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Direct Testimony of

Roger A. Morin

On

Behalf of

Union Electric Company

d/b/a AmerenUE

Return on Equity Considerations

July, 2009

UE Exhibit No. 111
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File No. ER-2010-0036

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DIRECT TESTIMONY

OF

ROGER A. MORIN

CASE NO. ER-2010-____

I. INTRODUCTION AND PURPOSE

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 Emeritus 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, Inc., where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last thirty years, I have conducted numerous national seminars on "Utility Finance," "Utility Cost of Capital," "Alternative Regulatory Frameworks," and on "Utility Capital Allocation," which I have developed on behalf of The Management Exchange Inc. and Exnet (now SNL Energy) 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. In late 1994, the same publisher released Regulatory Finance, a voluminous treatise I wrote on the application of finance to regulated utilities. A revised and expanded edition of this book entitled The New Regulatory Finance was published in August 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. Schedule RAM-E1 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 nearly fifty (50) regulatory bodies in North America, including the Missouri Public Service Commission ("MPSC", or "Commission"), the Federal Energy Regulatory Commission, and the Federal Communications Commission. Below is a comprehensive list of the state, provincial, and other local regulatory commissions to which I have provided testimony:

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

Details of my participation in regulatory proceedings are provided in Schedule RAM-E1.

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

A. The purpose of my direct testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on common equity ("ROE") for the integrated electric utility operations of Union Electric Company d/b/a AmerenUE ("UE," or "Company") in the State of Missouri. Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would: (1) be fair to the customer, (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.

This testimony and accompanying schedules and appendices were prepared by me or under my direct supervision and control. The source documents for my testimony are Company records, public documents, commercial data sources, and my personal knowledge and experience.

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

A. I have attached to my testimony Schedules RAM-E1 through RAM-E9 and Appendices A and B. These Schedules 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 UE'S COST OF COMMON EQUITY.

A. It is my opinion that a just and reasonable ROE for UE is 11.5%. My recommendation for an ROE for the Company falls well within the appropriate zone of reasonableness employed by the Commission in the past which, in this case, is 10.6% - 11.6%.

My recommendation 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: a "traditional" CAPM and a methodology using an empirical approximation of the CAPM ("ECAPM").

I performed a historical risk premium analysis on the electric utility industry. I also performed DCF analyses on two surrogates for the Company's electric utility business. They are: a group of investment-grade integrated electric utilities, and a group consisting of the electric utilities that make up Standard & Poor's Utility Index.

My recommended rate of return reflects the application of my professional judgment to the indicated returns from my CAPM, Risk Premium, CAPM, and DCF analyses, to the Company's current risk environment, which I estimate to be comparable on balance to the industry average, and to unprecedented capital market conditions of turmoil and uncertainty, as I discuss later in my testimony. My recommended ROE also assumes the adoption of a capital structure for the Company that is consistent with the capital structures of similar integrated electric utilities.

Q. WOULD IT BE IN THE BEST INTERESTS OF RATEPAYERS FOR THE COMMISSION TO ADOPT YOUR RECOMMENDED 11.5% RETURN ON EQUITY FOR UE'S ELECTRIC UTILITY OPERATIONS?

A. Yes. My analysis shows that a ROE of 11.5% is required to fairly compensate investors, maintain the Company's credit strength, and attract the capital needed for utility infrastructure and environmental compliance capital investments. Adopting a lower ROE would increase costs for UE's ratepayers.

Q. PLEASE EXPLAIN HOW A LOW AUTHORIZED ROE CAN INCREASE COSTS FOR RATEPAYERS.

A. If a utility is authorized a ROE 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 that 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 because as the utility's price per share of common stock decreases, the net proceeds from issuing common stock are reduced.

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 even 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 UE has access to capital markets for its capital needs, a fair and reasonable authorized ROE of 11.5% is required.

UE has a substantial construction program relative to its size for required environmental upgrades, infrastructure replacements and upgrades, and target renewable generation resource additions. The Company's ability to tap capital markets and attract funds on reasonable terms occurs at a crucial point in time when the Company has an ambitious capital expenditure program and requires external financing. UE's large capital expenditure program over the next several years, relative to its size, increases its dependence on capital markets that have become volatile and more unpredictable.

It is imperative the Company have access to capital funds at reasonable terms and conditions. The Company must secure outside funds from capital markets to finance required utility plant and equipment investments irrespective of capital market conditions, interest rate conditions and the quality consciousness of market participants. Because the Company will need to rely heavily on capital markets to finance its construction program, rate relief requirements and supportive regulatory treatment, including approval of my recommended ROE, are essential requirements.

Q. CAN YOU DESCRIBE FOR US THE CURRENT STATE OF THE CAPITAL MARKETS?

A. Capital markets have been, and continue to be, in a state of turmoil. In the past nine months, the financial markets, both in the U.S. and abroad, have become extremely volatile, unpredictable, and have displayed unusual behavior. To illustrate, daily percentage changes in the Dow Jones Industrial Index have experienced unprecedented swings. The Chicago Board of Options Exchange ("CBOE") Volatility Index ("VIX"), which measures the volatility of the S&P 500 Index, has increased to record highs. The turmoil in the capital markets is also reflected by highly unusual events, for example, the government bailout of $700 billion, the bankruptcy of Lehman Brothers, the collapse of Bear Stearns, the acquisition of Merrill Lynch by Bank of America, and the conversion of other major investment banks such as Morgan Stanley and Goldman Sachs to bank holdings companies, leaving no major investment banks.

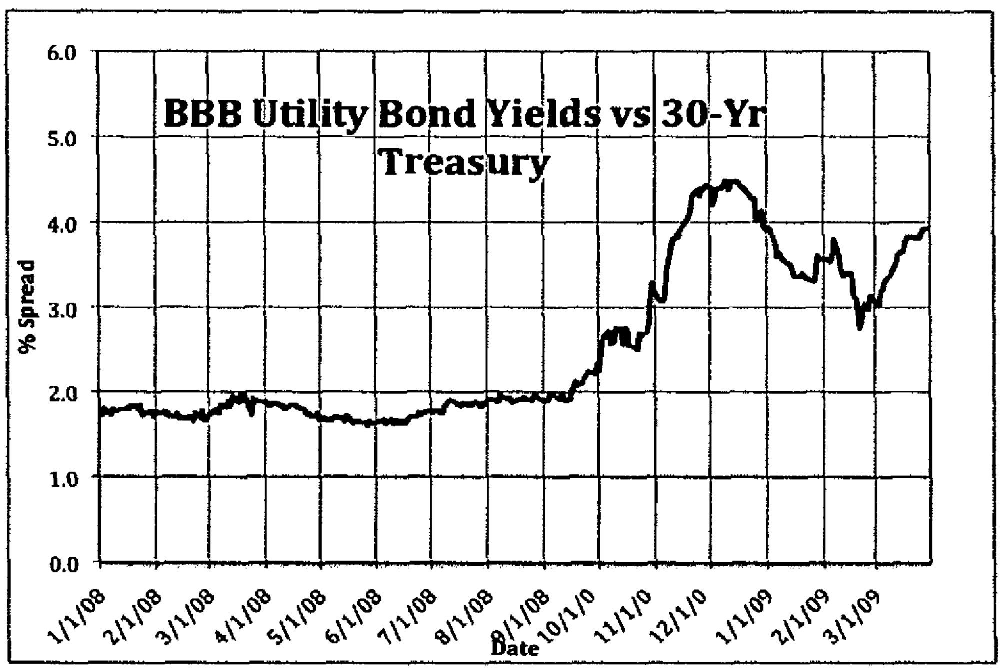
Borrowers are now forced to compete in a market with dramatically less capital to invest. As a result, the cost of money for corporations has increased, and new debt issues are limited to the highest rated issuers. Common stock issues are scarce. The commercial paper market functions only due to decisive U.S. Treasury intervention. The debt markets have witnessed record high yield spreads (*i.e.,* the incremental yield over Treasury rates needed to issue debt) and a more severe differentiation between the spreads charged to companies with different credit ratings. These market conditions have led to an increased value for higher credit ratings and for conservative capital structures.

To illustrate, the chart below depicts the rising and record high spreads in recent months for utilities rated BBB, the approximate average bond rating of the electric utility industry. Whereas throughout most of early 2008 utilities were borrowing money at some 150-200 basis points over Treasuries, the current secondary market spread (not including a significant new issuance premium) is

350-400 basis points, an increase of 150-200 basis points, virtually the same upward increase as has been observed in reliable DCF estimates. In a nutshell, there is a fundamental structural upward shift in risk aversion as capital markets are re-pricing risk, and capital has become, and will continue to be, more expensive for all market participants.

Q. PLEASE BRIEFLY DESCRIBE THE RECENT BEHAVIOR OF INTEREST RATES.

A. Draconian changes have occurred in capital market conditions in the last nine months. The current level of U.S. Treasury 30-year long-term bond yield is approximately 4.5%, versus 4.5% - 5.5% over the past several years. The decrease in interest rates produces very low CAPM and Risk Premium estimates that are based on the risk-free rate. However, capital costs for non-government entities have escalated to unprecedented levels relative to government securities since the financial crisis began in 2008.



Q. DR. MORIN, WHAT HAS HAPPENED TO HISTORICAL ELECTRIC UTILITY BETA RISK MEASURES RECENTLY?

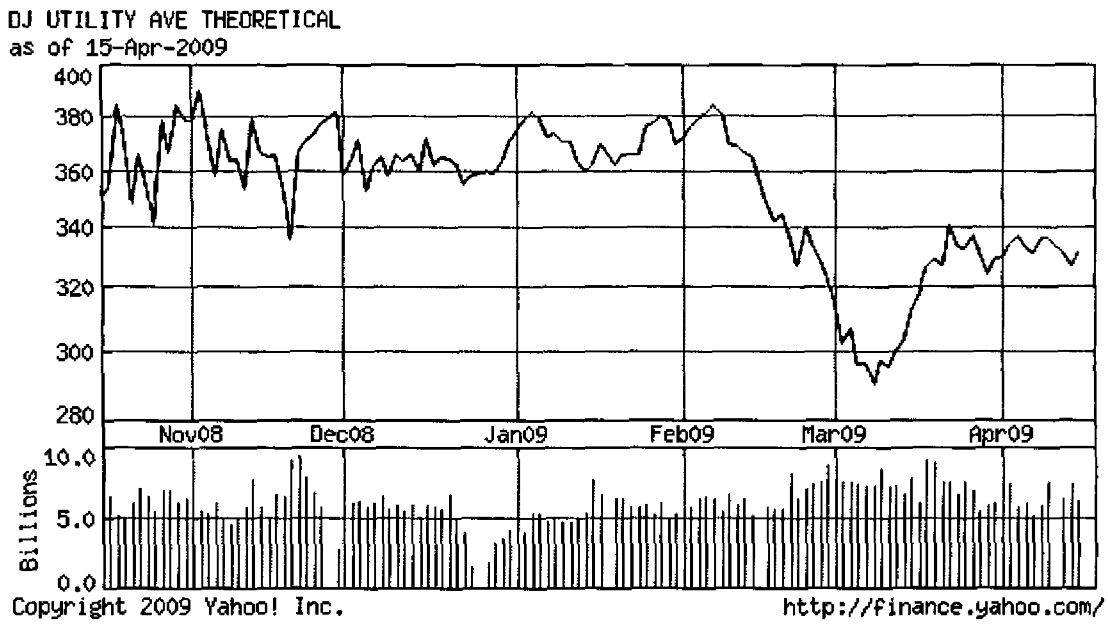
A. They have decreased from the 0.85 level to the 0.75 level, thus lowering the CAPM estimates. I note that beta estimates are based on five-years of historical results, and thus do not yet reflect the impact of the current financial crisis on volatility, and vastly understate risk.

Q. DR. MORIN, WHAT HAPPENED TO THE MARKET RISK PREMIUM IN THE CAPM ANALYSIS SINCE THE FINANCIAL CRISIS BEGAN?

A. While the historical market risk premium ("MRP") has not changed significantly, it is clear that the prospective MRP has increased markedly, given the disastrous performance of the equity markets and the ongoing re-pricing of risk by investors. It should be noted that the historical MRP that is often used in the CAPM analysis is measured over a long term and likely does not capture the re-pricing of risk that is occurring in the financial marketplace.

Q. DR. MORIN, PLEASE DESCRIBE WHAT HAS HAPPENED TO DCF ESTIMATES OF EQUITY CAPITAL COSTS SINCE THE COMMENCEMENT OF THE FINANCIAL CRISIS IN THE FALL OF 2008.

A. Set forth below is a graph that replicates the movements of the Dow Jones Utility Average over the past nine months. The devastating downward impact of the financial crisis on utility stock prices is clear from the graph, with the utility index falling from the 370 level to the 330 level over the past six months. Lower stock prices imply higher dividend yields, which in turn imply higher DCF estimates.



Q. WHAT IS THE IMPACT OF THE ONGOING FINANCIAL CRISIS ON UTILITIES' COST OF CAPITAL AND ON UE IN PARTICULAR?

A. In a nutshell, the cost of capital has increased markedly. During the past nine months, capital markets in the U.S. have been more volatile than at any time since the 1930s. Investors have witnessed unprecedented large swings in the stock market and unprecedented corporate interest rate spreads in the debt markets. Many large financial institutions were unable to survive as independent institutions and others have required multi-billion dollar capital infusions.

As shown above, the spreads between the yields on utility debt and U.S. Treasury securities have increased markedly. Since the commencement of the financial crisis, single-A yield spreads and BBB yield spreads for utility companies have increased to a level which is some three times higher than the spreads that existed little more than a year ago. In short, increased risk aversion and market illiquidity have resulted in significantly higher borrowing costs for corporations, including UE. In the current environment, investors' return expectations and requirements for providing capital to the utility industry remain high relative to the longer-term traditional view of the utility industry.

Q. DR. MORIN, PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. The remainder of my testimony is divided into three (3) sections:

II. Regulatory Framework and Rate of Return;

III. Cost of Equity Estimates; and

IV. Summary and Cost of Equity Recommendation.

The first section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The second section contains the application of CAPM, Risk Premium, and DCF tests. The third section summarizes the results from the various approaches used in determining a fair return.

II. REGULATORY FRAMEWORK AND RATE OF RETURN

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 UE's cost of common equity capital.

Q. WHAT FUNDAMENTAL PRINCIPLES UNDERLIE THE DETERMINATION OF A FAIR AND REASONABLE ROE?

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. Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 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 UE 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 (*i.e.*, 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 UE enjoy varying 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 they be 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 item 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 market 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 that they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. 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. Because utility debt and equity investors receive their returns on a different basis, have different types of investment objectives, and are affected in different ways by external market and company factors, their risks are quite dissimilar.

Q. WHAT ECONOMIC AND FINANCIAL CONCEPTS HAVE GUIDED YOUR ASSESSMENT OF UE'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.

On the supply side, the first principle asserts that rational investors maximize the performance of their portfolios only if they expect the returns earned on investments of comparable risk to be the same. If not, rational investors 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 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 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, 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.

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.

Q. WHAT MUST BE CONSIDERED IN ESTIMATING A FAIR ROE?

A. The basic premise is that the allowable ROE 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 the 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 that investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This return 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. HOW DOES UE'S COST OF CAPITAL RELATE TO THAT OF AMEREN CORPORATION?

A. I am treating UE as a separate stand-alone entity, distinct from Ameren Corporation ("Ameren"), because it is the cost of capital for UE that we are attempting to measure and not the cost of capital for Ameren's consolidated activities. Financial theory clearly establishes that the cost of equity is the risk-adjusted opportunity cost to the investor, in this case, Ameren. The true cost of capital depends on the use to which the capital is put, in this case UE's electric utility operations. 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% and invests the funds in a speculative oil extraction venture, the required return on the investment is not the 8% cost but, rather, the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return on UE is the return foregone in comparable risk integrated electric utility operations, 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 integrated electric utility such as UE is the return foregone on investments of similar risk and is unrelated to the investor's identity.

III. COST OF EQUITY ESTIMATES

Q. DR. MORIN, HOW DID YOU ESTIMATE THE FAIR ROE FOR UE?

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

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 to 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.

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. The weight accorded to any one methodology may very well vary depending on unusual circumstances in capital market conditions.

Each methodology requires the exercise of considerable judgment concerning the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology, especially in the current atmosphere of turmoil and volatility in capital markets. 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, are vivid examples of the potential shortcomings of the DCF model.

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. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of 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 equity.

Q. ARE THERE ANY PRACTICAL DIFFICULTIES IN APPLYING COST OF CAPITAL METHODS IN THE CURRENT ENVIRONMENT OF TURMOIL IN CAPITAL MARKETS?

A. Yes, there are. All the traditional cost of equity estimation methods are difficult to implement when you are dealing with the unprecedented conditions of instability and volatility in the capital markets and the fast-changing circumstances of the utility industry. This is not only because stock prices are extremely volatile at this time, but also utility company historical data have become less meaningful for an industry experiencing unprecedented volatility. Past earnings and dividend trends may simply not be 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, restructuring, and the transition to a more competitive environment. Moreover, historical growth rates may not be representative of future trends for several 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, PLEASE PROVIDE AN OVERVIEW OF YOUR RISK PREMIUM ANALYSES.

A. In order to quantify the risk premium for UE, I performed three risk premium studies. The first two studies deal with aggregate stock market risk premium evidence using two versions of the CAPM methodology, and the third study deals directly with the utility industry.

A. CAPM ESTIMATES

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 an empirical approximation to the CAPM (ECAPM). The 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 securities market as a whole by R_M, the CAPM is:

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

This is the seminal CAPM expression, which states that the return required by investors 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 4.5% based on the current level of long-term Treasury interest rates. For beta, I used 0.73 and for the market risk premium ("MRP"), I used 6.5%. These inputs to the CAPM are explained below.

Q. HOW DID YOU DERIVE THE RISK FREE RATE OF 4.5%?

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 current level of 30-year Treasury bond yields.

The appropriate proxy for the risk-free rate in the CAPM is the return on the longest term 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 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. Common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely. Thus, the yield on the longest-term possible government bonds, that is the yield on 30-year 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 investor'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. Thus the yield on the longest-term possible government bonds, that is the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM.

While long-term 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 (e.g., 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 Treasury bond possible is that common equity has an infinite life span, and the inflation expectations embodied in its market-required rate of return therefore will 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 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.

Q. DR. MORIN, ARE THERE OTHER REASONS WHY YOU REJECT SHORT-TERM INTEREST RATES AS PROXIES FOR THE RISK-FREE RATE IN IMPLEMENTING THE CAPM?

A. Yes. 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, as was seen since the commencement of the financial crisis, 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 Treasury Bills. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day 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 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 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 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 bonds prevailing in late June 2009 as reported in Value Line and the Federal Reserve Bank, is 4.5%. Accordingly, I shall use 4.5% as my estimate of the risk-free rate component of the CAPM. As I discuss later, while interest rates on government securities have decreased in the past year, the cost of borrowing for companies generally and utilities in particular have increased substantially.

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 the 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 that are reflected in investors' return requirements.

As a wholly-owned subsidiary of Ameren, UE is not publicly traded and, therefore, proxies must be used for UE. In the discussion of DCF estimates of the cost of common equity below, I examined a sample of widely-traded investment-grade dividend-paying vertically integrated electric utilities covered by Value Line that have (i) at least 50% of their revenues from regulated electric utility operations, and (ii) a market capitalization that is at least $500 million[1]. As displayed on page 1 of Schedule RAM-E2, the average beta for the group is currently 0.73.

I also examined the average beta of the electric utilities that make up Standard & Poor's Electric Utility Index as a second proxy. As shown on page 2 of Schedule RAM-E2, the average beta of the group is 0.76.

Based on these results, I shall use the average beta of the integrated electric utilities group, 0.73, as a beta estimate for UE. It is important to note that betas are estimated on five-year historical periods and, therefore, do not capture the re-pricing of risk and the dramatic increase in volatility and capital costs that have occurred since October 2008.

Q. WHAT MRP ESTIMATE DID YOU USE IN YOUR CAPM ANALYSIS?

A. For the MRP, I used 6.5%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums, mainly the latter. First, the Morningstar (formerly Ibbotson Associates) study, <u>Stocks,</u>

[1] This is necessary in order to minimize the well-known thin trading bias in measuring beta.

Bonds, Bills, and Inflation, 2009 Yearbook, compiling historical returns from 1926 to 2008, shows that a broad market sample of common stocks outperformed long-term U. S. Treasury bonds by 5.6%. The historical MRP over the income component of long-term Treasury bonds rather than over the total return is 6.5%. Morningstar recommends the use of the latter as a more reliable estimate of the historical MRP, 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 MRP. 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-horizon (1926-2008) MRP (based on income returns, as required) is specifically calculated to be 6.5% rather than 5.6%.

Q. ON WHAT MATURITY BOND DOES THE MORNINGSTAR HISTORICAL RISK PREMIUM DATA RELY?

A. Because 30-year bonds were not always traded or even available throughout the entire 1926-2008 period covered in the Morningstar study of historical returns, the latter study relied on bond return data based on 20-year 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 Morningstar study, the difference in yield is not material.

Q. WHY DID YOU USE LONG TIME PERIODS IN ARRIVING AT YOUR HISTORICAL MRP 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 MRP 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, because 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 MRP 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," the best estimate of the future risk premium is the historical mean. Because I found no evidence that the MRP in common stocks has changed over time (at least until now), that is, no significant serial correlation in the Morningstar study, it is reasonable to assume that these quantities will remain stable in the future.

Q. DID YOU CHECK YOUR HISTORICAL MRP ESTIMATE WITH ANY OTHER SOURCE?

A. Yes, I did. As a check on my final MRP estimate of 6.5%, I examined a 2003 comprehensive article published in Financial Management (see 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). These authors provide estimates of the prospective expected returns for S&P 500 companies over the period 1983-1998. They 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. 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 Table 2 of the aforementioned study, displays the average prospective risk premium estimate (Column 2) for each year from 1983 to 1998. The average MRP estimate for the overall period is 7.2%, which is reasonably close to the historical of 6.5%, and almost identical to the historical estimate of 7.1% if the disastrous performance of the capital markets during 2008 is excluded from the historical average.

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. DID YOU PERFORM ANY OTHER PROSPECTIVE ANALYSIS OF THE MRP?

A. No, I did not. Given the unsettled conditions in the equity market, I shall therefore retain the historical MRP estimate of 6.5%. I view this estimate as conservative in the current environment of chaos and instability in capital markets.

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

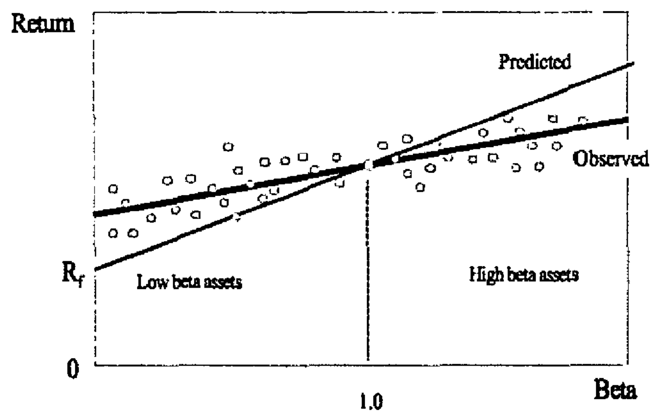
A. Inserting those input values in the CAPM equation, namely a risk-free rate of 4.5%, a beta of 0.73, and a MRP of 6.5%, the CAPM estimate of the cost of common equity for UE is: 4.5% + 0.73 x 6.5% = 9.3%. This estimate becomes 9.6% with flotation costs, discussed later in my testimony.

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 1994 book, <u>Regulatory Finance</u>, and Chapter 6 of my latest book, <u>The New Regulatory Finance</u>, both published by Public Utilities Report 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:

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

where the symbol alpha, α, represents the "constant" of the risk-return line, 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 in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following more tractable ECAPM expression:

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

An alpha range of 1% - 2% 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. In other words, 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 that has been tested. This is also because the use of adjusted betas rather than the use of raw betas incorporates some of the desired effect of using the ECAPM[2]. Thus, it is reasonable to apply a conservative alpha adjustment.

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 4.5% for the risk-free rate R_F, a MRP of 6.5% for $(R_M - R_F)$ and a beta of 0.73 in the above equation, the ROE is 9.7% without flotation costs and 10.0% with flotation costs discussed later in my testimony.

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. This is because the

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[22] The regression tendency of betas to converge to 1.0 over time is very well known and widely discussed in the financial literature. As a result of this beta drift, several commercial beta producers adjust their forecasted betas toward 1.00 in an effort to improve their forecasts. Value Line, Bloomberg, and Merrill Lynch betas are adjusted for their long-term tendency to regress toward 1.0 by giving approximately 66% weight to the measured raw beta and approximately 33% weight to the prior value of 1.0 for each stock.

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 observed 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 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, as explained in Appendix A.

Q. PLEASE SUMMARIZE YOUR CAPM ESTIMATES.

A. The table below summarizes the common equity estimates obtained from the CAPM studies.

CAPM	% ROE
CAPM plain	9.6%
Empirical CAPM	10.0%

Q. HOW MUCH WEIGHT SHOULD BE ACCORDED TO THE CAPM RESULTS UNDER CURRENT MARKET CIRCUMSTANCES?

A. The CAPM and ECAPM estimates are not significantly above the cost of new debt capital and likely understate the cost of equity capital under current unsettled capital market conditions. I believe that less weight should be accorded to the CAPM results under present circumstances for two reasons. First, because the betas employed in the CAPM analysis are estimated over five-year historical periods, the impact of the ongoing financial crisis is not yet fully captured in the five-year historical betas, and the betas do not reflect the current degree of volatility in the equity markets. Second, government interest rates have decreased substantially following the Federal Reserve's expansionary policies designed to jumpstart the stalled economy, thus lowering the CAPM results. At the same time, the cost of corporate debt and the cost of equity for utilities have increased significantly, as evidenced by the record high corporate yield spreads discussed earlier in my testimony, and by the DCF results for utilities that have increased by some 100-150 basis points in response to lower stock prices (higher dividend yields) following the financial crisis. The DCF analysis is presented below.

This anomaly between actual market costs and the estimation techniques used in this proceeding puts the Company at significant financing risk. As such, much less weight should be accorded to the CAPM method at present. As I mentioned above, there is a fundamental structural upward shift in risk aversion as capital markets are re-pricing risk, and capital has become, and will continue to be, more expensive for all non-government market participants over the next 18-24 months at least.

B. RISK PREMIUM ESTIMATE

Q. WHAT IS CURRENTLY HAPPENING IN THE DEBT AND EQUITY MARKETS?

A. Since the financial crisis began in 2008, the financial markets, both in the U.S. and abroad, have become extremely volatile, unpredictable, and have displayed unusual behavior. The debt markets have witnessed record high yield spreads (the incremental yield over Treasury rates needed to issue debt) and a more severe differentiation between the spreads charged to companies with different levels of credit. In light of a fundamental structural upward shift in risk aversion as capital markets are re-pricing risk, capital has become, and will continue to be, more expensive for all market participants, including utilities, relative to government bond yields.

Q. DR. MORIN, GIVEN THE CURRENT STATE OF THE CAPITAL MARKETS AT THIS TIME, IS A HISTORICAL RISK PREMIUM ANALYSIS USING GOVERNMENT BOND YIELDS APPROPRIATE?

A. No, I do not believe it is. Trends in utility cost of capital are directly reflected in their cost of debt and are not directly captured by a risk premium estimate tied to government bond yields. This is especially germane in the current financial crisis where corporate spreads have reached record levels. Because a utility's cost of capital is determined by its business and financial risks, it is reasonable to surmise that its cost of equity will track its cost of debt more closely than it will track the government bond yield. Therefore, in contrast to past testimonies I have performed a historical premium analysis using the utility bond yield instead of the government bond yield.

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

A. A historical risk premium for the electric utility industry was estimated with an annual time series analysis applied to the utility industry as a whole over the 1930-2007 period, using *Standard and Poor's Utility Index* as an industry proxy. The analysis is depicted on Schedule RAM-E3. The risk premium was estimated by computing the actual realized return on equity capital for the S&P Utility Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term utility bond return for that year.

As shown on Schedule RAM-E3, the average risk premium over the period was 5.0% over historical long-term utility bond returns and also 5.0% over long-term utility bond yields. Given that the current yield on A-rated utility bonds is 6.0%, and using the historical estimate of 5.0%, the implied cost of equity for the average risk utility from this particular method is 6.0% + 5.0% = 11.0% without flotation costs and 11.3% with the flotation cost allowance. The need for a flotation cost allowance is discussed at length later in my testimony.

Q. DR. MORIN, ARE RISK PREMIUM STUDIES WIDELY USED?

A. Yes, they are. Risk Premium analyses are widely used by analysts, investors, economists, and expert witnesses. Most college-level corporate finance and/or investment management texts, including Investments by Bodie, Kane, and Marcus, McGraw-Hill Irwin, 2002, which is a recommended textbook for CFA (Chartered Financial Analyst) certification and examination, contain detailed conceptual and empirical discussion of the risk premium approach. The latter is typically recommended as one of the three leading methods of estimating the cost of capital. Professor Brigham's best-selling corporate finance textbook, for example, Corporate Finance: A Focused Approach, 3rd ed., South-Western, 2008, recommends the use of risk premium studies, among others. Techniques of risk premium analysis are widespread in investment community reports. Professional certified financial analysts are certainly well versed in the use of this method.

Q. ARE YOU CONCERNED ABOUT THE REALISM OF THE ASSUMPTIONS THAT UNDERLIE THE HISTORICAL RISK PREMIUM METHODOLOGY?

A. No, I am not, for they are no more restrictive than the assumptions that underlie the DCF model or the CAPM. While it is true that the method looks backward in time and assumes that the risk premium is constant over time, these assumptions are not necessarily restrictive. By employing returns realized over long time periods rather than returns realized over more recent time periods, investor return expectations and realizations converge. Realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. By ensuring that the risk premium study encompasses 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, or else, investors would never invest any money.

C. DCF ESTIMATES

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 benefits. 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 standard 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, and Chapter 8 of my latest textbook, The New Regulatory Finance. The standard DCF model requires the following main assumptions: a constant average growth trend 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 standard 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. 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. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. 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 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 contained in Zacks as proxies for investors' growth expectations in applying the DCF model. The latter are also conveniently provided in the Value Line software. I also used Value Line's growth forecast as a proxy.

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

A. The average historical growth rates in earnings and dividends for electric utilities are 3.4%, and 1.8% over the past 5 years, respectively. Please see Schedule RAM-E4, columns 2 and 3, for the historical growth in earnings and dividends per share over the last five years for the electric utility companies that make up Value Line's Electric Utility composite group. Several companies have experienced negative earnings growth rates, as evidenced by the numerous historical growth rates reported on the table that are negative.

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/ten years, due to the structural transformation of the electric utility industry from a fully integrated regulated monopoly to a more competitive environment. 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 3.4% and 1.8% to the average dividend yield of approximately 5.5% prevailing currently for those same companies, produces preposterous cost of equity estimates of 8.9% and 7.3% using earnings and dividends growth rates, respectively. Of course, these estimates of equity costs are unreasonable as they are barely above the cost of long-term debt for these companies. A similar pattern emerges if ten-year instead of five-year historical growth rates are examined.

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 ANY OTHER METHOD OF ESTIMATING EXPECTED GROWTH IN THE DCF MODEL?

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by the company, 'b', by the expected return on book equity, 'ROE', as follows:

$$g = b \times ROE$$

where: g = expected growth rate in earnings/dividends
b = expected retention ratio
ROE = expected return on book equity

Q. DO YOU HAVE ANY RESERVATIONS WITH REGARD TO THE SUSTAINABLE GROWTH METHOD?

A. Yes, I do. First, the sustainable method of predicting growth is only accurate under the assumptions that the ROE is constant over time and that no new common stock is issued by the company, or if so, it is sold at book value. Second, and more importantly, the sustainable growth method contains a logic trap: the method requires an estimate of ROE to be implemented. But if the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Third, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock prices and price/earnings ratios, as analysts' growth forecasts. I therefore chose not to rely on this method.

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

A. No, not at this time. This is because it is widely expected that some utilities will continue to lower their dividend payout ratio over the next several years in response to heightened business risk and the need to fund very large construction programs over the next decade. In other words, earnings and dividends are not expected to grow at the same rate in the future.

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. Thus, 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 utilities in general. This result is because utilities' dividend policies have become increasingly conservative as business risks and financing needs 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 and finance gargantuan infrastructure investments. 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. Indeed, it is growth in earnings that will support future dividends and share prices.

Moreover, as a practical matter, while earnings growth forecasts are widely available, there are very few dividend growth forecasts.

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

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, 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, Value Line's principal investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, which account for 65% of the ranking.

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

A. I applied the DCF model to two proxies for UE: a group of investment-grade dividend-paying integrated electric utilities and a group consisting of the electric utilities that make up Standard & Poor's Utility Index. The latter index is representative of the electric utility industry as a whole.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/P_0) 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. This is because the current stock price provides 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, the current price reflects 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 evidence 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 current dividend yields reported in the latest edition of Value Line's VLIA software, dated June 2009. Basing dividend yields on average results from a large group of companies reduces the concern that idiosyncrasies of individual company stock prices will result in an unrepresentative dividend yield.

Q. CAN YOU DESCRIBE YOUR FIRST PROXY GROUP OF COMPANIES?

A. Yes. As a first proxy for UE's electric utility business, I examined a group of investment-grade dividend-paying utilities designated as "integrated" utilities by S&P, meaning that these companies all possess electricity generation, distribution, and transmission assets. I began with all the companies designated as electric utilities by Value Line, that is, with SIC codes 4911 to 4913. Foreign companies, private partnerships, private companies, non dividend-paying companies, and companies below investment-grade, that is, companies with a Moody's bond rating below Baa3, were eliminated as well as those companies whose market capitalization was less than $500 million in order to minimize any stock price anomalies due to thin trading. The group is further narrowed down to include only the electric utilities designated as "integrated" by S&P, as is UE. The final group of 29 companies only includes those companies with at least 50% of their revenues from regulated electric utility operations. The same group was utilized earlier in connection with beta estimates and is retained for the DCF analysis.

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

A. Page 1 of Schedule RAM-E5 shows the raw dividend yield and growth data for the 29 companies while page 2 displays the DCF analysis. ALLETE and Great Plains Energy were eliminated on account of their negative growth forecast. As shown on Column 3, line 29 of page 2 of Schedule RAM-E5, the average long-term growth forecast obtained from Value Line is 6.1% for this group. Adding this growth rate to the average expected dividend yield of 6.0% shown in Column 4 produces an estimate of equity costs of 12.1% for the group. Recognition of flotation costs brings the cost of equity estimate to 12.4%, shown in Column 6. In order to palliate the effect of outliers, the median estimate of 12.2% is preferable in this case.

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

A. From the original sample of 29 companies shown on page 1 of Schedule RAM-E6, Empire District was eliminated as no analysts' growth forecasts was available from Zacks. For the remaining 28 companies shown on page 2 of Schedule RAM-E6, using the consensus analysts' earnings growth forecast published by Zacks instead of the Value Line forecast, the median cost of equity for the group adjusted for flotation cost is 12.5%.

Q. WHAT DCF RESULTS DID YOU OBTAIN FOR THE S&P UTILITY INDEX GROUP?

A. Page 1 of Schedule RAM-E7 displays the electric utilities that make up Standard & Poor's Utility Index as well as input data necessary for the DCF analysis. Page 2 of Schedule RAM-E7 displays the DCF analysis using Value Line growth projections. As shown on Column 3 of Schedule RAM-E7, the average long-term growth forecast obtained from Value Line is 5.4% for this group. Coupling this growth rate with the average expected dividend yield of 5.8% shown in Column 4 for each company produces an estimate of equity costs of 11.2% for the group, unadjusted for flotation costs. Adding an allowance for flotation costs to the results of Column 5 brings the cost of equity estimate to 11.5%, as shown in Column 6. The median estimate is 11.9%. If we limit the sample to those companies with at least 50% of their revenues from regulated electric utility operations, the median cost of equity estimate is 12.1%. This analysis is shown on page 3 of Schedule RAM-E7.

Using the consensus analysts' growth forecast from Zacks instead of the Value Line growth forecast, the median cost of equity estimate for the S&P group is 12.6%. This analysis is displayed on pages 1, 2, and 3 of Schedule RAM-E8. As before, page 1 shows the input data, page 2 displays the DCF analysis, and page 3 shows the DCF analysis for those companies with a majority of their revenues that are regulated utility operations. If we limit the sample to those companies with a majority of their revenues that are regulated utility operations, the median cost of equity estimate is 12.5%.

Q. PLEASE SUMMARIZE YOUR DCF ESTIMATES.

A. The table below summarizes the DCF estimates which are remarkably similar:

DCF STUDY	ROE
Integrated Electric Utilities Value Line Growth	12.2%
Integrated Electric Utilities Zacks Growth	12.5%
S&P Electric Utilities Value Line Growth	12.1%
S&P Electric Utilities Zacks Growth	12.5%

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 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. Appendix B to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) 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% return, that is, \$10 of earnings. But if flotation costs are 5%, 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% must be allowed on this reduced equity base, here 10.52%.

According to the empirical finance literature discussed in Appendix B, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% 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% for utility stocks by 0.95 yields 5.3%, 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 item 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 UE 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, Ameren. 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 OF COST OF EQUITY RECOMMENDATION

Q. CAN YOU SUMMARIZE YOUR RESULTS AND RECOMENDATION?

A. To arrive at my final recommendation, I performed three 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 risk premium analysis was performed on historical risk premium data from electric utility industry aggregate data, using the current yield on long-term utility bonds. I also performed DCF analyses on two surrogates for UE: a group of investment-grade dividend-paying integrated electric utilities, and a group of electric utilities that make up the S&P Utility Index. The results from all the various tests are summarized in the table below.

METHODOLOGY	ROE
CAPM	9.6%
Empirical CAPM	10.0%
Historical Risk Premium Electric	11.3%
DCF Integrated Elec Utilities Value Line Growth	12.2%
DCF Integrated Elec Utilities Zacks Growth	12.5%
DCF S&P Elec Utilities Value Line Growth	12.1%
DCF S&P Elec Utilities Zacks Growth	12.5%

The average result from all the methodologies is 11.5%.

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

A. Based on the results of all my analyses, the application of my professional judgment, and the risk circumstances of UE, it is my opinion that a just and reasonable return on the common equity capital of UE's electric utility operations in the state of Missouri is 11.5%. In view of the current turmoil and uncertainty in capital markets, and in view of the CAPM's understatement of capital costs under these current conditions, I believe that my recommendation is conservative.

Q. HOW DOES YOUR ROE RECOMMENDATION COMPARE WITH THE MANNER IN WHICH THE COMMISSION HAS DETERMINED A FAIR AND REASONABLE ROE IN RECENT MISSOURI CASES?

A. In recent Missouri cases, the Commission has excluded flotation costs from the ROE, but has included an upward risk adjustment of 25 basis points in order to recognize that the proxy groups are less risky than the Company and an additional small upward adjustment to recognize the quarterly nature of dividend payments.

My recommendation would remain unaltered if those adjustments were implemented in this case.

Q. WHAT CAPITAL STRUCTURE ASSUMPTION UNDERLIES YOUR RECOMMENDED RETURN ON UE'S COMMON EQUITY CAPITAL?

A. My recommended return on common equity for UE is predicated on the adoption of a capital structure for the Company that is consistent with the range of capital structures of similar integrated electric utilities. UE's current capital structure is within that range.

Q. IS THERE A RELATIONSHIP BETWEEN FINANCIAL RISK AND THE AUTHORIZED RETURN ON EQUITY?

A. There certainly is. A low authorized return on equity increases the likelihood the utility will have to rely increasingly on debt financing for its capital needs. This creates the specter of a spiraling cycle that further increases risks to both equity and debt investors; the resulting increase in financing costs is ultimately borne by the utility's customers through higher capital costs and rates of returns.

V. ZONE OF REASONABLENESS

Q. DR. MORIN, ARE YOU FAMILIAR WITH THE "ZONE OF REASONABLENESS" THAT THE COMMISSION HAS USED IN RECENT YEARS AS ONE OF ITS TOOLS IN EVALUATING ROE RECOMMENDATIONS?

A. Yes, I am. As I understand it, the Commission has considered whether ROE recommendations are within 100 basis points of the average of awarded ROEs from a recent period [as reported by Regulatory Research Associates (now SNL)] and, in general, has viewed with skepticism any ROE recommendation that falls outside this zone. Analytically, there could be problems with such a zone if, for example, the actual cost of capital has changed since the time period for which the average that is being used is computed. I understand, however, that the Commission simply uses the zone of reasonableness as one means of assessing various ROE recommendations.

Q. IF THE COMMISSION WOULD LIKE TO USE A "ZONE OF REASONABLENESS" IN THIS CASE, WHAT ZONE WOULD BE APPROPRIATE?

A. Most of the utility companies in my proxy group are, like UE, vertically integrated electric utilities—companies that own electric generation, transmission and distribution facilities. These vertically integrated utilities are much more comparable to UE than "wires only" companies that do not own generation facilities, and are not subject to the additional risks that owning and operating generating facilities entail. As a consequence, an appropriate zone of reasonableness for assessing ROE recommendations for UE should be based on an average of ROEs awarded to integrated utilities, and should exclude wires only utilities.

Q. HAVE YOU CALCULATED SUCH AN AVERAGE?

A. Yes. Using RRA reported data for calendar year 2008, the average allowed ROE for integrated electric utilities was 10.6%. This means that the appropriate zone of reasonableness for the Commission to use in this case is 9.6% - 11.6%. My recommendation for an ROE for the Company, 11.5%, falls within this zone of reasonableness.

Q. **DID YOU ADJUST YOUR FINAL RECOMMENDATION IN ORDER TO ACCOUNT FOR THE COMPANY'S FUEL ADJUSTMENT CLAUSE OR ENVIRONMENTAL COST RECOVERY MECHANISM?**

A. No, I did not. Any risk-mitigating impact such mechanisms could have on the Company's risk profile is already reflected in the capital market data of the comparable companies. Most electric utilities in the industry are under some form of adjustment clause/cost recovery/rider mechanisms. The approval of adjustment clauses, ROE incentives riders, trackers, forward test years, and cost recovery mechanisms by regulatory commissions is widespread in the utility business and is already largely embedded in financial data, such as bond rating and business risk scores. While adjustment clauses, riders, and cost tracking mechanisms may mitigate (on an absolute basis but not on a relative basis) a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations, there are other significant factors to consider that work in the reverse direction for UE, namely, a huge capital spending program requiring external financing, weak financial metrics in its bond rating class, heightened regulatory risk that offset the presence of the aforementioned mechanisms, including significant regulatory lag to the use of a historical test year in Missouri, and the absence of CWIP in rate base.

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. The capital market environment is extremely volatile at this time. Interest rates, security prices and risk premiums do change over time. 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.

RESUME OF ROGER A. MORIN

(Spring 2009)

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Robinson 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 Pennsylvania, 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, 1979-2008
- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, Robinson College of Business, Georgia State University, 1985-2009
- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986
- Emeritus Professor of Finance, Georgia State University, 2007-9

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.

Allete

AmerenUE

American Water Works Company

Ameritech

Arkansas Western Gas

Baltimore Gas & Electric – Constellation Energy

Bangor Hydro-Electric

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

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

Detroit Edison Company

DTE Energy

Edison International

Edmonton Power Company

Elizabethtown Gas Co.

Emera

Energen

Engraph Corporation

Entergy Corp.

Entergy Arkansas Inc.

Entergy Gulf States, Inc.

Entergy Louisiana, Inc.

Entergy Mississippi Power

Entergy New Orleans, Inc.

First Energy

Florida Water Association

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

Hawaiian Elec & Light Co

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

Maui Electric Co.

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

Minnesota Power & Light

Mississippi Power Company

Missouri Gas Energy

Mountain Bell

National Grid

Nevada Power Company

New Brunswick Power

Newfoundland Power Inc. - Fortis Inc.

New Market Hydro

New Tel Enterprises Ltd.

New York Telephone Co.

Niagara Mohawk Power Corp

Norfolk-Southern

Northeast Utilities

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Power

Nova Scotia Utility and Review Board

NUI Corp.

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

PNM Resources

Pacific Northwest Bell

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Pepco Holdings

Potomac Electric Power Co.

Price Waterhouse

PSI Energy

Public Service Electric & Gas

Public Service of New Hampshire

Public Service of New Mexico

Puget Sound Energy

Quebec Telephone

Regie de l'Energie du Quebec

Rochester Telephone

San Diego Gas & Electric

SaskPower

Sierra Pacific Power Company

Sierra Pacific Resources

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 1981-2008.
  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
  Fundamentals of Utility Finance in a Restructured Environment
  Contemporary Issues in Utility Finance

- SNL Center for Financial Education. faculty member 2008-2009.
  National Seminars:

  Essentials of Utility Finance

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

<u>EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE</u>

Corporate Finance

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

Alabama Public Service Commission

Alaska Public Utility Commission

Alberta Public Service Board

Arizona Corporation Commission

Arkansas Public Service Commission

British Columbia Board of Public Utilities

California Public Service Commission

Canadian Radio-Television & Telecommunications Comm.

Colorado Public Utilities Board

Delaware Public Utility Commission

District of Columbia Public Service Commission

Federal Communications Commission

Federal Energy Regulatory Commission

Florida Public Service Commission

Georgia Public Service Commission

Georgia Senate Committee on Regulated Industries

Hawaii Public Service Commission

Illinois Commerce Commission

Indiana Utility Regulatory Commission

Iowa Board of Public Utilities

Louisiana Public Service Commission

Maine Public Service Commission

Manitoba Board of Public Utilities

Michigan Public Service Commission

Minnesota Public Utilities Commission

Mississippi Public Service Commission

Missouri Public Service Commission

Montana Public Service Commission

National Energy Board of Canada

Nevada Public Service Commission

New Brunswick Board of Public Commissioners

New Hampshire Public Utility Commission

New Jersey Board of Public Utilities

New Mexico Public Regulatory Commission

New Orleans City Council

New York Public Service Commission

Newfoundland Board of Commissioners of Public Utilities

North Carolina Utilities Commission

Ohio Public Utilities Commission

Oklahoma State Board of Equalization

Ontario Telephone Service Commission

Ontario Energy Board

Pennsylvania Public Service Commission

Quebec Natural Gas Board

Quebec Regie de l'Energie

Quebec Telephone Service Commission

South Carolina Public Service Commission

Tennessee Regulatory Authority

Texas Public Utility Commission

Utah Public Service Commission

Virginia Public Service Commission

Washington Utilities & Transportation Commission

West 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, 1989

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, 2007

Nevada Power Company, 2001

Mid American Energy, 2001, 2002

Entergy Louisiana Inc. 2001, 2002, 2004

Mississippi Power Company, 2001, 2002, 2007

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

New Brunswick 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 Energy 2006, 2007, 2009

Cascade Natural Gas 2006

Entergy Arkansas 2006-7

Bangor Hydro 2006-7

Delmarva 2006-7

Potomac Electric Power Co. 2006, 2007

Detroit Edison Co. 2007, 2008

Nevada Power Co. 2007
Hawaiian Electric Co. 2006-7-8

Hawaii Elec & Light Co. 2007

Maui Electric Co. 2007

Ameren Union Electric 2008

Consolidated Edison of New York 2007-2008-2009

CH Energy 2008

Orange & Rockland 2007-2008

Niagara Mohawk Power Corp 2008

ALLETE (Minnesota Power) 2007-2008

Sierra Pacific Power 2007-2008

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.

- Guest speaker, "Mythodology in Regulatory Finance", Society of Utility Rate of Return Analysts (SURFA), Annual Conference, Wash., D.C. February 2007.

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, 1978.

"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. 1982, 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., 2004

Driving Shareholder Value, McGraw-Hill, January 2001.

The New Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 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.

Schedule RAM-E2 Page 1 of 2

Integrated Elec Utilities

Line No.	(1) Company Name	(2) Beta
1	ALLETE	0.70
2	Allegheny Energy	1.00
3	Alliant Energy	0.70
4	Amer. Elec. Power	0.75
5	Ameren Corp.	0.80
6	CMS Energy Corp.	0.80
7	Cleco Corp.	0.70
8	DPL Inc.	0.60
9	DTE Energy	0.75
10	Duke Energy	0.65
11	Edison Int'l	0.80
12	Empire Dist. Elec.	0.75
13	Entergy Corp.	0.70
14	Exelon Corp.	0.85
15	FPL Group	0.75
16	FirstEnergy Corp.	0.85
17	G't Plains Energy	0.75
18	Hawaiian Elec.	0.70
19	IDACORP Inc.	0.70
20	PG&E Corp.	0.55
21	Pepco Holdings	0.80
22	Portland General	0.75
23	Progress Energy	0.65
24	Public Serv. Enterprise	0.80
25	Southern Co.	0.55
26	TECO Energy	0.80
27	Westar Energy	0.75
28	Wisconsin Energy	0.65
29	Xcel Energy Inc.	0.65
31	**AVERAGE**	**0.73**

Source: VLIA 6/2009

Schedule RAM-E2 Page 2 of 2

S&P Index Electric Utilities

	(1)	(2)
Line No.	Company Name	Beta
1	Allegheny Energy	1.00
2	Amer. Elec. Power	0.75
3	Ameren Corp.	0.80
4	CMS Energy Corp.	0.80
5	CenterPoint Energy	0.85
6	Consol. Edison	0.65
7	Constellation Energy	0.80
8	DTE Energy	0.75
9	Dominion Resources	0.70
10	Duke Energy	0.65
11	Edison Int'l	0.80
12	Entergy Corp.	0.70
13	Exelon Corp.	0.85
14	FPL Group	0.75
15	FirstEnergy Corp.	0.85
16	Integrys Energy	0.95
17	PG&E Corp.	0.55
18	PPL Corp.	0.70
19	Pepco Holdings	0.80

Schedule RAM-E3 Utility Industry Historical Risk Premium

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Year	Utlity A-Rated Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	S&P Utility Index Return	Utility Equity Risk Premium Over Bond Returns	Utility Equity Risk Premium Over Bond Yields
1	1931	5.12%	1,000.00						
2	1932	6.46%	850.73	-149.27	51.20	-9.81%	-0.54%	9.27%	-7.00%
3	1933	6.32%	1,015.77	15.77	64.60	8.04%	-21.87%	-29.91%	-28.19%
4	1934	5.50%	1,098.72	98.72	63.20	16.19%	-20.41%	-36.60%	-25.91%
5	1935	4.61%	1,115.47	115.47	55.00	17.05%	76.63%	59.58%	72.02%
6	1936	4.08%	1,071.99	71.99	46.10	11.81%	20.69%	8.88%	16.61%
7	1937	3.98%	1,013.70	13.70	40.80	5.45%	-37.04%	-42.49%	-41.02%
8	1938	3.90%	1,011.04	11.04	39.80	5.08%	22.45%	17.37%	18.55%
9	1939	3.52%	1,054.23	54.23	39.00	9.32%	11.26%	1.94%	7.74%
10	1940	3.24%	1,040.98	40.98	35.20	7.62%	-17.15%	-24.77%	-20.39%
11	1941	3.07%	1,025.27	25.27	32.40	5.77%	-31.57%	-37.34%	-34.64%
12	1942	3.09%	997.03	-2.97	30.70	2.77%	15.39%	12.62%	12.30%
13	1943	2.99%	1,014.97	14.97	30.90	4.59%	46.07%	41.48%	43.08%
14	1944	2.97%	1,003.00	3.00	29.90	3.29%	18.03%	14.74%	15.06%
15	1945	2.87%	1,015.14	15.14	29.70	4.48%	53.33%	48.85%	50.46%
16	1946	2.71%	1,024.58	24.58	28.70	5.33%	1.26%	-4.07%	-1.45%
17	1947	2.78%	989.32	-10.68	27.10	1.64%	-13.16%	-14.80%	-15.94%
18	1948	3.02%	964.17	-35.83	27.80	-0.80%	4.01%	4.81%	0.99%
19	1949	2.90%	1,018.11	18.11	30.20	4.83%	31.39%	26.56%	28.49%
20	1950	2.79%	1,016.77	16.77	29.00	4.58%	3.25%	-1.33%	0.46%
21	1951	3.11%	952.61	-47.39	27.90	-1.95%	18.63%	20.58%	15.52%
22	1952	3.24%	980.97	-19.03	31.10	1.21%	19.25%	18.04%	16.01%
23	1953	3.49%	964.23	-35.77	32.40	-0.34%	7.85%	8.19%	4.36%
24	1954	3.16%	1,048.65	48.65	34.90	8.35%	24.72%	16.37%	21.56%
25	1955	3.22%	991.20	-8.80	31.60	2.28%	11.26%	8.98%	8.04%
26	1956	3.56%	951.65	-48.35	32.20	-1.62%	5.06%	6.68%	1.50%
27	1957	4.24%	908.92	-91.08	35.60	-5.55%	6.36%	11.91%	2.12%
28	1958	4.20%	1,005.38	5.38	42.40	4.78%	40.70%	35.92%	36.50%
29	1959	4.78%	925.83	-74.17	42.00	-3.22%	7.49%	10.71%	2.71%
30	1960	4.78%	1,000.00	0.00	47.80	4.78%	20.26%	15.48%	15.48%
31	1961	4.62%	1,020.74	20.74	47.80	6.85%	29.33%	22.48%	24.71%
32	1962	4.54%	1,010.44	10.44	46.20	5.66%	-2.44%	-8.10%	-6.98%
33	1963	4.39%	1,019.83	19.83	45.40	6.52%	12.36%	5.84%	7.97%
34	1964	4.52%	983.00	-17.00	43.90	2.69%	15.91%	13.22%	11.39%
35	1965	4.58%	992.20	-7.80	45.20	3.74%	4.67%	0.93%	0.09%
36	1966	5.39%	901.59	-98.41	45.80	-5.26%	-4.48%	0.78%	-9.87%
37	1967	5.87%	943.94	-56.06	53.90	-0.22%	-0.63%	-0.41%	-6.50%
38	1968	6.51%	928.99	-71.01	58.70	-1.23%	10.32%	11.55%	3.81%
39	1969	7.54%	894.48	-105.52	65.10	-4.04%	-15.42%	-11.38%	-22.96%
40	1970	8.69%	891.81	-108.19	75.40	-3.28%	16.56%	19.84%	7.87%
41	1971	8.16%	1,051.83	51.83	86.90	13.87%	2.41%	-11.46%	-5.75%
42	1972	7.72%	1,044.47	44.47	81.60	12.61%	8.15%	-4.46%	0.43%
43	1973	7.84%	987.98	-12.02	77.20	6.52%	-18.07%	-24.59%	-25.91%
44	1974	9.50%	852.57	-147.43	78.40	-6.90%	-21.55%	-14.65%	-31.05%
45	1975	10.09%	949.69	-50.31	95.00	4.47%	44.49%	40.02%	34.40%
46	1976	9.29%	1,072.11	72.11	100.90	17.30%	31.81%	14.51%	22.52%

47	1977	8.61%	1,064.35	64.35	92.90	15.72%	8.64%	-7.08%	0.03%
48	1978	9.29%	938.71	-61.29	86.10	2.48%	-3.71%	-6.19%	-13.00%
49	1979	10.49%	900.41	-99.59	92.90	-0.67%	13.58%	14.25%	3.09%
50	1980	13.34%	802.50	-197.50	104.90	-9.26%	15.08%	24.34%	1.74%
51	1981	15.95%	843.97	-156.03	133.40	-2.26%	11.74%	14.00%	-4.21%
52	1982	15.86%	1,005.41	5.41	159.50	16.49%	26.52%	10.03%	10.66%
53	1983	13.66%	1,149.59	149.59	158.60	30.82%	20.01%	-10.81%	6.35%
54	1984	14.03%	975.38	-24.62	136.60	11.20%	26.04%	14.84%	12.01%
55	1985	12.47%	1,113.97	113.97	140.30	25.43%	33.05%	7.62%	20.58%
56	1986	9.58%	1,255.25	255.25	124.70	37.99%	28.53%	-9.46%	18.95%
57	1987	10.10%	955.69	-44.31	95.80	5.15%	-2.92%	-8.07%	-13.02%
58	1988	10.49%	967.63	-32.37	101.00	6.86%	18.27%	11.41%	7.78%
59	1989	9.77%	1,062.76	62.76	104.90	16.77%	47.80%	31.03%	38.03%
60	1990	9.86%	992.20	-7.80	97.70	8.99%	-2.57%	-11.56%	-12.43%
61	1991	9.36%	1,044.85	44.85	98.60	14.34%	14.61%	0.27%	5.25%
62	1992	8.69%	1,063.03	63.03	93.60	15.66%	8.10%	-7.56%	-0.59%
63	1993	7.59%	1,112.26	112.26	86.90	19.92%	14.41%	-5.51%	6.82%
64	1994	8.31%	930.36	-69.64	75.90	0.63%	-7.94%	-8.57%	-16.25%
65	1995	7.89%	1,041.91	41.91	83.10	12.50%	42.15%	29.65%	34.26%
66	1996	7.75%	1,014.12	14.12	78.90	9.30%	3.14%	-6.16%	-4.61%
67	1997	7.60%	1,015.30	15.30	77.50	9.28%	24.69%	15.41%	17.09%
68	1998	7.04%	1,059.61	59.61	76.00	13.56%	14.82%	1.26%	7.78%
69	1999	7.62%	940.94	-59.06	70.40	1.13%	-8.85%	-9.98%	-16.47%
70	2000	8.24%	939.72	-60.28	76.20	1.59%	59.70%	58.11%	51.46%
71	2001	7.78%	1,046.28	46.28	82.40	12.87%	-30.41%	-43.28%	-38.19%
72	2002	7.37%	1,042.55	42.55	77.80	12.03%	-30.04%	-42.07%	-37.41%
73	2003	6.58%	1,087.17	87.17	73.70	16.09%	26.11%	10.02%	19.53%
74	2004	6.16%	1,047.92	47.92	65.80	11.37%	24.22%	12.85%	18.06%
75	2005	5.65%	1,060.65	60.65	61.60	12.22%	16.79%	4.57%	11.14%
76	2006	6.07%	951.73	-48.27	56.50	0.82%	20.95%	20.13%	14.88%
77	2007	6.07%	1,000.00	0.00	60.70	6.07%	19.36%	13.29%	13.29%
78									
79	**Mean**							**5.0%**	**5.0%**

Source: Bloomberg Web site: Standard & Poors Utility Stock Index % Annual Change, Dec. to Dec.
Bond yields from Bloomberg

Schedule RAM-E4 Electric Utility Industry Historical Growth Rates

Line No.	(1) Company Name	(2) Earnings Growth 5-Year	(3) Dividend Growth 5-Year
1	ALLETE		
2	Allegheny Energy		-24.5
3	Alliant Energy	3.0	-10.5
4	Amer. Elec. Power		-6.0
5	Ameren Corp.	-1.5	
6	Avista Corp.	4.0	5.0
7	Black Hills	-8.0	3.5
8	CH Energy Group	-1.5	
9	CMS Energy Corp.		-26.0
10	Cen. Vermont Pub. Serv.	3.5	1.0
11	CenterPoint Energy	-2.0	-7.5
12	Cleco Corp.	0.5	0.5
13	Consol. Edison	1.5	1.0
14	Constellation Energy	3.5	16.0
15	DPL Inc.	7.0	2.0
16	DTE Energy	-2.5	0.5
17	Dominion Resources	5.5	2.5
18	Duke Energy		
19	Edison Int'l	13.5	
20	El Paso Electric	13.5	
21	Empire Dist. Elec.	3.5	
22	Entergy Corp.	10.5	13.0
23	Evergreen Energy Inc		
24	Exelon Corp.	10.5	15.0
25	FPL Group	9.5	7.0
26	FirstEnergy Corp.	12.5	6.5
27	Florida Public Utilities	5.0	3.5
28	G't Plains Energy	-4.5	
29	Hawaiian Elec.	-6.0	
30	IDACORP Inc.	1.5	-8.0
31	ITC Holdings		
32	Integrys Energy	-1.5	3.5
33	MGE Energy	6.0	1.0
34	Maine & Maritimes Corp	-14.5	
35	NSTAR	4.0	6.0
36	NV Energy Inc.		-3.5
37	NorthWestern Corp		
38	Northeast Utilities	3.0	8.5
39	OGE Energy	11.0	0.5
40	Otter Tail Corp.	-1.5	2.0
41	PG&E Corp.	26.5	
42	PNM Resources	-11.5	6.5
43	PPL Corp.	7.5	12.5
44	Pepco Holdings	-2.0	17.5
45	Pinnacle West Capital	-1.0	5.0
46	Portland General		
47	Progress Energy	-6.5	2.0
48	Public Serv. Enterprise	5.5	2.0
49	SCANA Corp.	3.5	6.5
50	Sempra Energy	10.0	3.5
51	Southern Co.	4.0	3.0
52	TECO Energy	-5.0	-9.0
53	U.S. Energy Sys Inc		
54	UIL Holdings		
55	UNITIL Corp.	1.5	
56	UniSource Energy	-1.5	12.5
57	Vectren Corp.	2.5	3.5
58	Westar Energy	32.0	-5.0
59	Wisconsin Energy	6.0	4.5
60	Xcel Energy Inc.	1.0	-4.0
62	**AVERAGE**	**3.4**	**1.8**

Source: Value Line Investment Analyzer 6/2009

Integrated Electric Utilities
DCF Analysis Value Line Growth Rates

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth
1	ALLETE	6.7	-1.0
2	Allegheny Energy	2.4	8.5
3	Alliant Energy	6.4	5.0
4	Amer. Elec. Power	6.4	4.5
5	Ameren Corp.	6.6	1.5
6	CMS Energy Corp.	4.8	10.0
7	Cleco Corp.	4.6	10.5
8	DPL Inc.	5.3	11.0
9	DTE Energy	7.0	4.5
10	Duke Energy	6.8	5.0
11	Edison Int'l	4.3	3.5
12	Empire Dist. Elec.	8.2	8.5
13	Entergy Corp.	4.1	6.0
14	Exelon Corp.	4.6	7.5
15	FPL Group	3.5	8.5
16	FirstEnergy Corp.	5.8	4.0
17	G't Plains Energy	5.5	-0.5
18	Hawaiian Elec.	7.4	7.0
19	IDACORP Inc.	5.2	4.5
20	PG&E Corp.	4.6	6.5
21	Pepco Holdings	8.5	3.0
22	Portland General	5.8	5.5
23	Progress Energy	7.0	6.0
24	Public Serv. Enterprise	4.3	7.5
25	Southern Co.	6.3	5.0
26	TECO Energy	7.2	4.5
27	Westar Energy	6.8	3.0
28	Wisconsin Energy	3.6	8.0

Schedule RAM-E5 Page 2 of 2
Integrated Electric Utilities
DCF Analysis Value Line Growth Rates

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Allegheny Energy	2.4	8.5	2.6	11.1	11.3
2	Alliant Energy	6.4	5.0	6.7	11.7	12.1
3	Amer. Elec. Power	6.4	4.5	6.7	11.2	11.6
4	Ameren Corp.	6.6	1.5	6.7	8.2	8.6
5	CMS Energy Corp.	4.8	10.0	5.2	15.2	15.5
6	Cleco Corp.	4.6	10.5	5.1	15.6	15.9
7	DPL Inc.	5.3	11.0	5.9	16.9	17.2
8	DTE Energy	7.0	4.5	7.3	11.8	12.2
9	Duke Energy	6.8	5.0	7.2	12.2	12.6
10	Edison Int'l	4.3	3.5	4.4	7.9	8.2
11	Empire Dist. Elec.	8.2	8.5	8.9	17.4	17.9
12	Entergy Corp.	4.1	6.0	4.3	10.3	10.5
13	Exelon Corp.	4.6	7.5	4.9	12.4	12.6
14	FPL Group	3.5	8.5	3.8	12.3	12.5
15	FirstEnergy Corp.	5.8	4.0	6.1	10.1	10.4
16	Hawaiian Elec.	7.4	7.0	7.9	14.9	15.3
17	IDACORP Inc.	5.2	4.5	5.4	9.9	10.2
18	PG&E Corp.	4.6	6.5	4.9	11.4	11.7
19	Pepco Holdings	8.5	3.0	8.8	11.8	12.2
20	Portland General	5.8	5.5	6.1	11.6	11.9
21	Progress Energy	7.0	6.0	7.4	13.4	13.8
22	Public Serv. Enterprise	4.3	7.5	4.6	12.1	12.4
23	Southern Co.	6.3	5.0	6.6	11.6	11.9
24	TECO Energy	7.2	4.5	7.5	12.0	12.4
25	Westar Energy	6.8	3.0	7.0	10.0	10.4
26	Wisconsin Energy	3.6	8.0	3.9	11.9	12.1
27	Xcel Energy Inc.	5.6	6.5	6.0	12.5	12.8
29	**AVERAGE**	**5.7**	**6.1**	**6.0**	**12.1**	**12.4**
30	**MEDIAN**					**12.2**

32 Notes:

Column 1, 2, 3: Value Line Investment Analyzer, 6/2009
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3
Negative growth projection for ALLETE, Great Plains Energy

Schedule RAM-E6 Page 1 of 2
Integrated Electric Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast
1	ALLETE	6.7	4.0
2	Allegheny Energy	2.4	14.0
3	Alliant Energy	6.4	5.3
4	Amer. Elec. Power	6.4	4.7
5	Ameren Corp.	6.6	4.0
6	CMS Energy Corp.	4.8	6.5
7	Cleco Corp.	4.6	14.5
8	DPL Inc.	5.3	6.3
9	DTE Energy	7.0	6.0
10	Duke Energy	6.8	5.0
11	Edison Int'l	4.3	6.3
12	Empire Dist. Elec.	8.2	
13	Entergy Corp.	4.1	7.3
14	Exelon Corp.	4.6	8.0
15	FPL Group	3.5	9.1
16	FirstEnergy Corp.	5.8	7.3
17	G't Plains Energy	5.5	5.8
18	Hawaiian Elec.	7.4	4.8
19	IDACORP Inc.	5.2	5.0
20	PG&E Corp.	4.6	6.9
21	Pepco Holdings	8.5	4.0
22	Portland General	5.8	6.7
23	Progress Energy	7.0	4.8
24	Public Serv. Enterprise	4.3	6.7
25	Southern Co.	6.3	5.0
26	TECO Energy	7.2	10.2
27	Westar Energy	6.8	5.7
28	Wisconsin Energy	3.6	8.5
29	Xcel Energy Inc.	5.6	5.2

31 Notes:
Column 2: Value Line Investment Analyzer, 6/2009
Column 3: Zacks long-term earnings growth forecast, 6/2009
No growth forecast available for Empire District

Schedule RAM-E6 Page 2 of 2
Integrated Electric Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	ALLETE	6.7	4.0	7.0	11.0	11.3
2	Allegheny Energy	2.4	14.0	2.8	16.8	16.9
3	Alliant Energy	6.4	5.3	6.8	12.1	12.4
4	Amer. Elec. Power	6.4	4.7	6.7	11.4	11.8
5	Ameren Corp.	6.6	4.0	6.9	10.9	11.2
6	CMS Energy Corp.	4.8	6.5	5.1	11.6	11.8
7	Cleco Corp.	4.6	14.5	5.3	19.8	20.1
8	DPL Inc.	5.3	6.3	5.6	12.0	12.3
9	DTE Energy	7.0	6.0	7.4	13.4	13.8
10	Duke Energy	6.8	5.0	7.2	12.2	12.6
11	Edison Int'l	4.3	6.3	4.6	10.9	11.1
12	Entergy Corp.	4.1	7.3	4.4	11.6	11.8
13	Exelon Corp.	4.6	8.0	4.9	12.9	13.2
14	FPL Group	3.5	9.1	3.8	12.9	13.1
15	FirstEnergy Corp.	5.8	7.3	6.2	13.6	13.9
16	G't Plains Energy	5.5	5.8	5.8	11.6	11.9
17	Hawaiian Elec.	7.4	4.8	7.7	12.5	12.9
18	IDACORP Inc.	5.2	5.0	5.5	10.5	10.8
19	PG&E Corp.	4.6	6.9	4.9	11.8	12.1
20	Pepco Holdings	8.5	4.0	8.9	12.9	13.3
21	Portland General	5.8	6.7	6.1	12.8	13.1
22	Progress Energy	7.0	4.8	7.4	12.2	12.5
23	Public Serv. Enterprise	4.3	6.7	4.6	11.2	11.5
24	Southern Co.	6.3	5.0	6.6	11.6	11.9
25	TECO Energy	7.2	10.2	7.9	18.1	18.6
26	Westar Energy	6.8	5.7	7.2	12.9	13.2
27	Wisconsin Energy	3.6	8.5	3.9	12.4	12.6
28	Xcel Energy Inc.	5.6	5.2	5.9	11.1	11.4
30	**AVERAGE**	**5.6**	**6.7**	**6.0**	**12.7**	**13.0**
31	**MEDIAN**					**12.5**

33 Notes:
34 Column 2: Value Line Investment Analyzer, 6/2009
35 Column 3: Zacks long-term earnings growth forecast, 6/2009
36 Column 4 = Column 2 times (1 + Column 3/100)
37 Column 5 = Column 4 + Column 3
38 Column 6 = (Column 4 /0.95) + Column 3

Schedule RAM-E7 Page 1 of 3
S&P Utility Index Electric Utilities
DCF Analysis Value Line Growth Forecasts

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Value Line Growth Forecast
1	Allegheny Energy	2.4	8.5
2	Amer. Elec. Power	6.4	4.5
3	Ameren Corp.	6.6	1.5
4	CMS Energy Corp.	4.8	10.0
5	CenterPoint Energy	7.6	3.0
6	Consol. Edison	6.7	2.5
7	Constellation Energy	3.8	-2.0
8	DTE Energy	7.0	4.5
9	Dominion Resources	5.9	8.0
10	Duke Energy	6.8	5.0
11	Edison Int'l	4.3	3.5
12	Entergy Corp.	4.1	6.0
13	Exelon Corp.	4.6	7.5
14	FPL Group	3.5	8.5
15	FirstEnergy Corp.	5.8	4.0
16	Integrys Energy	5.9	4.5
17	PG&E Corp.	4.6	6.5
18	PPL Corp.	4.6	10.5
19	Pepco Holdings	8.5	3.0
20	Pinnacle West Capital	7.7	3.0
21	Progress Energy	7.0	6.0
22	Public Serv. Enterprise	4.3	7.5
23	Sempra Energy	3.5	5.0
24	Southern Co.	6.3	5.0
25	TECO Energy	7.2	4.5
26	Wisconsin Energy	3.6	8.0
27	Xcel Energy Inc.	5.6	6.5
28			
29	Notes:		
30	Column 2, 3: Value Line Investment Analyzer, 6/2009		

Schedule RAM-E7 Page 2 of 3

S&P Index Electric Utilities: DCF Analysis Value Line Growth Forecasts

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Company Name	Current Dividend Yield	Value Line Growth Forecast	% Expected Divid Yield	Cost of Equity	ROE
1	Allegheny Energy	2.4	8.5	2.6	11.1	11.3
2	Amer. Elec. Power	6.4	4.5	6.7	11.2	11.6
3	Ameren Corp.	6.6	1.5	6.7	8.2	8.6
4	CMS Energy Corp.	4.8	10.0	5.2	15.2	15.5
5	CenterPoint Energy	7.6	3.0	7.8	10.8	11.3
6	Consol. Edison	6.7	2.5	6.8	9.3	9.7
7	Constellation Energy	3.8	-2.0	3.7	1.7	1.9
8	DTE Energy	7.0	4.5	7.3	11.8	12.2
9	Dominion Resources	5.9	8.0	6.3	14.3	14.7
10	Duke Energy	6.8	5.0	7.2	12.2	12.6
11	Edison Int'l	4.3	3.5	4.4	7.9	8.2
12	Entergy Corp.	4.1	6.0	4.3	10.3	10.5
13	Exelon Corp.	4.6	7.5	4.9	12.4	12.6
14	FPL Group	3.5	8.5	3.8	12.3	12.5
15	FirstEnergy Corp.	5.8	4.0	6.1	10.1	10.4
16	Integrys Energy	5.9	4.5	6.2	10.7	11.0
17	PG&E Corp.	4.6	6.5	4.9	11.4	11.7
18	PPL Corp.	4.6	10.5	5.1	15.6	15.9
19	Pepco Holdings	8.5	3.0	8.8	11.8	12.2
20	Pinnacle West Capital	7.7	3.0	7.9	10.9	11.3
21	Progress Energy	7.0	6.0	7.4	13.4	13.8
22	Public Serv. Enterprise	4.3	7.5	4.6	12.1	12.4
23	Sempra Energy	3.5	5.0	3.7	8.7	8.8
24	Southern Co.	6.3	5.0	6.6	11.6	11.9
25	TECO Energy	7.2	4.5	7.5	12.0	12.4
26	Wisconsin Energy	3.6	8.0	3.9	11.9	12.1
27	Xcel Energy Inc.	5.6	6.5	6.0	12.5	12.8
29	**AVERAGE**	**5.5**	**5.4**	**5.8**	**11.2**	**11.5**
30	**MEDIAN**					**11.9**

Notes:

Column 2, 3: Value Line Investment Analyzer, 6/2009
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3

S&P Index Electric Utilities: DCF Analysis Value Line Growth Forecasts

Line No.	Company Name	Current Dividend Yield	Value Line Growth Forecast	% Expected Divid Yield	Cost of Equity	ROE
	(1)	(2)	(3)	(4)	(5)	(6)
1	Allegheny Energy	2.4	8.5	2.6	11.1	11.3
2	Amer. Elec. Power	6.4	4.5	6.7	11.2	11.6
3	Ameren Corp.	6.6	1.5	6.7	8.2	8.6
4	CMS Energy Corp.	4.8	10.0	5.2	15.2	15.5
5	Consol. Edison	6.7	2.5	6.8	9.3	9.7
6	DTE Energy	7.0	4.5	7.3	11.8	12.2
7	Duke Energy	6.8	5.0	7.2	12.2	12.6
8	Edison Int'l	4.3	3.5	4.4	7.9	8.2
9	Entergy Corp.	4.1	6.0	4.3	10.3	10.5
10	Exelon Corp.	4.6	7.5	4.9	12.4	12.6
11	FPL Group	3.5	8.5	3.8	12.3	12.5
12	FirstEnergy Corp.	5.8	4.0	6.1	10.1	10.4
13	PG&E Corp.	4.6	6.5	4.9	11.4	11.7
14	Pepco Holdings	8.5	3.0	8.8	11.8	12.2
15	Pinnacle West Capital	7.7	3.0	7.9	10.9	11.3
16	Progress Energy	7.0	6.0	7.4	13.4	13.8
17	Public Serv. Enterprise	4.3	7.5	4.6	12.1	12.4
18	Southern Co.	6.3	5.0	6.6	11.6	11.9
19	TECO Energy	7.2	4.5	7.5	12.0	12.4
20	Wisconsin Energy	3.6	8.0	3.9	11.9	12.1
21	Xcel Energy Inc.	5.6	6.5	6.0	12.5	12.8
23	**AVERAGE**	**5.6**	**5.5**	**5.9**	**11.4**	**11.7**
24	**MEDIAN**					**12.1**

Notes:
Column 2, 3: Value Line Investment Analyzer, 6/2009
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3

Companies with less than 50% of revenues from electric regulated operations: CenterPoint, Constellation, Dominion, Integrys, PPL, Sempra.

Schedule RAM-E8 Page 1 of 3
S&P Utility Index Electric Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast
1	Allegheny Energy	2.4	14.0
2	Amer. Elec. Power	6.4	4.7
3	Ameren Corp.	6.6	4.0
4	CMS Energy Corp.	4.8	6.5
5	CenterPoint Energy	7.6	7.0
6	Consol. Edison	6.7	4.3
7	Constellation Energy	3.8	12.0
8	DTE Energy	7.0	6.0
9	Dominion Resources	5.9	5.6
10	Duke Energy	6.8	5.0
11	Edison Int'l	4.3	6.3
12	Entergy Corp.	4.1	7.3
13	Exelon Corp.	4.6	8.0
14	FPL Group	3.5	9.1
15	FirstEnergy Corp.	5.8	7.3
16	Integrys Energy	5.9	8.3
17	PG&E Corp.	4.6	6.9
18	PPL Corp.	4.6	9.0
19	Pepco Holdings	8.5	4.0
20	Pinnacle West Capital	7.7	5.5
21	Progress Energy	7.0	4.8
22	Public Serv. Enterprise	4.3	6.7
23	Sempra Energy	3.5	6.5
24	Southern Co.	6.3	5.0
25	TECO Energy	7.2	10.2
26	Wisconsin Energy	3.6	8.5
27	Xcel Energy Inc.	5.6	5.2
28			

30 Notes:
Column 2: Value Line Investment Analyzer, 6/2009
Column 3: Zacks long-term earnings growth forecast, 6/2009

S&P Utility Index Electric Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Allegheny Energy	2.4	14.0	2.8	16.8	16.9
2	Amer. Elec. Power	6.4	4.7	6.7	11.4	11.8
3	Ameren Corp.	6.6	4.0	6.9	10.9	11.2
4	CMS Energy Corp.	4.8	6.5	5.1	11.6	11.8
5	CenterPoint Energy	7.6	7.0	8.2	15.2	15.6
6	Consol. Edison	6.7	4.3	6.9	11.3	11.6
7	Constellation Energy	3.8	12.0	4.2	16.2	16.4
8	DTE Energy	7.0	6.0	7.4	13.4	13.8
9	Dominion Resources	5.9	5.6	6.2	11.8	12.1
10	Duke Energy	6.8	5.0	7.2	12.2	12.6
11	Edison Int'l	4.3	6.3	4.6	10.9	11.1
12	Entergy Corp.	4.1	7.3	4.4	11.6	11.8
13	Exelon Corp.	4.6	8.0	4.9	12.9	13.2
14	FPL Group	3.5	9.1	3.8	12.9	13.1
15	FirstEnergy Corp.	5.8	7.3	6.2	13.6	13.9
16	Integrys Energy	5.9	8.3	6.4	14.6	15.0
17	PG&E Corp.	4.6	6.9	4.9	11.8	12.1
18	PPL Corp.	4.6	9.0	5.0	14.0	14.3
19	Pepco Holdings	8.5	4.0	8.9	12.9	13.3
20	Pinnacle West Capital	7.7	5.5	8.1	13.6	14.0
21	Progress Energy	7.0	4.8	7.4	12.2	12.5
22	Public Serv. Enterprise	4.3	6.7	4.6	11.2	11.5
23	Sempra Energy	3.5	6.5	3.7	10.2	10.4
24	Southern Co.	6.3	5.0	6.6	11.6	11.9
25	TECO Energy	7.2	10.2	7.9	18.1	18.6
26	Wisconsin Energy	3.6	8.5	3.9	12.4	12.6
27	Xcel Energy Inc.	5.6	5.2	5.9	11.1	11.4
29	**AVERAGE**	**5.5**	**6.9**	**5.9**	**12.8**	**13.1**
30	**MEDIAN**					**12.6**

32 Notes:

Column 2: Value Line Investment Analyzer, 6/2009
Column 3: Zacks long-term earnings growth forecast, 6/2009
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3

Schedule RAM-E8 Page 3 of 3
S&P Utility Index Electric Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Allegheny Energy	2.4	14.0	2.8	16.8	16.9
2	Amer. Elec. Power	6.4	4.7	6.7	11.4	11.8
3	Ameren Corp.	6.6	4.0	6.9	10.9	11.2
4	CMS Energy Corp.	4.8	6.5	5.1	11.6	11.8
5	Consol. Edison	6.7	4.3	6.9	11.3	11.6
6	DTE Energy	7.0	6.0	7.4	13.4	13.8
7	Duke Energy	6.8	5.0	7.2	12.2	12.6
8	Edison Int'l	4.3	6.3	4.6	10.9	11.1
9	Entergy Corp.	4.1	7.3	4.4	11.6	11.8
10	Exelon Corp.	4.6	8.0	4.9	12.9	13.2
11	FPL Group	3.5	9.1	3.8	12.9	13.1
12	FirstEnergy Corp.	5.8	7.3	6.2	13.6	13.9
13	PG&E Corp.	4.6	6.9	4.9	11.8	12.1
14	Pepco Holdings	8.5	4.0	8.9	12.9	13.3
15	Pinnacle West Capital	7.7	5.5	8.1	13.6	14.0
16	Progress Energy	7.0	4.8	7.4	12.2	12.5
17	Public Serv. Enterprise	4.3	6.7	4.6	11.2	11.5
18	Southern Co.	6.3	5.0	6.6	11.6	11.9
19	TECO Energy	7.2	10.2	7.9	18.1	18.6
20	Wisconsin Energy	3.6	8.5	3.9	12.4	12.6
21	Xcel Energy Inc.	5.6	5.2	5.9	11.1	11.4
29	**AVERAGE**	**5.6**	**6.6**	**6.0**	**12.6**	**12.9**
30	**MEDIAN**					**12.5**

32 Notes:

Column 2: Value Line Investment Analyzer, 6/2009
Column 3: Zacks long-term earnings growth forecast, 6/2009
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3

Companies with less than 50% of revenues from electric regulated operations: CenterPoint, Constellation, Dominion, Integrys, PPL, Sempra.

SCHEDULE RAM-E9
COMMON EQUITY RATIOS
INTEGRATED ELEC UTILITIES

Line No.	Company Name	% Common Equity
1	ALLETE	58.4
2	Allegheny Energy	40.9
3	Alliant Energy	61.9
4	Amer. Elec. Power	40.7
5	Ameren Corp.	50.8
6	CMS Energy Corp.	27.4
7	Cleco Corp.	48.9
8	DPL Inc.	41.1
9	DTE Energy	43.6
10	Duke Energy	61.3
11	Edison Int'l	44.5
12	Empire Dist. Elec.	46.4
13	Entergy Corp.	40.2
14	Exelon Corp.	46.6
15	FPL Group	45.8
16	FirstEnergy Corp.	47.7
17	G't Plains Energy	49.6
18	Hawaiian Elec.	52.7
19	IDACORP Inc.	52.4
20	PG&E Corp.	46.5
21	Pepco Holdings	43.8
22	Portland General	53.8
23	Progress Energy	44.4
24	Public Serv. Enterprise	49.0
25	Southern Co.	42.6
26	TECO Energy	38.5
27	Westar Energy	48.9
28	Wisconsin Energy	44.8
29	Xcel Energy Inc.	47.1
30		
31	**AVERAGE**	**46.9**
32		
33	Source: VLIA 6/2009	

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:

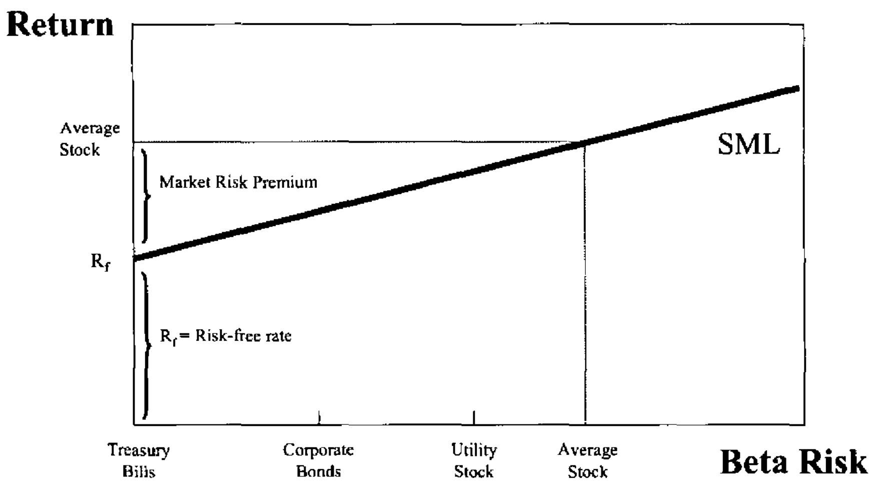
$$K = R_F + \beta(R_M - R_F) \qquad (1)$$

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.

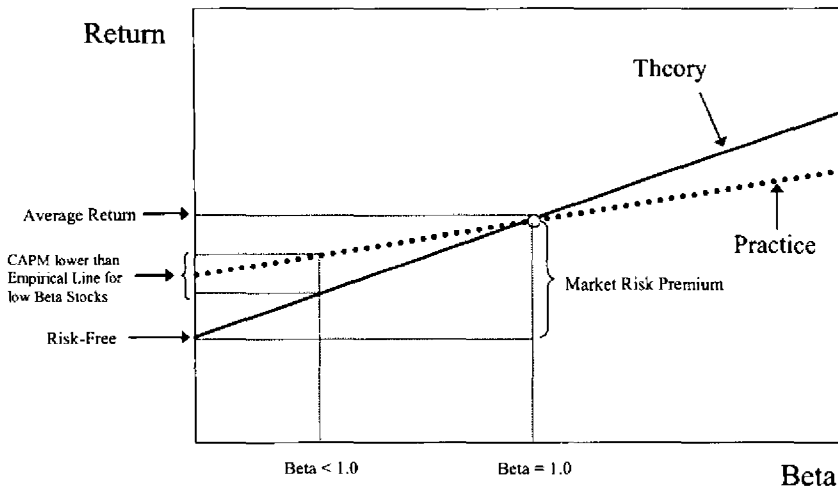
CAPM and Risk - Return
in Capital Markets



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:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \tag{3}$$

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:

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

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) and Litzenberger et al. (1980) 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**
Black (1993)	-3.6% to 3.6%	1931-1991
Black, 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 (2003)	2.0%	1983-1998

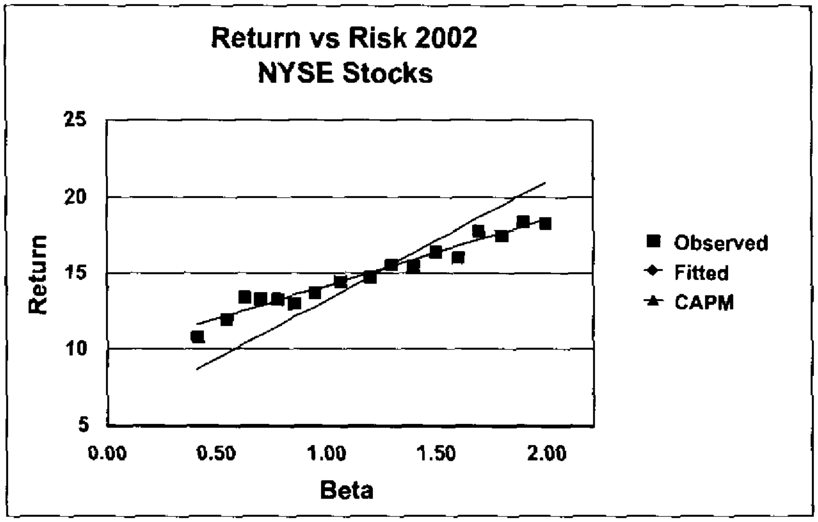
Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1989) over the period 1926-1984 indicating that the observed expected return on a security 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.

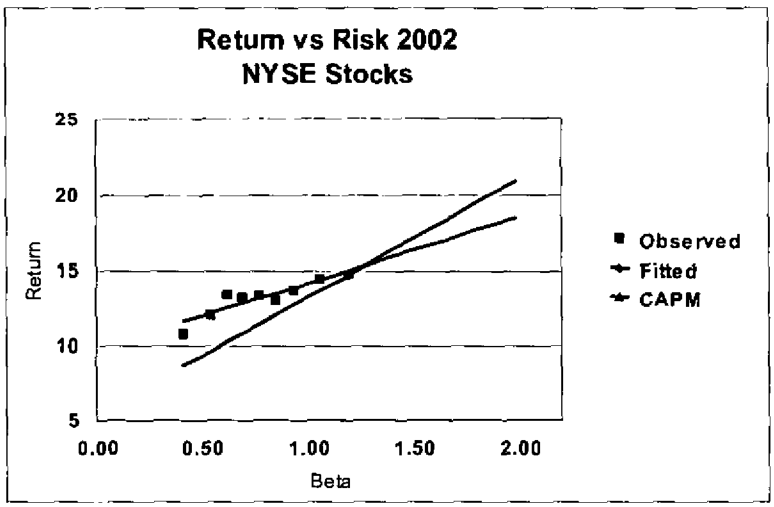
CAPM vs ECAPM



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

[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.

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).

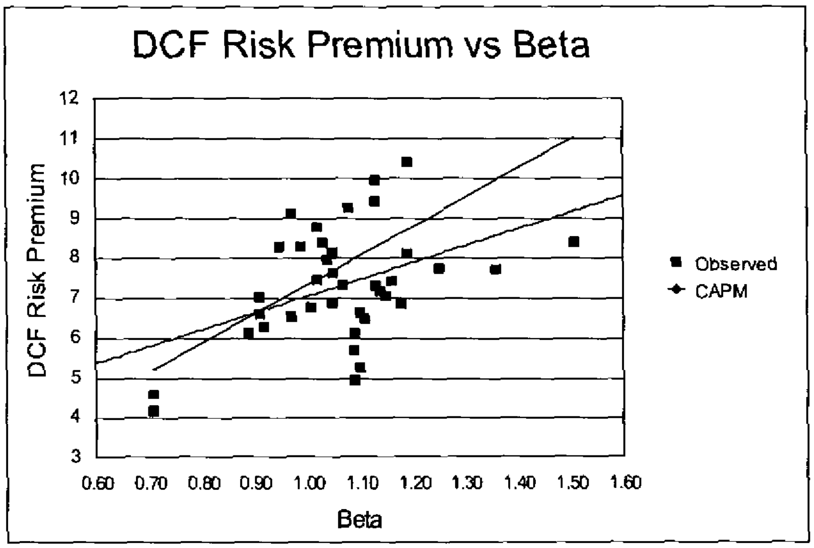
The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill 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.

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].

[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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APPENDIX B

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% 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%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% 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%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (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% 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%. 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% for industrial stock issues and 0.75% 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% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, 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% - 5% for stock issues between $60 and $500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

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% of gross proceeds. I have therefore assumed a 5% 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% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) 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 underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% 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% 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 7-9 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 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. 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% thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14\%$. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1\text{-}f) + g = .09/.95 + .05 = 14.47\%$.

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% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, 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% times the total common equity base. Dividends start at $2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% 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% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from $26.25 to $26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% 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 =	**14.00%**
(D/P + g)	
ALLOWED RETURN ON EQUITY =	**14.47%**
(D/P(1-f) + g)	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET / BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
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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%**	

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	)))))	Case No. ER-2010-

AFFIDAVIT OF ROGER A. MORIN

PROVINCE
STATE OF Nova Scotia)
) ss
CITY OF HALIFAX)

Roger A. Morin, being first duly sworn on his oath, states:

1. My name is Roger A. Morin. I work in Atlanta, Georgia, and I am employed by Georgia State University.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Union Electric Company d/b/a AmerenUE consisting of 60 pages, ~~Attachment~~ ___, Appendices A & B, and Schedules RAM-E1 - E9, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Roger A. Morin

Subscribed and sworn to before me this 21 day of July, 2009.

Notary Public
MICHAEL R. CROWELL
A Commissioner of the Supreme Court of Nova Scotia

My commission expires: