BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 06-101-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

DIRECT TESTIMONY

OF

ROGER A. MORIN

ON BEHALF OF

ENTERGY ARKANSAS, INC.

AUGUST 15, 2006

TABLE OF CONTENTS

EXHIBITS

EAI Exhibit RAM-1	Resume of Roger A. Morin
EAI Exhibit RAM-2	Vertically Integrated Electric Utilities Beta Estimates
EAI Exhibit RAM-3	Moody's Electric Utility Common Stocks Over Long-Term Treasury Bonds Annual Long-Term Risk Premium Analysis
EAI Exhibit RAM-4	Electric Utilities Historical Growth Rates
EAI Exhibit RAM-5	Standard & Poor's Vertically Integrated Electric Utilities
EAI Exhibit RAM-6	Vertically Integrated Electric Utilities DCF Analysis: Value Line Growth Projections
EAI Exhibit RAM-7	Vertically Integrated Electric Utilities DCF Analysis: Analysts' Growth Forecasts
EAI Exhibit RAM-8	Moody's Electric Utilities DCF Analysis: Value Line Growth Forecasts
EAI Exhibit RAM-9	Moody's Electric Utilities DCF Analysis: Analysts' Growth Forecasts

APPENDICES

EAI Appendix A	CAPM, Empirical CAPM
EAI Appendix B	Flotation Cost Allowance

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, ADDRESS, AND OCCUPATION.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. PLEASE SUMMARIZE YOUR ACADEMIC AND BUSINESS CAREER.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The

Management Exchange Inc. and Exnet, where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last twenty years, I have conducted numerous national seminars on “Utility Finance,” "Utility Cost of Capital," "Alternative Regulatory Frameworks," and "Utility Capital Allocation," which I have developed on behalf of The Management Exchange Inc. in conjunction with Public Utilities Reports, Inc.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including *The Journal of Finance*, *The Journal of Business Administration*, *International Management Review*, and *Public Utilities Fortnightly*. I published a widely-used treatise on regulatory finance, *Utilities' Cost of Capital*, Public Utilities Reports, Inc., Arlington, Va. 1984. My more recent book on regulatory matters, *Regulatory Finance*, is a voluminous treatise on the application of finance to regulated utilities and was released by the same publisher in late 1994. A revised and expanded edition is scheduled for publication in June 2006. I have engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation. EAI Exhibit RAM-1 describes my professional credentials in more detail.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON COST OF CAPITAL BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes, I have been a cost of capital witness before over fifty (50) regulatory bodies in North America. I have testified before regulatory bodies in the following jurisdictions:

Alabama	Florida	Montana	Oregon
Alaska	Georgia	Nevada	Pennsylvania
Alberta	Hawaii	New Brunswick	Quebec
Arizona	Illinois	New Hampshire	South Carolina
Arkansas	Indiana	New Jersey	South Dakota
British Columbia	Iowa	New York	Tennessee
California	Kentucky	Newfoundland	Texas
City of New Orleans	Louisiana	North Carolina	Utah
Colorado	Manitoba	North Dakota	Vermont
Delaware	Michigan	Nova Scotia	Virginia
District of Columbia	Minnesota	Ohio	Washington
FCC	Mississippi	Oklahoma	West Virginia
FERC	Missouri	Ontario	

The details of my participation in regulatory proceedings are provided in EAI Exhibit RAM-1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on the electric utility operations of Entergy Arkansas, Inc. ("EAI" or the "Company") in the State of Arkansas, with particular emphasis on the fair return on the Company's common equity capital committed to that business. Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would: (1) be fair to the ratepayer, (2) allow the Company to attract capital on reasonable terms, (3) maintain the Company's financial integrity, and (4) be comparable to returns offered on comparable risk investments. I will testify in this proceeding as to that opinion. Additionally, I will discuss the relationship between timely recovery of fuel and purchased power cost and the required return on common equity. Finally, I will discuss the importance of recognizing the impact on required return on common equity that stems from fixed payments under purchased power contracts.

Q. PLEASE BRIEFLY IDENTIFY THE EXHIBITS AND APPENDICES ACCOMPANYING YOUR TESTIMONY.

A. I have attached to my testimony EAI Exhibit RAM-1 through EAI Exhibit RAM-9 and EAI Appendices A and B. These Exhibits and Appendices relate directly to points in my testimony, and are described in further detail in connection with the discussion of those points in my testimony.

Q. PLEASE SUMMARIZE YOUR FINDINGS CONCERNING EAI'S COST OF COMMON EQUITY.

A. I recommend that a rate of return of 11.25 percent be used for ratemaking purposes on EAI's common equity capital. My recommended return of

11.25 percent is derived from studies I performed using the Capital Asset Pricing Model ("CAPM"), Risk Premium, and Discounted Cash Flow ("DCF") methodologies. I performed two CAPM analyses, one using the traditional CAPM and another using an empirical approximation of the CAPM ("ECAPM"). The CAPM and ECAPM analyses are actually forms of risk premium models that deal with aggregated stock market risk premium evidence. Additionally, I performed two risk premium analyses that relate directly to evidence from the energy utility industry: a historical risk premium analysis on the electric utility industry using U.S. Treasury Bond yields and a study of the risk premiums allowed in the electric utility industry. I also performed DCF analyses on two surrogates for the Company. They are: (1) a group of electric utilities that make up Moody's Electric Utility Index, and (2) a group of investment-grade vertically integrated electric utilities.

My recommended rate of return on common equity reflects the application of my professional judgment to the indicated returns from my CAPM, Risk Premium, and DCF analyses. Moreover, my recommended return is predicated on the assumption that the Arkansas Public Service Commission ("APSC" or the "Commission") will approve the continuation of the Company's current energy cost recovery mechanism, the Energy Cost Recovery Rider ("Rider ECR"), in the same manner as in the past and approve full and current recovery of the FERC allocated costs.

Q. PLEASE EXPLAIN HOW LOW AUTHORIZED RETURNS ON EQUITY CAN INCREASE BOTH THE FUTURE COST OF EQUITY AND DEBT FINANCING.

A. If a utility is authorized a return on equity below the level required by equity investors, the utility will find it difficult to access the equity market through common stock issuance at its current market price. Investors will not provide equity capital at the current market price if the earnable return on equity is below the level they require given the risks of an equity investment in the utility. The equity market corrects this by generating a stock price in equilibrium that reflects the valuation of the potential earnings stream from an equity investment at the risk-adjusted return equity investors require. In the case of a utility that has been authorized a return below the level investors believe is appropriate for the risk they bear, the result is a decrease in the utility's market price per share of common stock. This reduces the financial viability of equity financing in two ways. First, because the utility's share price per common stock decreases, the net proceeds from issuing common stock are reduced. Second, since the utility's market to book ratio decreases with the decrease in the share price of common stock, the potential risk from dilution of equity investments reduces investors' inclination to purchase new issues of common stock. The ultimate effect is the utility will have to rely more on debt financing to meet its capital needs.

As the company relies more on debt financing, its capital structure becomes more leveraged. Because debt payments are a fixed financial obligation to the utility, and income available to common equity is subordinate to fixed charges, this decreases the operating income available for dividend and earnings growth. Consequently, equity investors face greater uncertainty about future dividends and earnings from the firm. As a result, the firm's equity becomes a riskier investment. The risk of default on the company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility the company will not have access to the capital markets for its outside financing needs. Ultimately, to ensure that EAI has access to capital markets for its capital needs, a fair and reasonable authorized rate of return on common equity capital of 11.25 percent is required.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. The remainder of my testimony is divided into six (6) sections:

II. Regulatory Framework and Rate of Return

III. Cost of Equity Capital Estimates

IV. Summary and Recommendation

V. Risk Relating to Recovery of Fuel and Purchased Power Costs

VI. Impact of Purchased Power Contracts on Required Return

VII. Changing Capital Market Conditions

Section two discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The third section contains the application of CAPM, Risk Premium, and DCF tests. In the fourth section, the results from the various approaches used in determining a fair return are summarized. The fifth section discusses the impact on business risk and rate of return associated with recovery of fuel and purchased power costs through the Company's Energy Cost Recovery Rider. Section six discusses the impact of long-term purchased power contracts on required return. The final section discusses updates to testimony for substantial changes in the capital market.

II. <u>REGULATORY FRAMEWORK AND RATE OF RETURN</u>

Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF EAI'S COST OF COMMON EQUITY?

A. Two fundamental economic principles underlie the appraisal of the Company's cost of equity, one relating to the supply side of capital markets, the other to the demand side. According to the first principle, a rational investor is maximizing the performance of his portfolio only if he expects the returns earned on investments of comparable risk to be the same. If not, the rational investor will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract the capital funds it needs to meet its service demands and to maintain financial integrity unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk. On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments exceeds or equals the company's cost of capital. This concept suggests that a regulatory commission should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital.

Q. HOW DOES EAI'S COST OF CAPITAL RELATE TO THAT OF ITS PARENT COMPANY, ENTERGY CORP.?

A. I am treating EAI as a separate stand-alone entity, distinct from the parent company Entergy Corporation because it is the cost of capital for EAI that we are attempting to measure and not the cost of capital for Entergy Corporation's consolidated activities. Financial theory clearly establishes that the true cost of capital depends on the use to which the capital is put, in this case EAI's retail electric utility operations in the State of Arkansas. The specific source of funding an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at the bank at an after-tax cost of 8 percent and invests the funds in a speculative oil extraction venture, the required return on the investment is not the 8 percent cost but, rather, the return foregone in speculative projects of similar risk, say 20 percent. Similarly, the required return on EAI is the return foregone by not investing in comparable risk entities and is unrelated to the parent’s cost of capital. The cost of capital is governed by the risk to which the capital is exposed and not by the source of funds. The identity of the shareholders has no bearing on the cost of equity, be it either individual investors or a parent holding company.

Just as individual investors require different returns from different assets in managing their personal affairs, corporations behave in the same manner. A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as for long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between subsidiaries. Thus, the cost of investing funds in an operating utility company such as EAI is the return foregone on investments of similar risk and is unrelated to the investor’s identity.

Q. PLEASE EXPLAIN HOW A REGULATED COMPANY'S RATES SHOULD BE SET UNDER TRADITIONAL COST OF SERVICE REGULATION.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company recovers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable the company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of the next section of my testimony to estimate EAI's cost of common equity capital.

Q. DR. MORIN, WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR RETURN ON COMMON EQUITY?

A. The allowed return on common equity should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness, and ability to attract capital on reasonable terms. The attraction of capital standard focuses on investors' return requirements that are generally determined using market value methods, such as the Risk Premium, CAPM, or DCF methods. These market value tests define fair return as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from alternative investments of comparable risk.

Q. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A FAIR AND REASONABLE RATE OF RETURN ON COMMON EQUITY?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. <u>Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia</u>, 262 U.S. 679 (1923).

2. Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944).

The Bluefield case set the standard against which just and reasonable rates of return are measured:

> "A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties ... The return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties." (Emphasis added)

The Hope case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the Bluefield case and recognized that revenues must cover "capital costs." The Court stated:

> "From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock ... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital." (Emphasis added)

The United States Supreme Court reiterated the criteria set forth in Hope in Federal Power Commission v. Memphis Light, Gas & Water Division, 411 U.S. 458 (1973), in Permian Basin Rate Cases, 390 U.S. 747 (1968), and most recently in Duquesne Light Co. vs. Barasch, 488 U.S. 299 (1989). In the Permian cases, the Supreme Court stressed that a regulatory agency's rate of return order should:

> "...reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed..."

Therefore, the "end result" of the Commission's decision should be to allow EAI the opportunity to earn a return on equity that is: (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in the company's financial integrity, and (3) sufficient to maintain the company's creditworthiness and ability to attract capital on reasonable terms.

Q. HOW IS THE FAIR RATE OF RETURN DETERMINED?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the utility. It is the composite weighted cost of the various classes of capital (bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service in a particular jurisdiction.

While utilities like EAI enjoy varying (and declining) degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free, open market for the input factors of production, whether labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on debt capital, or the expected return on common and/or preferred equity.

Q. HOW DOES THE CONCEPT OF A FAIR RETURN RELATE TO THE CONCEPT OF OPPORTUNITY COST?

A. The concept of a fair return is intimately related to the economic concept of "opportunity cost." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they also are exposing their funds to risk and forgoing returns from investing their money in alternative comparable-risk investments. The compensation they require is the price of capital, or return. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different returns. These differences in risk are translated by the capital markets into price differences in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for the respective securities and the risks expected from the overall menu of available securities.

Q. HOW DOES THE COMPANY OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?

A. The funds employed by the Company are obtained in two general forms, debt capital and equity capital. The latter consists of preferred equity capital and common equity capital. The cost of debt funds and preferred stock funds can be ascertained easily from an examination of the contractual terms for the interest payments and preferred dividends. The cost of common equity funds, that is, common equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments. Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded cost of debt and preferred stock, based on the utility's capital structure, in order to arrive at the overall cost of capital.

I recognize that the APSC has long utilized the Modified Balance Sheet approach to determining capital structure, and therefore the weights assigned to various components of that capital structure, and that the Company is employing such a capital structure in its application in this proceeding. Therefore, I fully recognize that my recommended allowed return on common equity will be utilized in a capital structure consisting of several components other than common equity, preferred stock and long-term debt. This fact in no way alters the fundamental estimate of EAI's cost of common equity capital.

Q. WHAT IS THE MARKET REQUIRED RATE OF RETURN ON EQUITY CAPITAL?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments, and the returns available from other investments of comparable risk.

III. COST OF EQUITY CAPITAL ESTIMATES

Q. DR. MORIN, HOW DID YOU ESTIMATE THE FAIR RATE OF RETURN ON COMMON EQUITY FOR EAI?

A. I employed three methodologies: (1) the CAPM, (2) the Risk Premium, and (3) the DCF. All three are market-based methodologies and are designed to estimate the return required by investors on the common equity capital committed to EAI.

Q. WHY DID YOU USE MORE THAN ONE APPROACH FOR ESTIMATING THE COST OF EQUITY?

A. No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

Q. ARE THERE ANY DIFFICULTIES IN APPLYING COST OF CAPITAL METHODOLOGIES IN THE CURRENT ENVIRONMENT OF CHANGES IN THE ELECTRIC UTILITY INDUSTRY?

A. Yes, there are. All the traditional cost of common equity estimation methodologies are difficult to implement when you are dealing with the fast-changing circumstances of the electric utility industry. This is because utility company historical data have become less meaningful for an industry in a state of change. Past earnings and dividend trends are simply not indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including structural transformation and the transition to a more competitive environment. As a result, this historical data may not be representative of the future long-term earning power of these companies. Moreover, historical growth rates may not be representative of future trends for several electric utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available.

Q. DR. MORIN, ARE YOU AWARE THAT SOME REGULATORY COMMISSIONS AND SOME ANALYSTS HAVE PLACED PRINCIPAL RELIANCE ON DCF-BASED ANALYSES TO DETERMINE THE COST OF EQUITY FOR PUBLIC UTILITIES?

A. Yes, I am.

Q. DO YOU AGREE WITH THIS APPROACH?

A. While I agree that it is certainly appropriate to use the DCF methodology in developing a variety of estimates of the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. As I have stated, there are three broad generic methodologies available to measure the cost of equity: DCF, Risk Premium, and CAPM. All three of these methodologies are accepted and used by the financial community and firmly supported in the financial literature.

When measuring the cost of common equity, which essentially deals with the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology. The failure of the traditional infinite growth DCF model to account for changes in relative market valuation, and the practical difficulties of specifying the expected growth component, specifically a constant annual rate of growth over an infinite time horizon, are vivid examples of the potential shortcomings of the DCF model. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that all of these methodologies should be applied to multiple groups of comparable risk companies.

There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. Absent any hard evidence as to which method outperforms the other, all relevant evidence should be used, without discounting the value of any results, in order to minimize judgmental error, measurement error, and conceptual infirmities. I submit that a regulatory body should rely on the results of a variety of methods applied to a variety of comparable groups. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of common equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect explanation of a stock's price or the cost of common equity.

Q. DOES THE FINANCIAL LITERATURE SUPPORT THE USE OF MORE THAN A SINGLE METHOD?

A. Yes. Authoritative financial literature strongly supports the use of multiple methods. For example, Professor Brigham, a widely respected scholar and finance academician, asserts:

> In practical work, it is often best to use all three methods - CAPM, bond yield plus risk premium, and DCF - and then apply judgement when the methods produce different results. People experienced in estimating capital costs recognize that both careful analysis and some very fine judgements are required. It would be nice to pretend that these judgements are unnecessary and to specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible.[1]

In a subsequent edition of his best-selling corporate finance textbook, Dr. Brigham discusses the various methods used in estimating the cost of common equity capital, and states:

> However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive - no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with

[1] E. F. Brigham and L. C. Gapenski, *Financial Management Theory and Practice*, p. 256 (4th ed., Dryden Press, Chicago, 1985).

> the task of estimating a company' cost of equity, we generally use all three methods…..[2]

Another prominent finance scholar, Professor Stewart Myers, in his best selling corporate finance textbook, points out:

> The constant growth formula and the capital asset pricing model are two different ways of getting a handle on the same problem.[3]

In an earlier article, Professor Myers explains:

> Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.[4]

Q. DOES THE BROAD USAGE OF THE DCF METHODOLOGY IN PAST REGULATORY PROCEEDINGS INDICATE THAT IT IS SUPERIOR TO OTHER METHODS?

A. No, it does not. Uncritical acceptance of the standard DCF equation vests the model with a degree of infallibility that is undeserved. One of the

[2] E. F. Brigham and L. C. Gapenski, *Financial Management Theory and Practice*, p. 348 (8th ed., Dryden Press, Chicago, 2005).
[3] R. A. Brealey and S. C. Myers, *Principles of Corporate Finance*, p. 182 (3rd ed., McGraw Hill, New York, 1988)
[4] S. C. Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," *Financial Management*, p. 67 (Autumn 1978).

leading experts on public utility regulation, Dr. Charles F. Phillips, discusses the dangers of relying solely on the DCF model:

> [U]se of the DCF model for regulatory purposes involves both theoretical and practical difficulties. The theoretical issues include the assumption of a constant retention ratio (i.e. a fixed payout ratio) and the assumption that dividends will continue to grow at a rate 'g' in perpetuity. Neither of these assumptions has any validity, particularly in recent years. Further, the investors' capitalization rate and the cost of equity capital to a utility for application to book value (i.e. an original cost rate base) are identical only when market price is equal to book value. Indeed, DCF advocates assume that if the market price of a utility's common stock exceeds its book value, the allowable rate of return on common equity is too high and should be lowered; and vice versa. Many question the assumption that market price should equal book value, believing that "the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies."
>
> ...[T]here remains the circularity problem: Since regulation establishes a level of authorized earnings which, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. For all of these reasons, the DCF model 'suggests a degree of precision which is in fact not present' and leaves 'wide room for controversy about the level of k [cost of equity]'.[5]

Dr. Phillips also discusses the dangers of relying solely on the CAPM model because of the lack of realism of certain of its stringent assumptions, as is the case for any model in the social sciences.

[5] C. F. Phillips, *The Regulation of Public Utilities Theory and Practice*, pp. 376-77. (Public Utilities Reports, Inc., 1988) pp. 376-77. [Footnotes omitted]

Sole reliance on any one model, whether it is DCF, CAPM, or Risk Premium, simply ignores the capital market evidence and investors' use of the other theoretical frameworks. The DCF model is only one of many tools to be employed in conjunction with other methods to estimate the cost of equity. It is not a superior methodology that should supplant other financial theory and market evidence. The same is true of the CAPM and Risk Premium methodologies.

Q. DO THE ASSUMPTIONS UNDERLYING THE DCF MODEL REQUIRE THAT THE MODEL BE TREATED WITH CAUTION?

A. Yes, particularly in today's changing utility industry. Even ignoring the fundamental thesis that several methods and/or variants of such methods should be used in measuring equity costs, the DCF methodology, as those familiar with the electric utility industry and the accepted norms for estimating the cost of equity are aware, is dangerously fragile at this time.

Several fundamental and structural changes have transformed the electric utility industry since the standard DCF model and its assumptions were developed. Deregulation, increased competition triggered by national policy, changes in customer attitudes regarding utility services, the evolution of alternative energy sources, and mergers-acquisitions have all influenced stock prices in ways that deviated substantially from the early assumptions of the DCF model. These changes suggest that some of the fundamental assumptions underlying the standard DCF model, particularly that of constant growth, constant dividend payout, and constant relative market valuation, for example price/earnings ratios and market-to-book ratios, are problematic at this point in time for utility stocks, and that, therefore, alternate methodologies to estimate the cost of common equity should be accorded at least as much weight as the DCF method.

Q. IS THE CONSTANT RELATIVE MARKET VALUATION ASSUMPTION INHERENT IN THE DCF MODEL ALWAYS REASONABLE?

A. No, not always. Caution must be exercised when implementing the standard DCF model in a mechanistic fashion, for it may fail to recognize changes in relative market valuations over time. The traditional DCF model is not equipped to deal with surges in market-to-book (M/B) and price-earnings (P/E) ratios, as were experienced by a number of utility stocks in recent years. The standard DCF model assumes a constant market valuation multiple, that is, a constant P/E ratio and a constant M/B ratio. Stated another way, the model assumes that investors expect the ratio of market price to dividends (or earnings) in any given year to be the same as the current ratio of market price to dividends (or earnings), and that the stock price will grow at the same rate as the book value. This is a necessary result of the infinite growth assumption. This assumption is unrealistic under current conditions.

Q. WHAT IS YOUR RECOMMENDATION GIVEN SUCH MARKET CONDITIONS?

A. In short, caution and judgment are required in interpreting the results of the standard DCF model because of (1) the effect of changes in risk and growth on electric utility utilities, (2) the fragile applicability of the DCF model to electric utility stocks in the current capital market environment, and (3) the practical difficulties associated with the growth component of the standard DCF model. Hence, there is a clear need to go beyond the standard DCF results and take into account the results produced by alternate methodologies in arriving at a common equity recommendation.

Q. DO THE ASSUMPTIONS UNDERLYING THE CAPM REQUIRE THAT THE MODEL BE TREATED WITH CAUTION?

A. Yes, as was the case with the DCF model, the assumptions underlying the CAPM are stringent. Moreover, the empirical validity of the CAPM has been the subject of intense research in recent years. Although the CAPM provides useful evidence, it must be complemented by other methodologies.

Q. DR. MORIN, PLEASE PROVIDE AN OVERVIEW OF YOUR RISK PREMIUM ANALYSES.

A. In order to quantify the risk premium for a vertically integrated electric utility such as EAI, I have performed four risk premium studies. The first two studies deal with aggregate stock market risk premium evidence using two versions of the CAPM methodology and the other two deal directly with the energy utility industry.

A. <u>CAPM Estimates</u>

Q. PLEASE DESCRIBE YOUR APPLICATION OF THE CAPM RISK PREMIUM APPROACH.

A. My first two risk premium estimates are based on the CAPM and on the ECAPM. The CAPM is a fundamental paradigm of finance. The fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by “beta” or “β”. In short, beta measures the variability of a given firm’s returns relative to overall market returns. A beta of 1.0 implies return variation that mirrors that of the market, and therefore a risk and required return equal to that of the market portfolio. A beta of less than 1.0 implies return variability, and therefore risk and required return, below that of the market. Finally a beta in excess of 1.0 implies return variability, and therefore risk and required return, above that of the market. According to the CAPM, securities are priced such that:

REQUIRED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta(R_M - R_F)$$

This is the seminal CAPM expression, which states that the return required by investors, K, is made up of a risk-free component, R_F, plus a risk premium determined by $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, ($R_M - R_F$). For the risk-free rate, I used 5.0 percent based on current interest rates on long-term U.S. Treasury Bonds. For beta, I used 0.85, and for the market risk premium, I used 7.5 percent. These respective inputs to the CAPM are explained below.

Q. WHAT IS THE BASIS FOR THE RISK-FREE RATE THAT YOU USE IN YOUR CAPM AND RISK PREMIUM ANALYSES?

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. As a proxy for the risk-free rate, I have relied on the actual and forecasted yields on 30-year U.S. Treasury Bonds.

The appropriate proxy for the risk-free rate in the CAPM is the return on the longest term U.S. Treasury Bond possible. This is because common stocks are very long-term instruments more akin to very long-term bonds rather than to short-term or intermediate-term U.S. Treasury

Notes. In a risk premium model, the ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on the longest-term possible government bonds, that is the yield on 30-year U.S. Treasury Bonds, is the best measure of the risk-free rate for use in the CAPM. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments.

While long-term U.S. Treasury Bonds are potentially subject to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (pension funds, insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

Another reason for utilizing the longest maturity U.S. Treasury Bond possible is that common equity has an infinite life span, and the inflation expectations embodied in its market-required rate of return will therefore be equal to the inflation rate anticipated to prevail over the very long-term. The same expectation should be embodied in the risk free rate used in applying the CAPM model. It stands to reason that the actual yields on 30-year U.S. Treasury Bonds will more closely incorporate within their yield the inflation expectations that influence the prices of common stocks than do short-term or intermediate-term U.S. Treasury Notes.

Among U.S. Treasury securities, 30-year U.S. Treasury Bonds have the longest term to maturity and the yield on such securities should be used as proxies for the risk-free rate in applying the CAPM, provided there are no anomalous conditions existing in the 30-year Treasury market. In the absence of such conditions, I have relied on the yield on 30-year U.S. Treasury Bonds in implementing the CAPM and risk premium methods.

Q. DR. MORIN, WHY DID YOU REJECT SHORT-TERM INTEREST RATES AS A PROXY FOR THE RISK-FREE RATE IN IMPLEMENTING THE CAPM?

A. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, U.S. Treasury Bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are used by foreign governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it makes no sense to match the return on common stock to the yield on 90-day U.S. Treasury Bills. This is because short-term rates, such as the yield on 90-day U.S. Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day U.S. Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term U.S. Treasury Bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day U.S. Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term U.S. Treasury Bonds match more closely with common stock returns.

Q. WHAT IS YOUR ESTIMATE OF THE RISK-FREE RATE IN APPLYING THE CAPM?

A. The level of U.S. Treasury 30-year long-term bond yields prevailing in April 2006 as reported in the Value Line Investment Analyzer (“VLIA”) April

2006 edition was 5.0 percent. I also examined the long-term interest rate forecasts contained in the April 2006 edition of the Blue Chip Financial Forecasts. The consensus forecast reported in that publication for the yield on 30-year U.S. Treasury Bonds was 5.1 percent, virtually identical to the current level of 5.0 percent. I therefore used 5.0 percent as my estimate of the risk-free rate component of the CAPM.

Q. HOW DID YOU SELECT THE BETA FOR YOUR CAPM ANALYSIS?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta", or "systematic risk". The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement in the rate of return on a stock relative to the movement in the rate of return on the market as a whole. The beta coefficient indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation which are reflected in investors' return requirements.

As a wholly-owned subsidiary of Entergy, EAI is not publicly traded, and therefore, proxies must be used for EAI. I examined the betas of a sample of widely-traded investment-grade vertically integrated electric utilities covered by Standard & Poor's with at least 50 percent of their revenues from regulated utility operations. This group is examined in more detail later in my testimony, in connection with the DCF estimates of the cost of common equity. In order to minimize the well-known thin trading bias in measuring beta, I only considered those companies whose market capitalization exceeded $500 million. As displayed on page 1 of EAI Exhibit RAM-2, the average beta for the group is 0.85.

As a check on the beta estimate, I examined the average beta for the electric utility industry, as represented by the electric utilities that make up Moody's Electric Utility Index. As displayed on page 2 of EAI Exhibit RAM-2, the average beta for the group is 0.88 and becomes 0.85 with the two outliers (Duke Energy, American Electric Power) removed from the group. These two estimates are nearly identical to the previous estimates. Based on these results, I shall use 0.85 as a reasonable estimate for the beta applicable to EAI.

Q. WHAT MARKET RISK PREMIUM ESTIMATE DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the market risk premium ("MRP"), I used 7.5 percent. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums. First, the Ibbotson Associates study, *Stocks, Bonds, Bills, and Inflation, 2006 Yearbook,* compiling historical returns from 1926 to 2005, shows that a broad market sample of common stocks outperformed long-term U.S. Treasury Bonds by 6.5 percent. The historical market risk premium over the income component of long-term U.S. Treasury Bonds rather than over the total return is 7.1 percent[6]. Ibbotson Associates recommend the use of the latter as a more reliable estimate of the historical market risk premium, and I concur with this viewpoint. The historical MRP should be computed using the income component of bond returns because the intent, even using historical data, is to identify an expected market risk premium. The more accurate way to estimate the market risk premium from historic data is to use the income return, not total returns on government bonds, as explained at page 66 of Ibbotson Associates, Stocks, Bonds, Bills, and Inflation: Valuation Edition, 2005 Yearbook. This is because the income component of total bond return (*i.e.* the coupon rate) is a far better estimate of expected return than the total return (*i.e.* the coupon rate + capital gain), as realized capital gains/losses are largely unanticipated by bond investors. The long-

[6] Because 30-year bonds were not always traded or even available throughout the entire 1926-2005 long period covered in the Ibbotson Associate Study of historical returns, the latter study relied on bond return data based on 20-year U.S. Treasury Bonds. To the extent that the normal yield curve is virtually flat above maturities of 20 years over most of the period covered in the Ibbotson study, the difference in yield is not material. In fact, the difference in yield between 30-year and 20-year bonds is actually negative. The average difference in yield over the 1977-2006 period is 13 basis points, that is, the yield on 20-year bonds is slightly higher than the yield on 30-year bonds.

horizon (1926-2005) market risk premium (based on income returns, as required) is specifically calculated to be 7.1 percent rather than 6.5 percent.

Second, a DCF analysis applied to the aggregate equity market using Value Line's aggregate stock market index and growth forecasts indicates a prospective market risk premium of 7.9 percent, as discussed in detail below. The average of the historical (7.1 percent) and prospective estimates (7.9 percent), which is 7.5 percent, provides a reasonable estimate of the market risk premium.

Q. WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR HISTORICAL MARKET RISK PREMIUM ESTIMATE?

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the market risk premium with historical returns. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate market risk premium minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a “random walk,” one should expect the equity risk premium to remain at its historical mean. The best estimate of the future risk premium is the historical mean. Since I found no evidence that the market price of risk or the amount of risk in common stocks has changed over time, that is, no significant serial correlation in the Ibbotson study, it is reasonable to assume that these quantities will remain stable in the future.

Q. PLEASE DESCRIBE YOUR PROSPECTIVE APPROACH IN DERIVING THE MARKET RISK PREMIUM IN THE CAPM ANALYSIS.

A. For my prospective estimate of the market risk premium, I applied a DCF analysis to the aggregate equity market using Value Line's VLIA software. The application of the DCF model is discussed at length later in my testimony. The dividend yield on the dividend-paying stocks that make up the Value Line Composite index made up of some 1800 stocks is currently 1.19 percent (VLIA 04/2006 edition), and the average projected dividend growth rate is 11.33 percent. Adding the dividend yield to the growth component produces an expected return on the aggregate equity market of 12.52 percent. Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 12.65 percent. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings the market risk premium estimate to approximately 12.85 percent. Subtracting the risk-free rate of 5.0 percent from the latter, the implied risk premium is 7.9 percent over long-term U.S. Treasury Bonds. The average of the historical (7.1 percent) and prospective market risk premium (7.9 percent) estimates is 7.5 percent.

As a check on my market risk premium estimate, I examined a recent 2003 comprehensive article published in Financial Management by Harris, Marston, Mishra, and O'Brien ("HMMO") that provides estimates of the *ex ante* expected returns for S&P 500 companies over the period 1983-1998.[7] HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from

[7] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

January 1983 to August 1998 by using the constant growth DCF model. The prevailing risk-free rate for each year was then subtracted from the expected rate of return for the overall market to arrive at the market risk premium for that year. The table below, drawn from HMMO Table 2, displays the average prospective risk premium estimate for each year from 1983 to 1998. The average market risk premium estimate for the overall period is 7.2 percent, which is reasonably close to my own estimate of 7.5 percent.

Year	DCF Market Risk Premium
1983	6.6%
1984	5.3%
1985	5.7%
1986	7.4%
1987	6.1%
1988	6.4%
1989	6.6%
1990	7.1%
1991	7.5%
1992	7.8%
1993	8.2%
1994	7.3%
1995	7.7%
1996	7.8%
1997	8.2%
1998	9.2%
MEAN	**7.2%**

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE OF THE COMPANY'S COST OF EQUITY USING THE CAPM APPROACH?

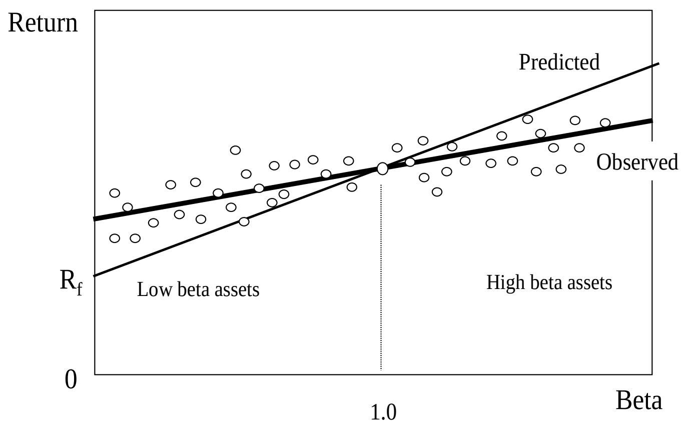
A. Inserting those input values in the CAPM equation, namely a risk-free rate of 5.0 percent, a beta of 0.85, and a market risk premium of 7.5 percent, the CAPM estimate of the cost of common equity is: 5.0% + 0.85 x 7.5%

= 11.4%. This estimate becomes 11.7 percent with flotation costs, discussed later in my testimony.

Q. WHAT IS YOUR RISK PREMIUM ESTIMATE USING THE EMPIRICAL VERSION OF THE CAPM?

A. With respect to the empirical validity of the plain vanilla CAPM, there have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 13 of my book, Regulatory Finance and in Chapter 6 of my latest book, The New Regulatory Finance, soon to be published by Public Utilities Reports, Inc. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. This is one of the most well-known results in finance, and it is displayed graphically below.

CAPM: Predicted vs Observed Returns



A number of variations on the original CAPM theory have been proposed to explain this finding. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + ά + \beta \times (MRP - ά)$$

where ά is the "alpha" of the risk-return line, a constant, MRP is the market risk premium ($R_M – R_F$), and the other symbols are defined as usual. Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha ("ά ") in the range of 1 percent - 2 percent, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following ECAPM expression:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$

As discussed in <u>EAI Appendix A</u>, an alpha range of 1 percent - 2 percent is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. This is also because the use of adjusted betas rather than raw betas also incorporate some of the desired effect of using the ECAPM. Thus, it is reasonable to apply a conservative alpha adjustment.

Q. IS THE USE OF THE ECAPM CONSISTENT WITH THE USE OF ADJUSTED BETAS?

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on a myriad empirical evidence.

The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to the previous graph, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

EAI Appendix A contains a full discussion of the ECAPM, including its theoretical and empirical underpinnings. In short, the following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\ \beta\,(R_M - R_F)$$

Inserting 5.0 percent for the risk-free rate R_F, a market risk premium of 7.5 percent for (R_M - R_F) and a beta of 0.85 in the above equation, the return on common equity is 11.7 percent without flotation costs and 12.0 percent with flotation costs, discussed later in my testimony.

B. <u>Risk Premium Estimates</u>

Q. PLEASE DESCRIBE YOUR HISTORICAL RISK PREMIUM ANALYSIS OF THE ELECTRIC UTILITY INDUSTRY.

A. As a proxy for the risk premium applicable to EAI, I estimated the historical risk premium for the electric utility industry with an annual time series analysis applied to the industry as a whole, using *Moody's Electric Utility Index* as an industry proxy. The analysis is depicted on <u>EAI Exhibit RAM-3</u>. The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year.

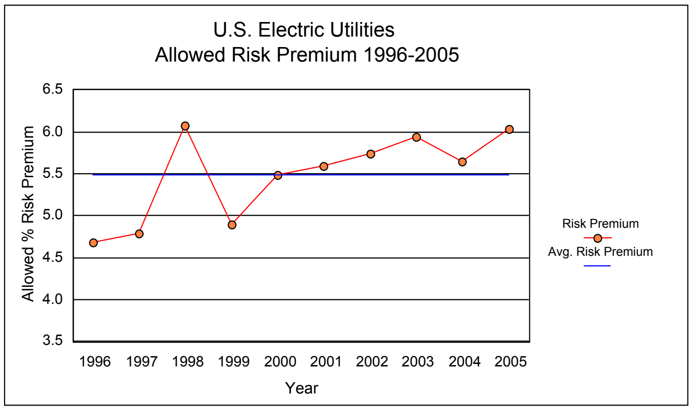
The average risk premium over the period was 5.6 percent over long-term U.S. Treasury Bonds. Given that long-term U.S. Treasury Bonds are currently yielding 5.0 percent, the implied cost of equity for the average risk electric utility from this particular method is 10.6 percent (i. e., 5.0 percent + 5.6 percent) without flotation costs and 10.9 percent with flotation costs. The need for a flotation cost allowance is discussed at length later in my testimony.

The historical risk premium analysis for the electric utility industry stops in 2001 because the annual Moody's Public Utility Manual from which the data were drawn was discontinued following the acquisition of Moody's by Mergent in 2002. In view of the rising risk premium allowed by regulators documented in the next section of my testimony, it would not be unreasonable to expect that the current utility risk premium exceeds the historical average. I did examine some more recent historical bond return and equity return data based on the S&P Utility Index instead of Moody's Electric Utility Index. The addition of 2002-2005 data actually raises the historical risk premium slightly. This is not surprising in view of the rising stock market during the 2003-2005 period.

C. <u>Allowed Risk Premiums</u>

Q. PLEASE DESCRIBE YOUR ANALYSIS OF ALLOWED RISK PREMIUMS IN THE ELECTRIC UTILITY INDUSTRY.

A. To estimate the Company's cost of common equity, I also examined the historical risk premiums implied in the returns on equity allowed by regulatory commissions for electric utilities over the last decade relative to the contemporaneous level of the long-term U.S. Treasury Bond yield. The allowed equity returns are reported on a quarterly basis by Regulatory Research Associates. The average common equity return spread over long-term Treasury yields was 5.5 percent for the 1996-2005 time period, as shown by the horizontal line in the graph below. The graph also shows the year-by-year allowed risk premium. The steadily escalating trend of the risk premium in response to lower interest rates and rising competition and restructuring is noteworthy. .



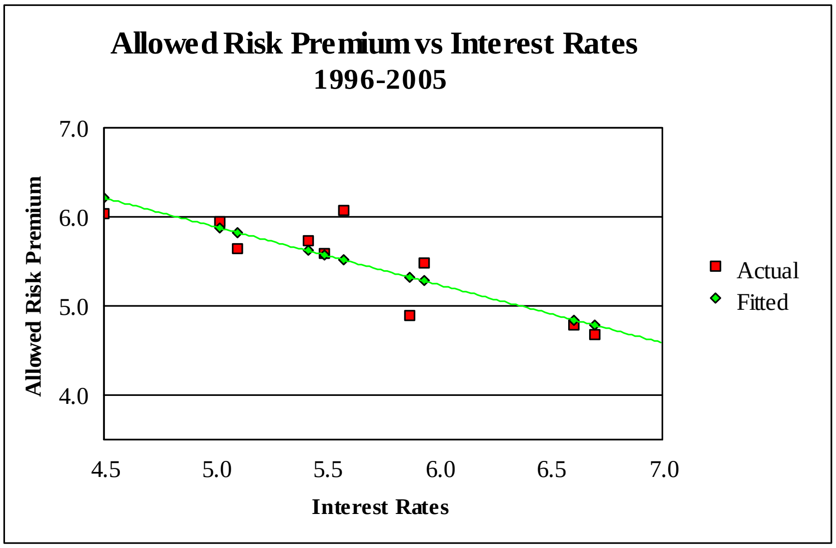
A careful review of these common equity decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the last decade:

$$RP = 9.1508 - 0.6505 \, YIELD \qquad R^2 = 0.74$$
$$(t = 4.7)$$

The relationship is highly statistically significant[8] as indicated by the high R^2 and statistically significant t-value of the slope coefficient. The

[8] The coefficient of determination R^2, sometimes called the "goodness of fit measure" is a measure of the degree of explanatory power of a statistical relationship. It is simply the ratio of the explained portion to the total sum of squares. The higher R^2 the higher is the degree of the overall fit of the estimated regression equation to the sample rata. The t-statistic is a standard measure of the statistical significance of an independent variable in a regression relationship. A t-value above 2.0 is considered highly statistically significant at the 95percent level.

figure below shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past common equity decisions.



Inserting the current long-term U.S. Treasury Bond yield of 5.0 percent in the above equation suggests that a risk premium estimate of 5.9 percent should be allowed for the average risk electric utility, implying a cost of equity of 10.9 percent for the average risk utility.[9]

[9] A flotation cost adjustment is not required here because it is assumed that the allowed ROEs already contemplate such an allowance, and to further add an explicit flotation adjustment would be duplicative. To the extent that flotation costs were not reflected in these allowed ROEs, the analysis understates the required ROE inclusive of flotation costs.

D. <u>DCF Estimates</u>

Q. PLEASE DESCRIBE THE DCF APPROACH TO ESTIMATING THE COST OF EQUITY CAPITAL.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other cash flows. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend at the end of the coming year

P_o = current stock price

g = expected growth rate of dividends, earnings, stock price, book value

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_o, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer 'K_e' from the observed share price, the observed dividend, and an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 4 of my reference book, *Regulatory Finance*. The traditional DCF model requires the following main assumptions: a constant and perpetual annual growth rate for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The traditional DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. IS THE CONSTANT GROWTH DCF MODEL APPLICABLE UNDER ALL CIRCUMSTANCES?

A. No, it is not, as I discussed earlier in my testimony. For companies in a mature industry, such as the electric utility industry had been until recent years, a constant growth rate is a reasonable assumption. For companies in a more dynamic evolving industry, such as the electric utility business in recent years and for the foreseeable future, this assumption may not be reasonable; the dividend growth rate may be expected to converge only over time toward a steady-state long-run level.

Q. HOW DID YOU ESTIMATE EAI'S COST OF EQUITY WITH THE DCF MODEL?

A. I applied the DCF model to two proxies for EAI: a group of vertically integrated electric utilities, and a group consisting of the electric utilities that make up Moody's electric utilities index.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/Po) and the expected long-term growth (g). The expected dividend D_1 in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the current price of the security at the time of estimating the cost of equity. The reason is that current stock prices provide a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, current prices reflect the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the dividend yields reported in the April 2006 edition of Value Line's VLIA. Basing dividend yields on average results from a large group of companies reduces the concern that vagaries of individual company stock prices will result in an unrepresentative dividend yield.

Q. HOW DID YOU ESTIMATE THE GROWTH COMPONENT OF THE DCF MODEL?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined growth estimates developed by professional analysts employed by large investment brokerage institutions. Investors' growth anticipations are influenced by projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities. These forecasts are made by large reputable organizations, and the data are readily available to investors and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model. Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. ("Zacks"). I used analysts' long-term growth forecasts of earnings contained in Zacks as proxies for investors' growth expectations in applying the DCF model. I also used Value Line's earnings growth forecast as an additional proxy.

Q. WHY DID YOU REJECT THE USE OF HISTORICAL GROWTH RATES IN APPLYING THE DCF MODEL TO ELECTRIC UTILITIES?

A. Columns 3, 4, and 5 of EAI Exhibit RAM-4 display the historical growth in earnings, dividends, and book value per share over the last five years for the electric utility companies that make up Value Line's Electric Utility composite group. The average historical growth rates in earnings, dividends, and book value for the group are 2.2 percent, 0.0 percent, and 3.2 percent over the past 5 years, respectively. Several companies have experienced a negative earnings growth rate, as evidenced by the numerous historical growth rates reported on the table that are negative.

These historical growth rates have little relevance as proxies for future long-term growth at this time. They are downward-biased by the sluggish earnings performance in the last five years, due to the structural transformation of the electric utility industry from a regulated monopoly to a more competitive environment. Several electric utility companies have experienced a negative earnings growth rate. The industry as a whole has experienced zero dividend growth over the past five years. These anemic historical growth rates are certainly not representative of these companies' long-term earning power, and produce unreasonably low DCF estimates, well outside reasonable limits of probability and common sense. To illustrate, adding the historical growth rates of 2.2 percent, 0.0 percent, and 3.2 percent to the average dividend yield of approximately 4.0 percent prevailing currently for those same companies, produces preposterous cost of equity estimates of 6.3 percent, 4.0 percent, and 7.2 percent, using earnings, dividends, and book value growth rates, respectively. Of course, these estimates of equity costs are outlandish as they are less than the cost of long-term debt for these companies.

I have therefore rejected historical growth rates as proxies for expected growth in the DCF calculation. In any event, historical growth rates are somewhat redundant because such historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model.

Q. DID YOU CONSIDER FUTURE DIVIDEND GROWTH ESTIMATES IN APPLYING THE DCF MODEL?

A. No, I did not. This is because it is widely expected that electric utilities will continue to lower their dividend payout ratio over the next several years in response to the gradual penetration of competition and its potential impact on the revenue stream. In other words, earnings and dividends are not expected to grow at the same rate in the foreseeable future. According to the latest edition of Value Line, the expected dividend growth of 2.7 percent for the electric utility industry, as proxied by Moody's Electric Utility Index companies, is significantly less than the expected earnings growth of 5.4 percent over the next few years.

Whenever the dividend payout ratio is expected to change, the intermediate growth rate in dividends cannot equal the long-term growth rate, because dividend/earnings growth must adjust to the changing payout ratio. The assumptions of constant perpetual growth and constant payout ratio are clearly not met. The implementation of the standard DCF model is of questionable relevance in this circumstance.

Dividend growth rates are unlikely to provide a meaningful guide to investors' growth expectations for electric utilities in general. This is because electric utilities' dividend policies have become increasing conservative as business risks in the industry have intensified steadily. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks. To wit, the dividend payout ratios of energy utilities have steadily decreased from about 80 percent ten years ago to the 60 percent level today. As a result, investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations. After all, it is growth in earnings that will support future dividends and share prices.

Q. IS THERE ANY EMPIRICAL EVIDENCE DOCUMENTING THE IMPORTANCE OF EARNINGS IN EVALUATING INVESTORS' EXPECTATIONS IN THE INVESTMENT COMMUNITY?

A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. First, the sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. To illustrate, Value Line, Zacks Investment, First Call Thompson, Yahoo! Finance, and Multex provide comprehensive compilations of investors' earnings forecasts, to name some. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Second, surveys of analytical techniques actually used by analysts reveal the dominance of earnings and conclude that earnings are considered far more important than dividends. Third, Value Line's principal investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, accounting for 65 percent of the ranking.

Q. PLEASE DESCRIBE YOUR FIRST PROXY GROUP FOR THE COMPANY'S VERTICALLY INTEGRATED ELECTRIC UTILITY BUSINESS?

A. As a first proxy for the Company's vertically integrated electric utility business, I examined a group of investment-grade utilities designated as "integrated" utilities by S&P in a recent comprehensive analysis of utility business risks. The original group is shown on Pages 1 - 3 of EAI Exhibit RAM-5 and includes electricity and natural gas utility operating companies engaged in predominantly integrated utility activities. As reflected on pages 4 – 6 of EAI Exhibit RAM-5, foreign companies, private partnerships, private companies, and companies below investment-grade, that is, companies with a bond rating below Baa3, were eliminated as well as those companies without Value Line coverage. Pages 7 - 8 of EAI Exhibit RAM-5 narrows the group down to include only the parent companies of investment-grade vertically integrated electric utility utilities. Two companies whose market capitalization was less than $500 million (Central Vermont, Green Mountain Power) were also eliminated in order to minimize any stock price anomalies due to thin trading. The remaining sample of 38 companies is made up of the parent company of these electric utility companies. The final group of 26 companies as shown on Page 9 of EAI Exhibit RAM-5 only includes those companies with at least 50 percent of their revenues from regulated electric utility operations. The same group was discussed earlier in connection with beta estimates and is retained for the DCF analysis.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE VERTICALLY INTEGRATED ELECTRIC UTILITY GROUP USING VALUE LINE GROWTH PROJECTIONS?

A. For purposes of conducting the DCF analysis, as shown on Page 1 of EAI Exhibit RAM-6, two companies (Allete, and Progress Energy) for which no growth forecast was available were discarded. One non-dividend paying company, El Paso Electric, was discarded also. PG&E was eliminated on account of its extraordinary outlying growth rate.

As shown on Column 2 of page 2 of EAI Exhibit RAM-6, the average long-term earnings growth forecast obtained from Value Line is 5.8 percent for this group. Adding this growth rate to the average expected dividend yield of 4.4 percent shown in Column 3 produces an estimate of equity costs of 10.1 percent for the group.[10] Recognition of flotation costs brings the cost of equity estimate to 10.4 percent, shown in Column 5.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE VERTICALLY INTEGRATED ELECTRIC UTILITY UTILITIES GROUP USING THE ANALYSTS' CONSENSUS GROWTH FORECAST?

A. From the original sample of 25 companies shown on page 1 of EAI Exhibit RAM-7, Empire District and MGE Energy were eliminated as no analysts'

[10] Some calculations may not add due to rounding.

growth forecasts were available from Zacks. One non-dividend paying company, El Paso Electric, was discarded also. For the remaining 22 companies shown on page 2 of EAI Exhibit RAM-7, using the consensus analysts' earnings growth forecast published by Zacks of 5.8 percent instead of the Value Line forecast, the cost of equity for the group is 10.1 percent unadjusted for flotation cost. Recognition of flotation costs brings the cost of equity estimate to 10.3 percent, shown in Column 5, virtually the same result obtained using the Value Line growth forecasts.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR MOODY'S ELECTRIC UTILITIES GROUP?

A. Page 1 of EAI Exhibit RAM-8 displays the electric utilities that make up Moody's Electric Utility Index. Progress Energy, for which no growth forecast was available, was eliminated from the group, along with DPL Inc on account of its outlying DCF estimate which was far less than the cost of debt. Public Service Enterprise Group and Cinergy were discarded on account of ongoing merger activity. As shown on Column 2 of page 2 of EAI Exhibit RAM-8, the average long-term growth forecast obtained from Value Line is 5.9 percent for this group. Coupling this growth rate with the average expected dividend yield of 4.4 percent shown in Column 3 produces an estimate of equity costs of 10.4 percent for the group, unadjusted for flotation costs. Adding an allowance for flotation costs to the results of Column 4 brings the cost of equity estimate to 10.6 percent, shown in Column 5.

Using the consensus analysts' earnings growth forecast of 5.7 percent from Zacks instead of the Value Line growth forecast, the cost of equity for the Moody's group is 10.4 percent inclusive of flotation costs. This analysis is displayed on Pages 1 and 2 of EAI Exhibit RAM-9. No growth projections were available for CH Energy and Duquesne Light, and those companies were therefore eliminated from the group. Public Service Enterprise and Cinergy were also discarded on account of ongoing merger activity.

Q. DO THESE DCF RESULTS UNDERSTATE THE COST OF EQUITY FOR EAI?

A. Yes, they do. Application of the standard DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock prices and book values are reasonably similar, that is, when the Market-to-Book ("M/B") ratio is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the M/B ratio of a given stock exceeds unity. This is particularly relevant in the current capital market environment where electric utility stocks are trading at M/B ratios well above unity and have been for two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's

M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.

Q. CAN YOU ILLUSTRATE THE EFFECT OF THE M/B RATIO ON THE DCF MODEL BY MEANS OF A SIMPLE EXAMPLE?

A. Yes. The simple numerical illustration shown in the table below demonstrates the result of applying a market value cost rate to a book value rate base under three different M/B scenarios. The three columns correspond to three M/B situations: the stock trades below, equal to, and above book value, respectively. The last situation (shaded portion of the table) is noteworthy and representative of the current capital market environment. The DCF cost rate of 10 percent, made up of a 5 percent expected dividend yield and a 5 percent growth rate, is applied to the book value rate base of $50 to produce $5.00 of earnings. Of the $5.00 of earnings, the full $5.00 is required for dividends to produce a dividend yield of 5 percent on a stock price of $100.00, and no dollars are available for growth. The investor's return is therefore only 5 percent versus his required return of 10 percent. A DCF cost rate of 10 percent, which implies $10.00 of earnings, translates to only $5.00 of earnings on book value, a 5 percent return.

The situation is reversed in the first column when the stock trades below book value. The $5.00 of earnings is more than enough to satisfy the investor's dividend requirements of $1.25, leaving $3.75 for growth, for a total return of 20 percent. This is because the DCF cost rate is applied to a book value rate base well above the market price.

Therefore, the DCF cost rate understates the investor's required return when stock prices are well above book, as is the case presently and has been for several years, and understates the cost of common equity capital.

Effect of M/B Ratio on Market Return

	CASE 1	CASE 2	CASE 3
Initial purchase price	$25.00	$50.00	$100.00
Initial book value	$50.00	$50.00	$50.00
Initial M/B	0.50	1.00	2.00
DCF Return 10% = 5% + 5%	10.00%	10.00%	10.00%
Dollar Return	$5.00	$5.00	$5.00
Dollar Dividends 5% Yield	$1.25	$2.50	$5.00
Dollar Growth 5% Growth	$3.75	$2.50	$0.00
Market Return	**20.00%**	**10.00%**	**5.00%**

E. Flotation Cost Allowance

Q. DR. MORIN, PLEASE NOW TURN TO THE NEED FOR A FLOTATION COST ALLOWANCE.

A. All the market-based estimates reported above include an adjustment for flotation costs. The simple fact of the matter is that common equity capital is not free. Flotation costs associated with stock issues are exactly like the flotation costs associated with bonds and preferred stocks. Flotation costs are incurred; they are not expensed at the time of issue and, therefore, must be recovered via a rate of return adjustment. This is done routinely for bond and preferred stock issues by most regulatory commissions, including FERC. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, *etc*.). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. EAI Appendix B to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5 percent to the dividend yield component of equity cost by dividing that yield by 0.95 (100 percent - 5 percent) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the Company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10 percent return, that is, $10 of earnings. But if flotation costs are 5 percent, the Company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10 percent must be allowed on this reduced equity base, here 10.53 percent.

According to the empirical finance literature discussed in EAI Appendix B, total flotation costs amount to 4 percent for the direct component and 1 percent for the market pressure component, for a total of 5 percent of gross proceeds. This in turn amounts to approximately 30 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of approximately 5.0 percent for utility stocks by 0.95 yields 5.3 percent, which is 30 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plan, employees' savings plan, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. IS A FLOTATION COST ADJUSTMENT REQUIRED FOR AN OPERATING SUBSIDIARY LIKE EAI THAT DOES NOT TRADE PUBLICLY?

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its parent, in this case, Entergy. This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

IV. SUMMARY & RECOMMENDATION ON COST OF COMMON EQUITY

Q. PLEASE SUMMARIZE YOUR RESULTS AND RECOMMENDATION.

A. To arrive at my final recommendation, I performed four risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other two risk premium analyses were performed on historical and allowed risk premium data from electric utility industry aggregate data, using the yield on long-term U.S. Treasury Bonds. I also performed DCF analyses on two surrogates for EAI: a group of vertically integrated electric utilities, and a group of companies that make up Moody's Electric Utility Index. The results are summarized in the table below.

STUDY	ROE
CAPM	11.7%
Empirical CAPM	12.0%
Risk Premium Electric	10.9%
Allowed Risk Premium	10.9%
DCF Vert. Integrated Electric Utilities Value Line Growth	10.4%
DCF Vert. Integrated Electric Utilities Zacks Growth	10.3%
DCF Moody's Elec Utilities Value Line Growth	10.6%
DCF Moody's Elec Utilities Zacks Growth	10.4%

The results range from a low of 10.3 percent to a high of 12.0 percent, with a midpoint of 11.2 percent. Yet another way of presenting the results is on a methodological basis. The average result from the three principal methodologies is as follows:

CAPM	11.9%
Risk Premium	10.9%
DCF	10.4%
AVERAGE	11.1%

The overall average result is 11.1 percent. Giving somewhat more weight to the CAPM and Risk Premium results due to the infirmities in the application of the DCF methodology to current markets, the central result is 11.25 percent. I stress that no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is hazardous when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others. Thus, the results shown in the above table must be viewed as a whole rather than each as a stand-alone. It would be inappropriate to select any particular number from the summary table and infer EAI's equity costs from that number alone.

Q. DID YOU ADJUST YOUR RESULTS TO ACCOUNT FOR THE COMPANY'S INVESTMENT RISK RELATIVE TO THE INDUSTRY?

A. No, I did not. In my view, the Company's total investment risks are comparable to those of the industry at this time, assuming that the Company's Energy Cost Rider mechanism remains in place, as discussed further below and the Company is allowed full and current recovery of the FERC allocated costs. The Company's bonds are rated "Baa1" by Moody's and "A-" by Standard & Poor's, which is approximately equivalent to the industry average. The Company's Business Risk Score of 5 on a Standard & Poor's scale of 1 to 10, with 1 being the least risky, is comparable to the industry average of 5.1. Because the various costs of common equity estimates reflect the risk of the average vertically integrated electric utility and because the Company's total investment risks are comparable to those of the industry, the expected equity return results from the various comparable groups are applicable to the Company.

Q. DR. MORIN, WHAT IS YOUR FINAL CONCLUSION REGARDING EAI'S COST OF EQUITY CAPITAL?

A. Based on the results of all my analyses and the application of my professional judgment, it is my opinion that a just and reasonable return on common equity for EAI is 11.25 percent.

V. RISK RELATING TO RECOVERY OF FUEL AND PURCHASED POWER EXPENSES

Q. DR. MORIN, CAN YOU PLEASE COMMENT ON THE IMPACT OF THE COMPANY'S ENERGY COST RECOVERY RIDER, WHICH RECOVERS FUEL AND PURCHASED ENERGY EXPENSES, ON THE COMPANY'S BUSINESS RISK?

A. Yes, certainly. Rider ECR serves to reimburse EAI for prudently-incurred fuel and purchased energy expenses in a manner that minimizes the negative financial effects caused by regulatory lag. Consideration of these energy expenses in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. Accordingly, the financial community relies on the presence of energy cost recovery mechanisms to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility. Rider ECR mitigates a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection would be factored into the Company's credit profile as a negative element which, in turn, would raise the Company's cost of capital.

The approval of energy cost recovery mechanisms by regulatory commissions is widespread in the utility business. Approval of fuel adjustment clauses, purchased water adjustment clauses, and purchased gas adjustment clauses has become the norm for regulated industries. All else remaining constant, such clauses reduce investment risk on an absolute basis and constitute sound regulatory policy.

My assessment of EAI's business risk, hence of the Company's cost of common equity, is heavily dependent on the continued presence of the ECR. I believe that, in the absence of continued implementation of Rider ECR requested by EAI in another proceeding, EAI's financial condition would significantly deteriorate, its credit ratings would most likely be downgraded, and its customers would be at risk of having to pay higher rates due to access to capital becoming more expensive for EAI. This situation would have a substantial effect on EAI and its customers because of the magnitude of the energy cost component in its cost of service. I note that the Company's bonds are already under "negative outlook."

Recovery of prudently incurred costs expended on energy allows a regulated utility to serve its native load customers in a reliable manner while maintaining its financial integrity or strength. Since the cost of energy is both a significant component of EAI's operations as well as variable over time, debt and equity investors consider the risks underlying these factors in their determinations as to whether to provide funding and upon what terms within a particular jurisdiction.

I very strongly encourage the Commission not to terminate Rider ECR, and I believe that approval of EAI's request for continued implementation of its Rider ECR is fair to EAI, its customers, and investors. I believe that the Rider ECR deals with the cost of fuel and purchased energy, as well as with the mix of resources, which can vary month-to-month and which can represent a considerable financial outlay, on a consistent basis, without need for recurring regulatory proceedings that are time-consuming, costly, and, significantly, create uncertainty within the financial community.

Q. WOULD TERMINATION OF RIDER ECR HAVE ANY IMPACT ON THE COMPANY'S COST OF COMMON EQUITY?

A. Yes, depending on whether there is any provision for some alternative mechanism for recovery of fuel and purchased power costs, there should be highly significant impacts on EAI's cost of common equity.

If Rider ECR were simply terminated, with no provision for recovery of on-going fuel and purchased power costs, the resulting increase in EAI's cost of common equity would be substantive. Given the proportion of fuel and purchased power costs as compared to total revenue requirement in this proceeding, the Company would quickly be incapable of acquiring incremental financing and would be expected to incur major financial deterioration.

If, on the other hand, the Commission were to terminate Rider ECR and instead include test year fuel and purchased power costs in base rates, the Company would be subject to significantly increased risks, and therefore would incur a significantly higher cost of common equity, than it would incur under the continued, timely application of Rider ECR. All risk associated with changes in fuel and purchased power costs would immediately transfer to the Company, and its cost of common equity would increase.

Only if an alternative mechanism to Rider ECR were approved that allowed for timely recovery of on-going fuel and purchased power costs, with carrying charges equal to the Company's overall required rate of return, would there be no impact on the cost of common equity.

My recommended return is predicated on the assumption that the Commission will not terminate the Company's current Rider ECR as in the past, thus avoiding significantly increased risk to investors. Absent this mechanism, the Company's risk with regard to volatile fuel prices would be significantly enhanced and the investor-required rate of return on common equity correspondingly significantly higher.

VI. IMPACT OF PURCHASED POWER CONTRACTS ON REQUIRED RETURN

Q. DR. MORIN, DO PURCHASED POWER CONTRACTS AFFECT AN ELECTRIC UTILITY'S FINANCIAL RISK PROFILE?

A. Yes, they do. An electric utility with long-term purchased power contracts possesses higher financial risks than a utility without such contracts, all else remaining constant. A company's obligations pursuant to long-term purchased power contracts are comparable to long-term debt and are treated as such by investors and bond rating agencies. The same is true for leveraged lease arrangements. In a recent article in Standard and Poor's The Global Sector Review, dated May 8, 2003, S&P updated its criteria for capital structure treatment of power purchase agreements ("PPA"), noting that industry changes warranted "recognition of a higher debt equivalent when capitalizing PPAs." S&P explained that this more stringent treatment would be factored into its current policy of adjusting the debt/equity ratio of a company for debt equivalents:

> "The principal capital structure ratio analyzed is total debt to total debt plus equity. However, analyzing debt leverage goes beyond the balance sheet and covers quasi-debt items and elements of hidden financial leverage. Non-capitalized leases, debt guarantees, receivables financing and purchased power contracts are all considered debt equivalents and are reflected as debt in calculating capital structure ratios."

The risk perceptions of the investment community and bond rating agencies are such that incremental long-term fixed obligations associated with acquiring energy through off-system purchases increase a utility's financial risk. Clearly, if a company's purchased power contract obligations are converted to a debt equivalent, that company's effective debt ratio increases, and so does its risk.

Q. DOES FINANCIAL THEORY PROVIDE A REASONABLE AND CONSISTENT METHOD OF ADJUSTING FOR THE INCREASED RISK AND RETURN ASSOCIATED WITH PURCHASED POWER CONTRACTS?

A. Yes, it does. The cost of equity for a company with substantial purchased power contracts is higher because that company's effective leverage is higher than otherwise would be the case. It is a rudimentary tenet of basic finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing and/or debt equivalents. In other words, the greater the effective debt ratio, and consequently, the lower the effective common equity ratio, the greater the return required by equity investors.

Several researchers have studied the empirical relationship between the cost of capital and effective capital-structure changes. Comprehensive and rigorous empirical studies of the relationship between cost of capital and leverage for public utilities are summarized in Morin, Regulatory Finance, Public Utilities Report, Inc., Arlington, VA, 1994, Chapter 17.

The results of empirical studies and theoretical studies indicate that equity costs increase from as little as 34 to as much as 237 basis points when the debt ratio increases by ten percentage points. The average increase is 138 basis points from the theoretical studies and 76 basis points from the empirical studies, or a range of 7.6 to 13.8 basis points per one percentage point increase in the debt ratio. The more recent studies indicate that the upper end of that range is more indicative of the effect on equity costs.

Q. CAN YOU PROVIDE A NUMERICAL EXAMPLE OF THE MANNER IN WHICH DEBT EQUIVALENTS INCREASE THE COST OF EQUITY?

A. Yes, I can. Consider an electric utility with a capital structure consisting of 50 percent debt capital and 50 percent common equity capital without any debt equivalents, and whose cost of common equity has been determined to be 11 percent. For illustrative purposes, let us assume that long-term purchased power contracts raise the company's effective debt ratio from 50 percent to 55 percent, indicating a significant increase in financial risk. An upward adjustment to the initial cost of common equity estimate of 11.0 percent would be required to reflect this additional risk. Since the capital structure difference amounts to 5 percent, that is, 55 percent - 50 percent = 5 percent, the required upward adjustment to the cost of equity ranges from 7.6 to 13.8 basis points times 5, which equals 38 to 69 basis points. The midpoint of this range is about 55 basis points. Therefore, in this particular example, the initial cost of equity of 11 percent would have to be adjusted upward by 55 basis points, raising the cost of equity from 11.00 percent to 11.55 percent, in order to reflect the weaker effective capital structure engendered by the purchased power contract debt equivalents. As a general proposition, therefore, for each 1 percent reduction in the common equity ratio, viewed on a traditional capital structure basis, the cost of common equity would increase by approximately 11 basis points (i.e. 55 basis points/5 percent).

VII. CHANGING CAPITAL MARKET CONDITIONS

Q. FINALLY, DR. MORIN, IF CAPITAL MARKET CONDITIONS CHANGE SIGNIFICANTLY BETWEEN THE DATE OF FILING YOUR PREPARED TESTIMONY AND THE DATE YOUR ORAL TESTIMONY IS PRESENTED, WOULD THIS CAUSE YOU TO REVISE YOUR ESTIMATED COST OF EQUITY?

A. Yes. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between the filing date and the time my oral testimony is presented, I will update my testimony accordingly.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 06-101-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT RAM-1

RESUME OF DR. ROGER A. MORIN

RESUME OF ROGER A. MORIN

(Spring 2006)

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(912) 635-3233 business fax
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E-MAIL ADDRESS: profmorin@msn.com

DATE OF BIRTH: 3/5/1945

PRESENT EMPLOYER: Georgia State University
Robinson College of Business
Atlanta, GA 30303

RANK: Professor of Finance

HONORS: Professor of Finance for Regulated Industry
Director Center for the Study of Regulated Industry,
College of Business, Georgia State University.

EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.

- Master of Business Administration, McGill University, Montreal, Canada, 1969.

- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pa., 1972-3

- Assistant Professor, University of Montreal School of Business, 1973-1976.

- Associate Professor, University of Montreal School of Business, 1976-1979.

- Professor of Finance, Georgia State University, 1979-2005

- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, College of Business, Georgia State University, 1985-2005

- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.

- Member of the Board of Directors, Financial Research Institute of Canada, 1974-1980.

- Co-founder and Director Canadian Finance Research Foundation, 1977.

- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.

- Executive Visions Inc., Board of Directors, Member

- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991

PROFESSIONAL CLIENTS

AGL Resources

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

Ameren

American Water Works Company

Ameritech

Arkansas Western Gas

Baltimore Gas & Electric – Constellation Energy

B.C. Telephone

B C GAS

Bell Canada

Bellcore

Bell South Corp.

Bruncor (New Brunswick Telephone)

Burlington-Northern

C & S Bank

Cajun Electric

Canadian Radio-Television & Telecomm. Commission

Canadian Utilities

Canadian Western Natural Gas

Cascade Natural Gas

Centel

Centra Gas

Central Illinois Light & Power Co.

PROFESSIONAL CLIENTS (CONT'D)

Central Telephone

Central & South West Corp.

Chattanoogee Gas Company

Cincinnatti Gas & Electric

Cinergy Corp.

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Consolidated Natural Gas

Constellation Energy

Delmarva Power & Light Co

Deerpath Group

Edison International

Edmonton Power Company

Elizabethtown Gas Co.

Energen

Engraph Corporation

Entergy Corp.

Entergy Arkansas Inc.

Entergy Gulf States, Inc.

Entergy Louisiana, Inc.

Entergy New Orleans, Inc.

First Energy

Florida Water Association

PROFESSIONAL CLIENTS (CONT'D)

Fortis

Garmaise-Thomson & Assoc., Investment Consultants

Gaz Metropolitain

General Public Utilities

Georgia Broadcasting Corp.

Georgia Power Company

GTE California - Verizon

GTE Northwest Inc. - Verizon

GTE Service Corp. - Verizon

GTE Southwest Incorporated - Verizon

Gulf Power Company

Havasu Water Inc.

Hawaiian Electric Company

Heater Utilities – Aqua - America

Hope Gas Inc.

Hydro-Quebec

ICG Utilities

Illinois Commerce Commission

Island Telephone

Jersey Central Power & Light

Kansas Power & Light

KeySpan Energy

Manitoba Hydro

Maritime Telephone

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

PROFESSIONAL CLIENTS (CONT'D)

Minnesota Power & Light

Mississippi Power Company

Missouri Gas Energy

Mountain Bell

Nevada Power Company

New Brunswick Power

Newfoundland Power Inc. - Fortis Inc.

New Tel Enterprises Ltd.

New York Telephone Co.

Norfolk-Southern

Northeast Utilities

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Power – Emera Inc.

Nova Scotia Utility and Review Board

NUI Corp.

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

Pacific Northwest Bell

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Pepco Holdings

PROFESSIONAL CLIENTS (CONT'D)

Price Waterhouse

PSI Energy

Public Service Electric & Gas

Public Service of New Hampshire

Puget Sound Electric Co.

Quebec Telephone

Regie de l'Energie du Quebec

Rochester Telephone

San Diego Gas & Electric

SaskPower

Sierra Pacific Power Company

Southern Bell

Southern States Utilities

Southern Union Gas

South Central Bell

Sun City Water Company

TECO Energy

The Southern Company

Touche Ross and Company

TransEnergie

Trans-Quebec & Maritimes Pipeline

TXU Corp

US WEST Communications

Union Heat Light & Power

Utah Power & Light

Vermont Gas Systems Inc.

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78
- Investment Dealers Association of Canada, 1977-78
- Financial Research Foundation, bi-annual seminar, 1975-79
- Advanced Management Research (AMR), faculty member, 1977-80
- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar
- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member 1981-2006
  National Seminars:

  Risk and Return on Capital Projects
  Cost of Capital for Regulated Utilities
  Capital Allocation for Utilities
  Alternative Regulatory Frameworks
  Utility Directors' Workshop
  Shareholder Value Creation for Utilities
  Real Options in Utility Capital Investments
  Fundamentals of Utility Finance in a Restructured Environment
  Contemporary Issues in Utility Finance

- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Rate of Return

Capital Structure

Generic Cost of Capital

Costing Methodology

Depreciation

Flow-Through vs Normalization

Revenue Requirements Methodology

Utility Capital Expenditures Analysis

Risk Analysis

Capital Allocation

Divisional Cost of Capital, Unbundling

Incentive Regulation & Alternative Regulatory Plans

Shareholder Value Creation

Value-Based Management

REGULATORY BODIES

Federal Communications Commission

Federal Energy Regulatory Commission

Georgia Public Service Commission

South Carolina Public Service Commission

North Carolina Utilities Commission

Pennsylvania Public Service Commission

Ontario Telephone Service Commission

Quebec Telephone Service Commission

Newfoundland Board of Commissioners of Public Utilities

Georgia Senate Committee on Regulated Industries

Alberta Public Service Board

Tennessee Regulatory Authority

Oklahoma State Board of Equalization

Mississippi Public Service Commission

Minnesota Public Utilities Commission

Canadian Radio-Television & Telecommunications Comm.

New Brunswick Board of Public Commissioners

Alaska Public Utility Commission

National Energy Board of Canada

Florida Public Service Commission

Montana Public Service Commission

Arizona Corporation Commission

Quebec Natural Gas Board

Quebec Regie de l'Energie

New York Public Service Commission

Washington Utilities & Transportation Commission

Manitoba Board of Public Utilities

New Jersey Board of Public Utilities

Alabama Public Service Commission

Utah Public Service Commission

Nevada Public Service Commission

Louisiana Public Service Commission

Colorado Public Utilities Board

West Virginia Public Service Commission

Ohio Public Utilities Commission

California Public Service Commission

Hawaii Public Service Commission

Illinois Commerce Commission

British Columbia Board of Public Utilities

Indiana Utility Regulatory Commission

Minnesota Public Utilities Commission

Texas Public Utility Commission

Michigan Public Service Commission

Iowa Board of Public Utilities

Missouri Public Service Commission

Arkansas Public Service Commission

Hawaii Public Utility Commission

New Hampshire Public Utility Commission

Delaware Public Utility Commission

Washington Utilities & Transportation Commission

Virginia Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C

Southern Bell, So. Carolina PSC, Docket #82-294C

Southern Bell, North Carolina PSC, Docket #P-55-816

Metropolitan Edison, Pennsylvania PUC, Docket #R-822249

Pennsylvania Electric, Pennsylvania PUC, Docket #R-822250

Georgia Power, Georgia PSC, Docket # 3270-U, 1981

Georgia Power, Georgia PSC, Docket # 3397-U, 1983

Georgia Power, Georgia PSC, Docket # 3673-U, 1987

Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327

Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731

Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731

Bell Canada, CRTC 1987

Northern Telephone, Ontario PSC

GTE-Quebec Telephone, Quebec PSC, Docket 84-052B

Newtel., Nfld. Brd of Public Commission PU 11-87

CN-CP Telecommunications, CRTC

Quebec Northern Telephone, Quebec PSC

Edmonton Power Company, Alberta Public Service Board

Kansas Power & Light, F.E.R.C., Docket # ER 83-418

NYNEX, FCC generic cost of capital Docket #84-800

Bell South, FCC generic cost of capital Docket #84-800

American Water Works - Tennessee, Docket #7226

Burlington-Northern - Oklahoma State Board of Taxes

Georgia Power, Georgia PSC, Docket # 3549-U

GTE Service Corp., FCC Docket #84-200

Mississippi Power Co., Miss. PSC, Docket U-4761

Citizens Utilities, Ariz. Corp. Comm., D # U2334-86020

Quebec Telephone, Quebec PSC, 1986, 1987, 1992

Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991

Northwestern Bell, Minnesota PSC, #P-421/CI-86-354

GTE Service Corp., FCC Docket #87-463

Anchorage Municipal Power & Light, Alaska PUC, 1988

New Brunswick Telephone, N.B. PUC, 1988

Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92

Gulf Power Co., Florida PSC, Docket #88-1167-EI

Mountain States Bell, Montana PSC, #88-1.2

Mountain States Bell, Arizona CC, #E-1051-88-146

Georgia Power, Georgia PSC, Docket # 3840-U, l989

Rochester Telephone, New York PSC, Docket # 89-C-022

Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89

GTE Northwest, Washington UTC, #U-89-3031

Orange & Rockland, New York PSC, Case 89-E-175

Central Illinois Light Company, ICC, Case 90-0127

Peoples Natural Gas, Pennsylvania PSC, Case

Gulf Power, Florida PSC, Case # 891345-EI

ICG Utilities, Manitoba BPU, Case 1989

New Tel Enterprises, CRTC, Docket #90-15

Peoples Gas Systems, Florida PSC

Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J

Alabama Gas Co., Alabama PSC, Case 890001

Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board

Mountain Bell, Utah PSC,

Mountain Bell, Colorado PUB

South Central Bell, Louisiana PS

Hope Gas, West Virginia PSC

Vermont Gas Systems, Vermont PSC

Alberta Power Ltd., Alberta PUB

Ohio Utilities Company, Ohio PSC

Georgia Power Company, Georgia PSC

Sun City Water Company

Havasu Water Inc.

Centra Gas (Manitoba) Co.

Central Telephone Co. Nevada

AGT Ltd., CRTC 1992

BC GAS, BCPUB 1992

California Water Association, California PUC 1992

Maritime Telephone 1993

BCE Enterprises, Bell Canada, 1993

Citizens Utilities Arizona gas division 1993

PSI Resources 1993-5

CILCORP gas division 1994

GTE Northwest Oregon 1993

Stentor Group 1994-5

Bell Canada 1994-1995

PSI Energy 1993, 1994, 1995, 1999

Cincinnati Gas & Electric 1994, 1996, 1999, 2004

Southern States Utilities, 1995

CILCO 1995, 1999, 2001

Commonwealth Telephone 1996

Edison International 1996, 1998

Citizens Utilities 1997

Stentor Companies 1997

Hydro-Quebec 1998

Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003

Detroit Edison, 1999, 2003

Entergy Gulf States, Texas, 2000, 2004

Hydro Quebec TransEnergie, 2001, 2004

Sierra Pacific Company, 2000, 2001, 2002

Nevada Power Company, 2001

Mid American Energy, 2001, 2002

Entergy Louisiana Inc. 2001, 2002, 2004

Mississippi Power Company, 2001, 2002

Oklahoma Gas & Electric Company, 2002 -2003

Public Service Electric & Gas, 2001, 2002

NUI Corp (Elizabethtown Gas Company), 2002

Jersey Central Power & Light, 2002

San Diego Gas & Electric, 2002

NB Power, 2002

Entergy New Orleans, 2002

Hydro-Quebec Distribution 2002

PSI Energy 2003

Fortis – Newfoundland Power & Light 2002

Emera – Nova Scotia Power 2004

Hydro-Quebec TransEnergie 2004

Hawaiian Electric 2004

Missouri Gas Energy 2004

AGL Resources 2004

Arkansas Western Gas 2004

Public Service of New Hampshire 2005

Hawaiian Electric Company 2005

Delmarva Power & Light Company 2005

Union Heat Power & Light 2005

Puget Sound Electric Co 2006-01-16

Cascade Natural Gas 2006

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982

- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982

- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983

- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.

- Committee on New Product Development, FMA, 1985

- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986

- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986

- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fla., 1988.

PAPERS PRESENTED:

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation

"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, l978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977

- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975

- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976

- Member, New Product Development Committee, Financial Management Association, 1985-1986

- Reviewer: Journal of Financial Research

  Financial Management

  Financial Review

  Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. l982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978.

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994.

Driving Shareholder Value, McGraw-Hill, January 2001.

The New Regulatory Finance, forthcoming February 2006.

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities
Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980. (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

“An Economic & Financial Profile of the Canadian Cablevision Industry,” Canadian Radio-Television & Telecommunication Commission (CRTC), 1978.

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

“Operational Risk Analysis: California Water Utilities,” Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company,1985.

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique",CRTC,1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement, 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry", International Institute of Quantitative Economics, CRTC.

"Application of the Averch-Johnson Model to Telecommunications Utilities", Canadian Radio-Television Commission. (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications.

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981.

"Firm Size and Beta Stability", Georgia State University College of Business, 1982.

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Chase Econometrics, Interactive Data Corp., Research Grant, $50,000 per annum, 1986-1989.

UNIVERSITY SERVICE

- University Senate, elected departmental senator 1987-1989, 1998-2002
- Faculty Affairs Committee, elected departmental representative
- Professional Continuing Education Committee member
- Director Master in Science (Finance) Program
- Course Coordinator, Corporate Finance, MBA program
- Chairman, Corporate Finance Curriculum Committee
- Executive Education: Departmental Coordinator 2000

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 06-101-U

EAI EXHIBIT RAM-2

VERTICALLY INTEGRATED ELECTRIC UTILTIES BETA ESTIMATES

VERTICALLY INTEGRATED ELECTRIC UTILITIES
BETA ESTIMATES

	Company Name	Industry	Beta
1	ALLETE	UTILCENT	
2	Alliant Energy	UTILCENT	0.85
3	Ameren Corp.	UTILCENT	0.75
4	Amer. Elec. Power	UTILCENT	1.20
5	Cen. Vermont Pub. Serv.	UTILEAST	0.60
6	Cleco Corp.	UTILCENT	1.20
7	Edison Int'l	UTILWEST	1.10
8	El Paso Electric	UTILWEST	0.70
9	Empire Dist. Elec.	UTILCENT	0.75
10	Energy East Corp.	UTILEAST	0.85
11	Entergy Corp.	UTILCENT	0.85
12	FirstEnergy Corp.	UTILEAST	0.75
13	FPL Group	UTILEAST	0.80
14	Green Mountain Pwr.	UTILEAST	0.60
15	Hawaiian Elec.	UTILWEST	0.70
16	IDACORP Inc.	UTILWEST	0.95
17	MGE Energy	UTILCENT	0.70
18	Northeast Utilities	UTILEAST	0.80
19	PG&E Corp.	UTILWEST	1.15
20	Pinnacle West Capital	UTILWEST	0.95
21	PNM Resources	UTILWEST	0.95
22	Progress Energy	UTILEAST	0.80
23	Puget Energy Inc.	UTILWEST	0.80
24	Southern Co.	UTILEAST	0.65
25	TECO Energy	UTILEAST	1.00
26	Wisconsin Energy	UTILCENT	0.75
27	Xcel Energy Inc.	UTILWEST	0.85
	AVERAGE		**0.85**

Source: VLIA 03/2006

MOODY'S ELECTRIC UTILITIES
BETA ESTIMATES

	Company Name	Beta
1	Amer. Elec. Power	1.20
2	CH Energy Group	0.80
3	Consol. Edison	0.65
4	Constellation Energy	0.95
5	Dominion Resources	0.95
6	DPL Inc.	0.95
7	Duquesne Light Hldgs	0.85
8	Duke Energy	1.20
9	Energy East Corp.	0.85
10	Exelon Corp.	0.80
11	FirstEnergy Corp.	0.75
12	IDACORP Inc.	0.95
13	NiSource Inc.	0.80
14	OGE Energy	0.75
15	PPL Corp.	1.00
16	Progress Energy	0.80
17	Public Serv. Enterprise	0.90
18	Southern Co.	0.65
19	TECO Energy	1.00
20	Xcel Energy Inc.	0.85
	AVERAGE	0.88
	AVERAGE w/o AEP, Duke	0.85

Source: VLIA 4/2006

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 06-101-U

EAI EXHIBIT RAM-3

MOODY'S ELECTRIC UTILITY COMMON STOCKS

OVER LONG-TERM TREASURY BONDS

ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10	-11
1931	4.07%	1,000.00				43.23					
1932	3.15%	1,135.75	135.75	40.70	17.64%	39.42	2.63	-8.81%	6.08%	-2.73%	-20.37%
1933	3.36%	969.60	-30.40	31.50	0.11%	28.73	1.95	-27.12%	4.95%	-22.17%	-22.28%
1934	2.93%	1,064.73	64.73	33.60	9.83%	21.06	1.60	-26.70%	5.57%	-21.13%	-30.96%
1935	2.76%	1,025.99	25.99	29.30	5.53%	36.06	1.32	71.23%	6.27%	77.49%	71.96%
1936	2.55%	1,032.74	32.74	27.60	6.03%	41.60	1.48	15.36%	4.10%	19.47%	13.43%
1937	2.73%	972.40	-27.60	25.50	-0.21%	24.24	1.74	-41.73%	4.18%	-37.55%	-37.34%
1938	2.52%	1,032.83	32.83	27.30	6.01%	27.55	1.50	13.66%	6.19%	19.84%	13.83%
1939	2.26%	1,041.65	41.65	25.20	6.68%	28.85	1.48	4.72%	5.37%	10.09%	3.41%
1940	1.94%	1,052.84	52.84	22.60	7.54%	22.22	1.54	-22.98%	5.34%	-17.64%	-25.19%
1941	2.04%	983.64	-16.36	19.40	0.30%	13.45	1.44	-39.47%	6.48%	-32.99%	-33.29%
1942	2.46%	933.97	-66.03	20.40	-4.56%	14.29	1.26	6.25%	9.37%	15.61%	20.18%
1943	2.48%	996.86	-3.14	24.60	2.15%	21.01	1.28	47.03%	8.96%	55.98%	53.84%
1944	2.46%	1,003.14	3.14	24.80	2.79%	21.09	1.31	0.38%	6.24%	6.62%	3.82%
1945	1.99%	1,077.23	77.23	24.60	10.18%	31.14	1.30	47.65%	6.16%	53.82%	43.63%
1946	2.12%	978.90	-21.10	19.90	-0.12%	32.71	1.43	5.04%	4.59%	9.63%	9.75%
1947	2.43%	951.13	-48.87	21.20	-2.77%	25.60	1.56	-21.74%	4.77%	-16.97%	-14.20%
1948	2.37%	1,009.51	9.51	24.30	3.38%	26.20	1.60	2.34%	6.25%	8.59%	5.21%
1949	2.09%	1,045.58	45.58	23.70	6.93%	30.57	1.66	16.68%	6.34%	23.02%	16.09%
1950	2.24%	975.93	-24.07	20.90	-0.32%	30.81	1.76	0.79%	5.76%	6.54%	6.86%
1951	2.69%	930.75	-69.25	22.40	-4.69%	33.85	1.88	9.87%	6.10%	15.97%	20.65%
1952	2.79%	984.75	-15.25	26.90	1.17%	37.85	1.91	11.82%	5.64%	17.46%	16.29%
1953	2.74%	1,007.66	7.66	27.90	3.56%	39.61	2.01	4.65%	5.31%	9.96%	6.40%
1954	2.72%	1,003.07	3.07	27.40	3.05%	47.56	2.13	20.07%	5.38%	25.45%	22.40%
1955	2.95%	965.44	-34.56	27.20	-0.74%	49.35	2.21	3.76%	4.65%	8.41%	9.15%
1956	3.45%	928.19	-71.81	29.50	-4.23%	48.96	2.32	-0.79%	4.70%	3.91%	8.14%
1957	3.23%	1,032.23	32.23	34.50	6.67%	50.30	2.43	2.74%	4.96%	7.70%	1.03%
1958	3.82%	918.01	-81.99	32.30	-4.97%	66.37	2.50	31.95%	4.97%	36.92%	41.89%
1959	4.47%	914.65	-85.35	38.20	-4.71%	65.77	2.61	-0.90%	3.93%	3.03%	7.74%
1960	3.80%	1,093.27	93.27	44.70	13.80%	76.82	2.68	16.80%	4.07%	20.88%	7.08%

Year	Long-Term Government Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	Moody's Electric Utility Stock Index	Dividend	Capital Gain/(Loss) % Growth	Yield	Stock Total Return	Equity Risk Premium
	-1	-2	-3	-4	-5	-6	-7	-8	-9	-10	-11
1961	4.15%	952.75	-47.25	38.00	-0.92%	99.32	2.81	29.29%	3.66%	32.95%	33.87%
1962	3.95%	1,027.48	27.48	41.50	6.90%	96.49	2.97	-2.85%	2.99%	0.14%	-6.76%
1963	4.17%	970.35	-29.65	39.50	0.99%	102.31	3.21	6.03%	3.33%	9.36%	8.37%
1964	4.23%	991.96	-8.04	41.70	3.37%	115.54	3.43	12.93%	3.35%	16.28%	12.92%
1965	4.50%	964.64	-35.36	42.30	0.69%	114.86	3.86	-0.59%	3.34%	2.75%	2.06%
1966	4.55%	993.48	-6.52	45.00	3.85%	105.99	4.11	-7.72%	3.58%	-4.14%	-7.99%
1967	5.56%	879.01	-120.99	45.50	-7.55%	98.19	4.34	-7.36%	4.09%	-3.26%	4.29%
1968	5.98%	951.38	-48.62	55.60	0.70%	104.04	4.50	5.96%	4.58%	10.54%	9.84%
1969	6.87%	904.00	-96.00	59.80	-3.62%	84.62	4.61	-18.67%	4.43%	-14.23%	-10.62%
1970	6.48%	1,043.38	43.38	68.70	11.21%	88.59	4.70	4.69%	5.55%	10.25%	-0.96%
1971	5.97%	1,059.09	59.09	64.80	12.39%	85.56	4.77	-3.42%	5.38%	1.96%	-10.42%
1972	5.99%	997.69	-2.31	59.70	5.74%	83.61	4.87	-2.28%	5.69%	3.41%	-2.33%
1973	7.26%	867.09	-132.91	59.90	-7.30%	60.87	5.01	-27.20%	5.99%	-21.21%	-13.90%
1974	7.60%	965.33	-34.67	72.60	3.79%	41.17	4.83	-32.36%	7.93%	-24.43%	-28.22%
1975	8.05%	955.63	-44.37	76.00	3.16%	55.66	4.97	35.20%	12.07%	47.27%	44.10%
1976	7.21%	1,088.25	88.25	80.50	16.87%	66.29	5.18	19.10%	9.31%	28.40%	11.53%
1977	8.03%	919.03	-80.97	72.10	-0.89%	68.19	5.54	2.87%	8.36%	11.22%	12.11%
1978	8.98%	912.47	-87.53	80.30	-0.72%	59.75	5.81	-12.38%	8.52%	-3.86%	-3.13%
1979	10.12%	902.99	-97.01	89.80	-0.72%	56.41	6.22	-5.59%	10.41%	4.82%	5.54%
1980	11.99%	859.23	-140.77	101.20	-3.96%	54.42	6.58	-3.53%	11.66%	8.14%	12.09%
1981	13.34%	906.45	-93.55	119.90	2.63%	57.20	6.99	5.11%	12.84%	17.95%	15.32%
1982	10.95%	1,192.38	192.38	133.40	32.58%	70.26	7.43	22.83%	12.99%	35.82%	3.24%
1983	11.97%	923.12	-76.88	109.50	3.26%	72.03	7.87	2.52%	11.20%	13.72%	10.46%
1984	11.70%	1,020.70	20.70	119.70	14.04%	80.16	8.26	11.29%	11.47%	22.75%	8.71%
1985	9.56%	1,189.27	189.27	117.00	30.63%	94.98	8.61	18.49%	10.74%	29.23%	-1.40%
1986	7.89%	1,166.63	166.63	95.60	26.22%	113.66	8.89	19.67%	9.36%	29.03%	2.80%
1987	9.20%	881.17	-118.83	78.90	-3.99%	94.24	9.12	-17.09%	8.02%	-9.06%	-5.07%
1988	9.18%	1,001.82	1.82	92.00	9.38%	100.94	8.87	7.11%	9.41%	16.52%	7.14%
1989	8.16%	1,099.75	99.75	91.80	19.16%	122.52	8.82	21.38%	8.74%	30.12%	10.96%
1990	8.44%	973.17	-26.83	81.60	5.48%	117.77	8.79	-3.88%	7.17%	3.30%	-2.18%
1991	7.30%	1,118.94	118.94	84.40	20.33%	144.02	8.95	22.29%	7.60%	29.89%	9.55%
1992	7.26%	1,004.19	4.19	73.00	7.72%	141.06	9.05	-2.06%	6.28%	4.23%	-3.49%
1993	6.54%	1,079.70	79.70	72.60	15.23%	146.70	8.99	4.00%	6.37%	10.37%	-4.86%

Year	Long-Term Government Bond Yield (1)	20 year Maturity Bond Value (2)	Gain/Loss (3)	Interest (4)	Bond Total Return (5)	Moody's Electric Utility Stock Index (6)	Dividend (7)	Capital Gain/(Loss) % Growth (8)	Yield (9)	Stock Total Return (10)	Equity Risk Premium (11)
1994	7.99%	856.40	-143.60	65.40	-7.82%	115.50	8.96	-21.27%	6.11%	-15.16%	-7.34%
1995	6.03%	1,225.98	225.98	79.90	30.59%	142.90	9.06	23.72%	7.84%	31.57%	0.98%
1996	6.73%	923.67	-76.33	60.30	-1.60%	136.00	9.06	-4.83%	6.34%	1.51%	3.11%
1997	6.02%	1,081.92	81.92	67.30	14.92%	155.73	9.06	14.51%	6.66%	21.17%	6.25%
1998	5.42%	1,072.71	72.71	60.20	13.29%	181.44	8.01	16.51%	5.14%	21.65%	8.36%
1999	6.82%	848.41	-151.59	54.20	-9.74%	137.30	8.06	-24.33%	4.44%	-19.89%	-10.15%
2000	5.58%	1,148.30	148.30	68.20	21.65%	227.09	8.71	65.40%	6.34%	71.74%	50.09%
2001	5.75%	979.95	-20.05	55.80	3.57%	214.08	8.56	-5.73%	3.77%	-1.96%	-5.54%
Mean											**5.55%**

Source: Mergent's (Moody's) Public Utility Manual 2002 December stock prices and dividends
Dec. Bond yields from Ibbotson Associates 2002 Yearbook Table B-9 Long-Term Government Bonds Yields

December stock price, dividends from Moody's Public Utility Manual

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 06-101-U

EAI EXHIBIT RAM-4

ELECTRIC UTILITIES HISTORICAL GROWTH RATES

ELECTRIC UTILITIES
HISTORICAL GROWTH RATES

	Company Name	Industry	Earnings Growth 5-Year	Dividend Growth 5-Year	Book Value Growth 5-Year
1	ALLETE	UTILCENT			
2	Alliant Energy	UTILCENT	-3.0	-7.5	-1.5
3	Amer. Elec. Power	UTILCENT	3.5	-9.0	-3.5
4	Ameren Corp.	UTILCENT	1.5		4.0
5	Avista Corp.	UTILWEST	-3.5	-5.0	4.5
6	Black Hills	UTILWEST	4.5	4.0	17.0
7	Cen. Vermont Pub. Serv.	UTILEAST	8.5	0.5	2.0
8	CH Energy Group	UTILEAST	-1.5		2.0
9	Cinergy Corp.	UTILCENT	1.5	0.5	5.0
10	Cleco Corp.	UTILCENT	1.0	2.0	4.0
11	Consol. Edison	UTILEAST	-2.0	1.0	2.5
12	Constellation Energy	UTILEAST	6.0	-9.0	4.5
13	Dominion Resources	UTILEAST	11.0		4.5
14	DPL Inc.	UTILCENT	-1.0	0.5	-3.5
15	DTE Energy	UTILCENT	-2.0		3.5
16	Duke Energy	UTILEAST	-4.5		7.5
17	Duquesne Light Hldgs	UTILEAST	-14.5	-5.5	-17.5
18	Edison Int'l	UTILWEST		-9.0	8.5
19	Empire Dist. Elec.	UTILCENT	-5.0		2.0
20	Energy East Corp.	UTILEAST	-0.5	5.5	5.5
21	Entergy Corp.	UTILCENT	11.0	1.5	5.5
22	Exelon Corp.	UTILEAST	6.5		
23	FirstEnergy Corp.	UTILEAST	1.0	2.0	6.0
24	Florida Public Utilities	UTILEAST	-0.5	4.5	8.0
25	FPL Group	UTILEAST	3.5	4.5	6.0
26	Green Mountain Pwr.	UTILEAST	37.5	-6.5	-0.5
27	Hawaiian Elec.	UTILWEST	1.0		2.5
28	IDACORP Inc.	UTILWEST	-3.0	-0.5	4.0
29	Maine & Maritimes Corp	UTILEAST	20.0	6.5	6.0
30	MDU Resources	UTILWEST	10.5	5.0	13.0
31	MGE Energy	UTILCENT	4.0	1.0	5.0
32	NiSource Inc.	UTILCENT		1.0	7.0
33	Northeast Utilities	UTILEAST		37.5	2.0
34	NSTAR	UTILEAST	4.0	1.0	2.0
35	OGE Energy	UTILCENT	-2.0		1.5

Company Name	Industry	Earnings Growth 5-Year	Dividend Growth 5-Year	Book Value Growth 5-Year
36 Otter Tail Corp.	UTILCENT	2.0	2.0	7.5
37 Pepco Holdings	UTILEAST			
38 PG&E Corp.	UTILWEST	-20.5		-8.0
39 Pinnacle West Capital	UTILWEST	-3.0	7.0	4.0
40 PNM Resources	UTILWEST	-2.0	4.5	5.0
41 PPL Corp.	UTILEAST	8.5	8.5	12.0
42 Progress Energy	UTILEAST	5.5	3.0	8.5
43 Public Serv. Enterprise	UTILEAST	5.0		0.5
44 Puget Energy Inc.	UTILWEST	-5.5	-10.5	0.5
45 SCANA Corp.	UTILEAST	7.0	2.0	3.0
46 Sempra Energy	UTILWEST	14.0	-8.5	6.0
47 Southern Co.	UTILEAST	2.5	1.0	-1.5
48 TECO Energy	UTILEAST	-11.0	-3.5	-2.0
49 UniSource Energy	UTILWEST	5.0		12.0
50 UNITIL Corp.	UTILEAST	-1.5		0.5
51 Vectren Corp.	UTILCENT	1.0	3.0	3.5
52 Westar Energy	UTILCENT	-1.5	-14.5	-11.0
53 Wisconsin Energy	UTILCENT	9.5	-12.0	3.5
54 WPS Resources	UTILCENT	11.0	2.0	8.5
55 Xcel Energy Inc.	UTILWEST	-9.5	-9.0	-5.0
AVERAGE		**2.2**	**0.0**	**3.2**

Source: Value Line Investment Analyzer 4/2006

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 06-101-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI EXHIBIT RAM-5

STANDARD & POOR'S VERTICALLY INTEGRATED UTILITIES

Integrated Electric, Gas, and Combination Utilities

	Company	Parent
1	AGL Resources Inc	AGL Resources Inc
2	Allete Inc.	Allete Inc.
3	Wisconsin Power & Light Co.	Alliant
4	Interstate Power & Light Co.	Alliant
5	Central Illinois Light Co.	Ameren Corp
6	CILCORP	Ameren Corp
7	Union Electric Co.	Ameren Corp
8	Ameren Corp.	Ameren Corp
9	Kentucky Power Co.	American Electric Power
10	Appalachian Power Co.	American Electric Power
11	Public Service Co. of Oklahoma	American Electric Power
12	Southwestern Electric Power Co.	American Electric Power
13	Atmos Energy Corp.	Atmos
14	Black Hills Power Inc.	Black Hills
15	Central Vermont Public Service	Central Vermont
16	Cincinnati Gas & Electric Co.	Cinergy Corp.
17	PSI Energy Inc.	Cinergy Corp.
18	Union Light Heat & Power Co.	Cinergy Corp.
19	Cleco Power LLC	CLECO
20	Virginia Electric& Power Co	Dominion Resources
21	Detroit Edison Co	DTE Energy Company
22	Michigan Consolidated Gas Co.	DTE Energy Company
23	Duke Energy Field Services LLC	Duke Energy
24	Southern California Edison Co.	Edison International
25	El Paso Electric Co.	El Paso Corp
26	Empire District Electric Co.	Empire District Electric Co.
27	Energen Corp	Energen Corp
28	RGS Energy Group Inc.	Energy East Corporation
29	Rochester Gas & Electric Corp.	Energy East Corp.
30	Energy East Corp.	Energy East Corp.
31	Entergy Gulf States Inc.	Entergy Corporation
32	Entergy New Orleans Inc.	Entergy Corporation
33	Entergy Mississippi Inc.	Entergy Corporation

	Company	Parent
34	Entergy Louisiana Inc,	Entergy Corporation
35	Entergy Arkansas Inc.	Entergy Corporation
36	System Energy Resources Inc.	Entergy Corporation
37	Equitable Resources Inc.	Equitable Resources Inc.
38	Ohio Edison Co	FirstEnergy
39	Toledo Edison Co.	FirstEnergy
40	Cleveland Electric Illuminating Co.	FirstEnergy
41	Pennsylvania Power Co.	FirstEnergy
42	Florida Power & Light Co.	FPL Group Inc
43	Kansas City Power & Light Co.	Great Plains Energy
44	Green Mountain Power Corp.	Green Mountain Power
45	Hawaiian Electric Co. Inc.	Hawaiian Electric Industries Inc
46	Idaho Power Co.	IDACORP
47	IDACORP Inc.	IDACORP Inc.
48	Kaneb Pipe Line OperPartnership L.P.	Kaneb Pipe Line LP
49	Kentucky Utilities Co.	LG&E Energy Corp
50	Montana-Dakota Utilities Co.	MDU Resources
51	Madison Gas & Electric Co.	MGE Energy
52	MidAmerican Energy Co	MidAmerican Energy Holding Co
53	National Fuel Gas Co.	National Fuel Gas Co
54	Northern Indiana Public Service Co.	NiSource
55	Columbia Energy Group	NiSource
56	NiSource Inc.	NiSource Inc.
57	Public Service Co. of New Hampshire	Northeast Utilities System
58	Northern Border Partners L.P.	Northern Plains
59	Enogex Inc.	OGE Energy
60	Oklahoma Gas & Electric Co.	OGE Energy Corp
61	Portland General Electric Co.	Oregon Electric Utility Co
62	Pacific Gas & Electric Co.	PG&E National Energy Group Inc
63	Arizona Public Service Co.	Pinnacle West Capital Corp.
64	Pinnacle West Capital Corp.	Pinnacle West Capital Corp.
65	Public Service Co. of New Mexico	PNM Resources
66	PNM Resources Inc.	PNM Resources Inc.
67	Louisville Gas & Electric Co.	Powergen Plc
68	Progress Energy Carolinas Inc.	Progress Energy Inc
69	Progress Energy Florida	Progress Energy Inc

	Company	Parent
70	Puget Energy Inc.	Puget Energy
71	Puget Sound Energy Inc.	Puget Energy
72	Questar Market Resources Inc.	Questar Corp
73	Questar Corp	Questar Corp
74	SCANA Corp.	SCANA Corp.
75	South Carolina Electric & Gas Co.	SCANA Corp.
76	PacifiCorp	Scottish Power Group
77	San Diego Gas & Electric Co	Sempra Energy
78	Southern Co.	Southern Company
79	Alabama Power Co	Southern Company
80	Georgia Power Co	Southern Company
81	Savannah Electric & Power Co	Southern Company
82	Gulf Power Co.	Southern Company
83	Mississippi Power Co	Southern Company
84	Tampa Electric Co.	TECO Energy Inc
85	TXU U.S. Holdings Co.	TXU
86	Vectren Utility Holdings Inc.	Vectren Corporation
87	Southern Indiana Gas & Electric Co.	Vectren Corporation
88	Wisconsin Electric Power Co.	Wisconsin Energy Corp.
89	Wisconsin Energy Corp.	Wisconsin Energy Corp.
90	Wisconsin Public Service Corp.	WPS Resources
91	Southwestern Public Service Co.	XCEL Energy Inc
92	Public Service Co. of Colorado	XCEL Energy Inc
93	Northern States Power Wisconsin	XCEL Energy Inc
94	Northern States Power Co.	XCEL Energy Inc
95	Xcel Energy Inc.	XCEL Energy Inc

Integrated Electric Utilities

	Company	Parent
1	Allete Inc.	Allete Inc.
2	Wisconsin Power & Light Co.	Alliant
3	Interstate Power & Light Co.	Alliant
4	Central Illinois Light Co.	Ameren Corp
5	CILCORP	Ameren Corp
6	Union Electric Co.	Ameren Corp
7	Ameren Corp.	Ameren Corp
8	Kentucky Power Co.	American Electric Power
9	Appalachian Power Co.	American Electric Power
10	Public Service Co. of Oklahoma	American Electric Power
11	Southwestern Electric Power Co.	American Electric Power
12	Black Hills Power Inc.	Black Hills
13	Central Vermont Public Service	Central Vermont
14	Cincinnati Gas & Electric Co.	Cinergy Corp.
15	PSI Energy Inc.	Cinergy Corp.
16	Union Light Heat & Power Co.	Cinergy Corp.
17	Cleco Power LLC	CLECO
18	Virginia Electric& Power Co	Dominion Resources
19	Detroit Edison Co	DTE Energy Company
20	Michigan Consolidated Gas Co.	DTE Energy Company
21	Duke Energy Field Services LLC	Duke Energy
22	Southern California Edison Co.	Edison International
23	El Paso Electric Co.	El Paso Corp
24	Empire District Electric Co.	Empire District Electric Co.
25	RGS Energy Group Inc.	Energy East Corporation
26	Rochester Gas & Electric Corp.	Energy East Corp.
27	Energy East Corp.	Energy East Corp.
28	Entergy Gulf States Inc.	Entergy Corporation
29	Entergy New Orleans Inc.	Entergy Corporation
30	Entergy Mississippi Inc.	Entergy Corporation
31	Entergy Louisiana Inc,	Entergy Corporation
32	Entergy Arkansas Inc.	Entergy Corporation
33	System Energy Resources Inc.	Entergy Corporation

	Company	Parent
34	Ohio Edison Co	FirstEnergy
35	Toledo Edison Co.	FirstEnergy
36	Cleveland Electric Illuminating Co.	FirstEnergy
37	Pennsylvania Power Co.	FirstEnergy
38	Florida Power & Light Co.	FPL Group Inc
39	Kansas City Power & Light Co.	Great Plains Energy
40	Green Mountain Power Corp.	Green Mountain Power
41	Hawaiian Electric Co. Inc.	Hawaiian Electric Industries Inc
42	Idaho Power Co.	IDACORP
43	IDACORP Inc.	IDACORP Inc.
44	Montana-Dakota Utilities Co.	MDU Resources
45	Madison Gas & Electric Co.	MGE Energy
46	Public Service Co. of New Hampshire	Northeast Utilities System
47	Enogex Inc.	OGE Energy
48	Oklahoma Gas & Electric Co.	OGE Energy Corp
49	Pacific Gas & Electric Co.	PG&E Corp
50	Arizona Public Service Co.	Pinnacle West Capital Corp.
51	Pinnacle West Capital Corp.	Pinnacle West Capital Corp.
52	Public Service Co. of New Mexico	PNM Resources
53	PNM Resources Inc.	PNM Resources Inc.
54	Progress Energy Carolinas Inc.	Progress Energy Inc
55	Progress Energy Florida	Progress Energy Inc
56	Puget Energy Inc.	Puget Energy
57	Puget Sound Energy Inc.	Puget Energy
58	SCANA Corp.	SCANA Corp.
59	South Carolina Electric & Gas Co.	SCANA Corp.
60	San Diego Gas & Electric Co	Sempra Energy
61	Southern Co.	Southern Company
62	Alabama Power Co	Southern Company
63	Georgia Power Co	Southern Company
64	Savannah Electric & Power Co	Southern Company
65	Gulf Power Co.	Southern Company
66	Mississippi Power Co	Southern Company
67	Tampa Electric Co.	TECO Energy Inc
68	TXU U.S. Holdings Co.	TXU

	Company	Parent
69	Vectren Utility Holdings Inc.	Vectren Corporation
70	Southern Indiana Gas & Electric Co.	Vectren Corporation
71	Wisconsin Electric Power Co.	Wisconsin Energy Corp.
72	Wisconsin Energy Corp.	Wisconsin Energy Corp.
73	Wisconsin Public Service Corp.	WPS Resources
74	Southwestern Public Service Co.	XCEL Energy Inc
75	Public Service Co. of Colorado	XCEL Energy Inc
76	Northern States Power Wisconsin	XCEL Energy Inc
77	Northern States Power Co.	XCEL Energy Inc
78	Xcel Energy Inc.	XCEL Energy Inc

Eliminated gas companies, UK utilities, partnerships, non-traded

Publicly-Traded Integrated Electric Utilities

	Company	Parent
1	Allete Inc.	Allete Inc.
2	Wisconsin Power & Light Co.	Alliant
3	Central Illinois Light Co.	Ameren Corp
4	Kentucky Power Co.	American Electric Power
5	Black Hills Power Inc.	Black Hills
6	Cincinnati Gas & Electric Co.	Cinergy Corp.
7	Cleco Power LLC	CLECO
8	Virginia Electric& Power Co	Dominion Resources
9	Detroit Edison Co	DTE Energy Company
10	Duke Energy Field Services LLC	Duke Energy
11	Southern California Edison Co.	Edison International
12	El Paso Electric Co.	El Paso Corp
13	Empire District Electric Co.	Empire District Electric Co.
14	RGS Energy Group Inc.	Energy East Corporation
15	Entergy Gulf States Inc.	Entergy Corporation
16	Ohio Edison Co	FirstEnergy
17	Florida Power & Light Co.	FPL Group Inc
18	Kansas City Power & Light Co.	Great Plains Energy
19	Hawaiian Electric Co. Inc.	Hawaiian Electric Industries Inc
20	Idaho Power Co.	IDACORP
21	Montana-Dakota Utilities Co.	MDU Resources
22	Madison Gas & Electric Co.	MGE Energy
23	Public Service Co. of New Hampshire	Northeast Utilities System
24	Enogex Inc.	OGE Energy
25	Pacific Gas & Electric Co.	PG&E Corp
26	Arizona Public Service Co.	Pinnacle West Capital Corp.
27	Public Service Co. of New Mexico	PNM Resources
28	Progress Energy Carolinas Inc.	Progress Energy Inc
29	Puget Energy Inc.	Puget Energy
30	SCANA Corp.	SCANA Corp.
31	San Diego Gas & Electric Co	Sempra Energy
32	Southern Co.	Southern Company
33	Tampa Electric Co.	TECO Energy Inc

	Company	Parent
34	TXU U.S. Holdings Co.	TXU
35	Vectren Utility Holdings Inc.	Vectren Corporation
36	Wisconsin Electric Power Co.	Wisconsin Energy Corp.
37	Wisconsin Public Service Corp.	WPS Resources
38	Southwestern Public Service Co.	XCEL Energy Inc

Eliminated gas companies, UK utilities, partnerships, non-traded
Duplicate parents deleted

Central Vermont and Green Mountain Power eliminated market cap < $500M

Publicly-Traded Integrated Electric Utilities
Predominant Regulated Utility Operations

1. ALLETE
2. Alliant Energy
3. Ameren Corp.
4. Amer. Elec. Power
5. Cinergy Corp.
6. Cleco Corp.
7. Edison Int'l
8. El Paso Electric
9. Empire Dist. Elec.
10. Energy East Corp.
11. Entergy Corp.
12. FirstEnergy Corp.
13. FPL Group
14. Hawaiian Elec.
15. IDACORP Inc.
16. MGE Energy
17. Northeast Utilities
18. PG&E Corp.
19. Pinnacle West Capital
20. PNM Resources
21. Progress Energy
22. Puget Energy Inc.
23. Southern Co.
24. TECO Energy
25. Wisconsin Energy
26. Xcel Energy Inc.

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 06-101-U

EAI EXHIBIT RAM-6

VERTICALLY INTEGRATED ELECTRIC UTILTIES DCF ANALYSIS

VALUE LINE GROWTH PROJECTIONS

S&P'S VERTICALLY INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	ALLETE	3.2	
2	Alliant Energy	3.6	6.0
3	Ameren Corp.	5.0	2.5
4	Amer. Elec. Power	4.4	2.5
5	Cleco Corp.	4.0	4.5
6	Edison Int'l	2.7	10.5
7	El Paso Electric	0.0	18.5
8	Empire Dist. Elec.	5.8	6.5
9	Energy East Corp.	4.8	4.0
10	Entergy Corp.	3.1	5.0
11	FirstEnergy Corp.	3.6	8.5
12	FPL Group	3.8	6.5
13	Hawaiian Elec.	4.6	2.5
14	IDACORP Inc.	3.7	4.5
15	MGE Energy	4.2	5.0
16	Northeast Utilities	3.5	9.0
17	PG&E Corp.	3.4	26.5
18	Pinnacle West Capital	5.1	5.5
19	PNM Resources	3.6	7.0
20	Progress Energy	5.5	
21	Puget Energy Inc.	4.7	5.5
22	Southern Co.	4.7	5.0
23	TECO Energy	4.6	8.5
24	Wisconsin Energy	2.3	5.0
25	Xcel Energy Inc.	4.8	7.5
	AVERAGE	3.9	7.2

Notes:
Column 1, 2: Value Line Investment Analyzer, 4/2006

S&P'S VERTICALLY INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Alliant Energy	3.6	6.0	3.8	9.8	10.0
2	Ameren Corp.	5.0	2.5	5.1	7.6	7.9
3	Amer. Elec. Power	4.4	2.5	4.5	7.0	7.2
4	Cleco Corp.	4.0	4.5	4.2	8.7	8.9
5	Edison Int'l	2.7	10.5	3.0	13.5	13.6
6	Empire Dist. Elec.	5.8	6.5	6.1	12.6	13.0
7	Energy East Corp.	4.8	4.0	5.0	9.0	9.3
8	Entergy Corp.	3.1	5.0	3.3	8.3	8.5
9	FirstEnergy Corp.	3.6	8.5	3.9	12.4	12.6
10	FPL Group	3.8	6.5	4.0	10.5	10.7
11	Hawaiian Elec.	4.6	2.5	4.7	7.2	7.4
12	IDACORP Inc.	3.7	4.5	3.9	8.4	8.6
13	MGE Energy	4.2	5.0	4.4	9.4	9.6
14	Northeast Utilities	3.5	9.0	3.8	12.8	13.0
15	Pinnacle West Capital	5.1	5.5	5.3	10.8	11.1
16	PNM Resources	3.6	7.0	3.9	10.9	11.1
17	Puget Energy Inc.	4.7	5.5	5.0	10.5	10.7
18	Southern Co.	4.7	5.0	4.9	9.9	10.2
19	TECO Energy	4.6	8.5	5.0	13.5	13.8
20	Wisconsin Energy	2.3	5.0	2.4	7.4	7.5
21	Xcel Energy Inc.	4.8	7.5	5.2	12.7	12.9
	AVERAGE	4.1		4.4	10.1	10.4

Notes:
Column 1, 2: Value Line Investment Analyzer, 4/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 06-101-U

EAI EXHIBIT RAM-7

VERTICALLY INTEGRATED ELECTRIC UTILTIES DCF ANLAYSIS:

ANALYSTS' GROWTH FORECASTS

S&P'S VERTICALLY INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)
1	ALLETE	3.2	6.8
2	Alliant Energy	3.6	4.0
3	Ameren Corp.	5.0	6.0
4	Amer. Elec. Power	4.4	3.0
5	Cleco Corp.	4.0	4.0
6	Edison Int'l	2.7	7.8
7	El Paso Electric	0.0	15.0
8	Empire Dist. Elec.	5.8	
9	Energy East Corp.	4.8	4.5
10	Entergy Corp.	3.1	7.4
11	FirstEnergy Corp.	3.6	4.8
12	FPL Group	3.8	6.5
13	Hawaiian Elec.	4.6	5.2
14	IDACORP Inc.	3.7	4.5
15	MGE Energy	4.2	
16	Northeast Utilities	3.5	8.7
17	PG&E Corp.	3.4	7.0
18	Pinnacle West Capital	5.1	6.8
19	PNM Resources	3.6	8.3
20	Progress Energy	5.5	3.8
21	Puget Energy Inc.	4.7	7.0
22	Southern Co.	4.7	4.8
23	TECO Energy	4.6	5.7
24	Wisconsin Energy	2.3	7.2
25	Xcel Energy Inc.	4.8	4.2

Notes:
Column 1: Value Line Investment Analyzer, 4/2006
Column 2: Zacks long-term earnings growth forecast, 4/2006

S&P'S VERTICALLY INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	ALLETE	3.2	6.8	3.4	10.1	10.3
2	Alliant Energy	3.6	4.0	3.7	7.7	7.9
3	Ameren Corp.	5.0	6.0	5.3	11.3	11.6
4	Amer. Elec. Power	4.4	3.0	4.5	7.5	7.7
5	Cleco Corp.	4.0	4.0	4.1	8.1	8.4
6	Edison Int'l	2.7	7.8	2.9	10.7	10.9
7	Energy East Corp.	4.8	4.5	5.0	9.5	9.8
8	Entergy Corp.	3.1	7.4	3.4	10.8	11.0
9	FirstEnergy Corp.	3.6	4.8	3.8	8.6	8.8
10	FPL Group	3.8	6.5	4.0	10.4	10.7
11	Hawaiian Elec.	4.6	5.2	4.8	10.0	10.2
12	IDACORP Inc.	3.7	4.5	3.9	8.4	8.6
13	Northeast Utilities	3.5	8.7	3.8	12.5	12.7
14	PG&E Corp.	3.4	7.0	3.6	10.6	10.8
15	Pinnacle West Capita	5.1	6.8	5.4	12.2	12.4
16	PNM Resources	3.6	8.3	3.9	12.2	12.4
17	Progress Energy	5.5	3.8	5.7	9.4	9.7
18	Puget Energy Inc.	4.7	7.0	5.1	12.1	12.3
19	Southern Co.	4.7	4.8	4.9	9.6	9.9
20	TECO Energy	4.6	5.7	4.9	10.6	10.8
21	Wisconsin Energy	2.3	7.2	2.5	9.7	9.8
22	Xcel Energy Inc.	4.8	4.2	5.0	9.2	9.4
	AVERAGE	4.0	5.8	4.3	10.1	10.3

Notes:
Column 1: Value Line Investment Analyzer, 4/2006
Column 2: Zacks long-term earnings growth forecast, 4/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 06-101-U

EAI EXHIBIT RAM-8

MOODY'S ELECTRIC UTILTIES DCF ANALYSIS:

VALUE LINE GROWTH FORECASTS

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	Amer. Elec. Power	4.1	2.0
2	CH Energy Group	4.4	3.5
3	Cinergy Corp.	4.5	4.0
4	Consol. Edison	5.0	2.5
5	Constellation Energy	2.6	13.5
6	Dominion Resources	3.7	8.0
7	DPL Inc.	3.7	1.0
8	Duquesne Light Hldgs	5.8	4.0
9	Duke Energy	4.5	8.5
10	Energy East Corp.	4.8	4.0
11	Exelon Corp.	3.0	7.0
12	FirstEnergy Corp.	3.6	8.5
13	IDACORP Inc.	3.7	4.5
14	NiSource Inc.	4.5	0.5
15	OGE Energy	4.7	5.5
16	PPL Corp.	3.5	8.0
17	Progress Energy	5.5	
18	Public Serv. Enterprise	3.3	1.5
19	Southern Co.	4.5	5.0
20	TECO Energy	4.5	8.5
21	Xcel Energy Inc.	4.8	7.5

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 4/2006
No Value Line growth forecasts available for Progress Energy

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1 Amer. Elec. Power	4.1	2.0	4.1	6.1	6.3
2 CH Energy Group	4.4	3.5	4.5	8.0	8.3
3 Consol. Edison	5.0	2.5	5.2	7.7	7.9
4 Constellation Energy	2.6	13.5	2.9	16.4	16.6
5 Dominion Resources	3.7	8.0	4.0	12.0	12.2
6 Duquesne Light Hldgs	5.8	4.0	6.0	10.0	10.3
7 Duke Energy	4.5	8.5	4.9	13.4	13.6
8 Energy East Corp.	4.8	4.0	5.0	9.0	9.2
9 Exelon Corp.	3.0	7.0	3.2	10.2	10.3
10 FirstEnergy Corp.	3.6	8.5	3.9	12.4	12.6
11 IDACORP Inc.	3.7	4.5	3.8	8.3	8.5
12 NiSource Inc.	4.5	0.5	4.5	5.0	5.3
13 OGE Energy	4.7	5.5	4.9	10.4	10.7
14 PPL Corp.	3.5	8.0	3.8	11.8	12.0
15 Southern Co.	4.5	5.0	4.7	9.7	10.0
16 TECO Energy	4.5	8.5	4.9	13.4	13.6
17 Xcel Energy Inc.	4.8	7.5	5.1	12.6	12.9
AVERAGE		5.9	4.4	10.4	10.6

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 3/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2
No Value Line growth forecasts available for Progress Energy
DPL Inc estimate less than cost of debt
Public Service Enterprise in merger activity

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 06-101-U

EAI EXHIBIT RAM-9

MOODY'S ELECTRIC UTILTIES ANALYSIS:

ANALYSTS'GROWTH FORECASTS

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)
1	Amer. Elec. Power	4.4	3.0
2	CH Energy Group	4.4	
3	Cinergy Corp.	4.5	4.0
4	Consol. Edison	5.2	4.2
5	Constellation Energy	2.7	11.0
6	Dominion Resources	4.0	9.0
7	DPL Inc.	3.6	7.0
8	Duquesne Light Hldgs	5.9	
9	Duke Energy	4.3	6.0
10	Energy East Corp.	4.8	4.5
11	Exelon Corp.	3.1	9.4
12	FirstEnergy Corp.	3.6	4.8
13	IDACORP Inc.	3.7	4.5
14	NiSource Inc.	4.5	3.4
15	OGE Energy	4.5	3.0
16	PPL Corp.	3.7	8.3
17	Progress Energy	5.5	3.8
18	Public Serv. Enterprise	3.5	7.8
19	Southern Co.	4.7	4.8
20	TECO Energy	4.6	5.7
21	Xcel Energy Inc.	4.8	4.2

Notes:
Column 1: Value Line Investment Analyzer, 4/2006
Column 2: Zacks long-term earnings growth forecast, 4/2006
No growth forecast available for CH Energy Group, Duquesne Light
Public Serv Enterprise and Cinergy in merger

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Amer. Elec. Power	4.4	3.0	4.5	7.5	7.7
2	Consol. Edison	5.2	4.2	5.4	9.6	9.9
3	Constellation Energy	2.7	11.0	3.0	14.0	14.2
4	Dominion Resources	4.0	9.0	4.3	13.3	13.5
5	DPL Inc.	3.6	7.0	3.9	10.9	11.1
6	Duke Energy	4.3	6.0	4.6	10.6	10.8
7	Energy East Corp.	4.8	4.5	5.0	9.5	9.8
8	Exelon Corp.	3.1	9.4	3.4	12.8	13.0
9	FirstEnergy Corp.	3.6	4.8	3.8	8.6	8.8
10	IDACORP Inc.	3.7	4.5	3.9	8.4	8.6
11	NiSource Inc.	4.5	3.4	4.6	8.1	8.3
12	OGE Energy	4.5	3.0	4.6	7.6	7.9
13	PPL Corp.	3.7	8.3	4.0	12.3	12.5
14	Progress Energy	5.5	3.8	5.7	9.4	9.7
15	Southern Co.	4.7	4.8	4.9	9.6	9.9
16	TECO Energy	4.6	5.7	4.9	10.6	10.8
17	Xcel Energy Inc.	4.8	4.2	5.0	9.2	9.4
	AVERAGE	**4.2**	**5.7**	**4.4**	**10.1**	**10.4**

Notes:
- Column 1: Value Line Investment Analyzer, 4/2006
- Column 2: Zacks long-term earnings growth forecast, 4/2006
- Column 3 = Column 1 times (1 + Column 2/100)
- Column 4 = Column 3 + Column 2
- Column 5 = (Column 3 /0.95) + Column 2
- No growth forecast available for CH Energy Group, Duquesne Lt.
- Public Serv Enterprise and Cinergy in merger

BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 06-101-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI APPENDIX A

CAPM, EMPIRICAL CAPM

APPENDIX A
CAPM, EMPIRICAL CAPM

The Capital Asset Pricing Model (CAPM) is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

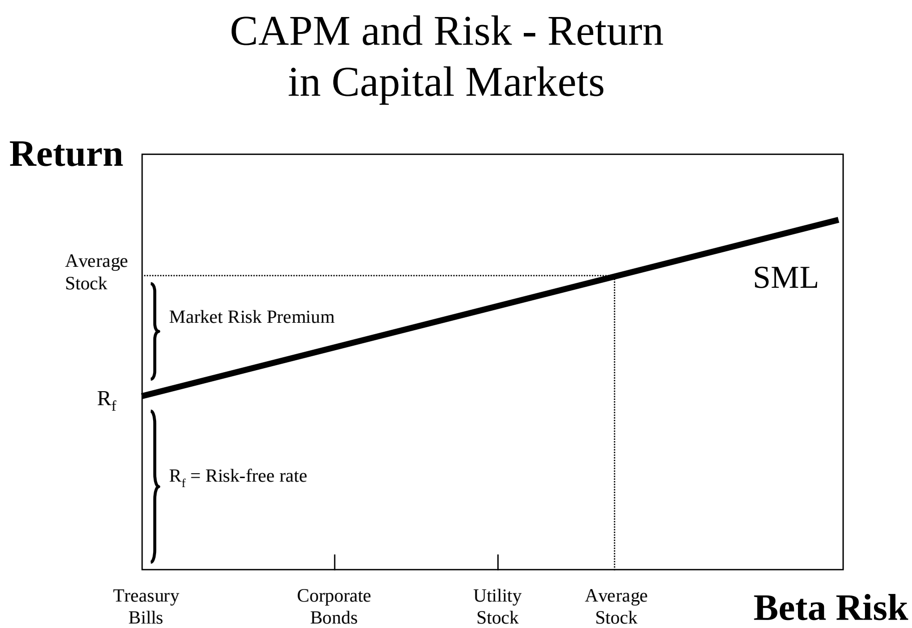
Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is:

$$K = R_F + \beta(R_M - R_F) \qquad (1)$$

Equation 1 is the CAPM expression which asserts that an investor expects to earn a return, K, that could be gained on a risk-free investment, R_F, plus a risk premium for assuming risk, proportional to the security's market risk, also known as beta, β, and the market risk premium, $(R_M - R_F)$, where R_M is the market return . The market risk premium $(R_M - R_F)$ can be abbreviated MRP so that the CAPM becomes:

$$K = R_F + \beta \times MRP \qquad (2)$$

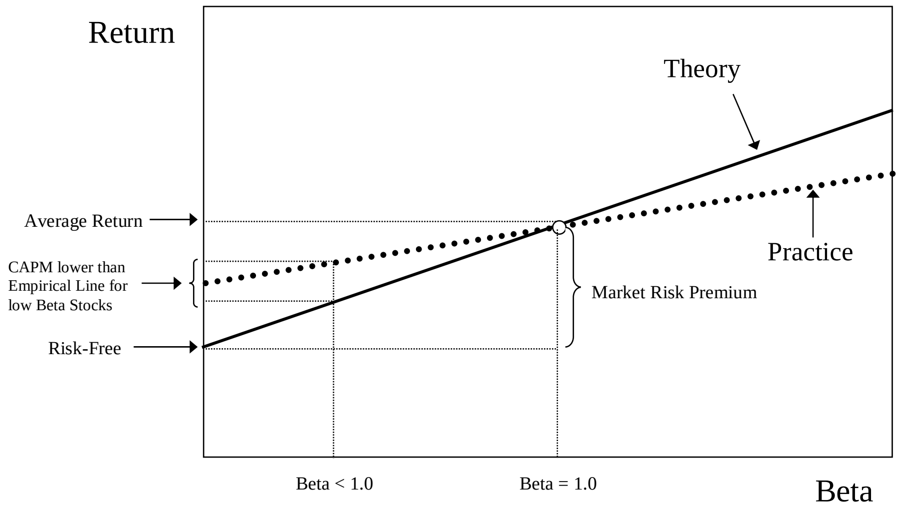
The CAPM risk-return relationship is depicted in the figure below and is typically labeled as the Security Market Line (SML) by the investment community.



A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM, however. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher returns and high-beta stocks tend to have lower risk returns than predicted by the CAPM. The difference between the CAPM and the type of relationship observed in the empirical studies is depicted in the figure below. This is one of the most widely known empirical findings of the finance literature. This extensive literature is summarized in Chapter 13 of Dr. Morin's book [Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 1994].

Risk vs Return

Theory vs. Practice



A number of refinements and expanded versions of the original CAPM theory have been proposed to explain the empirical findings. These revised CAPMs typically produce a risk-return relationship that is flatter than the standard CAPM prediction. The following equation makes use of these empirical findings by flattening the slope of the risk-return relationship and increasing the intercept:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \qquad (3)$$

where α is the "alpha" of the risk-return line, a constant determined empirically, and the other symbols are defined as before. Alternatively, Equation 3 can be written as follows:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP \qquad (4)$$

where a is a fraction to be determined empirically. Comparing Equations 3 and 4, it is easy to see that alpha equals ‘a’ times MRP, that is, $\alpha = a \times MRP$

Theoretical Underpinnings

The obvious question becomes what would produce a risk return relationship which is flatter than the CAPM prediction, or in other words, how do you explain the presence of “alpha” in the above equation. The exclusion of variables aside from beta would produce this result. Three such variables are noteworthy: dividend yield, skewness, and hedging potential.

The dividend yield effects stem from the differential taxation on corporate dividends and capital gains. The standard CAPM does not consider the regularity of dividends received by investors. Utilities generally maintain high dividend payout ratios relative to the market, and by ignoring dividend yield, the CAPM provides biased cost of capital estimates. To the extent that dividend income is taxed at a higher rate than capital gains, investors will require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks (e.g. utility stocks) with those of low-yielding stocks. In other words, high-yielding stocks must offer investors higher pre-tax returns. Even if dividends and capital gains are undifferentiated for tax purposes, there is still a tax bias in favor of earnings retention (lower dividend payout), as capital gains taxes are paid only when gains are realized.

Empirical studies by Litzenberger and Ramaswamy (1979), Litzenberger et al. (1980) and Rosenberg and Marathe (1975) find that security returns are positively related to dividend yield as well as to beta. These results are consistent with after-tax extensions of the CAPM developed by Breenan (1973) and Litzenberger and Ramaswamy (1979) and suggest that the relationship between return, beta, and dividend yield should be estimated and employed to calculate the cost of equity capital.

As far as skewness is concerned, investors are more concerned with losing money than with total variability of return. If risk is defined as the probability of loss, it appears more logical to measure risk as the probability of achieving a return which is below the expected return. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant. As shown by Kraus and Litzenberger (1976), expected return depends on both on a stock's systematic risk (beta) and the systematic skewness. Empirical studies by Kraus and Litzenberger (1976), Friend, Westerfield, and Granito (1978), and Morin (1981) found that, in addition to beta, skewness of returns has a significant negative relationship with security returns. This result is consistent with the skewness version of the CAPM developed by Rubinstein (1973) and Kraus and Litzenberger (1976).

This is particularly relevant for public utilities whose future profitability is constrained by the regulatory process on the upside and relatively unconstrained on the downside in the face of socio-political realities of public utility regulation. The process of regulation, by restricting the upward potential for returns and responding sluggishly on the downward side, may impart some asymmetry to the distribution of returns, and is more likely to result in utilities earning less, rather than more, than their cost of capital. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant.

As far as hedging potential is concerned, investors are exposed to another kind of risk, namely, the risk of unfavorable shifts in the investment opportunity set. Merton (1973) shows that investors will hold portfolios consisting of three funds: the risk-free asset, the market portfolio, and a portfolio whose returns are perfectly negatively correlated with the riskless asset so as to hedge against unforeseen changes in the future risk-free rate. The higher the degree of protection offered by an asset against unforeseen changes in interest rates, the lower the required return, and conversely. Merton argues that low beta assets, like utility stocks, offer little protection against changes in interest rates, and require higher returns than suggested by the standard CAPM.

Another explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index mis-specifies the

CAPM and biases the results found using only stock market data. Kolbe and Read (1983) illustrate the biases in beta estimates which result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relation between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship between returns and stock betas is best estimated empirically (ECAPM) rather than by relying on theoretical and elegant CAPM models expanded to include missing assets effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Yet another explanation for the CAPM's inability to fully explain the observed risk-return tradeoff involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

$$K = R_Z + \beta(R_m - R_F)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who found a flatter than predicted CAPM, consistent with the model and other researchers' findings.

The zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct difficult to replicate.

Empirical Evidence

A summary of the empirical evidence on the magnitude of alpha is provided in the table below.

Empirical Evidence on the Alpha Factor		
Author	**Range of alpha**	**Period relied upon**
Fischer (1993)	-3.6% to 3.6%	1931-1991
Fischer, Jensen and Scholes (1972)	-9.61% to 12.24%	1931-1965
Fama and McBeth (1972)	4.08% to 9.36%	1935-1968
Fama and French (1992)	10.08% to 13.56%	1941-1990
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%	
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%	1926-1978
Pettengill, Sundaram and Mathur (1995)	4.6%	
Morin (1994)	2.0%	1926-1984
Harris, Marston, Mishra, and O'Brien	2.0%	1983-1998

Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1994) over the period 1926-1984 indicating that the observed expected return on a security is related to its risk by the following equation:

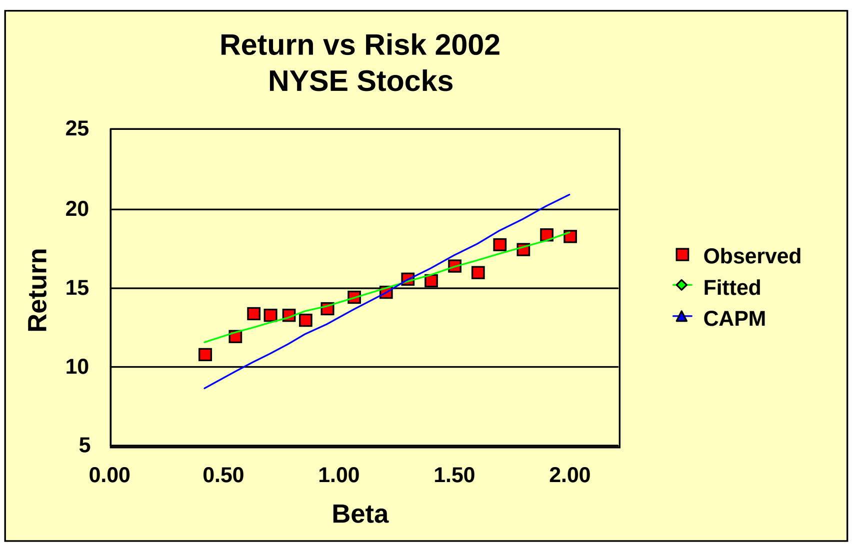
$$K = .0829 + .0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6 percent, this relationship implies that the intercept of the risk-return relationship is higher than the 6 percent risk-free rate, contrary to the CAPM's prediction. Given that the average return on an average risk stock exceeded the risk-free rate by about 8.0 percent in that period, that is, the market risk premium (R_M - R_F)

= 8 percent, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2 percent, suggesting an alpha factor of 2 percent.

Most of the empirical studies cited in the above table utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table 6-7 in Ibbotson Associates Valuation Yearbook 2001. If we exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM, as shown on the graph below. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

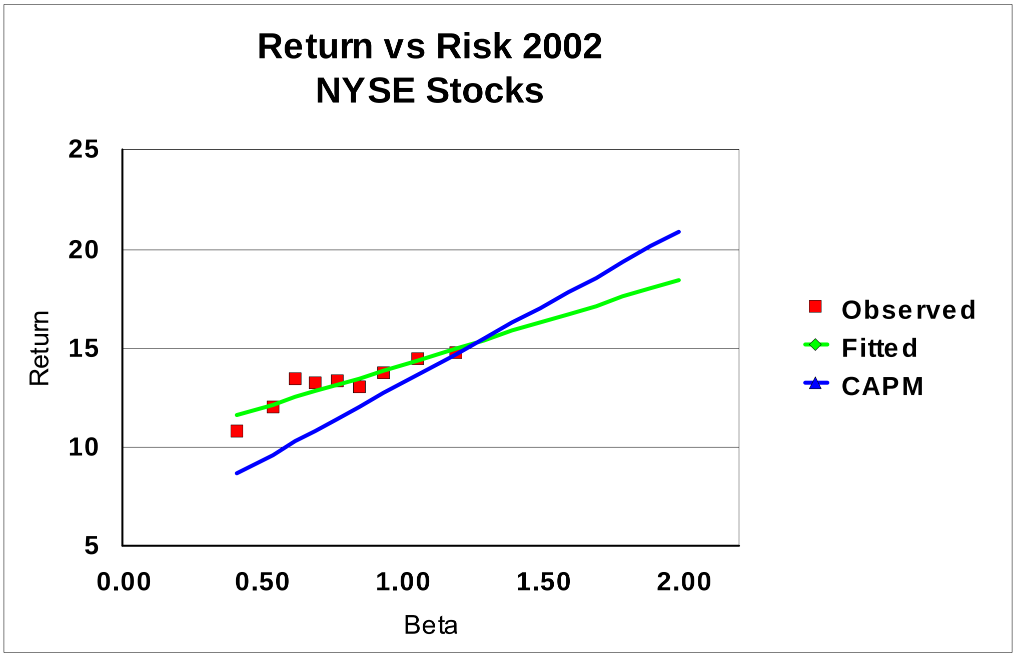
CAPM vs ECAPM



Another study by Morin in May 2002 provides empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total shareholder return (“TSR”) reported by Value Line over the past ten years. The Value Line adjusted beta was also retrieved from the same data base. The nearly 2000 companies for which all data were available were ranked in ascending order of beta, from lowest to highest. In order to palliate measurement error, the nearly 2000 securities were grouped into ten portfolios of approximately 180 securities for each portfolio. The average returns and betas for each portfolio were as follows:

Portfolio #	Beta	Return
portfolio 1	0.41	10.87
portfolio 2	0.54	12.02
portfolio 3	0.62	13.50
portfolio 4	0.69	13.30
portfolio 5	0.77	13.39
portfolio 6	0.85	13.07
portfolio 7	0.94	13.75
portfolio 8	1.06	14.53
portfolio 9	1.19	14.78
portfolio 10	1.48	20.78

It is clear from the graph below that the observed relationship between DCF returns and Value Line adjusted betas is flatter than that predicted by the plain vanilla CAPM. The observed intercept is higher than the prevailing risk-free rate of 5.7 percent while the slope is less than equal to the market risk premium of 7.7 percent predicted by the plain vanilla CAPM for that period.



In an article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") estimate ex ante expected returns for S&P 500 companies over the period 1983-1998[1]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. They then investigate the relation between the risk premium (expected return over the 20-year U.S. Treasury Bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

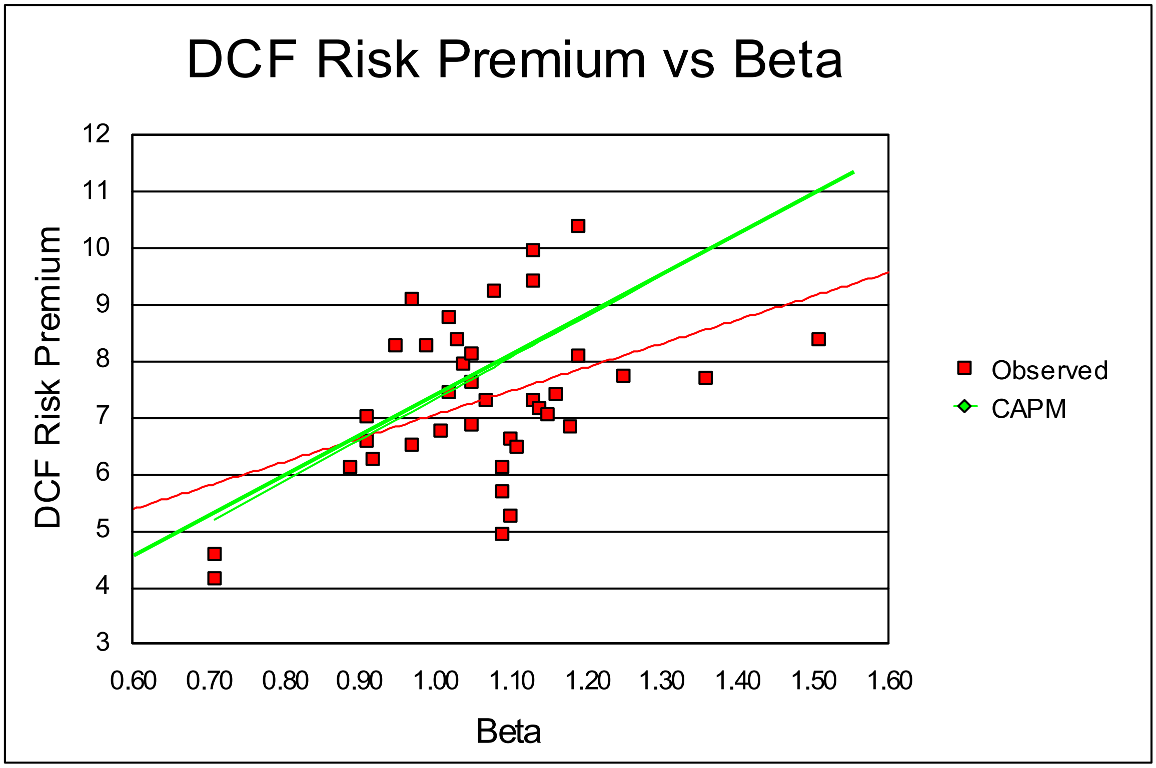
The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill Lynch – Bloomberg adjustment methodology by giving 1/3 weight of to a beta estimate of 1.00 and 2/3 weight to the raw beta estimate.

[1] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

Table A-1 Risk Premium and Beta Estimates by Industry

	Industry (1)	DCF Risk Premium (2)	Raw Industry Beta (3)	Adjusted Industry Beta (4)
1	Aero	6.63	1.15	1.10
2	Autos	5.29	1.15	1.10
3	Banks	7.16	1.21	1.14
4	Beer	6.60	0.87	0.91
5	BldMat	6.84	1.27	1.18
6	Books	7.64	1.07	1.05
7	Boxes	8.39	1.04	1.03
8	BusSv	8.15	1.07	1.05
9	Chems	6.49	1.16	1.11
10	Chips	8.11	1.28	1.19
11	Clths	7.74	1.37	1.25
12	Cnstr	7.70	1.54	1.36
13	Comps	9.42	1.19	1.13
14	Drugs	8.29	0.99	0.99
15	ElcEq	6.89	1.08	1.05
16	Energy	6.29	0.88	0.92
17	Fin	8.38	1.76	1.51
18	Food	7.02	0.86	0.91
19	Fun	9.98	1.19	1.13
20	Gold	4.59	0.57	0.71
21	Hlth	10.40	1.29	1.19
22	Hsld	6.77	1.02	1.01
23	Insur	7.46	1.03	1.02
24	LabEq	7.31	1.10	1.07
25	Mach	7.32	1.20	1.13
26	Meals	7.98	1.06	1.04
27	MedEq	8.80	1.03	1.02
28	Pap	6.14	1.13	1.09
29	PerSv	9.12	0.95	0.97
30	Retail	9.27	1.12	1.08
31	Rubber	7.06	1.22	1.15
32	Ships	1.95	0.95	0.97
33	Stee	4.96	1.13	1.09
34	Telc	6.12	0.83	0.89
35	Toys	7.42	1.24	1.16
36	Trans	5.70	1.14	1.09
37	Txtls	6.52	0.95	0.97
38	Util	4.15	0.57	0.71
39	Whlsl	8.29	0.92	0.95
	MEAN	**7.19**		

The observed statistical relationship between expected return and **adjusted beta** is shown in the graph below along with the CAPM prediction:



If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2 percent, that is approximately equal to 25 percent of the expected market risk premium of 7.2 percent shown at the bottom of Column 2 over the 1983-1998 period, as predicted by the ECAPM. The same is true for the slope of the graph. If the plain vanilla version of the CAPM is correct, then the slope of the relationship should equal the market risk premium of 7.2 percent. Instead, the observed slope of close to 5 percent is approximately equal to 75 percent of the expected market risk premium of 7.2 percent, as predicted by the ECAPM.

In short, the HMMO empirical findings are quite consistent with the predictions of the ECAPM.

Practical Implementation of the ECAPM

The empirical evidence reviewed above suggests that the expected return on a security is related to its risk by the following relationship:

$$K = R_F + \alpha + \beta(MRP - \alpha) \qquad (5)$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP \qquad (6)$$

The empirical findings support values of α from approximately 2 percent to 7 percent. If one is using the short-term U.S. Treasury Bills yield as a proxy for the risk-free rate, and given that utility stocks have lower than average betas, an alpha in the lower range of the empirical findings, 2 percent - 3 percent is reasonable, albeit conservative.

Using the long-term U.S. Treasury yield as a proxy for the risk-free rate, a lower alpha adjustment is indicated. This is because the use of the long-term U.S. Treasury yield as a proxy for the risk-free rate partially incorporates the desired effect of using the ECAPM[2]. An alpha in the range of 1 percent - 2 percent is therefore reasonable.

To illustrate, consider a utility with a beta of 0.80. The risk-free rate is 5 percent, the MRP is 7 percent, and the alpha factor is 2 percent. The cost of capital is determined as follows:

$$K = R_F + \alpha + \beta(MRP - \alpha)$$
$$K = 5\% + 2\% + 0.80(7\% - 2\%)$$
$$= 11\%$$

[2] The Security Market Line (SML) using the long-term risk-free rate has a higher intercept and a flatter slope than the SML using the short-term risk-free rate

A practical alternative is to rely on the second variation of the ECAPM:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP$$

With an alpha of 2 percent, a MRP in the 6 percent - 8 percent range, the ‘a” coefficient is 0.25, and the ECAPM becomes[3]:

$$K = R_F + 0.25\,MRP + 0.75\,\beta\,MRP$$

Returning to the numerical example, the utility’s cost of capital is:

$$K = 5\% + 0.25 \times 7\% + 0.75 \times 0.80 \times 7\%$$
$$= 11\%$$

For reasonable values of beta and the MRP, both renditions of the ECAPM produce results that are virtually identical[4].

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[3] Recall that alpha equals ‘a’ times MRP, that is, alpha = a MRP, and therefore a = alpha/MRP. If alpha is 2 percent, then a = 0.25

[4] In the Morin (1994) study, the value of “a” was actually derived by systematically varying the constant "a" in equation 6 from 0 to 1 in steps of 0.05 and choosing that value of 'a' that minimized the mean square error between the observed relationship between return and beta:

$$K = 0.0829 + .0520\,\beta$$

The value of a that best explained the observed relationship was 0.25.

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BEFORE THE
ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION	)	
OF ENTERGY ARKANSAS, INC. FOR	)	DOCKET NO. 06-101-U
APPROVAL OF CHANGES IN RATES FOR	)	
RETAIL ELECTRIC SERVICE	)	

EAI APPENDIX B

FLOTATION COST ALLOWANCE

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FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4 percent of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0 percent. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1 percent for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5 percent. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72 percent. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175 percent for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5 percent. In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14 percent for industrial stock issues and 0.75 percent for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.- Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2 percent to 3 percent. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0 percent, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, “The Costs of Raising Capital,” Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5 percent - 5 percent for stock issues between $60 and $500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5 percent.

FLOTATION COSTS: RAISING EXTERNAL CAPITAL
(Percent of Total Capital Raised)

Amount Raised in $ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
$ 2 - 9. 99	13.28%	4.39%
10 - 19. 99	8.72	2.76
20 - 39. 99	6.93	2.42
40 - 59. 99	5.87	1.32
60 - 79. 99	5.18	2.34
80 - 99. 99	4.73	2.16
100 - 199. 99	4.22	2.31
200 - 499. 99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than $10 million and about 6 percent if more than $500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research,* Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5 percent of gross proceeds. I have therefore assumed a 5 percent gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5 percent to the dividend yield component of equity cost by dividing that yield by

0.95 (100 percent - 5 percent) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_o + g$$

If P_o is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_o equals

B_o, the book value per share, then the company's required return is:

$$r = D_1/B_o + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_o are related to market price P_o as follows:

$$P - fP = B_o$$
$$P(1 - f) = B_o$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1\text{-}f) + g$$

that is, the utility's required return adjusted for under pricing. For flotation costs of 5 percent, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6 percent for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5 percent to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 8-10 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 8-10 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 8. The stock is selling in the market for $25, investors expect the firm to pay a dividend of $2.25 that will grow at a rate of 5 percent thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14$ percent. The firm sells one share stock, incurring a flotation cost of 5 percent. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1\text{-}f) + g = .09/.95 + .05 = 14.47$ percent.

The initial book value (rate base) is the net proceeds from the stock issue, which are $23.75, that is, the market price less the 5 percent flotation costs. The example demonstrates that only if the company is allowed to earn 14.47 percent on rate base will investors earn their cost of equity of 14 percent. On page 9, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47 percent times the total common equity base. Dividends start at $2.25 and grow at 5 percent thereafter, which they must do if investors are to earn a 14 percent return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5 percent rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47 percent on equity do investors earn 14 percent. For example, if the company is allowed only 14 percent, the stock price drops from $26.25 to $26.13 in the second year, inflicting a loss on shareholders. This is shown on page 10. The growth rate drops from 5 percent to 4.53 percent. Thus, investors only earn 9 percent + 4.53

percent = 13.53 percent on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH =	5.00%
EQUITY RETURN = (D/P + g)	**14.00%**
ALLOWED RETURN ON EQUITY = (D/P(1-f) + g)	**14.47%**

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
--------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65.45%
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%
			5.00%	**5.00%**		**5.00%**	**5.00%**	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET/ BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	**4.53%**		**4.53%**	**4.53%**	

CERTIFICATE OF SERVICE

I, Steven K. Strickland, do hereby certify that a copy of the foregoing has been served upon all parties of record this 15th day of August 2006.

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Steven K. Strickland