selected Information from Enbridge Inc's 2015 Amended Consolidated Financial Statements
Note 4 - Segmented Information

4. SEGMENTED INFORMATION

Year ended December 31, 2015	Liquids Pipelines	Gas Distribution	Gas Pipelines and Processing	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	5,589	3,609	3,803	498	20,842	(547)	33,794
Commodity and gas distribution costs	(9)	(2,349)	(3,002)	4	(20,443)	558	(25,241)
Operating and administrative	(2,849)	(536)	(522)	(143)	(66)	(132)	(4,248)
Depreciation and amortization	(1,227)	(308)	(272)	(186)	1	(32)	(2,024)
Environmental costs, net of recoveries	21	-	-	-	-	-	21
Goodwill impairment	-	-	(440)	-	-	-	(440)
	1,525	416	(433)	173	334	(153)	1,862
Income/(loss) from equity investments	296	(10)	200	2	(9)	(4)	475
Other income/(expense)	(15)	49	4	2	-	(742)	(702)
Earnings/(loss) before interest and income taxes	1,806	455	(229)	177	325	(899)	1,635
Interest expense							(1,624)
Income taxes							(170)
Loss							(159)
Loss attributable to noncontrolling interests and redeemable noncontrolling interests							410
Preference share dividends							(288)
Loss attributable to Enbridge Inc. common shareholders							(37)
Additions to property, plant and equipment[1]	5,884	858	385	68	-	80	7,275
Total assets	52,015	9,901	11,559	4,977	1,889	4,174	84,515

Source:
Enbridge Inc's 2015 Amended Consolidated Financial Statements, Note 4, Page 24

Selected Information from Plains All American Pipeline LP 2015 Form 10-K
Note 18 - Operating Segments

The following table reflects certain financial data for each segment for the periods indicated (in millions):

	Transportation		Facilities		Supply and Logistics		Total	
Year Ended December 31, 2015								
Revenues (1) :								
External customers	$	697	$	528	$	21,927	$	23,152
Intersegment (2)		897		522		18		1,437
Total revenues of reportable segments	$	1,594	$	1,050	$	21,945	$	24,589
Equity earnings in unconsolidated entities	$	183	$	—	$	—	$	183
Segment profit (3) (4)	$	917	$	579	$	381	$	1,877
Capital expenditures (5)	$	1,278	$	813	$	184	$	2,275
Maintenance capital	$	144	$	68	$	8	$	220
As of December 31, 2015								
Total assets	$	10,345	$	7,330	$	4,613	$	22,288
Investments in unconsolidated entities	$	1,998	$	29	$	—	$	2,027

Source:
Plains All American 2015 Form 10-K, Note 18, page F-47

Selected Information from Sunoco Logistics Partners 2015 Form 10-K
Note 7 - Properties, Plants, and Equipment

7. Properties, Plants and Equipment

The components of net properties, plants and equipment are as follows:

	Estimated Useful Lives	December 31, 2015	December 31, 2014
	(in years)	(in millions)	
Land and land improvements (including rights-of-way) (1)	—	$ 1,286	$ 1,212
Pipelines and related assets	16 - 39	5,943	4,253
Terminals and storage facilities	20 - 41	1,985	1,457
Buildings and improvements	25 - 32	509	245
Other	3 - 20	177	133
Construction-in-progress (2)		1,627	2,058
Total properties, plants and equipment		11,527	9,358
Less: Accumulated depreciation and amortization		(835)	(509)
Total properties, plants and equipment, net		$ 10,692	$ 8,849

(1) As of December 31, 2015 and 2014, the Partnership had rights-of-way with a book value of $1.1 and $1.0 billion, respectively.

(2) As of December 31, 2015 and 2014, accrued capital expenditures were $286 and $283 million, respectively.

Source:
Sunoco Logistics 2015 Form 10-K, Note 7, Page 81

Selected Information from Enbridge Energy Partners, L.P. 2015 Form 10-K
Note 16 - Segment Information

16. SEGMENT INFORMATION – (continued)

The following tables present certain financial information relating to our business segments and corporate activities:

	As of and for the year ended December 31, 2015			
	Liquids	Natural Gas	Corporate[1]	Total
	(in millions)			
Operating revenues:[2]				
Commodity sales	$ —	$ 2,646.4	$ —	$ 2,646.4
Transportation and other services	2,303.4	196.3	—	2,499.7
	2,303.4	2,842.7	—	5,146.1
Operating expenses:				
Commodity costs	—	2,372.9	—	2,372.9
Environmental costs, net of recoveries	3.1	—	—	3.1
Operating and administrative	605.9	351.0	14.4	971.3
Power	259.5	—	—	259.5
Goodwill impairment	—	246.7	—	246.7
Asset impairment	62.5	12.3	—	74.8
Depreciation and amortization	378.4	157.8	—	536.2
	1,309.4	3,140.7	14.4	4,464.5
Operating income (loss)	994.0	(298.0)	(14.4)	681.6
Interest expense, net	—	—	(322.0)	(322.0)
Allowance for equity used during construction	—	—	70.3	70.3
Other income	—	29.3[3]	—	29.3
Income (loss) before income tax expense	994.0	(268.7)	(266.1)	459.2
Income tax expense	—	—	(4.9)	(4.9)
Net income (loss)	994.0	(268.7)	(271.0)	454.3
Less: Net income attributable to:				
Noncontrolling interest	—	—	221.1	221.1
Series 1 preferred unit distributions	—	—	90.0	90.0
Accretion of discount on Series 1 preferred units	—	—	11.2	11.2
Net income (loss) attributable to general and limited partner ownership interests in Enbridge Energy Partners, L.P.	$ 994.0	$ (268.7)	$ (593.3)	$ 132.0
Total assets	$ 13,484.1	$ 5,142.3[4]	$ 189.4	$ 18,815.8
Capital expenditures (excluding acquisitions)	$ 1,975.9	$ 173.6	$ 4.8	$ 2,154.3

(1) Corporate consists of interest expense, interest income, allowance for equity during construction, noncontrolling interest and other costs such as income taxes, which are not allocated to the business segments.

(2) There were no intersegment revenues for the year ended December 31, 2015.

(3) Other income (expense) for our Natural Gas segment includes our equity investment in the Texas Express NGL system.

(4) Totals assets for our Natural Gas segment includes $372.3 million for our equity investment in the Texas Express NGL system.

Source:
Enbridge Energy Partners L.P. 2015 Form 10-K, Note 16, Page 158

BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(Millions)

ASSETS	December 31, 2015	December 31, 2014
Current Assets:		
Cash and cash equivalents	$ 3.1	$ 6.6
Receivables:		
Trade, net	117.2	102.6
Other	12.3	8.3
Gas transportation receivables	5.6	9.1
Gas and liquids stored underground	10.7	4.1
Prepayments	16.9	14.5
Other current assets	4.0	4.4
Total current assets	169.8	149.6
Property, Plant and Equipment:		
Natural gas transmission and other plant	9,504.7	9,250.1
Construction work in progress	201.9	105.5
Property, plant and equipment, gross	9,706.6	9,355.6
Less—accumulated depreciation and amortization	2,052.2	1,766.4
Property, plant and equipment, net	7,654.4	7,589.2
Other Assets:		
Goodwill	237.4	237.4
Gas stored underground	97.6	86.4
Other	141.1	131.7
Total other assets	476.1	455.5
Total Assets	$ 8,300.3	$ 8,194.3

Source:
Boardwalk Pipeline Partners LP 2015 Form 10K, Item 8, page 47

Selected Information from EQT Midstream Partners, L.P. 2015 Form 10-K
Item 1 - Business

Composition of Segment Operating Revenues

Presented below are operating revenues by segment as a percentage of total operating revenues of EQM.

	For the year ended December 31,		
	2015	2014	2013
Transmission and storage operating revenues	48%	53%	49%
Gathering operating revenues	52%	47%	51%

Source:
EQT Midstream Partners LP 2015 Form 10K, Item 1, page 21

Selected Information from EQT Midstream Partners, L.P. 2015 Form 10-K
Note 1 - Summary of Operations and Significant Accounting Policies

	As of December 31,	
	2015	2014
	(Thousands)	
Transmission and storage assets	$ 1,247,970	$ 1,045,207
Accumulated depreciation	(181,672)	(159,583)
Net transmission and storage assets	1,066,298	885,624
Gathering assets	980,997	776,596
Accumulated depreciation	(77,302)	(56,903)
Net gathering assets	903,695	719,693
Net property, plant and equipment	$ 1,969,993	$ 1,605,317

Source:
EQT Midstream Partners LP 2015 Form 10K, Note 1, page 72

Selected Information from Spectra Energy Partners, L.P. 2015 Form 10-K
Note 11 - Property, Plant, and Equipment

11. Property, Plant and Equipment

	Estimated Useful Life	December 31, 2015	December 31, 2014
	(years)	(in millions)	
Plant			
Natural gas transmission	2-100	$ 12,424	$ 11,516
Natural gas storage	17-122	1,617	1,546
Gathering and processing facilities	10-40	3	12
Crude oil transportation and storage	25-75	1,206	1,169
Land rights and rights of way	20-122	474	439
Other buildings and improvements	10-50	37	35
Equipment	3-60	80	80
Vehicles	3-15	12	11
Land	—	71	71
Construction in process	—	1,484	664
Software	2-15	12	9
Other	5-82	71	42
Total property, plant and equipment		17,491	15,594
Total accumulated depreciation		(3,533)	(3,347)
Total accumulated amortization		(121)	(112)
Total net property, plant and equipment		$ 13,837	$ 12,135

Source:
Spectra Energy Partners LP 2015 Form 10K, page 83

Selected Information from Oneok Partners, L.P. 2015 Form 10-K
Note E - Property, Plant, and Equipment

E. PROPERTY, PLANT AND EQUIPMENT

The following table sets forth our property, plant and equipment by property type, for the periods indicated:

	Estimated Useful Lives (Years)	December 31, 2015	December 31, 2014
		(Thousands of dollars)	
Nonregulated			
Gathering pipelines and related equipment	5 to 40	$ **2,961,388**	$ 2,449,343
Processing and fractionation and related equipment	3 to 40	**3,627,062**	2,880,572
Storage and related equipment	5 to 54	**456,437**	478,276
Transmission pipelines and related equipment	5 to 54	**416,391**	518,585
General plant and other	2 to 60	**186,358**	142,276
Construction work in process	—	**690,179**	1,233,808
Regulated			
Storage and related equipment	5 to 54	**76,468**	115,799
Natural gas transmission pipelines and related equipment	5 to 77	**1,507,220**	1,478,035
Natural gas liquids transmission pipelines and related equipment	5 to 88	**4,208,121**	3,822,799
General plant and other	2 to 54	**94,461**	63,424
Construction work in process	—	**83,461**	194,700
Property, plant and equipment		**14,307,546**	13,377,617
Accumulated depreciation and amortization - nonregulated		**(1,219,435)**	(1,123,261)
Accumulated depreciation and amortization - regulated		**(831,320)**	(718,823)
Net property, plant and equipment		$ **12,256,791**	$ 11,535,533

Source:
Oneok Partners LP 2015 Form 10K, Note E, page 103

Selected Information from TC Pipelines LP 2015 Form 10-K
Note 5 - Plant, Property, and Equipment

NOTE 5 PLANT, PROPERTY AND EQUIPMENT

The following table includes plant, property and equipment from our consolidated subsidiaries.

	2015		
December 31 (millions of dollars)	Cost	Accumulated Depreciation	Net Book Value
Pipeline	2,086	(638)	1,448
Compression	516	(134)	382
Metering and other	156	(39)	117
Construction in progress	2	–	2
	2,760	(811)	1,949

Source:
TC Pipelines LP 2015 Form 10-K, Note 5, F-14

Selected Information from Enterprise Prodcuts Partners, L.P. 2015 Form 10-K
Note 10 - Business Segments

	Reportable Business Segments						
	NGL Pipelines & Services	Crude Oil Pipelines & Services	Natural Gas Pipelines & Services	Petrochemical & Refined Products Services	Offshore Pipelines & Services	Adjustments and Eliminations	Consolidated Total
Revenues from third parties:							
Year ended December 31, 2015	$ 9,779.0	$ 10,258.3	$ 2,729.5	$ 4,111.9	$ 76.9	$ --	$ 26,955.6
Year ended December 31, 2014	17,078.4	20,151.9	4,182.6	6,316.5	150.3	--	47,879.7
Year ended December 31, 2013	17,119.1	20,609.1	3,522.7	6,258.5	151.7	--	47,661.1
Revenues from related parties:							
Year ended December 31, 2015	9.0	47.6	13.8	--	1.9	--	72.3
Year ended December 31, 2014	11.4	32.4	21.2	--	6.5	--	71.5
Year ended December 31, 2013	1.1	41.3	15.8	--	7.7	--	65.9
Intersegment and intrasegment revenues:							
Year ended December 31, 2015	10,217.9	5,162.0	662.1	1,126.0	0.6	(17,168.6)	--
Year ended December 31, 2014	13,716.5	12,678.7	1,106.7	1,779.6	6.5	(29,288.0)	--
Year ended December 31, 2013	11,096.6	10,222.3	959.7	1,764.0	9.6	(24,052.2)	--
Total revenues:							
Year ended December 31, 2015	20,005.9	15,467.9	3,405.4	5,237.9	79.4	(17,168.6)	27,027.9
Year ended December 31, 2014	30,806.3	32,863.0	5,310.5	8,096.1	163.3	(29,288.0)	47,951.2
Year ended December 31, 2013	28,216.8	30,872.7	4,498.2	8,022.5	169.0	(24,052.2)	47,727.0
Equity in income (loss) of unconsolidated affiliates:							
Year ended December 31, 2015	57.5	281.4	3.8	(15.7)	46.6	--	373.6
Year ended December 31, 2014	30.6	184.6	3.6	(13.3)	54.0	--	259.5
Year ended December 31, 2013	15.7	140.3	3.8	(22.3)	29.8	--	167.3
Gross operating margin:							
Year ended December 31, 2015	2,771.6	961.9	782.6	718.5	97.5	--	5,332.1
Year ended December 31, 2014	2,877.7	762.5	803.3	681.0	162.0	--	5,286.5
Year ended December 31, 2013	2,514.4	742.7	789.0	625.9	146.1	--	4,818.1
Property, plant and equipment, net: (see Note 5)							
At December 31, 2015	12,909.7	3,550.3	8,620.0	3,060.7	--	3,894.0	32,034.7
At December 31, 2014	11,766.9	2,332.2	8,835.5	3,047.2	1,145.1	2,754.7	29,881.6
At December 31, 2013	9,957.8	1,479.9	8,917.3	2,712.4	1,223.7	2,655.5	26,946.6
Investments in unconsolidated affiliates: (see Note 6)							
At December 31, 2015	718.7	1,813.4	22.5	73.9	--	--	2,628.5
At December 31, 2014	682.3	1,767.7	23.2	75.1	493.7	--	3,042.0
At December 31, 2013	645.5	1,165.2	24.2	70.4	531.8	--	2,437.1
Intangible assets, net: (see Note 7)							
At December 31, 2015	380.3	2,377.5	1,087.7	191.7	--	--	4,037.2
At December 31, 2014	689.2	2,223.6	972.9	374.8	41.6	--	4,302.1
At December 31, 2013	285.2	4.5	1,017.8	100.0	54.7	--	1,462.2
Goodwill: (see Note 7)							
At December 31, 2015	2,651.7	1,841.0	296.3	956.2	--	--	5,745.2
At December 31, 2014	2,210.2	918.7	296.3	793.0	82.0	--	4,300.2
At December 31, 2013	341.2	305.1	296.3	1,055.3	82.1	--	2,080.0
Segment assets:							
At December 31, 2015	16,660.4	9,582.2	10,026.5	4,282.5	--	3,894.0	44,445.6
At December 31, 2014	15,348.6	7,242.2	10,127.9	4,290.1	1,762.4	2,754.7	41,525.9
At December 31, 2013	11,229.7	2,954.7	10,255.6	3,938.1	1,892.3	2,655.5	32,925.9

Source:
Enterprise Products Partners L.P. 2015 Form 10-K, Note 10, Page F-43

Selected Information from TransCanada Corp. 2015 Consolidated Financial Statements
Note 4 - Segmented Information

at December 31 (millions of Canadian $)	2015
Total Assets	
Natural Gas Pipelines	**31,072**
Liquids Pipelines	**16,046**
Energy	**15,558**
Corporate	**1,807**
	64,483

Source:
TransCanada Corp. 2015 Consolidated Financial Statements, Note 4, page 138

APPENDIX D: Description of Freight Rail Sample Companies

Revenue Information by Segment
Asciano, 2015 Annual Report
For the Year Ended December 31, 2015
(Australian $ millions)

Segment		Revenues	% of Total Revenues
[1]		[2]	[3]
Bulk Commodity Freight:			
Coal / Grain / Minerals	[a]	$1,519	39.6%
Other Freight Segments:			
Intermodal	[b]	$912	23.8%
Total Freight Revenues	[c]	$2,431	63.3%
Other Company Revenues	[d]	$1,408	36.7%
Total Revenues	[e]	$3,839	100.0%

Sources & Notes:
Asciano, 2015 Annual Report
[a]: Pacific National bulk rail includes coal, grain, and minerals (see page 91, 2015 AR).
[d]: Revenues from Terminals & Logistics, Bulk & Automotive Port Services, and Eliminations

Revenue Information by Segment
Aurizon Holdings, 2015 Annual Report
For the Year Ended December 31, 2015
(Australian $ millions)

Segment		Revenues	% of Total Revenues
[1]		[2]	[3]
Bulk Commodity Freight:			
Coal	[a]	$1,182	31.7%
Iron Ore	[b]	$338	9.1%
Freight	[c]	$787	21.1%
Total Bulk Freight	[d]	$2,307	61.8%
Total Freight Revenues	[e]	$2,307	61.8%
Other Revenues from external customers	[f]	$1,425	38.2%
Total Revenues from external customers	[g]	$3,732	100.0%

Sources & Notes:
Aurizon Holdings, 2015 Annual Report
[c]: "Freight" includes transport of "bulk mineral commodities, agricultral products, mining and industrial inputs, and general freight" (page 58 of 2015 Annual Report).

Revenue Information by Segment
Canadian National Railroad, 2015 Annual Report
For the Year Ended December 31, 2015
(Canadian $ millions)

Segment		Revenues	% of Total Revenues
[1]		[2]	[3]
Bulk Commodity Freight:			
Grain and Fertilizer	[a]	$2,071	16.4%
Coal	[b]	$612	4.9%
Metals and minerals	[c]	$1,437	11.4%
Total Bulk Freight	[d]	$4,120	32.7%
Other Freight Segments:			
Automotive	[e]	$719	5.7%
Forest Products	[f]	$1,728	13.7%
Petroleum and Chemicals	[g]	$2,442	19.4%
Intermodal	[h]	$2,896	23.0%
Total Other Freight	[i]	$7,785	61.7%
Total Freight Revenues	[j]	$11,905	94.4%
Other Company Revenues	[k]	$706	5.6%
Total Revenues	[l]	$12,611	100.0%

Sources & Notes:
Canadian National Railroad, 2015 Annual Report

Revenue Information by Segment
Canadian Pacific Railway Limited, 2015 Form 10-K
For the Year Ended December 31, 2015
(Canadian $ millions)

Segment		Revenues	% of Total Revenues
[1]		[2]	[3]
Bulk Commodity Freight:			
Canadian Grain	[a]	$1,067	15.9%
Coal	[b]	$634	9.5%
Fertilizer and Sulphur	[c]	$288	4.3%
Potash	[d]	$375	5.6%
U.S. Grain	[e]	$519	7.7%
Total Bulk Freight	[f]	$2,883	43.0%
Other Freight Segments:			
Automotive	[g]	$354	5.3%
Chemicals & Plastics	[h]	$708	10.5%
Crude	[i]	$401	6.0%
Forest Products	[j]	$259	3.9%
Metals, Minerals, Consumer Products	[k]	$637	9.5%
Intermodal	[l]	$1,310	19.5%
Total Other Freight	[m]	$3,669	54.7%
Total Freight Revenues	[n]	$6,552	97.6%
Other Company Revenues	[o]	$160	2.4%
Total Revenues	[p]	$6,712	100.0%

Sources & Notes:
Canadian Pacific Railway Limited's 2015 Form 10-K

Revenue Information by Segment
Daqin Railway Co. Ltd.
For the Year Ended December 31, 2015
(USD $ millions)

Segment		Revenues	% of Total Revenues
[1]		[2]	[3]
Bulk Commodity Freight:			
Coal	[a]	$6,601	79.0%
Total Bulk Freight	[b]	$6,601	79.0%
Total Freight Revenues	[c]	$6,601	79.0%
Other Company Revenues	[d]	$1,760	21.0%
Total Revenues	[e]	$8,361	100.0%

Sources & Notes:
Bloomberg LP

Revenue Information by Segment
Genesee and Wyoming Inc., 2015 Form 10-K
For the Year Ended December 31, 2015
(USD $ thousands)

Segment		Revenues	% of Total Revenues
[1]		[2]	[3]
Bulk Commodity Freight:			
Agricultural Products	[a]	$146,250	7.3%
Coal	[b]	$117,437	5.9%
Metallic Ores	[c]	$63,960	3.2%
Metals	[d]	$103,898	5.2%
Minerals & Stone	[e]	$176,439	8.8%
Total Bulk Freight	[f]	$607,984	30.4%
Other Freight Segments:			
Automotive	[g]	$17,313	0.9%
Chemicals	[h]	$140,400	7.0%
Food & Kindred Products	[i]	$34,899	1.7%
Intermodal	[j]	$298,964	14.9%
Lumber & Forest Products	[k]	$80,209	4.0%
Petroleum Products	[l]	$68,881	3.4%
Pulp & Paper	[m]	$113,830	5.7%
Waste	[n]	$18,078	0.9%
Other	[o]	$24,556	1.2%
Total Other Freight	[p]	$797,130	39.8%
Total Freight Revenues	[q]	$1,405,114	70.2%
Freight-related Revenues	[r]	$497,516	24.9%
Other Company Revenues	[s]	$97,771	4.9%
Total Revenue	[t]	$2,000,401	100.0%

Sources & Notes:
Genesee and Wyoming's 2015 Form 10-K

Revenue Information by Segment
CSX Corporation, 2015 Form 10-K
For the Year Ended December 31, 2015
(USD $ millions)

Segment		Revenues	% of Total Revenues
[1]		[2]	[3]
Bulk Commodity Freight:			
Agricultural Products	[a]	$1,087	9.2%
Coal	[b]	$2,300	19.5%
Metals	[c]	$596	5.0%
Minerals	[d]	$469	4.0%
Phosphates and Fertilizers	[e]	$489	4.1%
Total Bulk Freight	[f]	$4,941	41.8%
Other Freight Segments:			
Automotive	[g]	$1,175	9.9%
Chemicals	[h]	$2,093	17.7%
Food and Consumer	[i]	$258	2.2%
Forest Products	[j]	$796	6.7%
Intermodal	[k]	$1,762	14.9%
Waste and Equipment	[l]	$308	2.6%
Total Other Freight	[m]	$6,392	54.1%
Total Freight Revenues	[n]	$11,333	96.0%
Other Company Revenues	[o]	$478	4.0%
Total Revenues	[p]	$11,811	100.0%

Sources & Notes:
CSX Corporation's 2015 Form 10-K

Revenue Information by Segment
Kansas City Southern, 2015 Form 10-K
For the Year Ended December 31, 2015
(USD $ millions)

Segment		Revenues	% of Total Revenues
[1]		[2]	[3]
Bulk Commodity Freight:			
Agriculture and minerals	[a]	$429	17.7%
Energy	[b]	$252	10.4%
Total Bulk Freight	[c]	$682	28.2%
Other Freight Segments:			
Automotive	[d]	$219	9.0%
Chemicals and petroleum	[e]	$474	19.6%
Industrial and Consumer Products	[f]	$570	23.6%
Intermodal	[g]	$382	15.8%
Total Other Freight	[h]	$1,645	68.0%
Total Freight Revenues	[i]	$2,326	96.2%
Other Company Revenues	[j]	$92	3.8%
Total Revenues	[k]	$2,419	100.0%

Sources & Notes:
Kansas City Southern's 2015 Form 10-K

Revenue Information by Segment
Norfolk Southern Corporation, 2015 Form 10-K
For the Year Ended December 31, 2015
(USD $ millions)

Segment		Revenues	% of Total Revenues
[1]		[2]	[3]
Bulk Commodity Freight:			
Coal	[a]	$1,823	17.1%
Metals/construction	[b]	$1,263	11.8%
Total Bulk Freight	[c]	$3,086	28.9%
Other Freight Segments:			
Automotive	[d]	$969	9.1%
Agr./consumer/gov't	[e]	$1,516	14.2%
Paper/clay/forest	[f]	$771	7.2%
Chemicals	[g]	$1,760	16.5%
Intermodal	[h]	$2,409	22.6%
Total Other Freight	[i]	$7,425	69.6%
Total Freight Revenues	[j]	$10,511	98.5%
Other Company Revenues	[k]	$162	1.5%
Total Revenues	[l]	$10,673	100.0%

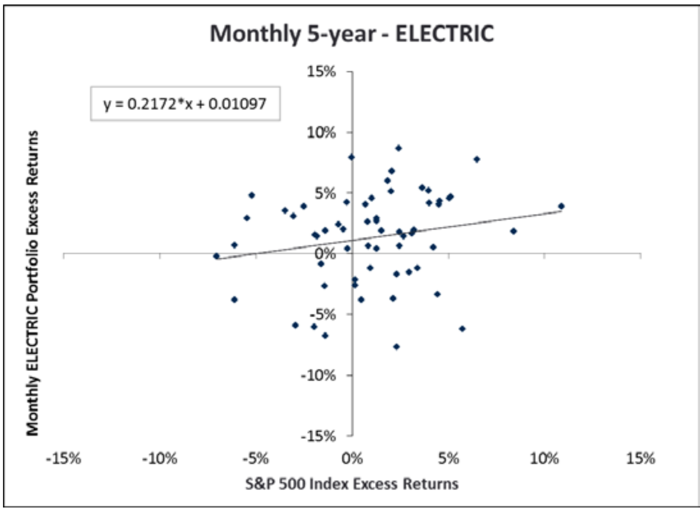
Sources & Notes:
Norfolk Southern Corporation's 2015 Form 10-K
[k]: Calculations based on page K 46

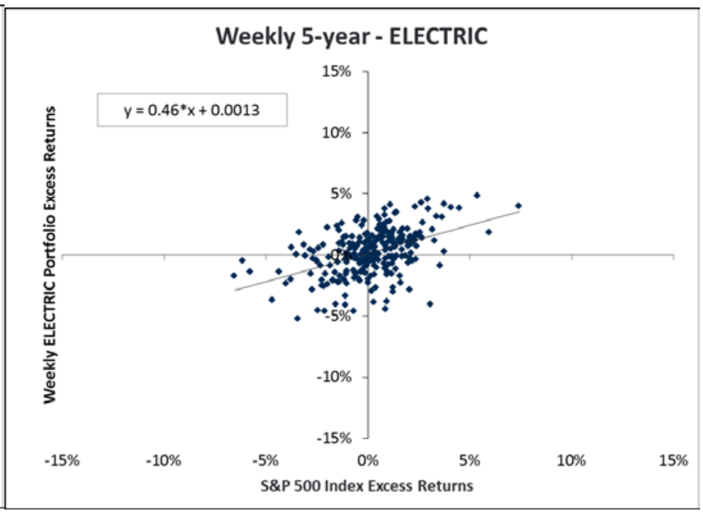
Revenue Information by Segment
Union Pacific Corporation, 2015 Form 10-K
For the Year Ended December 31, 2015
(USD $ millions)

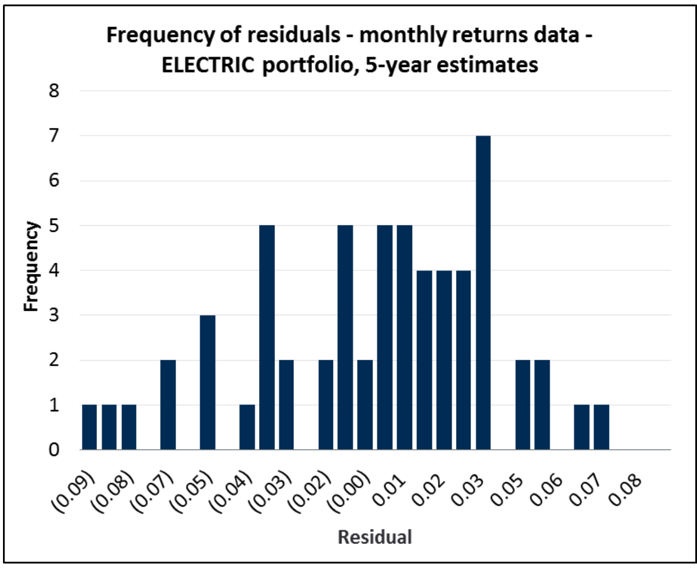
Segment		Revenues	% of Total Revenues
[1]		[2]	[3]
Bulk Commodity Freight:			
Agricultural Products	[a]	$3,581	16.4%
Coal	[b]	$3,237	14.8%
Total Bulk Freight	[c]	$6,818	31.3%
Other Freight Segments:			
Automotive	[d]	$2,154	9.9%
Chemicals	[e]	$3,543	16.2%
Industrial Products	[f]	$3,808	17.5%
Intermodal	[g]	$4,074	18.7%
Total Other Freight	[h]	$13,579	62.3%
Total Freight Revenues	[i]	$20,397	93.5%
Other Company Revenues	[j]	$1,416	6.5%
Total Revenues	[k]	$21,813	100.0%

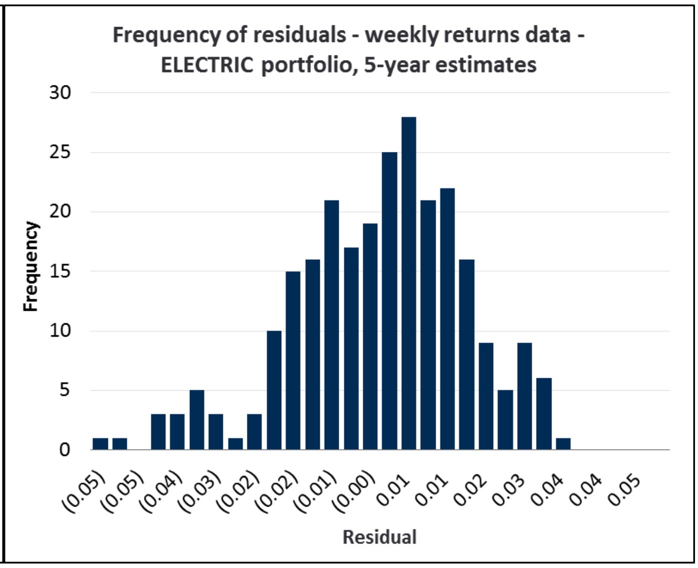
Sources & Notes:
Union Pacific Railway's 2015 Form 10-K

APPENDIX E: Industry Portfolio Regression Outputs



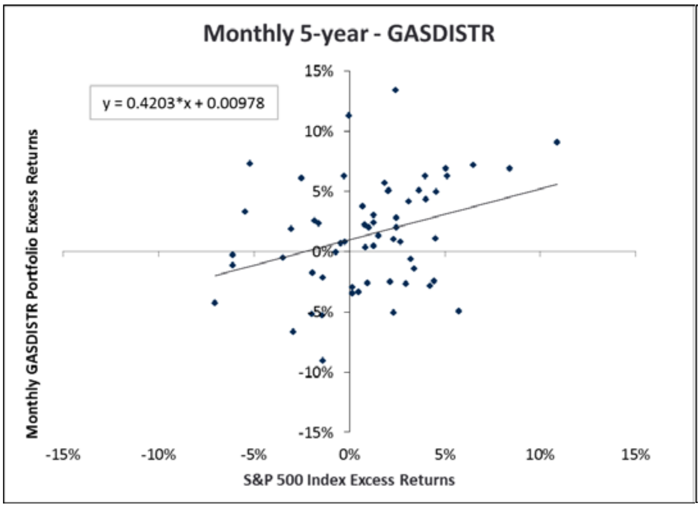


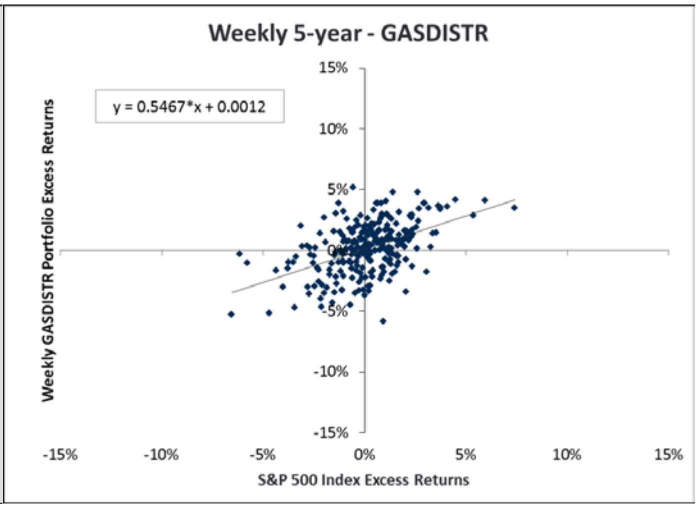


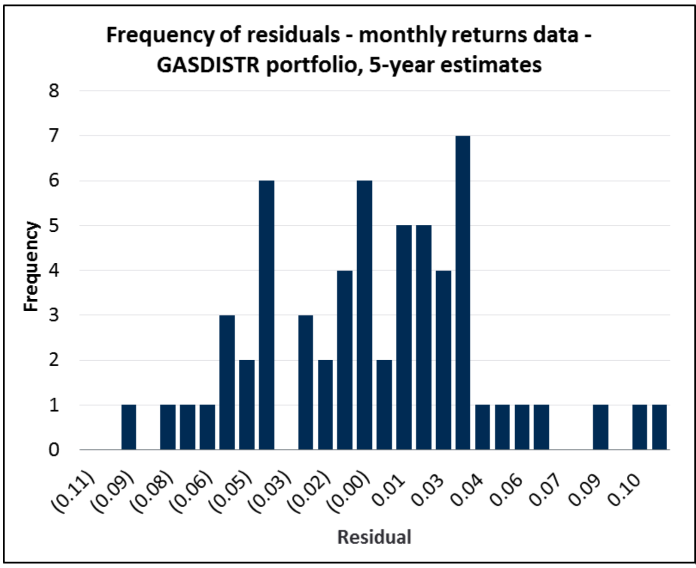


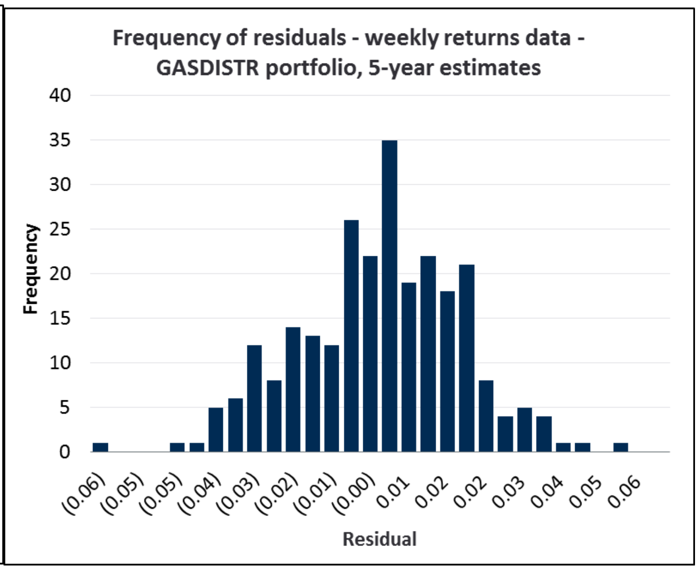
Regession Summary Statistics
ELECTRIC Portfolio - 5-year betas

	Monthly Returns Data	Weekly Returns Data
alpha t-stat	2.172	1.240
beta t-stat	1.551	8.286
NRMSE	0.225	0.166



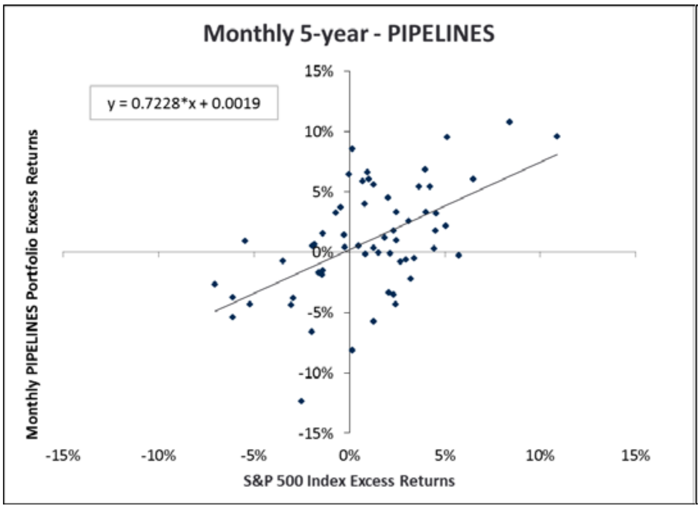


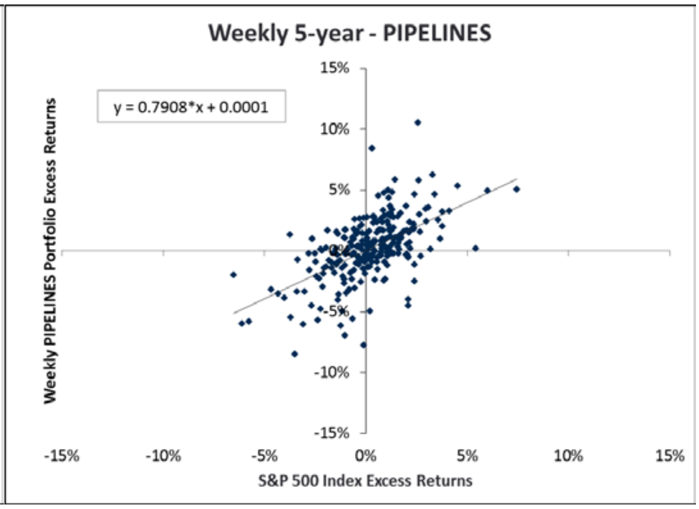


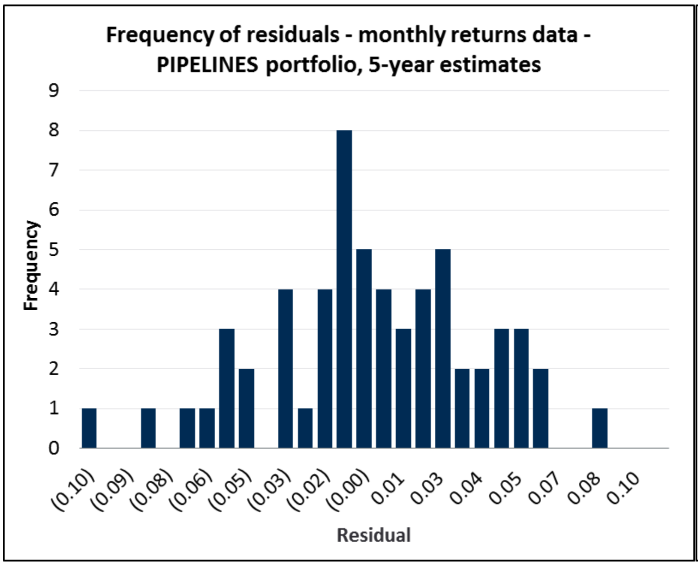


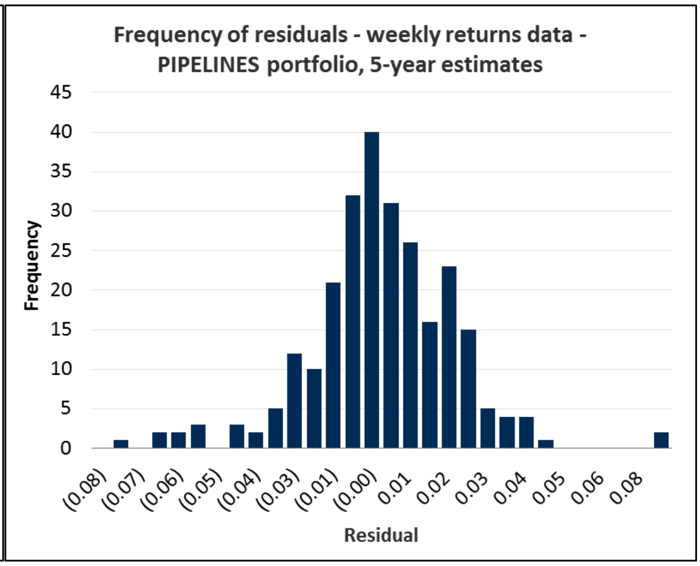
Regession Summary Statistics
GASDISTR Portfolio - 5-year betas

	Monthly Returns Data	Weekly Returns Data
alpha t-stat	1.684	1.021
beta t-stat	2.609	8.998
NRMSE	0.189	0.165



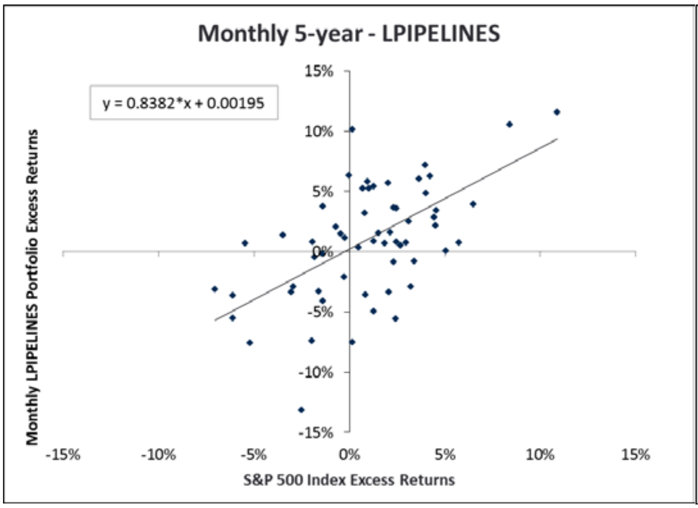


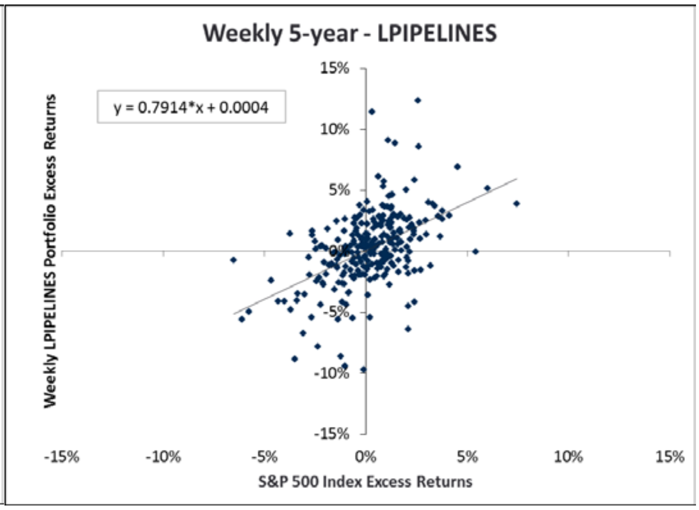


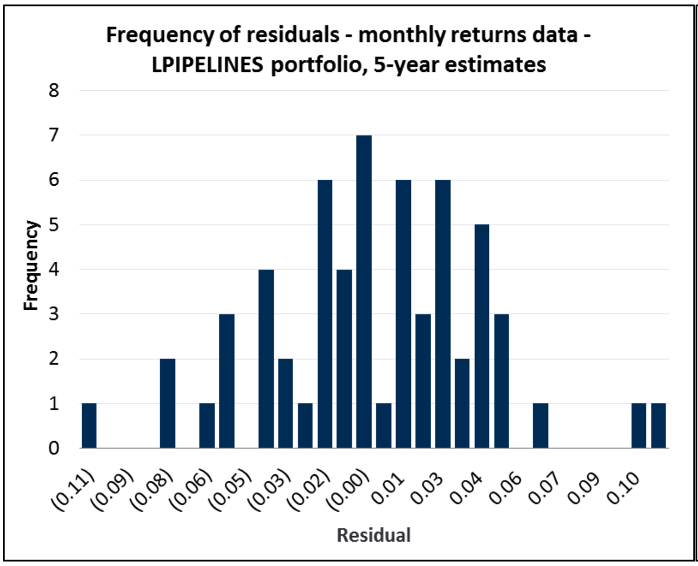


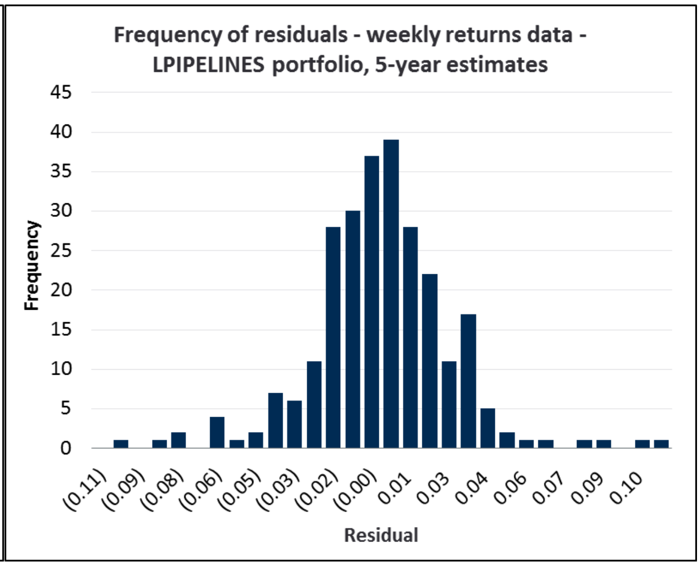
Regession Summary Statistics
PIPELINES Portfolio - 5-year betas

	Monthly Returns Data	Weekly Returns Data
alpha t-stat	0.369	0.093
beta t-stat	5.058	11.278
NRMSE	0.163	0.111



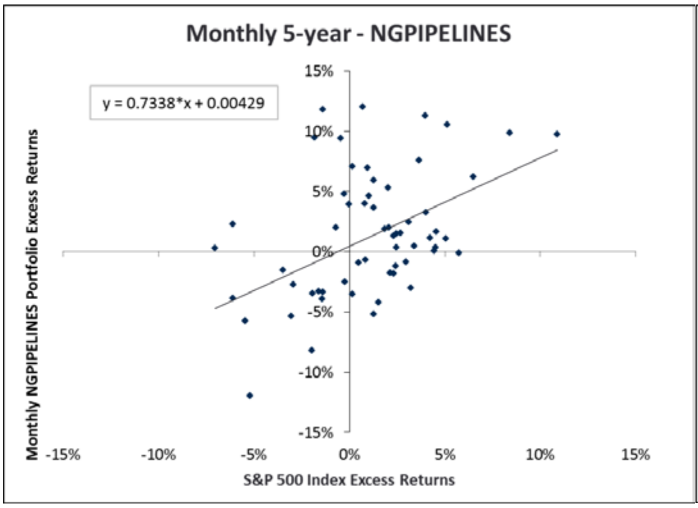


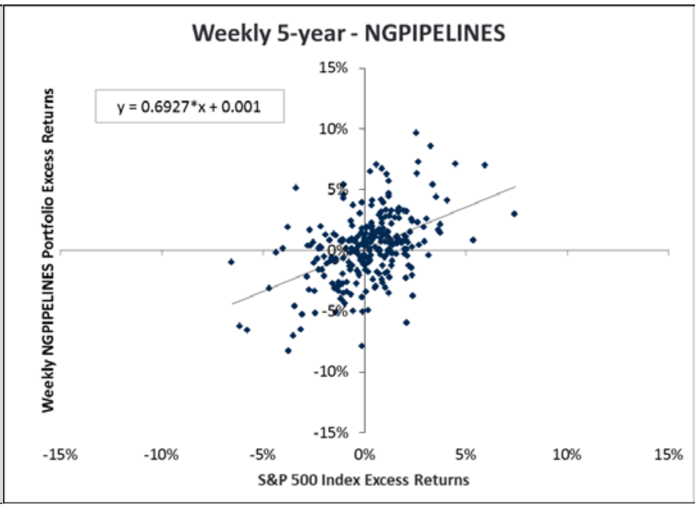


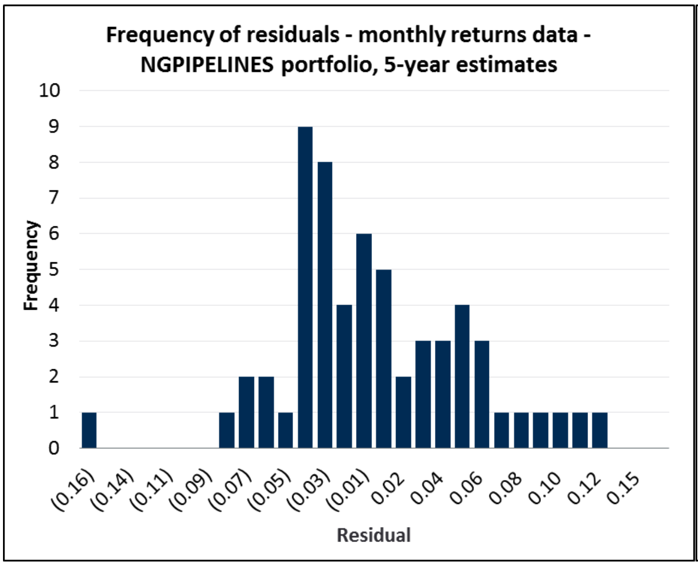


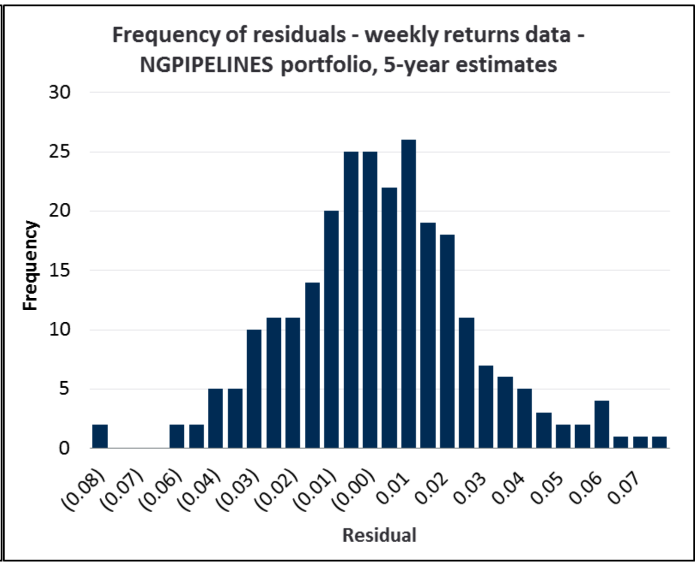
Regession Summary Statistics
LPIPELINES Portfolio - 5-year betas

	Monthly Returns Data	Weekly Returns Data
alpha t-stat	0.348	0.222
beta t-stat	5.398	8.943
NRMSE	0.144	0.121



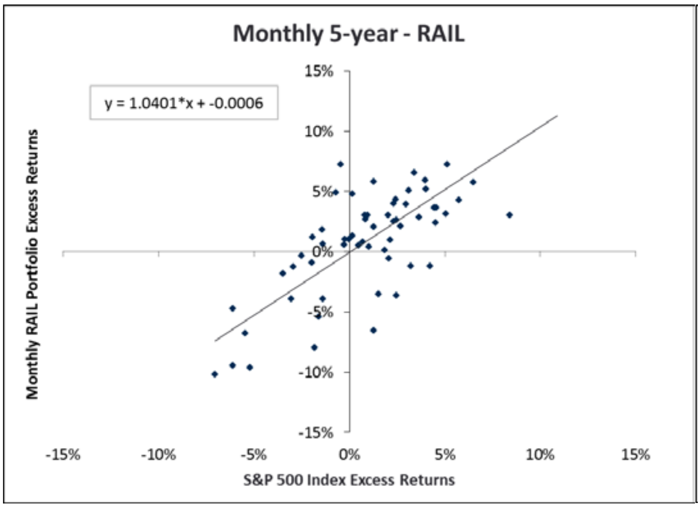


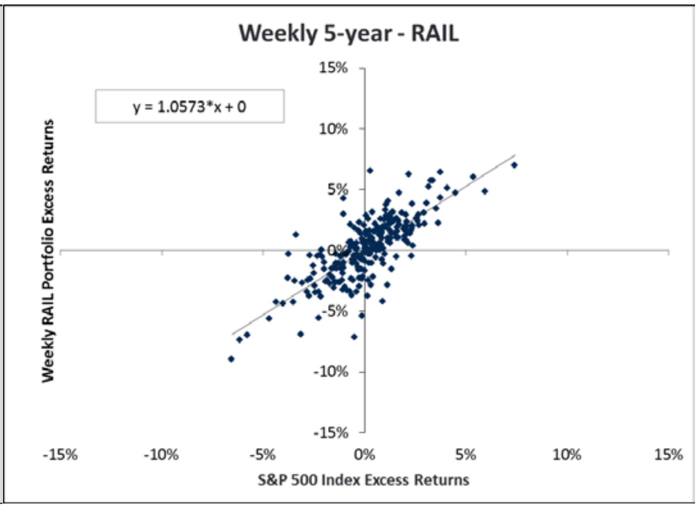


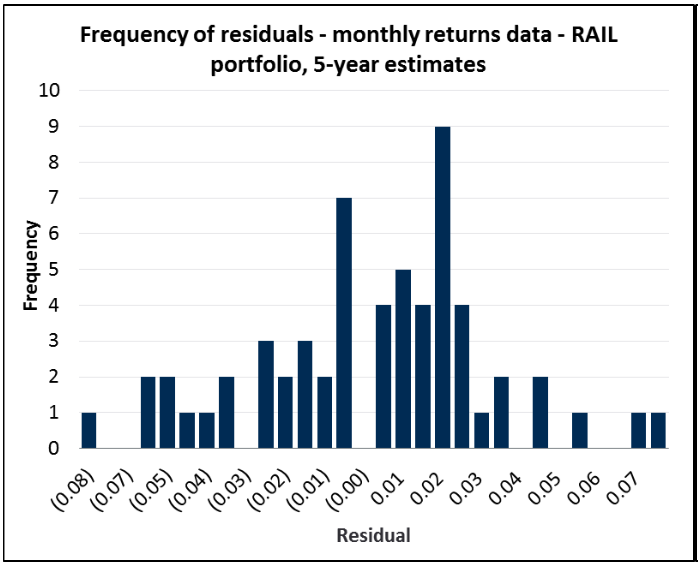


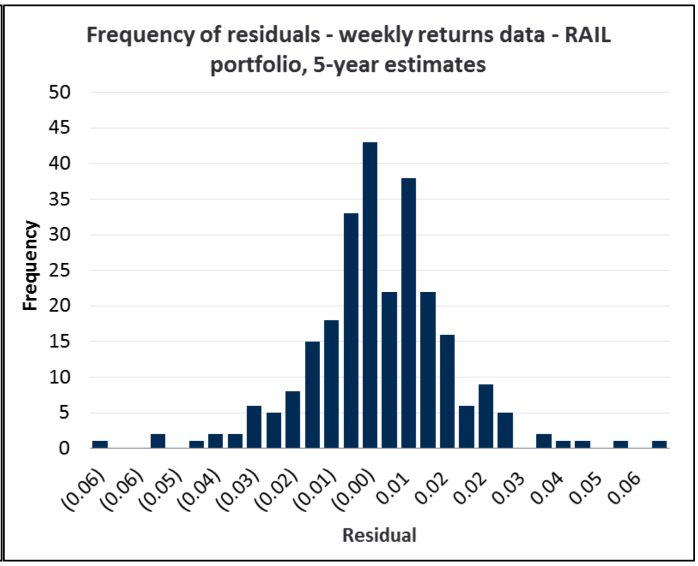
Regession Summary Statistics
NGPIPELINES Portfolio - 5-year betas

	Monthly Returns Data	Weekly Returns Data
alpha t-stat	0.615	0.655
beta t-stat	3.796	8.309
NRMSE	0.172	0.140



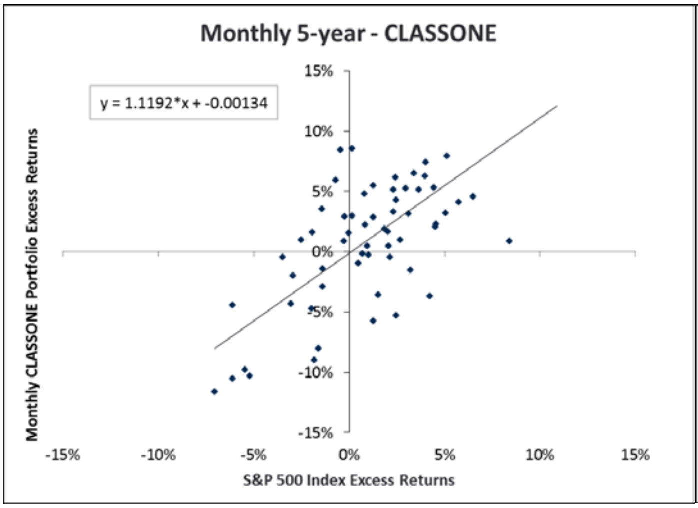


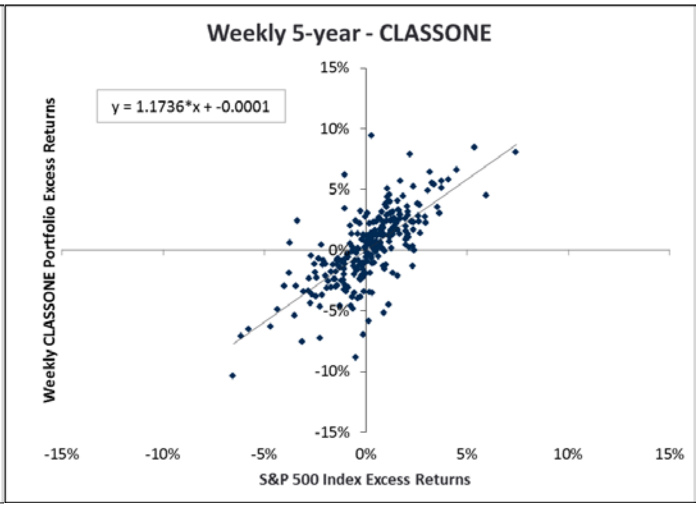


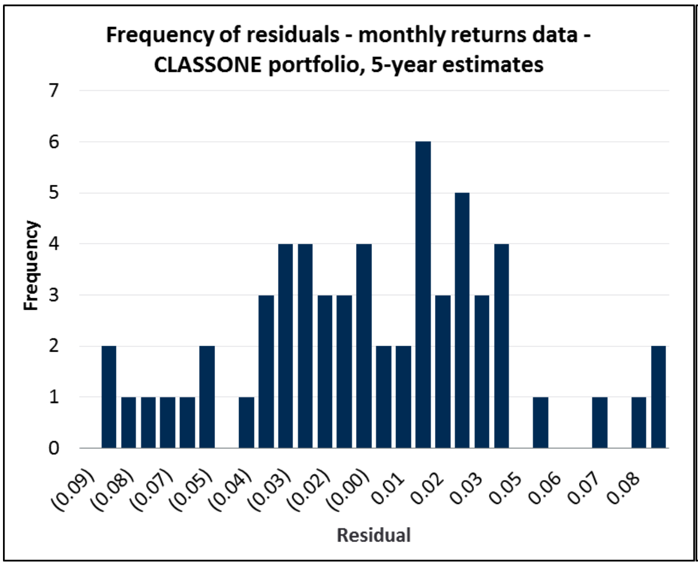


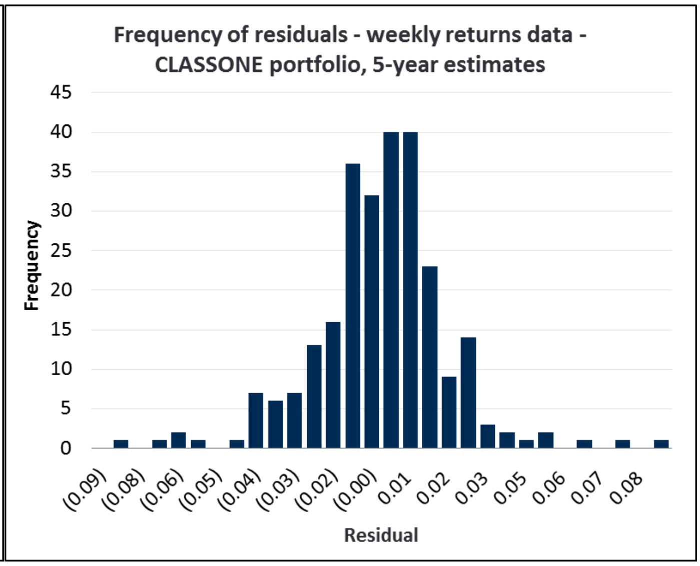
Regession Summary Statistics
RAIL Portfolio - 5-year betas

	Monthly Returns Data	Weekly Returns Data
alpha t-stat	-0.137	0.020
beta t-stat	8.614	19.664
NRMSE	0.111	0.102



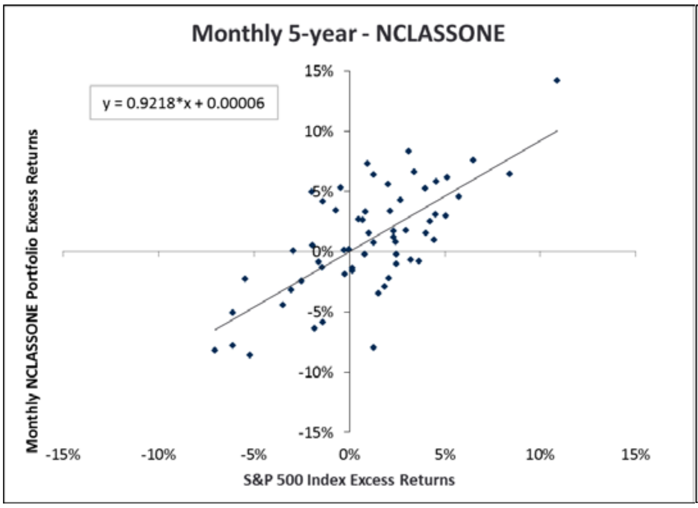


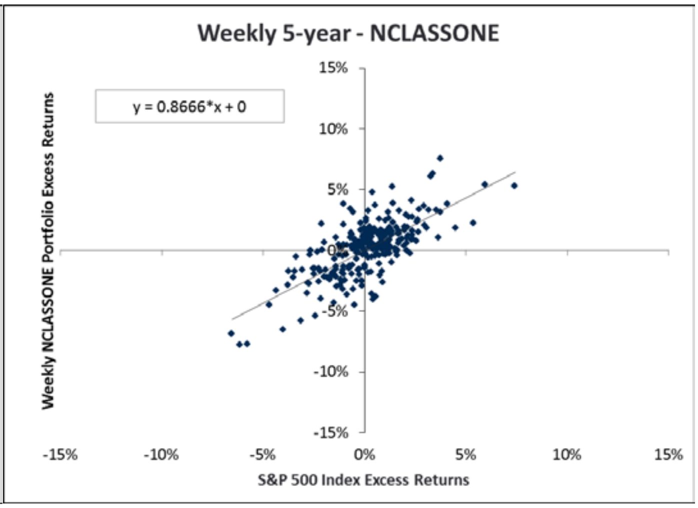


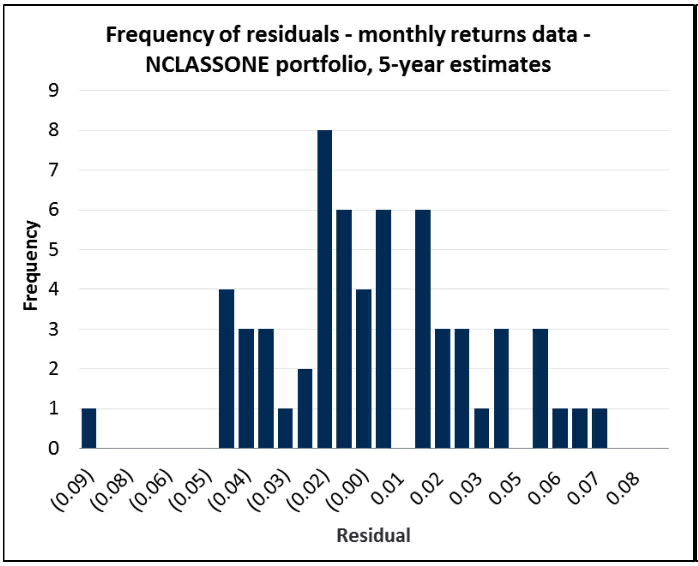


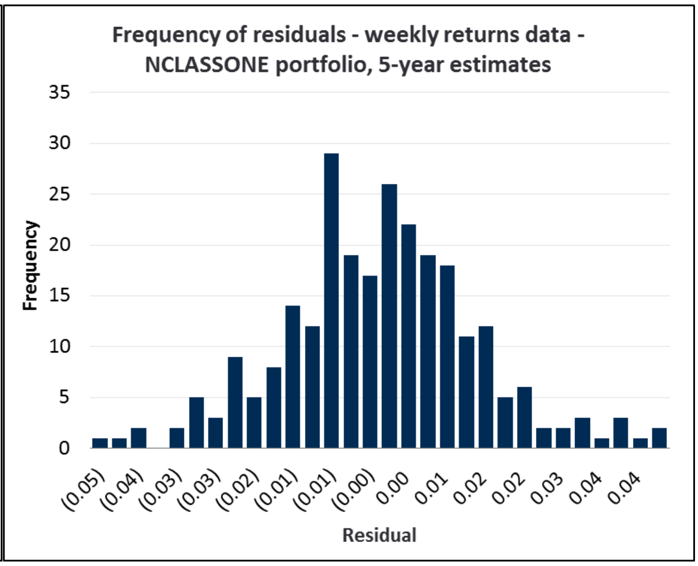
Regession Summary Statistics
CLASSONE Portfolio - 5-year betas

	Monthly Returns Data	Weekly Returns Data
alpha t-stat	-0.242	-0.074
beta t-stat	7.265	16.862
NRMSE	0.123	0.106



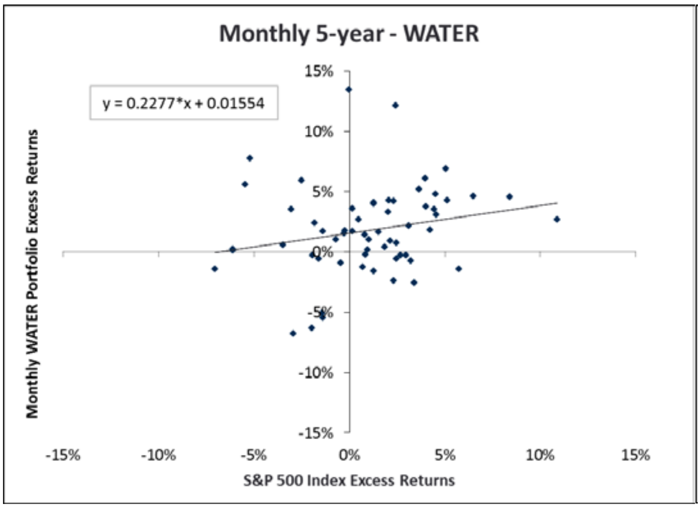


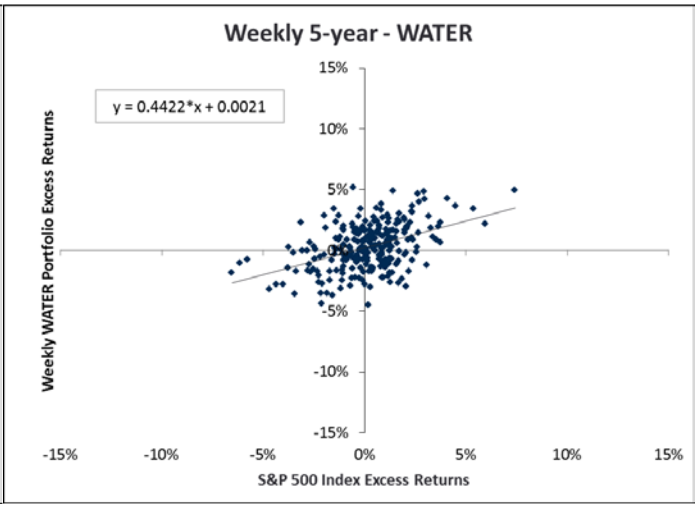


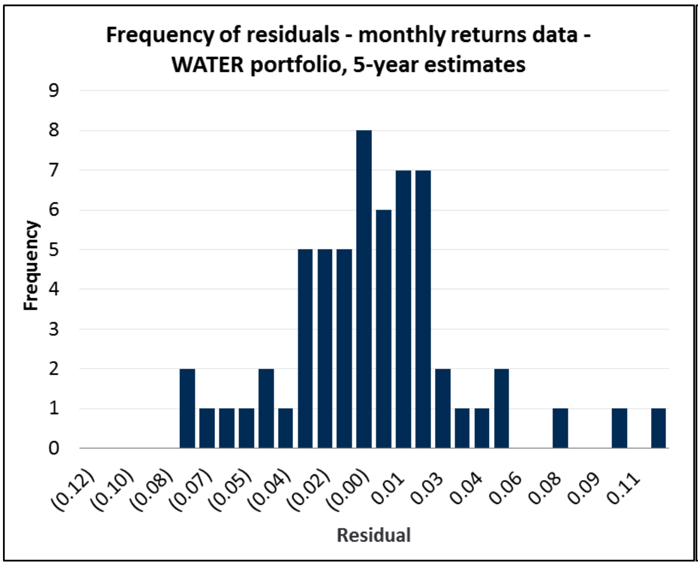


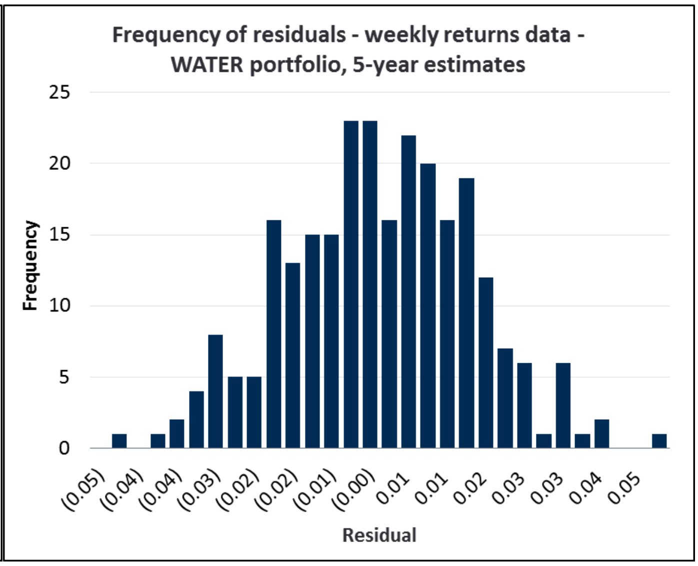
Regession Summary Statistics
NCLASSONE Portfolio - 5-year betas

	Monthly Returns Data	Weekly Returns Data
alpha t-stat	0.015	0.020
beta t-stat	7.583	16.415
NRMSE	0.140	0.103









Regession Summary Statistics
WATER Portfolio - 5-year betas

	Monthly Returns Data	Weekly Returns Data
alpha t-stat	3.156	2.028
beta t-stat	1.669	7.913
NRMSE	0.178	0.174

APPENDIX F: Rolling 3- and 5-Year Weekly Portfolio Betas

Figure F-1
Rolling 3- and 5-Year Electric Portfolio
Raw Equity Weekly Beta Estimates with Error Bars

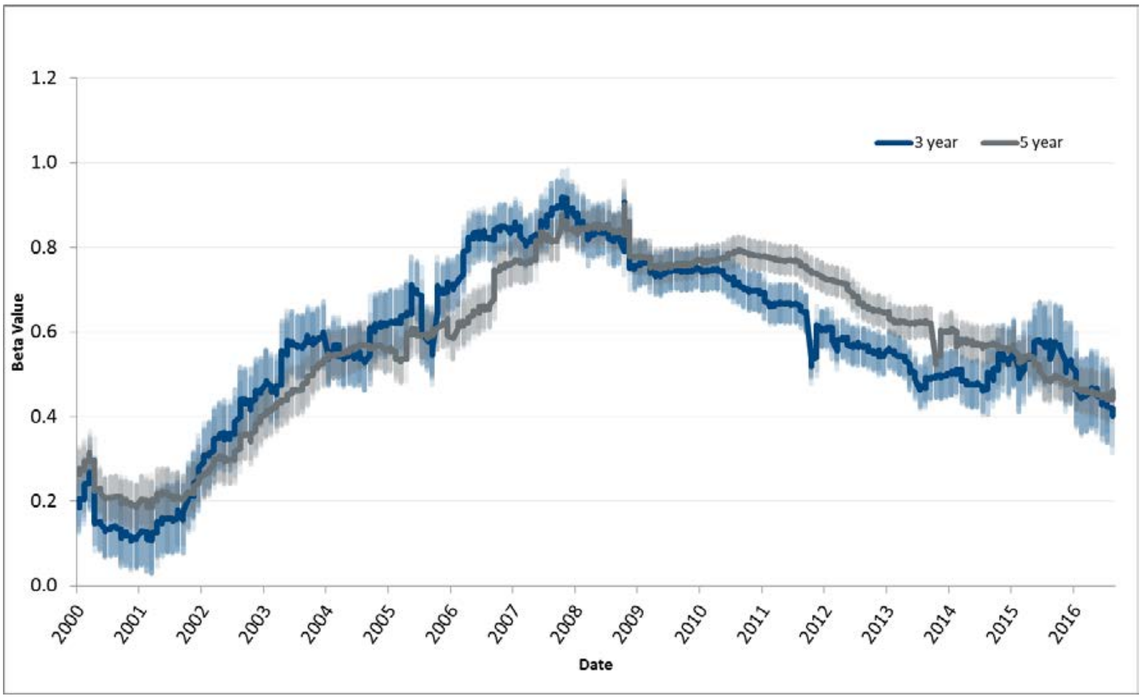


Figure F-2
Rolling 3- and 5-Year Gas Distribution Portfolio
Raw Equity Weekly Beta Estimates with Error Bars

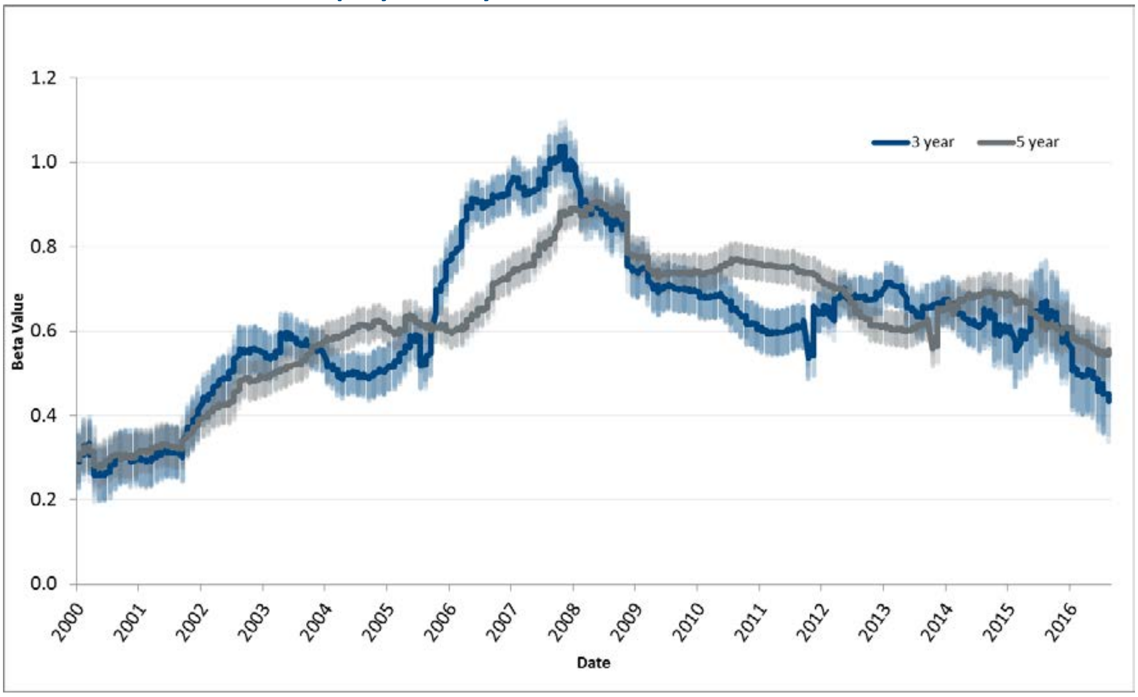


Figure F-3
Rolling 3- and 5-Year Pipeline Portfolio
Raw Equity Weekly Beta Estimates with Error Bars

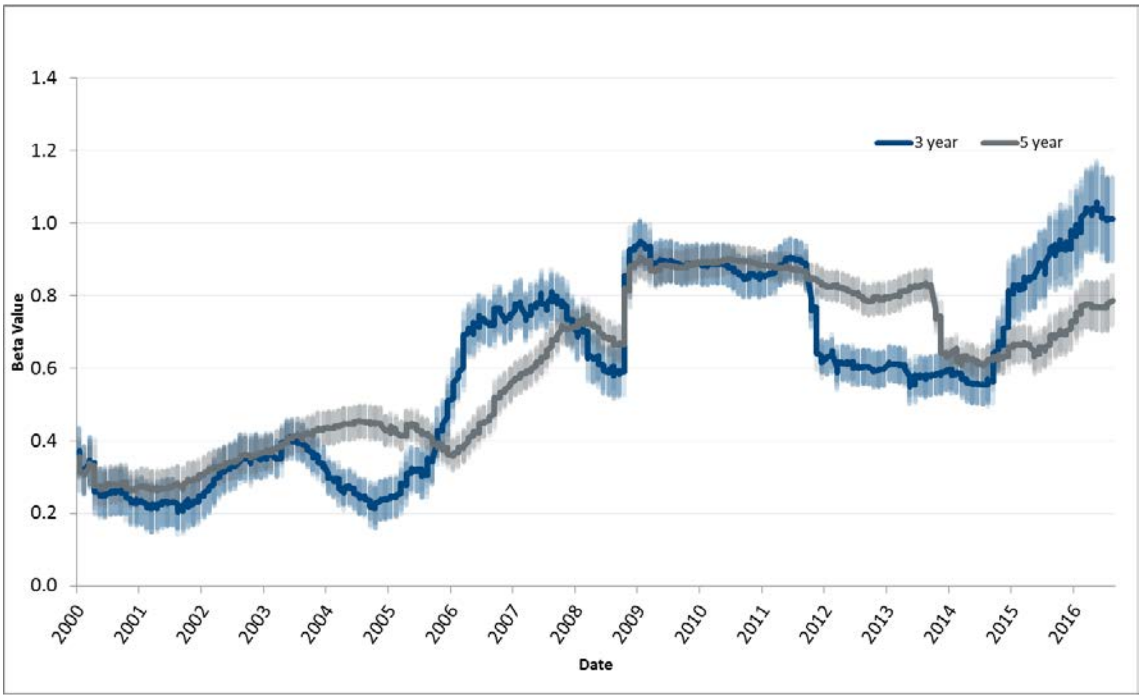


Figure F-4
Rolling 3- and 5-Year Liquids Pipeline Portfolio
Raw Equity Weekly Beta Estimates with Error Bars

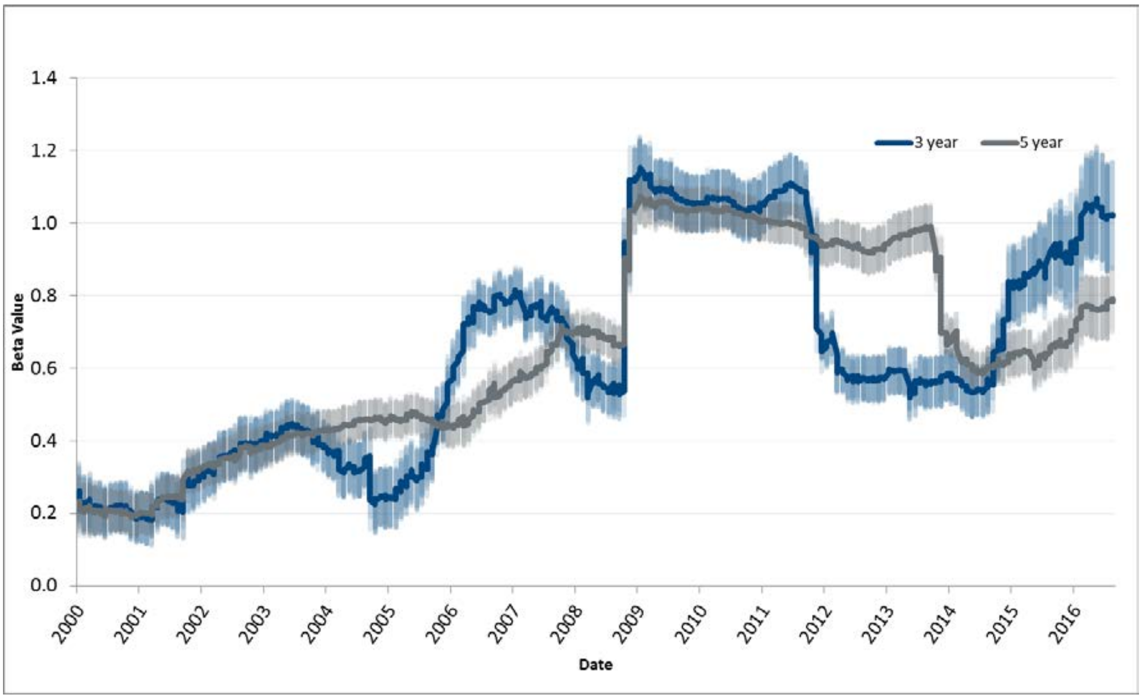


Figure F-5
Rolling 3- and 5-Year Natural Gas Pipeline Portfolio
Raw Equity Weekly Beta Estimates with Error Bars

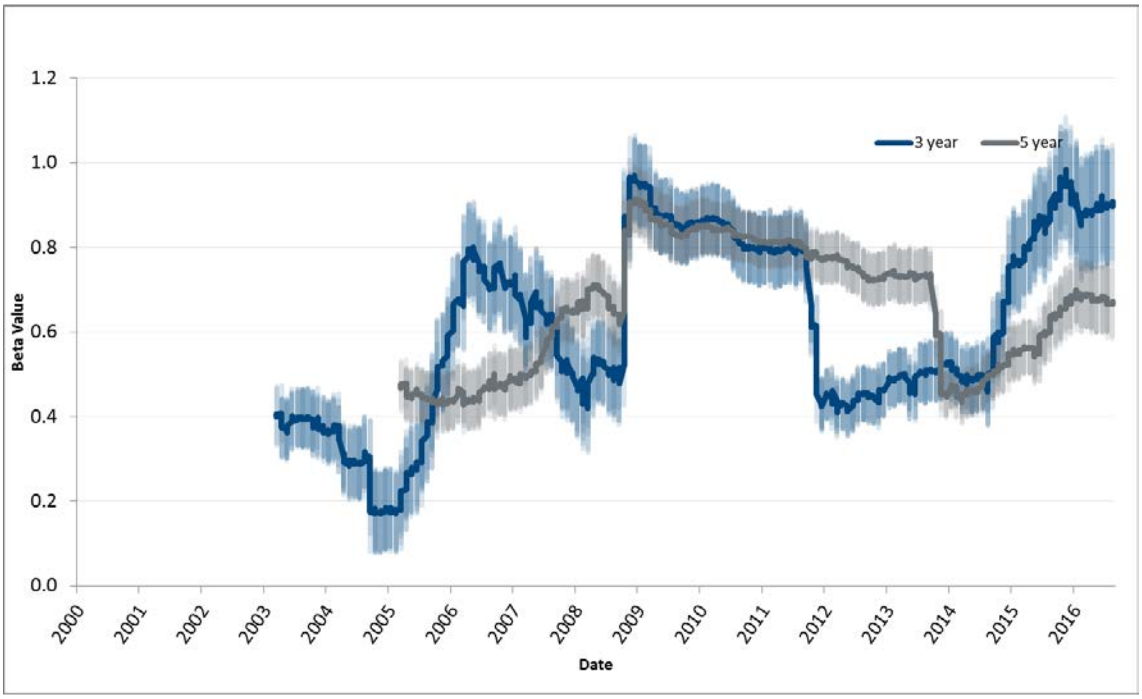


Figure F-6
Rolling 3- and 5-Year Rail Portfolio
Raw Equity Weekly Beta Estimates with Error Bars

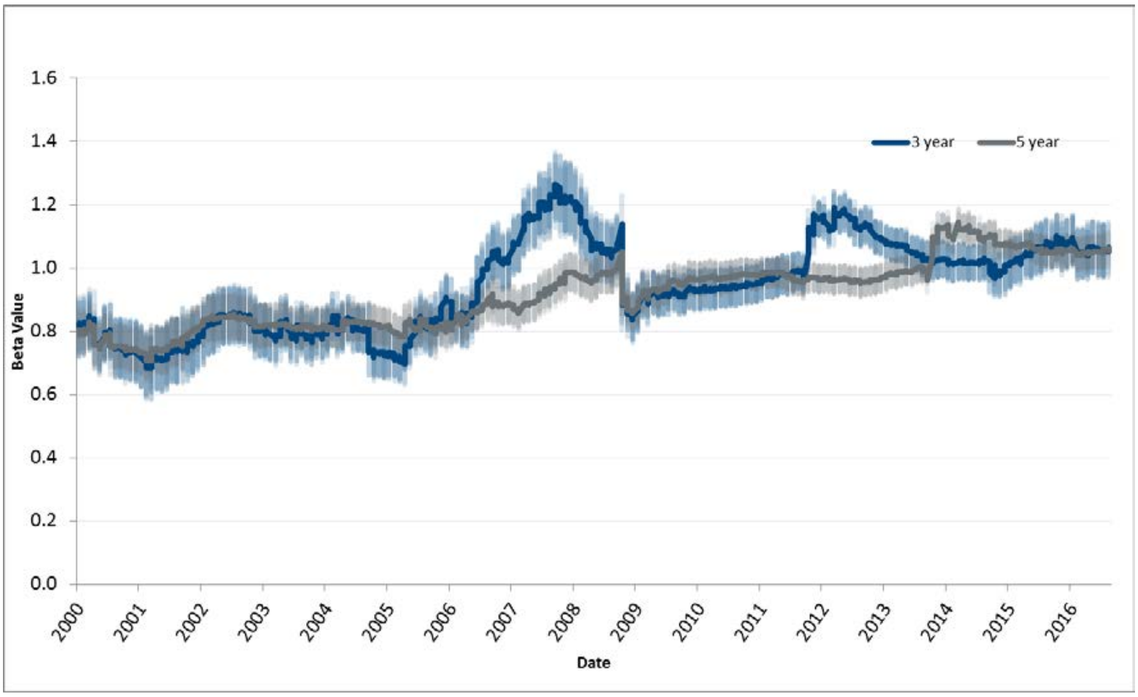


Figure F-7
Rolling 3- and 5-Year U.S. Class 1 Portfolio
Raw Equity Weekly Beta Estimates with Error Bars

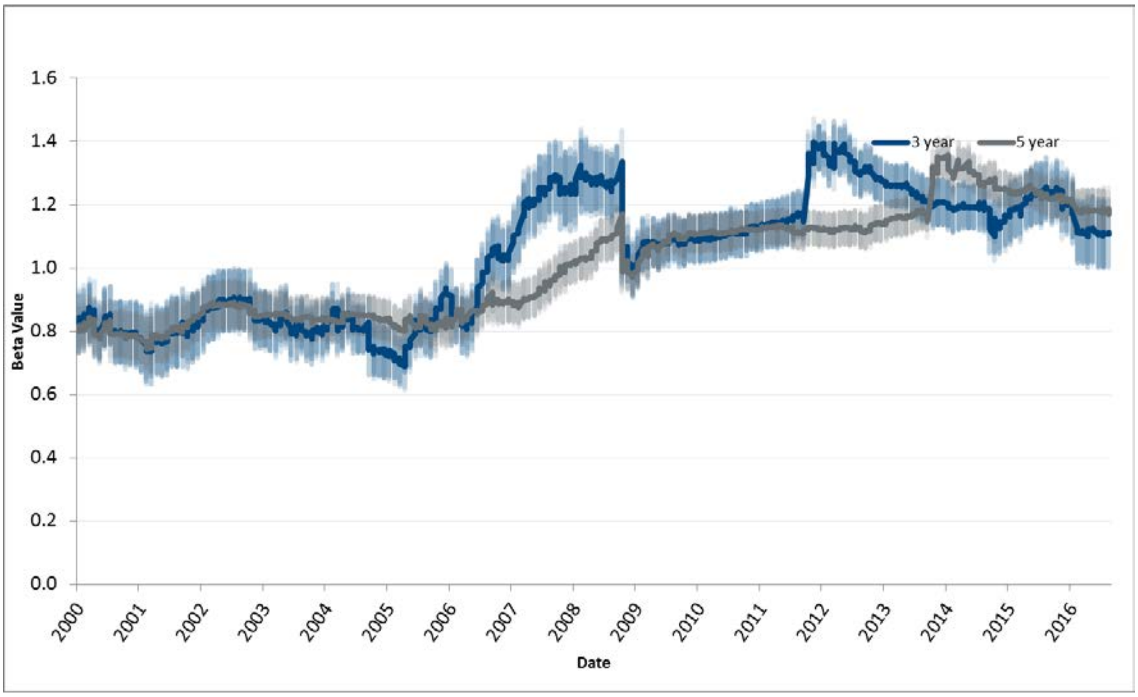


Figure F-8
Rolling 3- and 5-Year Non-Class 1 Portfolio
Raw Equity Weekly Beta Estimates with Error Bars

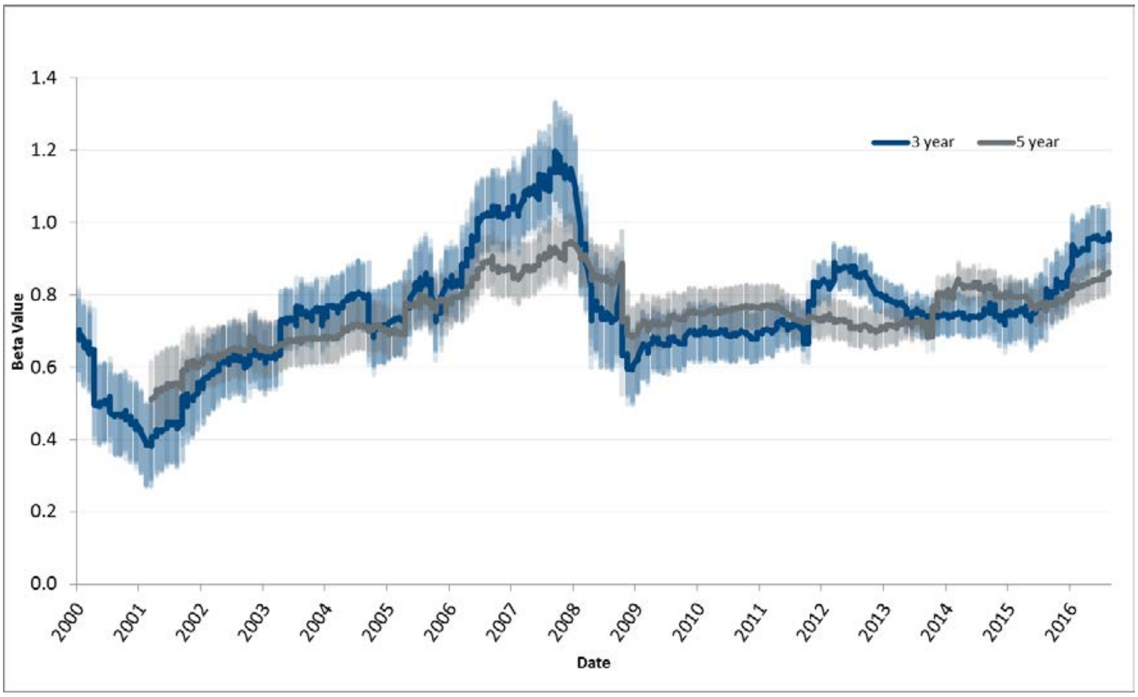
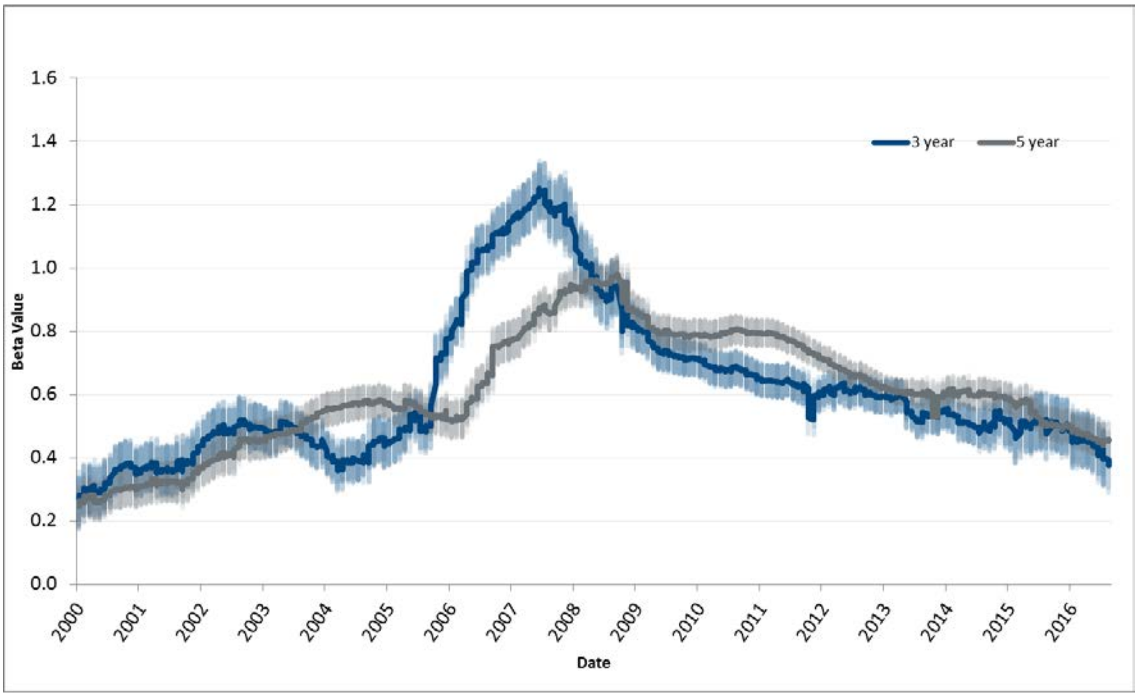


Figure F-9
Rolling 3- and 5-Year Water Portfolio
Raw Equity Weekly Beta Estimates with Error Bars



APPENDIX G: Industry Sample Asset Betas Estimated Using 3-, 5-, and 10-Year Historical Weekly Returns

Sample Group	Unlevered 10-yr Historical Beta Average	Unlevered 10-yr Historical Beta Median	Unlevered 5-yr Historical Beta Average	Unlevered 5-yr Historical Beta Median	Unlevered 3-yr Historical Beta Average	Unlevered 3-yr Historical Beta Median
[1]	[2]	[3]	[4]	[5]	[6]	[7]
Rail Freight Sample	1.01	1.00	0.96	0.99	0.92	0.95
U.S. Class 1 Subsample	1.12	1.03	1.11	1.07	1.03	1.01
Non U.S. Class 1 Subsample	0.89	0.81	0.85	0.76	0.85	0.82
Pipeline Sample	0.66	0.66	0.61	0.58	0.84	0.80
Natural Gas Subsample	0.57	0.57	0.55	0.56	0.78	0.78
Liquids Subsample	0.76	0.79	0.66	0.67	0.90	0.86
Electric Sample	0.48	0.48	0.39	0.38	0.34	0.32
Gas LDC Sample	0.49	0.49	0.46	0.46	0.37	0.36
Water Utility Sample	0.52	0.52	0.44	0.46	0.43	0.44

Sources and Notes:
Analysis of Bloomberg data by The Brattle Group

APPENDIX H: Empirical Tests of the CAPM

EMPIRICAL EVIDENCE ON THE ALPHA FACTOR IN ECAPM*

AUTHOR	RANGE OF ALPHA	PERIOD RELIED UPON
Black (1993)[1]	1% for betas 0 to 0.80	1931-1991
Black, Jensen and Scholes (1972)[2]	4.31%	1931-1965
Fama and McBeth (1972)	5.76%	1935-1968
Fama and French (1992)[3]	7.32%	1941-1990
Fama and French (2004)[4]	N/A	
Litzenberger and Ramaswamy (1979)[5]	5.32%	1936-1977
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 3.91%	1926-1978
Pettengill, Sundaram and Mathur (1995)[6]	4.6%	1936-1990

*The figures reported in this table are for the longest estimation period available and, when applicable, use the authors' recommended estimation technique. Many of the articles cited also estimate alpha for sub-periods and those alphas may vary.

[1]Black estimates alpha in a one step procedure rather than in an un-biased two-step procedure.

[2]Estimate a negative alpha for the subperiod 1931-39 which contain the depression years 1931-33 and 1937-39.

[3]Calculated using Ibbotson's data for the 30-day treasury yield.

[4]The article does not provide a specific estimate of alpha; however, it supports the general finding that the CAPM underestimates returns for low-beta stocks and overestimates returns for high-beta stocks.

[5]Relies on Lizenberger and Ramaswamy's before-tax estimation results. Comparable after-tax alpha estimate is 4.4%.

[6]Pettengill, Sundaram and Mathur rely on total returns for the period 1936 through 1990 and use 90-day treasuries. The 4.6% figure is calculated using auction averages 90-day treasuries back to 1941 as no other series were found this far back.

Sources:
Black, Fischer. 1993. Beta and Return. *The Journal of Portfolio Management* 20 (Fall): 8-18.
Black, F., Michael C. Jensen, and Myron Scholes. 1972. The Capital Asset Pricing Model: Some Empirical Tests, from Studies in the theory of Capital Markets. In *Studies in the Theory of Capital Markets*, edited by Michael C. Jensen, 79-121. New York: Praeger.
Fama, Eugene F. and James D. MacBeth. 1972. Risk, Returns and Equilibrium: Empirical Tests. *Journal of Political Economy* 81 (3): 607-636.
Fama, Eugene F. and Kenneth R. French. 1992. The Cross-Section of Expected Stock Returns. *Journal of Finance* 47 (June): 427-465.
Fama, Eugene F. and Kenneth R. French. 2004. The Capital Asset Pricing Model: Theory and Evidence. *Journal of Economic Perspectives* 18 (3): 25-46.
Litzenberger, Robert H. and Krishna Ramaswamy. 1979. The Effect of Personal Taxes and Dividends on Capital Asset Prices, Theory and Empirical Evidence. *Journal of Financial Economics* XX (June): 163-195.
Litzenberger, Robert H. and Krishna Ramaswamy and Howard Sosin. 1980. On the CAPM Approach to Estimation of a Public Utility's Cost of Equity Capital. *The Journal of Finance* 35 (2): 369-387.