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FOUNDED 1866

November 27, 2007

By Courier

Vernon A. Williams
Secretary
Surface Transportation Board
395 E Street, S.W.
Washington, D.C. 20005

Re SFB Ex Parte No. 664, *Methodology To Be Employed
In Determining the Railroad Industry's Cost of Capital*

Dear Secretary Williams

Pursuant to the Notice of Public Hearing served October 24, 2007, in the above-referenced proceeding, please find enclosed for filing the originals and ten (10) copies of the written testimony of the following witnesses for the Association of American Railroads ("AAR") (1) R. Glenn Hubbard and Bruce E. Stangle, (2) Stewart C. Myers, and (3) G. Paul Moates

It is our understanding that the Board will "embargo" this testimony until next Tuesday morning (the date of the Public Hearing) and will itself release the testimony on that morning. Consequently, the AAR has not served copies of the testimony on other parties of record in this proceeding.

If you have any questions, please contact the undersigned counsel.

Sincerely,

Richard E. Young

*Counsel to the Association of American
Railroads*

Enclosures



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**BEFORE THE
SURFACE TRANSPORTATION BOARD**



METHODOLOGY TO BE EMPLOYED IN
DETERMINING THE RAILROAD INDUSTRY'S
COST OF CAPITAL

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Ex Parte No 664

**SUMMARY OF THE PRESENTATION OF THE
ASSOCIATION OF AMERICAN RAILROADS**

WITNESSES

**R. GLENN HUBBARD
DEAN, COLUMBIA BUSINESS SCHOOL
AND
BRUCE E. STANGLE
CHAIRMAN, ANALYSIS GROUP, INC.**

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I. INTRODUCTION AND SUMMARY

- 1 Our names are R. Glenn Hubbard and Bruce E. Stangle, and we submitted a joint verified statement on behalf of the Association of American Railroads ("AAR") in this proceeding on September 27, 2007. We also submitted a joint reply verified statement on October 29, 2007, focusing primarily on the comments of the Western Coal Traffic League ("WCTL"). Our backgrounds and qualifications are described in our September 27, 2007 statement.
- 2 The Board has invited comments on its proposed methodology for determining the railroad industry's cost of capital and the record developed in this proceeding to date. The key issue in the Board's proposed methodology is the proposal to shift from a single-stage Discounted Cash Flow ("DCF") model to the Capital Asset Pricing Model ("CAPM") for purposes of determining the railroad industry's cost of equity. After carefully reviewing the details of the Board's proposal and the submissions of the interested parties, we believe the Board should reconsider its proposal and find common ground among the various submissions.
- 3 We believe common ground can be largely achieved through three steps:
 - 3.1 The Board should use both a multi-stage DCF model and the CAPM in determining the railroad industry's cost of equity. We recommend that the Board give equal weight to the results of each model in its decision making process.
 - 3.2 In implementing the CAPM, the Board should adopt a market risk premium measured over a much longer period than the 50-year period it originally proposed. Relevant data are available at least as far back as 1926.
 - 3.3 The railroad betas used in implementing the CAPM should be estimated in a way that gives more weight to recent developments in the industry and the stock market generally. In place of the Board's proposal to use 10 years of monthly data, a good

compromise would be to rely on betas estimated from the most recent five years of weekly data, which is a widely accepted practice in financial research

- 4 Estimates of the market risk premium, railroad industry betas, and the inputs to the multi-stage DCF model are available from widely respected financial data providers such as Morningstar/Ibbotson,¹ Bloomberg, and Value Line. Morningstar/Ibbotson also publishes cost of equity estimates for the railroad industry using a multi-stage DCF model. Using estimates from a commercial data provider should be cost effective and make the process more open and transparent.

II. RATIONALE FOR USING BOTH A MULTI-STAGE DCF MODEL AND THE CAPM

- 5 While we understand the reluctance of the Board to rely on a single-stage DCF model, multi-stage DCF models are widely accepted by economists and regulators, including the FERC.
- 6 A major point in favor of DCF models in general is that they are forward-looking in both their nature and implementation, thus focusing on the industry's future capital needs. As the Board is aware, changes have occurred in the economic conditions facing the railroad industry in recent years. Revenues, expenses, and capital investments have increased, and the mix of traffic and associated revenues has also changed. These changes underscore the value of the forward-looking approach of DCF models. DCF models are implemented using investors' expectations of future earnings growth. In contrast, the CAPM is implemented using only historical or backward-looking data.

¹ Ibbotson Associates was acquired by Morningstar, Inc. in March 2006.

- 7 Professor Mohanram of Columbia University made a strong case for the continued use of a variant of the DCF model in his submission.² and we believe the three-stage DCF model implemented by Morningstar/Ibbotson would be a responsible way for the Board to incorporate information from DCF models into its decision making process
- 8 While the Morningstar/Ibbotson three-stage DCF methodology reflects specific choices and judgments made by that organization, we believe these choices are sensible from an economic perspective. In the Morningstar/Ibbotson three-stage model, each firm's earnings growth rate during the first five years is the industry analysts' consensus estimate for that firm. The firm's growth rate during years 6 through 10 is the average of the consensus analysts' estimates for the earnings growth of the industry as a whole. Starting in year 11, the firm's growth rate is the long-run growth rate of the aggregate economy.³ These assumptions effectively deal with many of the criticisms that were leveled earlier at the single-stage DCF model by the WCTL and others
- 9 The recent reply verified statements of the WCTL's experts express qualified support for the Board's use of a multi-stage DCF model in combination with the CAPM.⁴ Similarly, the U.S. Department of Transportation indicates in its recent reply comments that "We also see real value in the use of a multi-stage DCF methodology in tandem with the CAPM for at least some period."⁵

² Partha S. Mohanram, "Determining an Appropriate Cost of Capital for Railroads," In the Matter of Methodology to be Employed in Determining the Railroad Industry's Cost of Capital, STB Ex Parte No. 664, September 13, 2007

³ *Stocks, Bonds, Bills and Inflation, Market Results for 1926-2006, 2007 Yearbook, Valuation Edition* ("SBBBI"), Morningstar Inc., p. 68

⁴ "Reply Verified Statement of Dr. James E. Hodder," In the Matter of Methodology to be Employed in Determining the Railroad Industry's Cost of Capital, STB Ex Parte No. 664, October 29, 2007, pp. 2-3. ("I endorse the suggestion that a multiphase DCF model similar to the procedure outlined in the Crowley/Fapp Reply VS be used to provide a check on results obtained using the CAPM.")

⁵ "Comments of the United States Department of Transportation," In the Matter of Methodology to be Employed in Determining the Railroad Industry's Cost of Capital, STB Ex Parte No. 664, October 29, 2007 ("U.S. DOT Reply Comments"), p. 11

- 10 Mr. Crowley and Mr. Fapp (hereafter “Crowley/Fapp”) present cost of equity estimates from a three-stage model.⁶ While we do not agree with the overly simplistic way in which Crowley/Fapp implement their three-stage model, their willingness to discuss this approach is encouraging for finding common ground. An important shortcoming of the Crowley/Fapp three-stage model is that the estimates are based only on the actual growth in dividends, and so the model ignores other cash flows that equity investors might receive such as stock buybacks. The Crowley/Fapp approach represents an older generation cost of equity model called a dividend discount model (“DDM”) that has been supplanted by more modern approaches.⁷ In fact, the single-stage DCF model that the Board proposes to replace can also be considered a DDM.
- 11 Morningstar/Ibbotson incorporates a broader set of potential cash flows for equity investors into its multi-stage DCF model by applying expectations of earnings growth to the firm’s cash flows, not just the actual dividend payout. While the Crowley/Fapp DDM yields a railroad industry cost of equity of 8.67 percent for 2006, the modern three-stage DCF model as implemented by Morningstar/Ibbotson yields a median cost of equity for the railroad industry of 11.4 percent, which is very close to the 11.0 percent median cost of equity estimated by Morningstar/Ibbotson using the CAPM.⁸ These results illustrate that, when properly implemented, the multi-stage DCF model and CAPM may serve as useful cross checks without generating an unworkably wide range of estimates.

⁶ “Reply Verified Statement of Thomas D. Crowley and Daniel L. Fapp,” In the Matter of Methodology to be Employed in Determining the Railroad Industry’s Cost of Capital, STB Ex Parte No. 664, October 29, 2007, pp. 24-28.

⁷ See, for example, the discussion of DCF models in Aswath Damodaran, *Damodaran on Valuation* 2nd ed., Wiley, 2006, Chapter 5.

⁸ *Cost of Capital Yearbook* 2007, Morningstar, Inc., p. 4-4. Results are for SIC 4011 (Railroads, Line Haul Operating) and incorporate data through March 2007.

III. RECOMMENDED INPUTS FOR THE CAPM

12 **The Market Risk Premium.** The rationale for basing the market risk premium on a very long time series of historical data is well established. Conceptually, the market risk premium is the excess return over the risk-free rate that investors demand for holding a well-diversified portfolio of investments. Because the return on even a well-diversified portfolio can be extremely volatile in the short-run, a large number of observations are required to obtain a reasonably precise and stable estimate of the market risk premium. To obtain a large number of observations in this case requires the use of a long time series of historical data. While the Board has expressed concern that the use of a long time series may introduce irrelevant information into the estimate of the market risk premium, it is important to recognize that many types of historical events tend to repeat themselves over time, and so even events that occurred long ago may tell us something about the future performance of financial markets as a whole. Morningstar/Ibbotson explains the relevance of including data as far back as 1926 to estimate the market risk premium as follows:

The 81-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to repeat themselves, long-run capital market return studies can reveal a great deal about the future. Investors probably expect "unusual" events to occur from time to time, and their return expectations reflect this.⁹

13 While Crowley/Fapp currently endorse the Board's use of a 50-year average, it is important to note that Mr. Crowley himself used a market risk premium estimate of 7.1 percent produced by Morningstar/Ibbotson (which was based on data beginning in 1926) when implementing the CAPM in testimony submitted to the Board as recently as April 28, 2006. Furthermore, Mr. Crowley noted in

⁹ SHBI, pp. 82-83

his testimony that "The Ibbotson calculation of the equity risk premium is widely considered the best estimate of the equity risk premium available"¹⁰

- 14 **Railroad Betas.** In the CAPM, beta measures the incremental risk that a particular stock adds to a market portfolio consisting of the entire universe of traded assets¹¹. The specific numerical value of beta depends on the extent to which changes in the price of an individual stock are statistically related to changes in the price of the market portfolio. While no hard and fast rules exist for estimating beta, a relatively short time period -- typically 5 years or less -- is the most common practice and is usually appropriate. To ensure enough observations are available for a reasonably precise estimate of beta, weekly price data are often used rather than monthly data.
- 15 Using a long historical time series to estimate beta is problematic because beta depends primarily on how changes in a company's stock price are tied to changes in the overall economy. Such relationships can and do change substantially over time as a firm's mix of business changes, the firm acquires or divests assets, or the ratio of debt to equity changes, just to name a few factors. Such changes directly affect a firm's beta and the premium over the risk-free rate that investors will demand to hold that particular stock in their portfolio.
- 16 Using a relatively short time period to estimate beta may appear to conflict with the practice of using as much data as possible when estimating the market risk premium, but in fact there is no contradiction. The relevance of past events to predicting the future performance of financial markets as a whole is fundamentally different from the relevance of past events to predicting the future performance of a particular firm or industry. For example, as we previously indicated in our September 27, 2007 verified statement, Morningstar/Ibbotson maintains that the events of September 11, 2001 may

¹⁰ "Verified Statement of Thomas D. Crowley." In the Matter of Railroad Cost of Capital 2005, STB Ex Parte No. 558, April 28, 2006, pp. 11-12, 16 (citing Shannon P. Pratt, *Cost of Capital, Estimation and Applications* 2nd ed. Wiley, 2002, p. 116).

¹¹ In practice, equity indices such as the S&P 500 are typically used as proxies for the universe of traded assets.

have brought about a fundamental change in the risk associated with particular companies¹² However, from the perspective of financial markets as a whole, such events are not unlike other major events regarding war and peace that have occurred in the past, such as the 1941 attack on Pearl Harbor But while data from 1941 may help to define the risks facing financial markets as a whole going forward, such data have no bearing on how stocks in any industry today would be expected to respond to changes in the overall market, and so should play no role in estimating beta

17 In previous submissions we have presented clear evidence that railroad betas have increased as the five-year estimation period is extended into 2007¹³ As railroads have become a more integral part of the global supply chain in recent years, railroad stock prices have become more closely tied to factors affecting the economy as a whole, with the result being that railroad betas have once again increased towards 1.0, and in some cases now exceed 1.0¹⁴

18 Regarding the estimation of beta, there appears to be significant common ground among the parties The WCTL and its experts essentially agree with our view regarding the appropriate sample period The WCTL has stated that “a measurement period of as short as 5 years, which is the period used by Ibbotson and some other notable providers (Value Line, Standard & Poor’s, and Merrill Lynch), would also be reasonable”¹⁵ Furthermore, in their reply verified

¹² SBBI, p. 107 (“After September 11, 2001 Southwest Airlines, together with other airlines, was forced to cope with reduced airline travel, the implementation of new safety and security measures, restructuring, and other changes Measuring the beta of Southwest Airlines using a longer time period may not be appropriate due to differences in the risk characteristics of the company pre- and post-September 11, 2001.”)

¹³ See “Verified Statement of R. Glenn Hubbard and Bruce E. Stangle,” In the Matter of Methodology to be Employed in Determining the Railroad Industry’s Cost of Capital STB Ex Parte No. 664, September 27, 2007, Exhibits 1a-1d

¹⁴ For evidence on railroad betas over time, see written testimony of Bruce E. Stangle, “Summary of the Presentation of the American Association of Railroads,” In the Matter of Methodology to be Employed in Determining the Railroad Industry’s Cost of Capital STB Ex Parte 664 February 12, 2007 Figure 1

¹⁵ “Opening Comments of the Western Coal Traffic League,” In the Matter of Methodology to be Employed in Determining the Railroad Industry’s Cost of Capital STB Ex Parte No. 664, September 27, 2007, p. 7

statement. Crowley/Tapp note that "the STB's proposed use of a 10 year analysis period is outside the norm of analysis periods used by commercial suppliers of financial data."¹⁶

IV. CONCLUDING OBSERVATIONS

- 19 Our review of the record in this proceeding indicates a substantial amount of consensus on certain key issues, and we urge the Board to reconsider its original proposal in light of the record that has been developed. The similarity among prior expert submissions has also been noted in the reply comments of the U S Department of Transportation.¹⁷
- 20 To the extent that the Board may use the CAPM going forward, we believe it is critically important that key inputs to the CAPM *not* be estimated in the manner originally proposed by the Board. All of the key inputs to the CAPM are available through highly reputable financial data providers using methodologies that are superior to those proposed by the Board. The use of a commercially available set of estimates would be a cost-effective way to make the process more open and transparent.
- 21 In addition, giving results from a multi-stage DCF model equal weight to the CAPM results would not only serve as useful cross check on the CAPM, it would also help to ensure a degree of consistency with prior STB decisions. In regulating an industry, we believe that great care must be taken to avoid creating inefficient investment incentives and to avoid abruptly and significantly changing the regulatory environment that influenced past investment decisions.

¹⁶ "Reply Verified Statement of Thomas D. Crowley and Daniel J. Tapp," In the Matter of Methodology to be Employed in Determining the Railroad Industry's Cost of Capital, STB Ex Parte No. 664, October 29, 2007, p. 8.

¹⁷ U S DOT Reply Comments, p. 11.

**BEFORE THE
SURFACE TRANSPORTATION BOARD**

METHODOLOGY TO BE EMPLOYED IN)
DETERMINING THE RAILROAD INDUSTRY'S)
COST OF CAPITAL)

Ex Parte No 664

**WRITTEN TESTIMONY OF

STEWART C. MYERS

ON BEHALF OF THE

ASSOCIATION OF AMERICAN RAILROADS**

November 27, 2007

**BEFORE THE
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**WRITTEN TESTIMONY OF

STEWART C. MYERS

ON BEHALF OF THE

ASSOCIATION OF AMERICAN RAILROADS**

I My name is Stewart C Myers. I am the Robert C Merton (1970) Professor of Finance at MIT's Sloan School of Management. I submitted verified statements to the Board on behalf of the Association of American Railroads (AAR) and its member railroads in this proceeding on September 27 and October 29, 2007. This written testimony summarizes the points that I plan to make during my oral testimony before the Board on December 4, 2007.

Models for estimating the cost of equity

2 The Capital Asset Pricing Model (CAPM) is a useful model, but the Board should not take the model as literally true and complete or rely on it exclusively. The Board should recognize that the CAPM generates a range of cost of equity estimates, not precise measurements. The Board should not discard other useful information, particularly from Discounted Cash Flow (DCF) models.

Reasonable inputs for the CAPM

3 The divergence of CAPM cost of equity estimates in this proceeding comes primarily from differences in two inputs the market risk premium (MRP) and beta

4 The Board's proposed MRP of 5.2%, based on a 50-year average from 1956 to 2005, is ill-advised. Standard practice averages over longer periods, in order to isolate investors' underlying expectations from shorter-term market volatility. For example, the average MRP vs. long-term bond returns is 6.6% from 1900 to 2006. Ibbotson S&P reports 7.1% from 1926 to 2005.¹ WCTI witnesses Thomas D. Crowley and Daniel L. Fapp have described the Ibbotson S&P average as "widely considered the best estimate of the equity risk premium available."²

5 The Board's proposed method of estimating betas from ten years of monthly returns is also ill-advised. Standard practice uses returns from the most recent three to five years to avoid contamination from market conditions that no longer prevail. The ten-year betas proposed by the Board illustrate this problem. A ten-year period reaches back to returns in the dot com and technology boom and bust. Railroad betas were unusually low during that period because the stock market was driven largely by fluctuations in the prices of dot coms and other tech stocks. Recent estimates indicate that railroad betas are close to 1.0 and increasing, as shown by Table 1 from my September 27 statement and Figure 1 (Panels A and B) from my October 29 reply

¹ See Table 3 of my September 27 V.S. The table is reproduced for convenience at the end of this testimony.

² V.S. of Thomas D. Crowley and Daniel L. Fapp in Ex Parte No. 558 (Sub-No. 10), July 25, 2007, p. 6.

statement I have attached this table and figures here, as well as a plot (Panel C) of betas estimated from three years of weekly returns. Panel C suggests that railroad betas are now above 1.0.

6 The idiosyncratic inputs and assumptions used by the STB (and endorsed by the WCTL) produce CAPM cost of equity estimates ranging from 8.4% to 9.0% for 2005. These estimates are much too low. The CAPM, implemented with reasonable ranges for MRPs and beta, gives cost of equity estimates ranging from 9.1% to 12.2% for 2007, and only slightly lower estimates for 2005. Although I have not calculated a final point estimate, 11% is a good illustration of standard practice.³

DCF models

7 The Board has expressed concern that a constant-growth DCF model can produce upward-biased cost of equity estimates for firms with high near-term projected earnings growth. Two- or three-stage DCF models can correct such biases, but these models can also introduce downward bias if their assumptions are wrong. For example, WCTL witnesses Mr. Crowley and Mr. Fapp now propose a three-stage DCF model that assumes an initial growth stage of five years and a transition to a terminal growth rate after 15 years.⁴ Their model assumes that dividend payout ratios will remain constant forever. But I understand that the demand for rail transportation is likely to continue growing for several decades.⁵ In addition, average dividend yields for the major railroads

³ See my September 27 V.S. at p. 11 and my October 29 V.S. at pp. 7-9.

⁴ Reply V.S. of Thomas D. Crowley and Daniel L. Fapp, October 29, 2007, pp. 25-28.

⁵ Cambridge Systematics, Inc., *National Rail Freight Infrastructure Capacity and Investment Study* (September 2007), attached to AAR comments filed September 27, 2007.

are now relatively low. When growth and investment slow down, payout ratios should rise.⁶ I doubt that the DCF model proposed by Mr. Crowley and Mr. Fapp can produce accurate results, given railroads' likely future investment and payout policies.

Financing

8 The Board should decline WCTL's invitation to reduce the overall weighted average cost of capital for the railroad industry on the theory that the industry is financed with too much equity and too little debt. There is no magic in financial leverage. Increasing the percentage of debt in railroads' capital structures would increase the financial risk borne by equity investors, and thus increase their required returns. The net result would be a near-wash for reasonable capital structures.

9 The WCTL also seems to say that the railroads must be revenue-adequate because they have the cash flow to pay dividends, repurchase shares and support additional borrowing. But untapped borrowing capacity does not prove revenue adequacy. Revenue-inadequate firms can borrow money. Railroads will borrow to modernize and expand only if they believe that future returns will justify the investment.

10 Paying dividends and repurchasing shares does not prove that railroads could expect adequate returns if the amounts distributed were reinvested instead. But railroads' recent cash payouts are small compared with capital investment and not unusually high compared to historical payouts. See the attached Figure 2 from my verified statement of October 29.

⁶ The returns expected by investors also include distributions by stock repurchases. The DCF model offered by Mr. Crowley and Mr. Fapp only considers dividends.

Setting the cost of equity

11 My October 29 reply verified statement presents a range for the cost of equity from about 9% to about 12%. One could call this a "reasonable range," though it relies only on the CAPM and not on other inputs, such as DCF estimates. The bottom of a reasonable range is *not* a reasonable place to be, however. Setting a cost of equity that falls below the bottom of a reasonable range would be still worse.

12 When choosing a point estimate from a reasonable range for the cost of equity, the Board should operate in the heart of the range and favor the upper side of it. Railroads face heavy capital investment to modernize and expand to meet growth in demand. The costs to society from underestimating the cost of capital and deterring investment are likely to exceed the costs of overestimating the cost of capital and encouraging investment. Higher returns on equity would also help compensate for asymmetric risk: railroads' upside profitability is limited by regulation and competition, but there is no corresponding downside protection.

13 I understand that the Department of Transportation has proposed adoption of some form of transition from the current one-stage DCF standard to a future CAPM or CAPM plus DCF standard. A phased transition makes sense, provided that the transition goes to the right place, that is, to a sensible and well-supported estimate of the cost of equity.

Table 3
Market Risk Premiums

From Myers Verified Statement
September 27, 2007

	NYSE Long Term MRP	NYSE Short Term MRP	S&P Long Term MRP	S&P Short Term MRP	US Long Term MRP	US Short Term MRP
	[1]	[2]	[3]	[4]	[5]	[6]
1900-2006	-	-	-	-	6.60%	7.40%
1926-2005	6.81%	8.27%	7.10%	8.50%	-	-
1947-2005	6.83%	8.18%	7.00%	8.40%	-	-
1956-2005	5.20%	6.55%	5.00%	6.40%	-	-

Sources and Notes

[1] - [2] NYSE Returns from CRSP Interest Rates from Ibbotson Associates, *Stocks Bonds Bills and Inflation (SBBBI)* monthly reports
 [3] - [4] Ibbotson Associates, *SBBBI 2006 Yearbook, Valuation Edition*, Tables A-1 and A-3 S&P refers to Standard & Poor 500 Index
 [5] - [6] Dimson, Marsh and Staunton, *Global Investment Returns Yearbook 2007*, p. 44

Long-term MRPs are average spreads between market returns and income or total returns on long-term Treasuries Short-term MRPs are spreads vs Treasury bill rates

Table 1
Beta Estimates for 2007 and 2005
From Myers Verified Statement
September 27, 2007

Company	Bloomberg 5-year Weekly Beta (Adjusted)		Bloomberg 5-year Monthly Beta (Adjusted)		Value Line Beta		MSN MoneyCentral Beta		Yahoo Finance 36-month Beta	
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Burlington Northern Santa Fe Corp	1.02 (1.01)	1.07 (1.04)	1.00	0.90	1.64					
CNSX Corp	1.23 (1.16)	1.14 (1.10)	1.05	0.80	1.03					
Norfolk Southern Corp	1.11 (1.08)	0.88 (.92)	1.05	1.01	2.00					
Union Pacific Corp	0.90 (.93)	0.81 (.87)	0.95	0.90	1.49					

Source and Notes

[1], [2] Bloomberg, September 25, 2007 5-year weekly betas are calculated from September 20 2002 to September 14 2007
5-year monthly betas are calculated from August 30 2002 to August 31, 2007

[3] Value Line September 7 2007

[4] Money Central MSN, September 21 2007

[5] Yahoo Finance, September 21, 2007

Adjusted betas are shifted towards 1.0 Low (high) estimated betas tend to increase (decrease) when estimated in later periods

Table 1
Beta Estimates for 2007 and 2005
From Myers Verified Statement
September 27, 2007

IB. Estimates for 2005

Company	Bloomberg 5-year Weekly Beta (Adjusted*) [1]	Bloomberg 5-year Monthly Beta (Adjusted*) [2]	Value Line Beta [3]	STB Proposed Beta [4]
Burlington Northern Santa Fe Corp	0.76 (.84)	0.65 (.77)	0.95	0.85
CSX Corp	1.09 (1.06)	0.84 (.90)	1.00	0.83
Norfolk Southern Corp	1.02 (1.01)	0.90 (.93)	1.00	0.85
Union Pacific Corp	0.67 (.78)	0.60 (.73)	0.85	0.68

Source and Notes

[1], [2] Bloomberg September 25, 2007 5-year weekly betas are calculated from January 05, 2001 to December 30, 2005

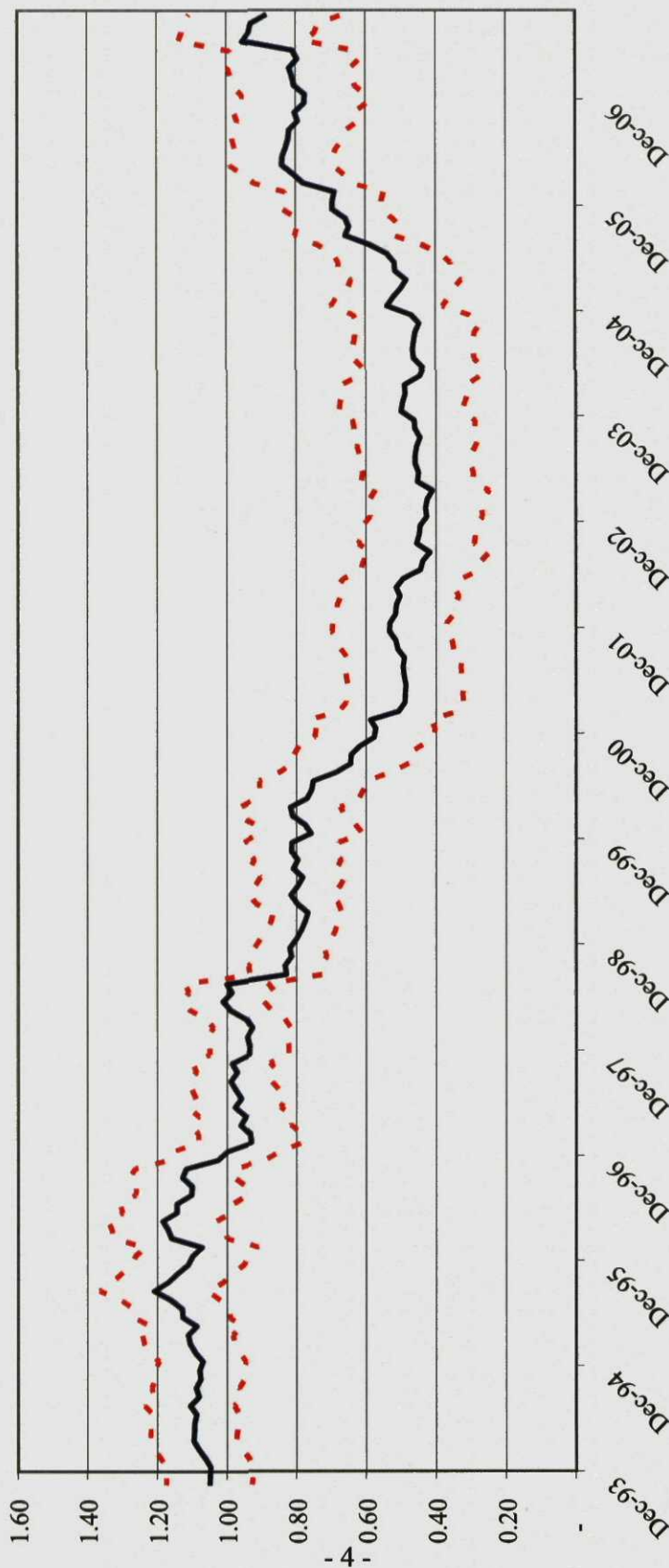
5-year monthly betas are calculated from December 29, 2000 to December 30, 2005

[3] Value Line, December 9, 2005

[4] STB CAPM work paper

Adjusted betas are shifted towards 1.0. Low (high) estimated betas tend to increase (decrease) when estimated in later periods

Figure 1
Rolling Five-Year Betas for the Railroad Industry
Panel A: Monthly Returns



Sources and Notes: Returns for railroad stocks and the S&P 500 Index from Bloomberg as of 10/10/2007. Betas are calculated from monthly rates of return on a market-value weighted portfolio of the four major U.S. railroads. Treasury bill rates are subtracted from the portfolio and market returns. The regression equation includes an intercept. Data include returns from 1988. Dashed lines show the beta estimates plus and minus one standard error.

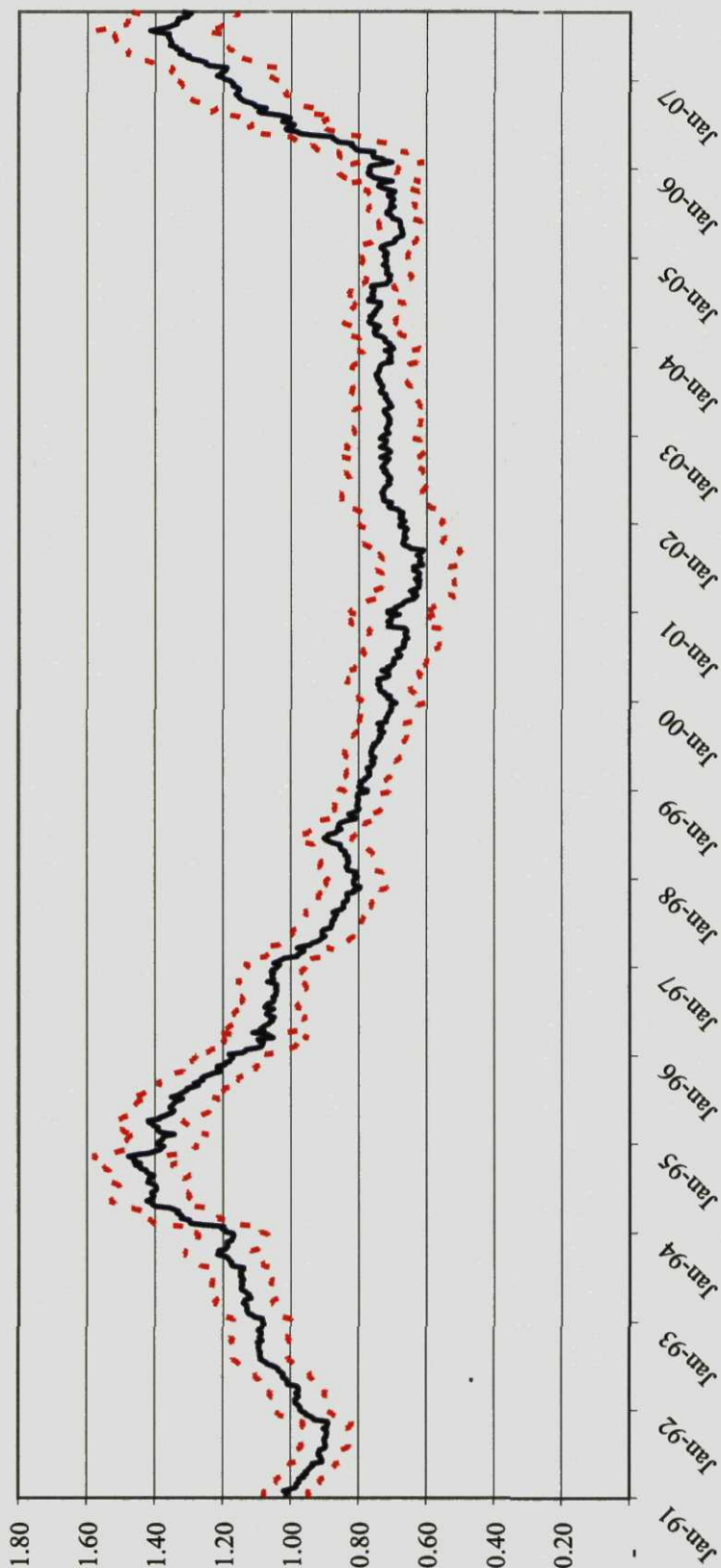
Figure 1
Rolling Five-Year Betas for the Railroad Industry
Panel B: Weekly Returns

From Myers Reply Verified
Statement
October 29, 2007



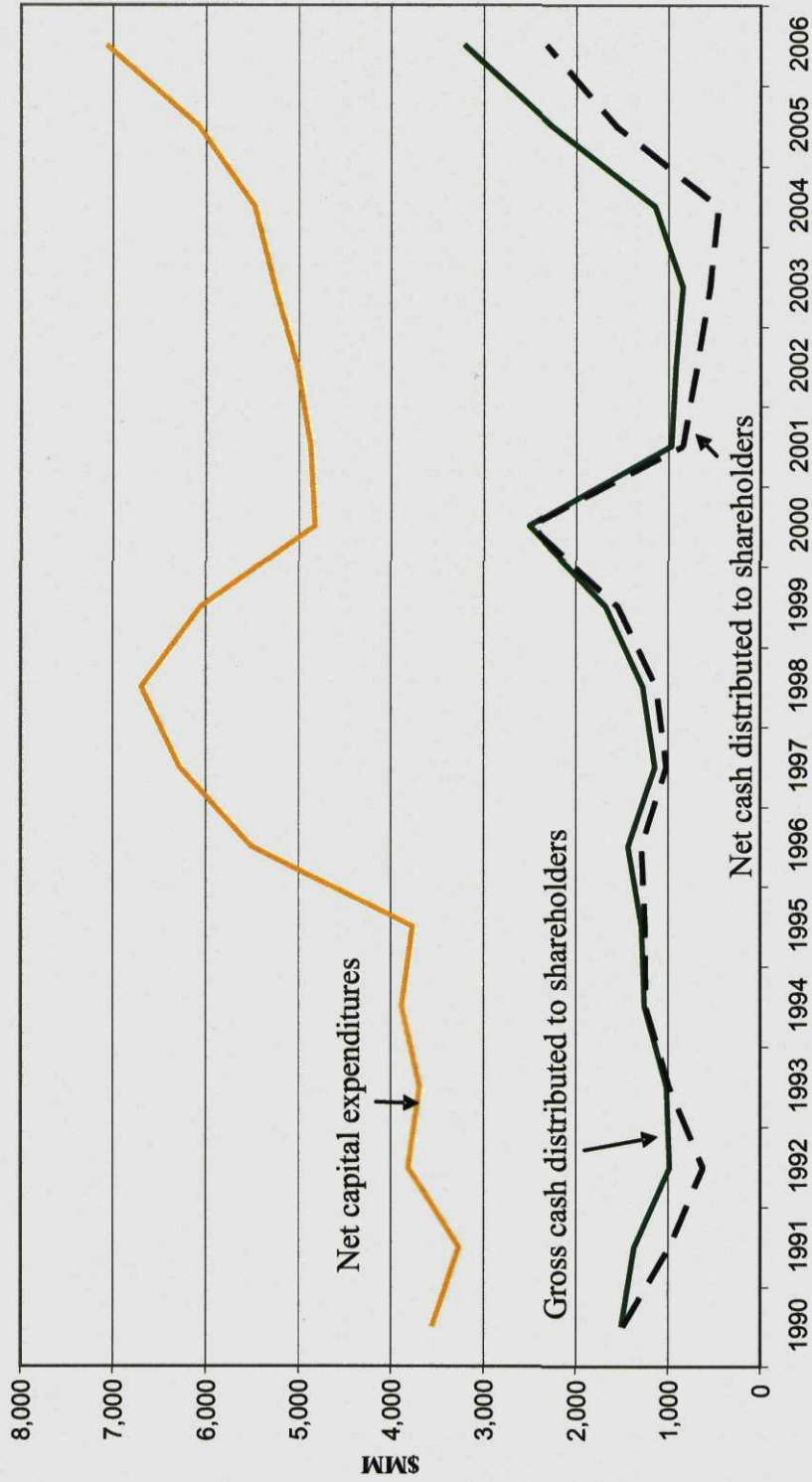
Sources and Notes: Returns for railroad stocks and the S&P 500 Index from Bloomberg as of 10/10/2007. Betas are calculated from weekly rates of return on a market-value weighted portfolio of the four major U.S. railroads. Treasury bill rates are subtracted from the portfolio and market returns. The regression equation includes an intercept. Data include returns from 1988. Dashed lines show the beta estimates plus and minus one standard error.

Figure 1
Rolling Three-Year Betas for the Railroad Industry
Panel C: Weekly Returns



Sources and Notes: Returns for railroad stocks and the S&P 500 Index from Bloomberg as of 10/10/2007. Betas are calculated from weekly rates of return on a market-value weighted portfolio of the four major U.S. railroads. Treasury bill rates are subtracted from the portfolio and market returns. The regression equation includes an intercept. Data include returns from 1988. Dashed lines show the beta estimates plus and minus one standard error.

Figure 2
Railroad Industry Capital Investment vs. Cash Distributed to Shareholders
1990-2006



Sources and Notes: Compustat as of October, 2007. Net capital expenditure is calculated as the capital expenditure net of sale of assets. Gross cash distributed to common and preferred shareholders includes dividends and share repurchases.

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**WRITTEN TESTIMONY OF
G. PAUL MOATES
ON BEHALF OF THE
ASSOCIATION OF AMERICAN RAILROADS**

My name is G Paul Moates. I am a Partner with the law firm of Sidley Austin LLP and an attorney for the Association of American Railroads ("AAR") The purpose of this written testimony is to summarize the main points that I intend to cover at the December 4 hearing on behalf of AAR

I. THE RECORD IN THIS PROCEEDING, AND THE SHIPPERS' OWN STATEMENTS IN OTHER FORUMS, CONFIRM THAT THE RAILROADS' COST OF EQUITY IS IN THE RANGE OF 11 TO 14 PERCENT—NOT THE 8.4 PERCENT VALUE ADVOCATED BY WCTL AND ITS ALLIES IN THIS PROCEEDING.

The record in this proceeding offers strong support for a cost of equity in the range of 11 to 14 percent, not 8 4 percent, as well as strong support for the following points

- Both the CAPM and DCF models should be considered in estimating the cost of equity
- The input values proposed by the STB and WCTL for the CAPM and the DCF are unreasonably low, and the resulting range of cost of equity estimates (roughly 8 4 to 9 0 percent) is well below the middle of the range produced by more reasonable inputs (approximately 11 0 to 11 5 percent)
- Underestimating the cost of capital would lead to underinvestment at a point when large new investment is crucial to meet growth in demand

Perhaps the most dramatic evidence for these propositions, however, does not appear in this proceeding. It is found in the dockets of the state public utility commissions that regulate the maximum rates that franchised electric utilities—including the members of Western Coal Traffic League (“WCTL”)—may charge their customers for market dominant services. In those dockets, the electric utilities do not have their returns on equity limited to eight or nine percent. Rather, they are generally allowed returns on equity in the range of 10 or 11 percent. According to a January 2007 report by Regulatory Research Associates, the *average* return on equity authorized for regulated electric utilities in 2006 was 10.36 percent, down slightly from the 10.54 percent authorized in 2005 and the 10.75 percent authorized in 2004.¹

Moreover, the electric utilities typically submit sworn testimony arguing that even higher returns are warranted. Attached as Attachment B is a summary of some recent rate case decisions involving the cost of capital of several WCTL members. The decisions reveal that

- In justifying their proposed returns on equity, the electric utility members of WCTL often rely on the DCF model as well as the CAPM.
- Relying on these models, the utilities routinely seek authorized returns on equity in the range of 10 to 13 percent, or even more.

The discrepancy between what WCTL and its allies are arguing to this Board, and what WCTL’s members and other electric utilities testify under oath to their own regulators, cannot be explained away on the theory that utilities are riskier than the railroads. The utilities face considerably *less* risk overall than do the railroads. Data submitted by AAR witness Bruce Stangle to the Board earlier this year indicate that the

¹ Regulatory Research Associates, *Regulatory Focus* (Jan. 30, 2007) at 3 (reproduced as Attachment A, *infra*)

average electric utility beta is approximately *half* the median railroad beta² The magnitude of this difference implies that the cost of equity for railroads should be approximately *4-5 percentage points higher* than the cost of equity for utilities³

Furthermore, the inconsistencies between WCTL's posture here and the electric utilities' sworn testimony in their own rate cases extend even to the market risk premium, a key CAPM input whose value by definition does not vary with the risk of the particular industry or firm being studied. In one recent Minnesota proceeding, for example, the witness for Northern States Power-Minnesota (an affiliate of Xcel Energy, a member of WCTL) used Ibbotson data from 1926 to 2003, explaining that "The calculation of the market risk premium should be based on the *longest period possible in order to avoid giving undue consideration to unusual market conditions*"⁴ And in a rate case before the Missouri PSC this year, KCP&L's cost of capital witness used Ibbotson Associates risk premium data for the period 1926-2005, which he described as "the most widely followed risk premium data" Direct Testimony of Samuel C. Hadaway on Behalf of KCP&L in

² Ex Parte No. 664, Summary of Presentation of the AAR (filed Feb. 12, 2007) at 20-21 (Stangle testimony)

³ *Id.* at 21

⁴ Opening Testimony of Robert V. Hevert on Return on Equity filed September 17, 2004, in Minnesota PUC Docket No. G002/GR-04-1511, *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy For authority to Increase Rates for Gas Utility Service in Minnesota*, at 14 ("Hevert Test") (emphasis added) See also, e.g., Direct Testimony of Kathleen C. McShane on Behalf of Illinois Power Company d/b/a Ameren IP, filed December 27, 2005 in Illinois Commerce Commission Docket Nos. 06-070, *et al.*, at 40-41 & Sch. 11 ("McShane Test") (witness for Illinois Power, an affiliate of WCTL member Ameren, calculated "achieved"/"experienced" equity risk premium by using two periods – 1926-2004 (because 1926 was "the first year for which the seminal Ibbotson Associates risk premium data are available") and 1947-2004 ("because the end of World War II marked significant changes in the economic structure, which remain relevant today"))

Missouri PSC Case No ER-2007-0291, filed January 31, 2007, at 37⁵ The electric utilities' reliance on the complete Ibbotson data series—all the way back to 1926—to calculate the market risk premium appears to be the rule rather than the exception⁶

⁵ See also, e.g., Direct Testimony of Zvi Benderly For Wisconsin Public Service Corp., filed March 31, 2006, in Wisconsin PSC Docket No. 6690-UR-118, at 16 ("Benderly Test") (using Ibbotson Associates' data for the period 1926-2004 to calculate expected market risk premium), Direct Testimony of Frank J. Hanley on Behalf of Interstate Power & Light Company in Minnesota PUC Docket No. E001/GR-05-748, filed May 16, 2005, at 38 ("Hanley Test") (using Ibbotson Associates' data for time period of 1926-2004 to derive historical market equity risk premium for "risk premium" model, "the use of holding period returns over a very long period of time is useful in the application of the beta approach") Wisconsin Public Service Corporation is a member of WCTL, and Interstate Power & Light Company is a subsidiary of a member of WCTL (Alliant Energy) *Id.* at 2, WCTL Comments, Exhibit A

⁶ See, e.g., *The United Illuminating Co.*, 246 P.U.R. 357, 442, 449 (Conn. DPUC 2006) (utility proposed, and DPUC approved, use of Ibbotson data from 1926 to 2004), *Montana-Dakota Utilities Co.*, 222 P.U.R. 4th 36, 51 (N.D. PSC 2002) (in his risk premium analysis, utility's witness used Ibbotson data going back to 1926 to calculate historical differences in experienced earnings from stocks and bonds), *Fitchburg Gas and Electric Co.*, D.T.E. 02-24/25, 2002 WL 39958793, at *98 (Mass. D.T.E., Dec. 2, 2002) (utility proposed risk premium based on 1926-2001 Ibbotson data), *Consumers Maine Water Co.—Millinocket*, 204 P.U.R. 4th 316, 334-335 (Me. PUC 2000) (utility used Ibbotson data for period since 1926 to calculate "historical" risk premium, and commission adopted risk premium adopted risk premium from the period 1926-1998 from Ibbotson's yearbook); *San Diego Gas and Electric Co.*, 196 P.U.R. 4th 438, 1999 WL 687698 (Cal. PUC 1999) (two electric utilities developed risk premium using 1926-1997 period or 1947-1997 period data from Ibbotson), *PSI Energy, Inc.*, 173 P.U.R. 4th 393, 414 (Ind. U.R.C. 1996) (utility used market premium based on Ibbotson data for period 1926-1994), *Consumers Power Co.*, 167 P.U.R. 4th 461, 474 (Mich. PSC 1996) (utility used market risk premium based on Ibbotson's 1926-1994 historical data); *GTE Northwest, Inc.*, Case No. UT 113, Order No. 94-336, 1994 WL 114354, at *14 (Or. PUC 1994) (utility developed upper end of range of risk premium by using Ibbotson data for 1926-1991), *GTE California Inc.*, 30 C.P.U.C. 2d 433 (1988) (utility's witness used 1926-1987 Ibbotson data to calculate historical risk premium), *Pennsylvania Public Utility Commission v. Philadelphia Suburban Water Co.*, 61 Pa. PUC 328, 370 & n.19 (1986) (utility determined risk premium using data "for a period of almost 60 years based on the well-known methods of Ibbotson and Sinquefeld")

II. UNDERESTIMATING THE COST OF CAPITAL WOULD LEAD TO UNDERINVESTMENT AT A TIME WHEN MASSIVE ADDITIONAL INVESTMENT IS CRUCIAL TO MEET ANTICIPATED GROWTH IN DEMAND.

The record also makes clear that setting the regulatory cost of equity below the railroads' actual cost of equity could discourage necessary investment in expanding the capacity of the rail system just when such increased capacity is crucial to meet decades of anticipated growth in demand. The shippers' responses are little more than exercises in denial.

Some parties assert that the debate over the railroads' cost of equity is academic because the outcome of this proceeding will have no real effect on the railroads' actual rates or earnings. *See, e.g.,* Reply Comments of the Hon. Brian Schweitzer and grain shippers (Oct. 29, 2007) at 3-8, WCTL Reply Comments at 28. Those parties' claims are belied by the zeal with which they have pursued this issue. If they really believed that reducing the return on equity as determined by the Board would have no effect on railroad rates or revenue, why have the shippers invested litigation resources in this proceeding and related cost of capital proceedings? The answer is obvious. As AK Steel has forthrightly stated, changes in the Board's cost of capital determination could "dramatically" change the STB's "jurisdictional threshold"—and could have an "even greater effect on 'stand-alone' cost maximum rate calculations" as well as on revenue adequacy determinations. AK Steel Reply Comments at 3.

The shippers' further response—that little or no additional investment in network capacity will be needed to meet the anticipated growth in railroad traffic over the next several decades—is equally fanciful. *See* Arkansas Electric Reply 4-6, WCTL Reply 25. The notion that "growth in traffic volume" or "productivity improvements" would enable the railroads to handle the additional growth in traffic volume without major additional

capital investment is frivolous. Growth in traffic volume will not materialize beyond the capacity of the railroad networks to handle it; and the capacity will not materialize unless the railroads anticipate earning an adequate return on the necessary investment. Further, the \$148 billion estimate of the additional capital investments developed by Cambridge Systematics (attached to AAR's September 27 comments) is merely for the expansion of infrastructure capacity (track, signals, and structures), and does not include the on-going capital investment needed for infrastructure *replacement*. Moreover, this estimate also excludes the additional necessary investments in additional freight cars, locomotives, labor and technology, and the related outlays for replacement and maintenance of these assets. The finding of the study that Class I railroads could fund \$96 billion of the additional capital investment assumes continued growth in the productivity of a given infrastructure—*i.e.*, that more tonnage could be moved over a double track CTC line by running longer trains with heavier loadings per car—with no additional costs incurred from the necessary operational changes. For these reasons, there is (and can be) no serious dispute to the assessment offered by DOT

even if this precise amount [the \$148 billion estimate] is self-serving, there is no dispute from any quarter that massive capital investment is required. Still more will be necessary if railroads are to grow their market share and provide some relief to highway congestion and pollution.

DOT Reply Comments at 6-7

III. PROPOSALS FOR TRANSITIONING TO A NEW COST OF EQUITY STANDARD

The DOT, in its reply comments, urges the Board, in "the interests of avoiding untoward consequences for investment decisions in an industry in need of substantial capital investment," to "implement its chosen methodology in a gradual manner if that

model results in a significant difference from the cost of capital as calculated in recent years " DOT Reply Comments at 2.

AAR agrees with the DOT that adoption of a methodology for determining the railroad industry's cost of capital would reduce the willingness of investors (and therefore railroad managements) to deploy capital in the railroad industry if the revised methodology produced cost of equity and cost of capital values significantly below those produced by the Board's long-established DCF model. The reduced cost of equity proposed by the Board and many parties in this proceeding would be a radical departure from a quarter century of precedent. Not once since 1982 has the Board or the ICC found the railroad industry cost of equity to be below 12.4 percent in any year. Moreover, the harms resulting from such a large reduction in the cost of equity would be real, and ultimately would be borne by all railroad constituencies—including employees, shippers and American consumers. But the answer to these concerns is not to transition to an inadequate and erroneous methodology, but to get the methodology right in the first place. To accomplish that, the Board needs to correct the proposed inputs to the CAPM model and to give weight to a multi-stage DCF model as well—not as a transitional remedy, but as a permanent solution.

ATTACHMENT A

Regulatory Research Associates, *Regulatory Focus*
(January 30, 2007)

REGULATORY FOCUS

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January 30, 2007

MAJOR RATE CASE DECISIONS—JANUARY 2005-DECEMBER 2006 SUPPLEMENTAL STUDY

This Supplemental Study was prepared in conjunction with the Regulatory Study entitled *Major Rate Case Decisions—January 1990-December 2006* that will be uploaded to our website later today. The Supplemental Study contains chronological listings of all electric and gas cases for the years 2005 and 2006. These listings, with key data concerning each case, appear on pages 5 through 10 of this report. Tables summarizing cases decided in the last 11 years appear on pages 2 and 3. The average return on equity (ROE) authorized electric utilities in 2006 approximated 10.4%, compared to 10.5% in 2005. There were 25 electric ROE determinations in 2006, and 29 in 2005. The average ROE authorized gas utilities also approximated 10.4% in 2006, compared to 10.5% in 2005. There were 15 gas cases that included an ROE determination in 2006, and 26 in 2005. We note that these ROEs are simple, non-weighted averages. Not included in these averages is a September 20, 2006 steam rate case decision for Consolidated Edison of New York, in which the New York Public Service Commission adopted a settlement that incorporates a 9.8% return on common equity (48% of capital) and a 7.74% return on rate base.

After reaching a low in the late-1990's and early-2000's, the number of equity return determinations for energy companies has generally increased over the last several years. Increased costs (especially medical insurance and pension expenses), the need for generation and delivery system infrastructure upgrades and expansion at many companies, and the expiration of restructuring-related rate freezes argue for a continuation of the increased level of rate case activity over the next several years. However, relatively low inflation and interest rates, competitive pressures, technological improvements, the use of settlements that do not specify return parameters, and a reduced number of companies due to mergers, may prevent the number of rate cases and equity return determinations from significantly increasing further. We note that electric industry restructuring in many states has led to the unbundling of rates, with state commissions authorizing revenue requirement and return parameters for distribution and/or transmission operations only (which we footnote in our chronology), thus complicating historical data comparability.

The individual electric and gas cases listed on pages 5 through 10 are presented with the decision date shown first, followed by the company name, the abbreviation of the state issuing the decision, the authorized rate of return (ROR) and ROE, and the common equity component of the adopted capital structure. If the capital structure included cost-free capital or investment tax credit balances at the overall rate of return, an asterisk (*) follows the number in this column. Next we show the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base valuation, and the amount of the permanent rate change authorized. Fuel adjustment clause rate changes are not reflected in this study.

(Text continued on page 4)

Average Equity Returns Authorized January 1996 - December 2006
 (Return Percent - No. of Observations)

	Period	Electric Utilities	Gas Utilities
1996	Full Year	11.39 (22)	11.19 (20)
1997	Full Year	11.40 (11)	11.29 (13)
1998	Full Year	11.66 (10)	11.51 (10)
1999	Full Year	10.77 (20)	10.66 (9)
2000	1st Quarter	11.06 (5)	10.71 (1)
	2nd Quarter	11.11 (2)	11.08 (4)
	3rd Quarter	11.68 (2)	11.33 (5)
	4th Quarter	12.08 (3)	12.50 (2)
2000	Full Year	11.43 (12)	11.39 (12)
2001	1st Quarter	11.38 (2)	11.16 (4)
	2nd Quarter	10.88 (2)	10.75 (1)
	3rd Quarter	10.78 (8)	— (0)
	4th Quarter	11.50 (6)	10.65 (2)
2001	Full Year	11.09 (18)	10.95 (7)
2002	1st Quarter	10.87 (5)	10.67 (3)
	2nd Quarter	11.41 (6)	11.64 (4)
	3rd Quarter	11.06 (4)	11.50 (3)
	4th Quarter	11.20 (7)	10.78 (11)
2002	Full Year	11.16 (22)	11.03 (21)
2003	1st Quarter	11.47 (7)	11.38 (5)
	2nd Quarter	11.16 (4)	11.36 (4)
	3rd Quarter	9.95 (5)	10.61 (5)
	4th Quarter	11.09 (6)	10.84 (11)
2003	Full Year	10.97 (22)	10.99 (25)
2004	1st Quarter	11.00 (3)	11.10 (4)
	2nd Quarter	10.54 (6)	10.25 (2)
	3rd Quarter	10.33 (2)	10.37 (8)
	4th Quarter	10.91 (8)	10.66 (6)
2004	Full Year	10.75 (19)	10.59 (20)
2005	1st Quarter	10.51 (7)	10.65 (2)
	2nd Quarter	10.05 (7)	10.54 (5)
	3rd Quarter	10.84 (4)	10.47 (5)
	4th Quarter	10.75 (11)	10.40 (14)
2005	Full Year	10.54 (29)	10.46 (26)
2006	1st Quarter	10.38 (3)	10.63 (6)
	2nd Quarter	10.69 (5)	10.50 (2)
	3rd Quarter	10.06 (7)	10.45 (3)
	4th Quarter	10.39 (10)	10.13 (4)
2006	Full Year	10.36 (25)	10.44 (15)

Electric Utilities--Summary Table*

	Period	ROR %—	ROE %—	Eq as % Cap. Struc.	Amt. \$ MIL.
1996	Full Year	9 21 (20)	11 39 (22)	44 34 (20)	-5 6 (38)
1997	Full Year	9 16 (12)	11 40 (11)	48 79 (11)	-553 3 (33)
1998	Full Year	9 44 (9)	11 66 (10)	46 14 (8)	-429 3 (31)
1999	Full Year	8 81 (18)	10 77 (20)	45 08 (17)	-1,683 8 (30)
2000	Full Year	9 20 (12)	11 43 (12)	48 85 (12)	-291 4 (34)
2001	Full Year	8 93 (15)	11 09 (18)	47 20 (13)	14 2 (21)
2002	Full Year	8 72 (20)	11 16 (22)	46 27 (19)	-475 4 (24)
2003	Full Year	8 86 (20)	10 97 (22)	49 41 (19)	313 8 (22)
2004	Full Year	8 44 (18)	10 75 (19)	46 84 (17)	1,092 6 (30)
2005	1st Quarter	8 57 (6)	10 51 (7)	44 55 (7)	482 1 (8)
	2nd Quarter	8 27 (5)	10 05 (7)	48 30 (5)	180 2 (9)
	3rd Quarter	7 78 (4)	10 84 (4)	43 58 (4)	40 2 (5)
	4th Quarter	8 37 (11)	10 75 (11)	48 55 (11)	671 2 (14)
2005	Full Year	8 30 (26)	10 54 (29)	46 73 (27)	1,373 7 (36)
2006	1st Quarter	8 13 (3)	10 38 (3)	50 25 (3)	444 6 (9)
	2nd Quarter	8 02 (5)	10 69 (5)	45 40 (4)	130 7 (6)
	3rd Quarter	7 89 (7)	10 06 (7)	46 86 (6)	251 3 (9)
	4th Quarter	8 55 (9)	10 39 (10)	50 59 (10)	638 4 (18)
2006	Full Year	8 20 (24)	10 36 (25)	48 67 (23)	1,465 0 (42)

Gas Utilities--Summary Table*

1996	Full Year	9 25 (23)	11 19 (20)	47 69 (19)	193 4 (34)
1997	Full Year	9 13 (13)	11 29 (13)	47 78 (11)	-82 5 (21)
1998	Full Year	9 48 (10)	11 51 (10)	49 50 (10)	93 9 (20)
1999	Full Year	8 86 (9)	10 66 (9)	49 06 (9)	51 0 (14)
2000	Full Year	9 33 (13)	11 39 (12)	48 59 (12)	135 9 (20)
2001	Full Year	8 51 (6)	10 95 (7)	43 96 (5)	114 0 (11)
2002	Full Year	8 80 (20)	11 03 (21)	48 29 (18)	303 6 (26)
2003	Full Year	8 75 (22)	10 99 (25)	49 93 (22)	260 1 (30)
2004	Full Year	8 34 (21)	10 59 (20)	45 90 (20)	303 5 (31)
2005	1st Quarter	8 19 (3)	10 65 (2)	43 00 (1)	50 8 (4)
	2nd Quarter	8 17 (5)	10 54 (5)	47 69 (4)	99 5 (6)
	3rd Quarter	8 15 (6)	10 47 (5)	49 54 (5)	75 3 (7)
	4th Quarter	8 33 (15)	10 40 (14)	49 03 (14)	232 8 (17)
2005	Full Year	8 25 (29)	10 46 (26)	48 66 (24)	458 4 (34)
2006	1st Quarter	8 62 (6)	10 63 (6)	51 18 (6)	138 7 (6)
	2nd Quarter	7 98 (1)	10 50 (2)	44 38 (2)	-4 8 (2)
	3rd Quarter	8 15 (3)	10 45 (3)	47 19 (3)	38 8 (5)
	4th Quarter	7 82 (5)	10 13 (4)	44 15 (4)	268 5 (11)
2006	Full Year	8 22 (15)	10 44 (15)	47 60 (15)	441 2 (24)

* Number of observations in each period indicated in parentheses

The table on page 2 shows the average ROE authorized annually since 1996 and by quarter since 2000, in major electric and gas rate decisions, followed by the number of observations in each period. The tables on page 3 show the composite electric and gas industry data for all the cases included in the chronology of this and earlier reports, summarized annually since 1996 and by quarter for the past eight quarters.

The table below tracks the average equity return authorized for all electric and gas rate cases combined, by year, for the last 17 years. As the table reveals, since 1990 authorized ROEs have generally trended downward, reflecting the significant decline in interest rates that has occurred over this time frame. The combined average equity returns authorized for all utilities in each of the years 1990 through 2006, and the number of observations for each year are as follows:

1990	12.69%	(75)	1999	10.74%	(29)
1991	12.51	(80)	2000	11.41	(24)
1992	12.06	(77)	2001	11.05	(25)
1993	11.37	(77)	2002	11.10	(43)
1994	11.34	(59)	2003	10.98	(47)
1995	11.51	(49)	2004	10.67	(39)
1996	11.29	(42)	2005	10.50	(55)
1997	11.34	(24)	2006	10.39	(40)
1998	11.59	(20)			

Dennis Sperduto

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ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq as % Cap. Str.	Test Year & Rate Base	Amt \$ Mil.
1/6/05	South Carolina Electric & Gas (SC)	8.64	10.70	50.31	12/04-YE	41.4
1/28/05	Aquila Networks-WPK (KS)	8.73	10.50	33.63	12/03-YE	7.4
2/18/05	Puget Sound Energy (WA)	8.40	10.30	43.00	9/03-A	56.6
2/25/05	PacifiCorp (UT)	8.37	10.50	47.80	3/06	51.0 (B)
3/10/05	Empire District Electric (MO)	9.18	11.00	49.14	12/03-YE	25.7 (B)
3/18/05	Dominion North Carolina Power (NC)	—	—	—	12/03	-12.0 (B)
3/24/05	Consolidated Edison of New York (NY)	8.08	10.30	48.00	3/06-A	325.0 (B,Z,TD)
3/31/05	Texas-New Mexico Power (TX)	—	10.25	40.00	—	-13.0 (B,D1)
2005	1ST QUARTER AVERAGES/TOTAL OBSERVATIONS	8.57 6	10.51 7	44.55 7		482.1 8
4/4/05	Central Vermont Public Service (VT)	8.14	10.00	55.53	12/03-A	-7.2 (R)
4/7/05	Anzona Public Service (AZ)	7.80	10.25	45.00 (Hy)	12/02-YE	67.6 (B)
5/2/05	Public Service Co. of Oklahoma (OK)	—	—	—	6/03-YE	-6.9 (B)
5/18/05	Entergy Louisiana (LA)	8.76	10.25	48.73	12/02-A	0.0 (B)
5/18/05	Wisconsin Electric Power (WI)	—	—	—	12/05-A	59.7
5/25/05	Savannah Electric and Power (GA)	—	10.75	—	—	9.6 (B)
5/26/05	Atlantic City Electric (NJ)	8.14	9.75	46.22	12/02-YE	-3.1 (D1,B)
5/26/05	Idaho Power (ID)	—	—	—	—	9.4
6/1/05	Jersey Central Power & Light (NJ)	8.50	9.75	46.00	12/02-YE	51.1 (D1,B)
6/8/05	Public Service New Hampshire (NH)	—	9.62 (R, Gn)	—	—	—
2005	2ND QUARTER AVERAGES/TOTAL OBSERVATIONS	8.27 5	10.05 7	48.30 5		180.2 9
7/19/05	Wisconsin Power and Light (WI)	9.41 (G)	11.50	61.75	6/06-A/P	18.6
7/22/05	PacifiCorp (ID)	—	—	—	—	5.8 (B)
8/5/05	Cap Rock Energy (TX)	6.17	11.75	25.00 (Hy)	9/03-YE	-1.3
8/15/05	AEP Texas Central (TX)	7.48	10.13	40.00	6/03-YE	-8.8 (TD,B)
9/28/05	PacifiCorp (OR)	8.06	10.00	47.56	12/06-A	25.9 (Bp)
2005	3RD QUARTER AVERAGES/TOTAL OBSERVATIONS	7.78 4	10.84 4	43.58 4		40.2 5
12/9/05	Empire District Electric (KS)	—	—	—	—	2.2 (B)
12/12/05	Madison Gas and Electric (WI)	8.88 (G)	11.00	56.65	12/06-A/P	35.9
12/13/05	OGE Electric Service(OK)	8.66	10.75	55.69	12/04-YE	42.3
12/16/05	Pacific Gas and Electric (CA)	8.79	11.35	52.00	12/06	3.3
12/16/05	San Diego Gas & Electric (CA)	8.23	10.70	49.00	12/06	0.0
12/16/05	Southern California Edison (CA)	8.77	11.60	48.00	12/06	-26.4
12/21/05	Cincinnati Gas & Electric (OH)	8.24	10.29	47.53	6/05-A	51.5 (D1,B)
12/21/05	Avista (WA)	9.11	10.40	40.00	12/04-A	22.1 (B)
12/22/05	Consumers Energy (MI)	6.78	11.15	36.31 *	12/03-A	177.4
12/22/05	Wisconsin Public Service (WI)	8.82 (G)	11.00	59.73	12/06-A/P	79.9
12/28/05	Westar Energy North (KS)	7.89	10.00	44.59	12/04-YE	24.2
12/28/05	Kansas Gas and Electric (KS)	7.89	10.00	44.59	12/04-YE	-21.2
12/28/05	Dayton Power & Light (OH)	—	—	—	—	250.0 (E,B,Z)
12/30/05	NSTAR Electric (MA)	—	—	—	—	30.0 (B,D1,1)
2005	4TH QUARTER AVERAGES/TOTAL OBSERVATIONS	8.37 11	10.75 11	48.55 11		671.2 14
2005	FULL-YEAR AVERAGES/TOTAL OBSERVATIONS	8.30 26	10.54 29	46.73 27		1373.7 36

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR _ % _	ROE _ % _	Common Eq. as % Cap Str	Test Year & Rate Base	Amt. \$ Mil
1/5/06	Northern States Power (WI)	8.94 (G)	11.00	53.66	12/06-A	43.4
1/25/06	Wisconsin Electric Power (WI)	—	—	—	—	229.7 (2)
1/27/06	United Illuminating (CT)	6.88 (3)	9.75	48.00	12/04-A	41.2 (R,D,Z,3)
2/23/06	Aquila Networks-MPS (MO)	—	—	—	—	22.4 (B)
2/23/06	Aquila Networks-L&P (MO)	—	—	—	—	3.9 (B)
3/3/06	Interstate Power and Light (MN)	8.58	10.39	49.10	12/04-A	1.2 (I,B)
3/14/06	Kentucky Power (KY)	—	—	—	—	41.0 (B)
3/24/06	PacifiCorp (WY)	—	—	—	—	25.0 (B,Z)
3/29/06	Entergy Gulf States (LA)	—	—	—	—	36.8 (I,B)
2006	1ST QUARTER: AVERAGES/TOTAL	8.13	10.38	50.25		444.6
	MEDIAN	8.58	10.39	49.10		—
	OBSERVATIONS	3	3	3		9
4/17/06	PacifiCorp (WA)	8.10	10.20	46.00	9/04-A	0.0
4/18/06	MidAmerican Energy (IA)	—	11.90 (4)	—	—	—
4/26/06	Sierra Pacific Power (NV)	8.96	10.60	40.76	5/05-YE	-14.0
5/12/06	Idaho Power (ID)	8.10	—	—	12/05	18.1 (B)
5/17/06	Southern California Edison (CA)	—	—	—	12/06-A	133.9 (5)
6/6/06	Delmarva Power & Light (DE)	7.17	10.00	47.72	3/05-A	-11.1 (D)
6/27/06	Upper Peninsula Power (MI)	7.75	10.75	47.12	12/06	3.8 (B)
2006	2ND QUARTER: AVERAGES/TOTAL	8.02	10.69	45.40		130.7
	MEDIAN	8.10	10.60	46.56		—
	OBSERVATIONS	5	5	4		6
7/6/06	Maine Public Service (ME)	8.45	10.20	50.00	12/05	1.8 (B,D)
7/24/06	Central Hudson Gas & Electric (NY)	7.05 (6)	9.60	45.00	3/06-A	53.7 (B,Z,TD)
7/26/06	Appalachian Power (WV)	7.60	10.50	—	12/04-A	111.7 (B,Z)
7/28/06	Commonwealth Edison (IL)	8.01	10.05	42.86	12/04-YE	82.6 (R,TD,7)
8/23/06	New York State Electric & Gas (NY)	7.18	9.55	41.60	12/07-A	-36.3 (TD)
8/31/06	Detroit Edison (MI)	—	—	—	—	-78.8 (B,Z)
9/1/06	Northern States Power (MN)	8.81	10.54	51.67	12/06-A	131.5 (I,8)
9/5/06	CenterPoint Energy Houston Electric (TX)	—	—	—	12/05	-57.9 (B,TD)
9/14/06	PacifiCorp (OR)	8.16	10.00	50.00	12/07-A	43.0 (B,7)
2006	3RD QUARTER: AVERAGES/TOTAL	7.89	10.06	46.86		251.3
	MEDIAN	8.01	10.05	47.50		—
	OBSERVATIONS	7	7	6		9
10/6/06	Unitil Energy Systems (NH)	8.70	9.67	43.10	6/05-YE	2.8 (B,D,Z)
10/27/06	Entergy New Orleans (LA)	—	—	—	—	3.9 (B,9)

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR _ % _	ROE _ % _	Common Eq as % Cap Str	Test Year & Rate Base	Amt \$ Mil
11/21/06	Delmarva Power & Light (DE)	—	—	—	—	-12 0 (B,I,Tr)
11/21/06	Central Illinois Light (IL)	7 94	10 12	45 57	12/04-YE	20 7 (TD)
11/21/06	Central Illinois Public Service (IL)	8 06	10 08	48 92	12/04-YE	-8 0 (TD)
11/21/06	Illinois Power (IL)	8 33	10 08	51 56	12/04-YE	84 0 (TD)
12/1/06	Duquesne Light (PA)	—	—	45 00	12/06	117 0 (B,D)
12/1/06	PacifiCorp (UT)	—	10 25	—	—	115 0 (B,Z)
12/1/06	Public Service of Colorado (CO)	8 85	10 50	60 00	—	107 0 (B)
12/4/06	Kansas City Power & Light (KS)	—	—	—	—	29 0 (B)
12/7/06	Central Vermont Public Service (VT)	8 55	10 75	55 57	12/05-A	10 8 (B)
12/14/06	Western Massachusetts Electric (MA)	—	—	—	—	4 0 (B,D,Z)
12/18/06	PacifiCorp (ID)	—	—	—	—	8 3 (B)
12/21/06	Duke Energy Kentucky (KY)	—	—	—	—	49 0 (B)
12/21/06	Empire District Electric (MO)	9 07	10 90	49 74	12/05-YE	29 4
12/21/06	Kansas City Power & Light (MO)	8 83 (E)	11 25	53 69	12/05-YE	50 6
12/22/06	Green Mountain Power (VT)	8 65	10 25	52 76	12/05-A	19 0 (B)
12/28/06	Black Hills Power (SD)	—	—	—	—	7 9 (B)
2006	4TH QUARTER: AVERAGES/TOTAL	8.55	10.39	50.59		638 4
	MEDIAN	8 65	10 25	50 65		—
	OBSERVATIONS	9	10	10		18
2006	FULL YEAR AVERAGES/TOTAL	8.20	10 36	48 67		1465 0
	MEDIAN	8 25	10 25	48 92		—
	OBSERVATIONS	24	25	23		42

GAS UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap Str	Test Year & Rate Base	Amt. \$ Mil
1/5/05	Avista Corporation (WA)	8 68	---	---	---	5 4 (B)
2/18/05	Puget Sound Energy (WA)	8 40	10 30	43 00	9/03-A	26 3
3/29/05	SEMCO Energy Gas (MI)	7 49	11 00	---	12/05	7 1 (B)
3/30/05	National Fuel Gas Distribution (PA)	---	---	---	5/04-YE	12 0 (B)
2005	1ST QUARTER AVERAGES/TOTAL OBSERVATIONS	8 19 3	10 65 2	43 00 1		50 8 4
4/13/05	Vectren Energy Delivery of Ohio (OH)	8 94	10 60	48 10 (E)	12/04-A	15 7
4/28/05	Michigan Consolidated Gas (MI)	7 19	11 00	39 31 *	12/02-A	60 8 (I)
5/4/05	Aquila Networks-KGO (KS)	---	---	---	---	2 7 (B)
5/17/05	AmerenIP (IL)	8 18	10 00	53 09	12/03-YE	11 3 (Bp)
6/8/05	CenterPoint Energy Minnegasco (MN)	8 03	10 18	50 27	9/05-A	9 0 (I,B)
6/10/05	Atlanta Gas Light (GA)	8 53 (R)	10 90 (R)	---	11/05-A	0 0 (R,B,10)
2005	2ND QUARTER AVERAGES/TOTAL OBSERVATIONS	8 17 5	10 54 5	47 69 4		99 5 6
7/6/05	Entergy Gulf States (LA)	8 11	10 50	47 52	9/03-A	5 8 (B)
7/19/05	Wisconsin Power and Light (WI)	9 41 (G)	11 50	61 75	6/06-A/P	2 0
7/22/05	National Fuel Gas Distribution (NY)	---	---	---	7/06-A	21 0 (B)
8/11/05	Northern States Power (MN)	8 76	10 40	50 24	12/04-A	5 8 (I,B)
8/24/05	Mountaineer Gas (WV)	8 43	---	---	12/03-YE	17 3 (B,Z)
9/19/05	CenterPoint Energy Arkansas Gas (AR)	5 31	9 45	31 80 *	4/04-YE	-11 3
9/30/05	Northern Illinois Gas (IL)	8 85	10 51	56 37	12/05-A	34 7 (11)
2005	3RD QUARTER AVERAGES/TOTAL OBSERVATIONS	8.15 6	10 47 5	49 54 5		75 3 7
10/3/05	Laclede Gas (MO)	---	---	---	---	8 5 (B)
10/4/05	Oklahoma Natural Gas (OK)	8 74	9 90	48 76	7/04-YE	57 5 (B)
10/14/05	Interstate Power & Light (IA)	8 68	10 40	49 35	12/04-A	14 0 (I,B)
10/21/05	Dominion Hope Gas (WV)	---	---	---	12/04-YE	4 0 (B)
10/31/05	South Carolina Electric & Gas (SC)	8 43	10 25	50 75	12/04-YE	22 9 (B)
11/2/05	Arkansas Western Gas (AR)	5 93	9 70	33 03 *	1/05-YE	4 6
11/3/05	Piedmont Natural Gas (NC)	9 04	---	---	12/04	22 4 (B)
11/30/05	Bay State Gas (MA)	8 22	10 00	53 95	12/04-YE	11 1
12/9/05	Arkansas Oklahoma Gas (AR)	6 61	9 70	41 04 *(E)	8/04-YE	4 4
12/12/05	Madison Gas and Electric (WI)	8 88 (G)	11 00	56 65	12/06-A/P	3 8
12/16/05	Pacific Gas and Electric (CA)	8 79	11 35	52 00	12/06	1 0
12/16/05	San Diego Gas & Electric (CA)	8 23	10 70	49 00	12/06	0 0
12/21/05	Baltimore Gas & Electric (MD)	8 49	11 00	48 40	7/05-A	35 6
12/21/05	Avista (WA)	9 11	10 40	40 00	12/04-A	1 0 (B)
12/22/05	Union Light, Heat and Power (KY)	8 10 (G)	10 20	54 45	9/06-A	8 1
12/22/05	Wisconsin Public Service (WI)	8 82 (G)	11 00	59 73	12/06-A/P	7 2
12/28/05	Southern Connecticut Gas (CT)	8 85	10 00	51 28	12/04-YE	26 7 (B)
2005	4TH QUARTER AVERAGES/TOTAL OBSERVATIONS	8.33 15	10 40 14	49.03 14		232 8 17
2005	FULL-YEAR AVERAGES/TOTAL OBSERVATIONS	8 25 29	10 46 26	48 66 24		458 4 34

GAS UTILITY DECISIONS (continued)

Date	Company (State)	ROR _ % _	ROE _ % _	Common Eq. as % Cap Str	Test Year & Rate Base	Amt \$ Mil.
1/5/06	Northern States Power (WI)	8 94 (G)	11 00	53 66	12/06-A	3 9
1/25/06	Wisconsin Electric Power (WI)	8 52 (G)	11 20	56 34	12/06-A	21 4
1/25/06	Wisconsin Gas (WI)	8 29 (G)	11 20	50 20	12/06-A/P	38 7
2/3/06	Public Service of Colorado (CO)	8 70	10 50	55 49	12/04-A	22 5 (B)
2/23/06	Southwest Gas (AZ)	8 40	9 50	40 00 (Hy)	8/04-YE	49 3
3/1/06	Aquila (IA)	8 88	10 40 (E)	51 39	12/04-A	2 9 (I,B)
2006	1ST QUARTER: AVERAGES/TOTAL	8.62	10.63	51 18		138 7
	MEDIAN	8 61	10 75	52.53		—
	OBSERVATIONS	6	6	6		6
4/26/06	Sierra Pacific Power (NV)	7 98	10 60	40 76	5/05-YE	4 9
5/25/06	Atmos Energy (LA)	—	10 40	48 00 (Hy)	—	— (B)
5/26/06	Questar Gas (UT)	—	—	—	—	-9 7 (B)
2006	2ND QUARTER: AVERAGES/TOTAL	7 98	10 50	44 38		-4 8
	MEDIAN	7 98	10 50	44 38		—
	OBSERVATIONS	1	2	2		2
7/24/06	Central Hudson Gas & Electric (NY)	7 05 (6)	9 60	45 00	3/06-A	14 1 (B,Z,D)
7/24/06	Virginia Natural Gas (VA)	—	—	—	3/05-A	0 0 (B,12)
9/20/06	Kinder Morgan (WY)	8 36	11 00	43 56	6/05-YE	6 5 (B,13)
9/26/06	Chesapeake Utilities (MD)	9 03	10 75	53 00	12/05	0 8 (B)
9/27/06	South Carolina Electric and Gas (SC)	—	—	—	3/06	17 4
2006	3RD QUARTER: AVERAGES/TOTAL	8 15	10.45	47.19		38.8
	MEDIAN	8.36	10.75	45.00		—
	OBSERVATIONS	3	3	3		5
10/20/06	Orange & Rockland Utilities (NY)	7 99	9 80	48 00	10/07-A	14 8 (B,Z,D)
10/23/06	Public Service Co. of North Carolina (NC)	8 90	—	—	12/05-YE	15 2 (B)
10/27/06	Entergy New Orleans (LA)	—	—	—	—	9 6 (B,Z)
11/02/06	CenterPoint Energy Minnesota Gas (MN)	7 54	9 71	46 14	12/06-A	21 0 (I)
11/09/06	Public Service Electric & Gas (NJ)	7 96	10 00	47 40	9/05-YE	40 0 (B,7)
11/16/06	Kansas Gas Service (KS)	—	—	—	—	52 0 (B)
11/21/06	Consumers Energy (MI)	6 69	11 00	35 06 *	12/06-A	80 8 (I)
11/30/06	UGI Penn Natural Gas (PA)	—	—	—	12/06	12 5 (B)
12/4/06	National Fuel Gas Distribution (PA)	—	—	—	12/05	14 3 (B)
12/27/06	Kinder Morgan (NE)	—	—	—	—	8 3 (I,B)
12/28/06	Columbia Gas of Virginia (VA)	—	—	—	9/06-A	0 0 (B,14)
2006	4TH QUARTER: AVERAGES/TOTAL	7 82	10.13	44 15		268 5
	MEDIAN	7.96	9 90	46 77		—
	OBSERVATIONS	5	4	4		11
2006	FULL YEAR: AVERAGES/TOTAL	8 22	10 44	47 60		441 2
	MEDIAN	8 36	10 50	48 00		—
	OBSERVATIONS	15	15	15		24

FOOTNOTES

- A- Average
 - B- Order followed stipulation or settlement by the parties Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body
 - Bp- Order followed partial stipulation or settlement by the parties Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body
 - Di- Rate change applicable to electric distribution or gas delivery rates only
 - E- Estimated
 - G- Return on capital
 - Gn- Return applicable to generation assets only
 - Hy- Hypothetical capital structure utilized
 - I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund
 - P- Partial inclusion of CWIP in rate base without AFUDC offset to income
 - PBR- Performance Based Rate-making
 - R- Revised
 - TD- Rate change applicable to electric transmission and distribution rates only
 - Tr- Rate change applicable to electric transmission rates only
 - YE- Year-end
 - Z- Rate change implemented in multiple steps
 - * Capital structure includes cost-free items or tax credit balances at the overall rate of return
- (1) Indicated distribution rate increase to be effective 5/1/06
 - (2) The electric rate increase was not supported by a traditional cost-of-service analysis, but reflected recovery of certain specific costs
 - (3) Indicated rate increase to be phased-in over four years, with a 6.88% ROR authorized for 2006, 6.89% for 2007, 7.09% for 2008, and 7.48% for 2009
 - (4) ROE applies only to a proposed 545-mW wind generation project
 - (5) Increase is net of a \$139.6 million one-time reduction resulting from a post-retirement-benefits-other-than-pensions overcollection. Additional increases of \$73.5 million and \$104.1 million authorized for 2007 and 2008, respectively
 - (6) Multi-year rate increase adopted. Authorized ROR for year one is 7.05%, for year two is 7.09%, and for year three is 7.13%
 - (7) Rate increase became effective 1/1/07
 - (8) Rate increase declined to \$114.9 million effective 1/1/07
 - (9) Rate increase to become effective 1/1/08
 - (10) The stipulation requires the company to freeze rates for five years, and over this time period, to credit its pipeline replacement program a total of \$25 million and senior citizen rates \$7.5 million
 - (11) Indicated rate increase does not include \$19.5 million of revenue previously collected through the purchased gas adjustment clause
 - (12) Commission adopted a stipulated PBR plan, with no earnings restrictions. Absent PBR plan, PSC indicated that it would have ordered a \$9.8 million decrease premised upon a 10% ROE (44.96% of capital) and a 7.83% ROR
 - (13) While the rate increase was voted 9/20/06 and became effective 10/1/06, a final order was not issued until 12/4/06
 - (14) Commission adopted a stipulated PBR plan under which 75% of earnings above a 10.5% ROE flow to ratepayers

Dennis Speduto

ATTACHMENT B

COST OF EQUITY ADVOCATED BY WCTL MEMBERS IN RECENT REGULATORY LITIGATION INVOLVING THEIR OWN RATES

A. Ameren (Central Illinois Light Company, Central Illinois Public Service and Illinois Power Company)

In *Central Illinois Light Co d/b/a AmerenCILCO*, Nos 06-0070 *et al*, 2006 WL 3863623 (Ill C.C., Nov 21, 2006), Ameren and three of its affiliates argued, in a rate case arising over proposed rate increases for Ameren delivery services, that it should receive a return on equity of 11.0 percent, based on a DCF analysis, an equity risk premium analysis, a CAPM analysis, and a comparable earnings test *Id* at *99. For its CAPM estimate, Ameren proposed a risk-free return of 5.5 percent, an equity risk premium of 5.0 to 6.0 percent, and a beta of 1.0, with a resulting “market-derived” cost of equity in the range of 10.5 to 11.5 percent *Id* at *102. For its DCF estimates, Ameren relied on both a one-stage (constant growth) and a two-stage DCF model *Id* at *101. The DCF analysis, Ameren argued, warranted equity returns in the range of 12.0 to 13.0 percent *Id* at 103. Ameren added that “the risk-adjusted comparable earnings test indicates that low risk competitive firms are able to earn returns in a very similar range, 12.75-13.25%” *Id*. The Illinois Commerce Commission ultimately adopted a cost of equity of 10.12% for this regulated monopoly *Id* at *135.

B. Ameren (Union Electric)

In *Union Electric Co d/b/a AmerenUE*, 257 P U R 4th 259, modified on other grounds, 2007 WL 2239245 (Mo P S C 2007), Ameren sponsored two expert witnesses on the company’s cost of equity. The witnesses (including Prof James Vander Weide of Duke University) testified that the cost of equity was 12.0 or 12.5 percent, despite

acknowledging that “AmerenUE’s risk is about average for the electric utility industry” *Id.*, 257 P U R 4th at 279-283. The Missouri P.S.C. ultimately adopted a cost of equity of 10.2 percent. *Id.* at 284

C. Kansas City Power & Light Company

In *Kansas City Power & Light Co.*, 2006 WL 4041675 (Mo. P.S.C. 2007), the primary cost of capital witness sponsored by the utility, Prof. Samuel Hadaway, derived an equity cost estimate of 9.3-9.4 percent based on a “traditional discounted cash flow (DCF) model.” *Id.* at *8 “However, finding these results unreasonably low, Dr Hadaway then used recalculated constant growth results with the growth rate based on long-term forecasted growth in GDP,” yielding an estimated cost of equity of 11.2 to 11.3 percent *Id.* Using a multi-stage DCF, Dr. Hadaway arrived at a cost of equity in the range of 10.6 to 10.8 percent *Id.* Finally, using a “risk premium model,” he derived an equity cost estimate in the range of 10.6 to 11.3 percent *Id.* He ultimately recommended a point estimate of 11.5 percent *Id.* The Missouri P.S.C. ultimately adopted a cost of equity of 11.25 percent. *Id.* at *11

D. Northern States Power Company (Xcel Energy)

In *Northern States Power Co. d/b/a Xcel Energy*, 253 P U R 4th 40 (Minnesota P.U.C., Sept. 1, 2006), the utility proposed a cost of equity of 11 percent, based on both DCF and CAPM analyses *Id.* at 61-62 The Minnesota PUC ultimately adopted a cost of equity of 10.54 percent *Id.* at 63

E. Public Service Company of Colorado (Xcel Energy)

In *Public Service Company of Colorado*, 258 P.U.R.4th 185 (Colorado P U C 2007), the utility, relying on both DCF and CAPM analyses, proposed a cost of equity in the range of 10.25 to 11.25 percent *Id.*, 258 P U R 4th at 189-190 Most of the parties

ultimately settled on a cost of equity of 10.25 percent, which the PUC found just and reasonable. *Id.* at 190-191.

F. Wisconsin Public Service Corporation

In *Wisconsin Public Service Corp.*, 2007 WL 496358 (Wisc. P.S.C. 2007), the utility requested a return on equity of 11.75 percent, and the Wisconsin PSC authorized a return of 10.9 percent. *Id.* at 16-17.