Exhibit No.: 003
Issues: Return on Equity (ROE)
Witness: Roger A. Morin
Sponsoring Party: Union Electric Company
Type of Exhibit: Direct Testimony
Case No.: ER-2008-0318
Date Testimony Prepared: April 3, 2008

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO. ER-2008-0318

DIRECT TESTIMONY

OF

ROGER A. MORIN

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a AmerenUE

St. Louis, Missouri
April, 2008

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DIRECT TESTIMONY

OF

ROGER A. MORIN

CASE NO. ER-2008-____

I. INTRODUCTION

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 Robinson 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 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 Utility Fortnightly*. I published a widely-used treatise on regulatory finance, *Utilities' Cost of Capital*, Public Utilities Reports, Inc., Arlington, Va. 1984. My second book on regulatory matters, *Regulatory Finance*, is a comprehensive treatise on the application of finance to regulated utilities and was released by the same publisher in late 1994. A revised and expanded edition, *The New Regulatory Finance*, was recently published in July 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 some fifty (50) regulatory bodies in North America, including the Missouri Public Service

Commission ("MPSC", or "Commission"), the Federal Energy Regulatory Commission ("FERC"), and the Federal Communications Commission. I have also testified before the following state, provincial, and other local regulatory commissions:

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	

The 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 vertically 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 ratepayer, (2) allow the Company to attract capital on reasonable terms, (3) maintain the Company's financial integrity, and

(4) be comparable to returns offered on comparable risk investments. I will testify in this proceeding as to that opinion.

Q. Please briefly identify the schedules and appendices accompanying your testimony.

A. I have attached to my testimony Schedules RAM-E1 through RAM-E8 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. Were these Schedules and Appendices prepared by you or under your supervision?

A. Yes, they were.

Q. Please summarize your findings concerning UE's cost of common equity.

A. I have examined UE's risks, and concluded that UE's risk environment remains above the industry average due mostly to the absence of a fuel adjustment clause compared to its peers who generally have such a clause.

In order to estimate a fair rate of return on UE's common equity capital invested in electric utility operations, I have employed the traditional methodologies that assume business-as-usual circumstances and then performed risk adjustments in order to account for UE's higher than average risk circumstances. It is my opinion that a just and reasonable ROE for UE is 11.15%. Assuming that the Company's proposed fuel adjustment clause ("FAC") is adopted, my recommended ROE is 10.9%. My recommendations for an ROE for the Company, 10.9% if an FAC is approved, and 11.15% if an FAC is not approved, fall well within the appropriate zone of reasonableness employed by the Commission in the past, in this case is 9.56% - 11.56%.

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, one using the CAPM and another using the empirical version of the CAPM ("ECAPM"). I performed two risk premium analyses: (1) a historical risk premium analysis on the electric utility industry, and (2) a study of the risk premiums reflected in ROEs allowed in 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 companies that make up Moody's Electric Utility Index, representative of the industry. The results from the various methodologies were adjusted to account for the above average risks faced by UE relative to the industry.

My recommended rate of return reflects the application of my professional judgment to the indicated returns from my CAPM, Risk Premium, and DCF analyses, and UE's current risk environment.

Q. Would it be in the best interests of ratepayers for the Commission to adopt your recommended 11.15% return on equity for UE's electric utility operations?

A. Yes. My analysis shows that a ROE of 11.15% 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 in two ways. First, because the utility's price per share of common stock decreases, the net proceeds from issuing common stock are reduced. Second, because the utility's market to book ratio decreases with the decrease in the share price of common stock, the potential risk from dilution of equity investments reduces investors' inclination to purchase new issues of common stock. The ultimate effect is the utility will have to rely more on debt financing to meet its capital needs.

As the company relies more on debt financing, its capital structure becomes more leveraged. Because debt payments are a fixed financial obligation to the utility, and income available to common equity is subordinate to fixed charges, this decreases the operating income available for dividend and earnings growth. Consequently, equity investors face 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 through its parent company, a fair and reasonable authorized ROE of 11.15% 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 expenditures 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 which 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. Please describe how the rest of your testimony is organized.

A. In Section II, I address the regulatory framework and rate of return. This section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. In Section III, I present cost of equity estimates. This section contains the application of CAPM, Risk Premium, and DCF tests. In Section IV, I provide my summary and recommendation. The results from the various approaches used in determining a fair return are summarized.

II. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. What economic and financial concepts have guided your assessment of the Company's cost of common equity?

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

Q. How does 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 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.

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

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. Dr. Morin, what must be considered in estimating a fair return on common equity?

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

Q. What core principles underlie the determination of a fair and reasonable rate of return on common equity?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States

Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1) 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 this 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 Company. It is the composite weighted cost of the various classes of capital (e.g., 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 labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on debt capital, or the expected return on 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 are also exposing their funds to risk and forgoing returns from investing their money in alternative comparable risk investments. The compensation they require is the price of capital. 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 differences in required return, in much the same way that differences in the characteristics of commodities are reflected in different prices.

The important point is that the required return on capital is set by supply and demand, and is influenced by the relationship between the risk and return expected for those securities and the risks expected from the overall menu of available securities.

Q. How does the Company obtain its capital and how is its overall cost of capital determined?

A. The funds employed by the Company are obtained in two general forms, debt capital and common equity capital. The embedded cost of debt can be ascertained easily from an examination of the contractual interest payments. 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, 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 in capital markets. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments in other companies, and the returns available from other investments of comparable risk.

III. COST OF EQUITY CAPITAL ESTIMATES

Q. Dr. Morin, how did you estimate the fair rate of return on common equity for UE?

A. I employed three methodologies: (1) the CAPM, (2) the Risk Premium, and (3) the DCF. All three are market-based methodologies and are designed to estimate the return required by investors on the common equity capital committed to UE's electric utility business. I have applied the aforementioned methodologies to samples of average risk utilities representative of the industry as a whole and adjusted the results upward to recognize UE's higher relative risk.

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 informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

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

Q. Are there any practical difficulties in applying cost of capital methodologies in the current environment of changes in the electric utility industry?

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

Q. Dr. Morin, are you aware that some regulatory commissions and some analysts have placed principal reliance on DCF-based analyses to determine the cost of equity for public utilities?

A. Yes, I am.

Q. Do you agree with this approach?

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

When measuring the cost of common equity, which essentially deals with the measurement of investor expectations, no one single methodology provides a foolproof approach. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology. To illustrate, the DCF model assumes a constant perpetual growth rate in dividends, earnings, and market valuation (stock price, book value). 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. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that all of these methodologies should be applied to multiple groups of comparable risk companies.

There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. Absent any hard evidence as to which method outperforms the others, all relevant evidence should be used, without discounting the value of any results, in order to minimize judgmental error, measurement error, and conceptual infirmities. A regulatory body should rely on the results of a variety of methods applied to a variety of comparable groups. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of 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. Does the financial literature support the use of more than a single method to determine return on equity?

A. Yes. Authoritative financial literature strongly supports the use of multiple methods. For example, Professor Eugene F. Brigham, a widely respected scholar and finance academician, discusses the various methods used in estimating the cost of common equity capital, and states (see E. F. Brigham and M. C. Ehrhardt, Financial Management Theory and Practice, p. 311 ,11th ed., Thomson South-Western, 2005):

> *Three methods typically are used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods are not mutually exclusive - no method dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company' cost of equity, we generally use all three methods....*

Another prominent finance scholar, Professor Stewart Myers, points out (see S. C. Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," Financial Management, p. 67, Autumn 1978):

> *Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and*

> *exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.*

Q. Doesn't the wide use of the DCF methodology in past regulatory proceedings indicate that it is superior to other methods?

A. No, it does not. Uncritical acceptance of the standard DCF equation vests the model with a degree of infallibility that is not necessarily present. One of the leading experts on public utility regulation, Dr. Charles Phillips, discusses the dangers of relying solely on the DCF model:

> *Use of the DCF model for regulatory purposes involves both theoretical and practical difficulties. The theoretical issues include the assumption of a constant retention ratio (i.e. a fixed payout ratio) and the assumption that dividends will continue to grow at a rate 'g' in perpetuity. Neither of these assumptions has any validity, particularly in recent years. Further, the investors' capitalization rate and the cost of equity capital to a utility for application to book value (i.e. an original cost rate base) are identical only when market price is equal to book value. Indeed, DCF advocates assume that if the market price of a utility's common stock exceeds its book value, the allowable rate of return on common equity is too high and should be lowered; and vice versa. Many question the assumption that market price should equal book value, believing that the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.*
>
> *Most frequently, the major practical issue involves the determination of the growth rate; a determination that is highly complex and that requires considerable judgment......[T]here remains the circularity problem: Since regulation establishes a level of authorized earnings which, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. For all of these reasons, the DCF model "suggests a degree of precision which is in fact not present" and leaves "wide room for controversy about the level of k [cost of equity]".*[1]

Dr. Charles F. Phillips also discusses the dangers of relying solely on the CAPM model because of the stringency of certain of its underlying assumptions, as is the case for any model in the social sciences.

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[1] C. F. Phillips, *The Regulation of Public Utilities Theory and Practice*, pp. 376-77. (Public Utilities

Sole reliance on the DCF model simply ignores the capital market evidence and investors' use of other theoretical frameworks such as the Risk Premium and CAPM methodologies. The DCF model is only one of many tools to be employed to estimate the cost of equity. It is not a superior methodology which supplants other financial theory and market evidence. The same is true of the CAPM.

Q. Does the DCF model understate the cost of equity?

A. Yes, it does, especially when applied to utilities operating in the current climate. Application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar-- that is, when the Market-to-Book ("M/B") ratio is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the M/B ratio of a given stock exceeds unity. This item is particularly relevant in the current capital market environment where utility stocks are trading at M/B ratios well above unity and have been for two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.

Q. Can you illustrate the effect of the M/B ratio on the DCF model by means of a simple example?

Reports, Inc., 1988) pp. 376-77. [Footnotes omitted]

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

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

Therefore, the DCF cost rate understates the investor's required return when stock prices are well above book, as is the case presently.

EFFECT OF MARKET-TO-BOOK RATIO ON MARKET RETURN

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

Q. Does the annual version of the DCF model understate the cost of equity also?

A. Yes, it does, for an unrelated reason. The annual DCF model usually employed in regulatory settings assumes that dividend payments are made annually at the end of the year, while most utilities in fact pay dividends on a quarterly basis. Failure to recognize the quarterly nature of dividend payments understates the cost of equity capital by about 30 basis points. By analogy, a bank rate on deposits which does not take into consideration the timing of the interest payments understates the true yield of your investment if you receive the interest payments more than once a year. Because the stock price employed in the DCF model already reflects the quarterly stream of dividends to be received, consistency therefore requires explicit recognition of the quarterly nature of dividend payments. One only has to think of what would happen to a company's stock price if the company were to suddenly announce that, from now on, it would be paying dividends once a year at the end of the year instead of four times a year each quarter. Clearly, the stock price would decline by an amount reflecting the lost time value of money.

Q. Do regulators rely primarily on the DCF model?

A. No. According to the results posted in a survey conducted by the National Association of Regulatory Utility Commissioners ("NARUC"), regulators utilize a variety of methods and rely on all the evidence submitted. The majority of regulatory commissions do not, as a matter of practice, rely solely on the DCF model results in setting the allowed rate of return on common equity.

Q. Do regulators share your reservations on the reliability of the DCF model?

A. Yes, I believe they do. While a majority of regulatory commissions, including FERC, do not, as a matter of practice, rely solely on the DCF model results in setting the allowed rate of return on common equity, some regulatory commissions have explicitly recognized the need to avoid exclusive reliance upon the DCF model and have acknowledged the need to adjust the DCF result when M/B ratios exceed one[2]. For example, the Indiana Utility Regulatory Commission (IURC) expressed concerns with the DCF model in Cause No. 39871 Final Order, page 24:

> *...the DCF model, heavily relied upon by the Public, understates the cost of common equity. The Commission has recognized this fact before. In Indiana Mich. Power Co. (IURC 8/24/90), Cause No. 38728, 116 PUR4th 1, 17-18, we found:*
>
> *The unadjusted DCF result is almost always well below what any informed financial analyst would regard as defensible, and therefore requires an upward adjustment based largely on the expert witness's judgment.*

The IURC also expressed its concern with a witness relying solely on one methodology:

[2] See the Indiana Utility Regulatory Commission decision in Indiana Mich. Power Co. (IURC 8/24/90), Cause No. 38728, 116 PUR4th 1, 17-18. See also the Iowa Utilities Board decision in U.S. West Communications, Inc., Docket No., RPR-93-9, 152 PUR4th 459. See also the Hawaii Public

> *...the Commission has had concerns in our past orders with a witness relying solely on one methodology in reaching an opinion on a proper return on equity figure. (page 25)*

In a recent case involving Pacific Bell Telephone Company, the California Commission (Application No. 01-02-024, Joint Application of ATT Communications, Opinion Establishing Revised Unbundled Network Element Rates at VI.N, October 2004) declined to place any reliance on the DCF method, finding that it was "*too dependent on one forecasted input.*"

FERC in the *Distrigas of Massachusetts Corp.* decision concluded that[3]:

> *no one methodology is preferred to the exclusion of all others. The DCF methodology, which we endorse, is but one analytical tool.*

The Federal Communications Commission also recognized the need to rely on several methodologies[4]:

> *Equity prices are established in highly volatile and uncertain capital markets....Different forecasting methodologies compete with each other for eminence, only to be superseded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude the we should adopt a more accommodating and flexible position.*

Finally, the fact that M/B ratios have exceeded unity for over two decades is clear evidence that regulators have in fact not relied on the DCF model exclusively. Had regulators relied exclusively on the DCF model, utility stocks would have traded at or near book value. Regulators have "corrected" for this M/B problem by considering alternative methods for estimating capital cost.

Utilities Commission decision in Hawaiian Electric Company, Inc., Docket No. 6998, PUR4th 134. n

[3] Distrigas of Massachusetts Corp., 41 FERC ¶ 61,205 at 61,550 (1987).

[4] Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995)

Q. Is the usage of the DCF model prevalent in other industries?

A. No, not really. The CAPM continues to be widely used by analysts, investors, and corporations. Bruner, Eades, Harris, and Higgins (1998) in a comprehensive survey[5] of current practices for estimating the cost of capital found that 81% of companies used the CAPM to estimate the cost of equity, 4% used a modified CAPM, and 15% were uncertain. In another comprehensive survey conducted by Graham and Harvey (2001), the managers surveyed reported using more than one methodology to estimate the cost of equity, and 73% used the CAPM.[6] Since its introduction by Professor William F. Sharpe in 1964, the CAPM has gained immense popularity as the practitioner's method of choice when estimating cost of capital under conditions of risk.[7] The intuitive simplicity of its basic concept (that investors must get compensated for the risk they assume), and the relatively easy application of the CAPM are the main reasons behind its popularity.

Q. Do the assumptions underlying the DCF model require that the model be treated with caution?

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

[5]Bruner, R. F., Eades, K. M., Harris, R. S., and Higgins, R. C., "Best Practices in Estimating the Cost of Capital: Survey and Synthesis," *Financial Practice and Education,* Vol. 8, Number 1, Spring/Summer 1998, page 18.

[6]Graham, J. R. and Harvey, C. R., "The Theory and Practice of Corporate Finance: Evidence from the Field," *Journal of Financial Economics*, Vol. 61, 2001, pp. 187-243.

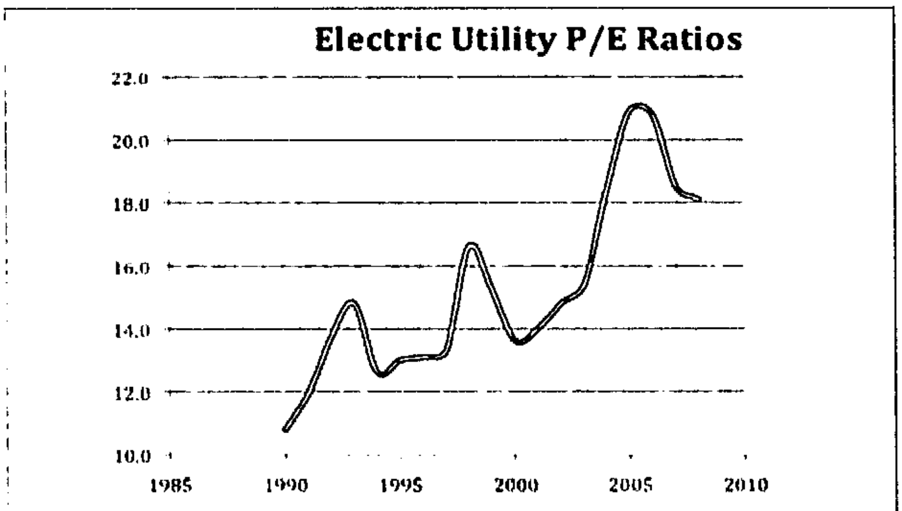
[7] See practitioner surveys by Graham & Harvey (2001) and Bruner, et. al. (1988)

are aware, is problematic for use in estimating the cost of equity for electric utilities at this time.

Several fundamental structural changes have transformed the electric utility industry since the standard DCF model and its assumptions were first developed. For example, deregulation, increased wholesale competition triggered by national policy, accounting rule changes, changes in customer attitudes regarding utility services, the evolution of alternative energy sources, highly volatile fuel prices, and mergers-acquisitions all have influenced stock prices in ways that have deviated substantially from the assumptions of the DCF model. These changes suggest that some of the fundamental assumptions underlying the standard DCF model, particularly that of constant growth and constant relative market valuation (for example price/earnings ("P/E") ratios and M/B ratios), are problematic at this particular point in time and particularly for utility stocks, and that alternate methodologies to estimate the cost of common equity should be accorded at least as much weight as the DCF method.

Q. Is the constant relative market valuation assumption inherent in the DCF model always reasonable?

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



Q. What is your recommendation given such market conditions?

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

Q. Do the assumptions underlying the CAPM require that the model be treated with caution?

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

Q. What are the assumptions underlying the CAPM?

A. The CAPM can be viewed as a special case of the broader Arbitrage Pricing Model ("APM"). The APM derives from only two major reasonable assumptions: that security returns are linear functions of several economic factors, and that no profitable arbitrage opportunities exist because investors are able to eliminate such opportunities through risk-free arbitrage transactions. The other assumptions required by the APM are that investors are greedy and risk averse, that they can diversify company-specific risks by holding large portfolios, and that enough investors possess similar expectations to trigger the arbitrage process.

As a tool in the regulatory arena, the CAPM is a rigorous conceptual framework, and is logical insofar as it is not subject to circularity problems. Inputs are objective, market-based quantities, largely immune to regulatory decisions. The data requirements of the model are not prohibitive. Thus the CAPM is one of several tools in the arsenal of techniques to determine the cost of equity capital. Caution, appropriate training in finance and econometrics, and judgment are required for its successful execution, as is the case with the DCF and Risk Premium methodologies.

Q. Dr. Morin, can you please provide an overview of your risk premium analyses?

A. In order to quantify the risk premium for UE's assets, I have performed four risk premium studies. The first two studies deal with aggregate stock market risk premium evidence using two versions of the CAPM methodology, and the other two studies deal directly with the electric utility industry.

A. CAPM Estimates

Q. Can you 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:

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 stated as follows:

$$K = R_F + ß(R_M - R_F)$$

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 given by ß times (R_M - R_F). To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (ß), and the market risk premium, (R_M - R_F). For the risk-free rate, I used 4.5%, based on the current level of yields on long-term U.S. Treasury bonds. For beta, I used 0.87 and for the market risk premium ("MRP") I used 7.4%. These respective 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 bonds.

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. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on the longest-term possible government bonds, that is the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments. 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 (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 will therefore be equal to the inflation rate anticipated to prevail over the very long-term. The same expectation should be embodied in the risk free rate used in applying the CAPM model. It stands to reason that the actual yields on 30-year Treasury bonds will more closely incorporate within their yield the inflation expectations that influence the prices of common stocks than do short-term or intermediate-term U.S. Treasury notes.

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

Q. Dr. Morin, are short-term interest rates appropriate proxies for the risk-free rate in implementing the CAPM?

A. No, they are not. 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, 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 returns are U.S. Treasury 30-year bonds currently yielding?

A. The yield on U.S. Treasury 30-year bonds prevailing in February 2008 as reported in the Federal Reserve Bank Web site and Value Line, was 4.5%. Accordingly, I shall use 4.5% as my estimate of the risk-free rate component of the CAPM.

Q. How did you select the beta for your CAPM analysis?

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

As a proxy for the beta of the electric utility business, I examined the betas of a sample of widely-traded investment-grade vertically integrated electric utilities covered by Standard & Poor's with at least 50% of their revenues from regulated utility operations. This group is examined in more detail later in my testimony, in connection with the DCF estimates of the cost of common equity. In order to minimize the well-known thin trading bias in measuring beta, I excluded those companies whose market capitalization was less than $500 million. As displayed on page 1 of Schedule RAM-E2, the average beta for the group is currently 0.87. I note from this schedule that the beta of Ameren is substantially higher than the industry average at 0.95.

I also examined the average beta of the companies that make up Moody's Electric Utility Index as a second proxy. As displayed on page 2 of Schedule RAM-E2, the average beta for the group is 0.86.

Based on these results, I shall use 0.87, as a reasonable estimate for the beta applicable to an average risk vertically integrated electric utility.

Q. Why did you use an MRP estimate of 7.4% in your CAPM analysis?

A. This estimate was based on the results of both historical and forward-looking studies of long-term risk premiums. First, the Ibbotson Associates (now Morningstar) study, <u>Stocks, Bonds, Bills, and Inflation, 2007 Yearbook</u>, compiling historical returns from 1926 to 2006, shows that a broad market sample of common stocks outperformed long-term U.S. Treasury bonds by 6.5%. The historical MRP over the income component of long-term Treasury bonds rather than over the total return is 7.1%. Ibbotson Associates recommend 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. The more accurate way to estimate the MRP from historic data is to use the income return, not total returns on government bonds, as explained at pages 75-77 of Ibbotson Associates, Stocks, Bonds, Bills, and Inflation: Valuation Edition, 2007 Yearbook. This is because the income component of total bond return (i.e., the coupon rate) is a far better estimate of expected return than the total return (i.e., the coupon rate + capital gain), as realized capital gains/losses are largely unanticipated by bond investors. The long-horizon (1926-2005) MRP (based on income returns, as required) is specifically calculated to be 7.1% rather than 6.5%.

Second, a DCF analysis applied to the aggregate equity market using the S&P 500 Index and Value Line growth forecasts indicates a prospective MRP of 7.7%. Therefore, I shall employ the average of the two estimates, 7.4%, as a reasonable estimate of the MRP.

a. Historical Market Risk Premium

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, since they are heavily dependent on short-term market movements. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate 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. Since I found no evidence that the MRP in common stocks has changed over time, that is, no significant serial correlation in the Ibbotson study, it is reasonable to assume that these quantities will remain stable in the future.

Q. On what maturity bond does the Ibbotson historical risk premium data rely on?

A. Because 30-year bonds were not always traded or even available throughout the entire 1926-2006 period covered in the Ibbotson Associate 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 Ibbotson study, the difference in yield is not material. In fact, the difference in yield between 30-year and 20-year bonds is actually negative. The average difference in yield over the 1977-2006 period is 13 basis points, that is, the yield on 20-year bonds is slightly higher than the yield on 30-year bonds.

b. Prospective Market Risk Premium

Q. Please describe your prospective approach in deriving the MRP in the CAPM analysis.

A. For my prospective estimate of the MRP, I applied a DCF analysis to the aggregate equity market using Value Line's VLIA software. The dividend yield on the dividend-paying stocks that make up the S&P 500 Index is currently 2.4% (VLIA 02/2008 edition), and the average projected long-term growth rate in dividends is 9.3%. Adding the dividend yield to the growth component produces an expected return on the aggregate equity market of 11.7%. Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 12.0%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings the MRP estimate to approximately 12.2%. Subtracting the risk-free rate of 4.5% from the latter, the implied risk premium is 7.7% over long-term U.S. Treasury bonds.

Q. Did you check your MRP estimate of 7.4% from any other source?

A. Yes, I did. As a check on my final MRP estimate of 7.4%, 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 very close to my own estimate of 7.4%.

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

Q. What is your risk premium estimate of the Company's cost of equity using the CAPM approach?

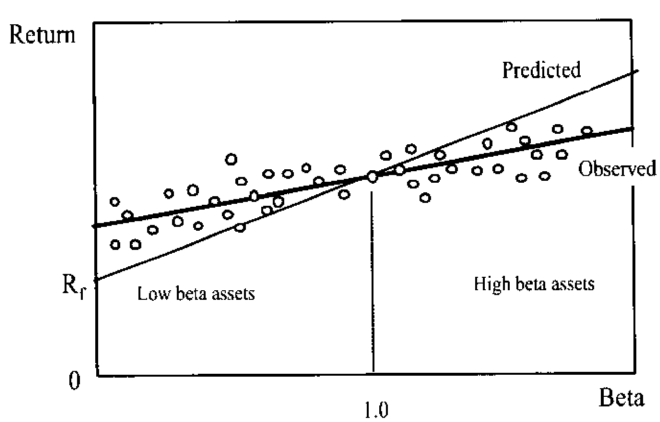
A. Inserting those input values in the CAPM equation, namely a risk-free rate of 4.5%, a beta of 0.87, and a MRP of 7.4%, the CAPM estimate of the cost of common equity is: 4.5% + 0.87 x 7.4% = 10.9%. This estimate becomes 11.2% with flotation costs, discussed later in my testimony.

Q. Can you describe your application of the empirical version of the CAPM?

A. There have been countless empirical tests of the CAPM in the finance literature in order 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, Regulatory Finance, and Chapter 6 of my latest book, The New

Regulatory Finance 2006, 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. In other words, 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:

$$K = R_F + ? + ß \text{ x } (MRP - ?)$$

where the symbol alpha, ? , 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 which has been tested. This is also because the use of adjusted betas rather than the use of raw betas also incorporates some of the desired effect of using the ECAPM. Thus, it is reasonable to apply a conservative alpha adjustment.

Q. Is the use of the ECAPM consistent with the use of adjusted betas?

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line, Bloomberg, and Ibbotson Associates. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. 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 the interest rate sensitivity of utility stocks not captured by unadjusted betas.

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 7.4% for $(R_M - R_F)$ and a beta of 0.87 in the above equation, the return on common equity is 11.2%. This estimate becomes 11.5% with flotation costs, discussed later in my testimony.

Q. Please summarize your CAPM estimates.

A. The table below summarizes the common equity estimates obtained from my CAPM studies. The average CAPM result is 11.35%, rounded to 11.4%.

CAPM	% ROE
CAPM	11.2%
Empirical CAPM	11.5%
AVERAGE	11.35%

B. Risk Premium Estimates

Q. Can you describe your historical risk premium analysis of the electric utility industry?

A. As a proxy for the risk premium applicable to the electric utility business, I estimated the historical risk premium for the electric utility industry with an annual time series analysis applied to the industry as a whole, using *Moody's Electric Utility Index* as an industry proxy. The analysis is depicted on Schedule RAM-E3. The risk premium was estimated by computing the actual realized return on equity capital for Moody's Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year.

As shown on Schedule RAM-E3, the average risk premium over the period was 5.7% over historical long-term Treasury bond returns and 5.8% over long-term Treasury bond yields. Given that the risk-free rate is 4.5%, and using the historical estimate of 5.7%, the implied cost of equity for the average electric utility from this particular method is 4.5% + 5.7% = 10.2% without flotation costs and 10.5% with flotation costs.

Q. Dr. Morin, are risk premium studies widely used?

A. Yes, they are. Risk Premium analyses are widely used by analysts, investors, 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 (Financial Management: Theory and Practice, 11th ed., South-Western, 2005), 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.

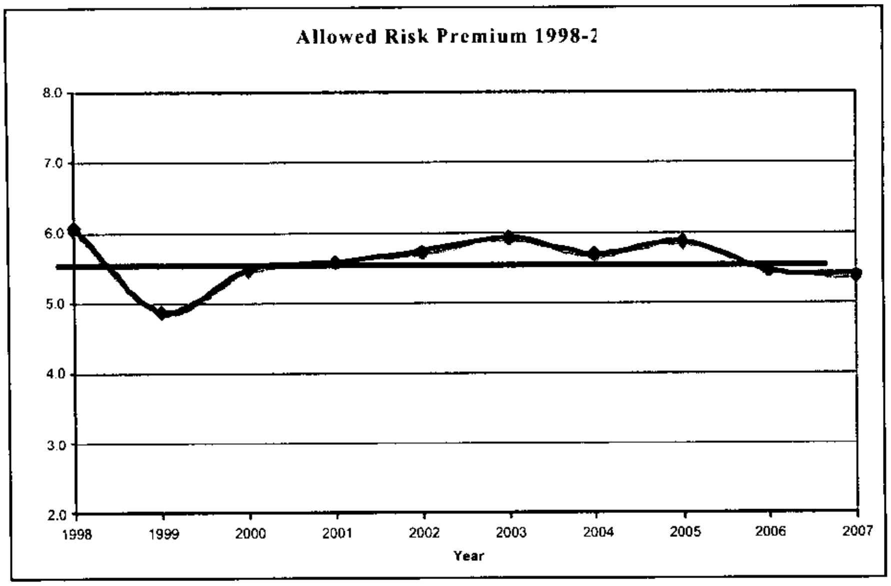
Q. Are you concerned about the realism of the assumptions that underlie the historical risk premium method?

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. Allowed Risk Premiums

Q. Can you describe your analysis of allowed risk premiums in the electric utility industry?

A. To estimate the Company's cost of common equity, I also examined the historical risk premiums implied in the ROEs allowed by regulatory commissions for electric utilities over the last decade relative to the contemporaneous level of the long-term Treasury bond yield. This variation of the risk premium approach is reasonable because allowed risk premiums are presumably based on the results of market-based methodologies (DCF, Risk Premium, CAPM, *etc.*) presented to regulators in rate hearings and on the actions of objective unbiased investors in a competitive marketplace. Historical allowed ROE data are readily available over long periods on a quarterly basis from Regulatory Research Associates ("RRA") and easily verifiable from RRA publications and past commission decision archives. The average ROE spread over long-term Treasury yields was 5.6% for the 1998-2007 time period, as shown in the graph below. I note that this estimate is nearly identical to the 5.7% estimate obtained from the historical risk premium study of the electric utility industry.



Given the current long-term Treasury bond yield of 4.5% and a risk premium of 5.6%, the implied allowed ROE for the average risk electric utility is 10.1%. No flotation cost adjustment is required here since the return figures are allowed book returns on common equity capital.

Q. Why did you rely on the last decade to conduct your allowed risk premium analysis?

A. Because allowed returns already reflect investor expectations, that is, are forward-looking in nature, the need for relying on long historical periods is minimized. The last decade is a reasonable period of analysis in the case of allowed returns in view of the stability of the inflation rate experienced over the last decade.

Q. Do investors take into account allowed returns in formulating their return expectations?

A. Yes, they do. Investors do take into account returns granted by various regulators in formulating their risk and return expectations, as evidenced by the availability of commercial publications disseminating such data, including Value

Line and RRA. Allowed returns, while certainly not a precise indication of a particular company's cost of equity capital, are nevertheless an important determinant of investor growth perceptions and investor expected returns.

Q. Please summarize your risk premium estimates.

A. The table below summarizes the ROE estimates obtained from the two risk premium studies. The average risk premium result is 10.3%.

Risk Premium Method	ROE
Historical Risk Premium Electric	10.5%
Allowed Risk Premium	10.1%

D. 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 traditional DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend at the end of the coming year

P_o = current stock price

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

stock price

The standard 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, <u>Regulatory Finance</u>, and Chapter 8 of my new text, <u>The New Regulatory Finance</u>. 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. Is the constant growth DCF model applicable under all circumstances?

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

Q. How did you estimate 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 companies that make up Moody's Electric Utility Index.

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

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

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

Q. How did you estimate the growth component of the DCF model?

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

As proxies for expected growth, I examined the consensus growth estimate 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 several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. ("Zacks"). I used analysts' long-term growth forecasts 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 own growth forecast as an additional proxy.

Q. Why didn't you use historical growth rates in applying the DCF model to electric utilities?

A. I have rejected historical growth rates as proxies for expected growth in the DCF calculation for two reasons. First, to the extent that historical growth patterns are relevant, they already have been incorporated in analysts' growth forecasts that should be used in the DCF model, and are therefore somewhat redundant.

Second, historical growth rates have little relevance as proxies for future long-term growth at this time. They are downward-biased by the sluggish earnings performance in the last five years caused by the structural transformation of the electric utility industry from a fully integrated regulated monopoly to a more competitive environment. As I show in Schedule RAM-E4, the industry as a whole has experienced very little dividend growth over the past five years, and several electric utility companies have experienced a negative earnings growth rate. Columns 3, 4, and 5 of Schedule RAM-E4 display the historical growth in earnings, dividends, and book value per share over the last five years for the electric utility companies that make up Value Line's Electric Utility composite group. The average historical growth rates in earnings, dividends, and book value for the group are 0.7%, 0.7%, and 1.5% over the past 5 years, respectively. Negative earnings growth rates are evidenced with negative numbers.

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 0.5%, 0.8%, and 2.1% to the average dividend yield of approximately 4.0% prevailing currently for those same companies, produces preposterous cost of equity estimates of 4.5%, 4.8%, and 6.1%, using earnings, dividends, and book value growth rates, respectively. Of course, these estimates of equity costs are outlandish as they are less than the cost of long-term debt for these companies.

I have therefore rejected historical growth rates as proxies for expected growth in the DCF calculation at this time.

Q. Did you consider any other method of estimating expected growth for the DCF model?

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. The latter method has been frequently used by FERC in determining the cost of common equity capital. 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'. That is, g = b x ROE

where: g = expected growth rate in earnings/dividends

b = expected retention ratio

ROE = expected return on book equity

Q. Dr. Morin, do you have any reservations in 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 return on book equity (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 projected dividend growth in applying the DCF model?

A. I did, but chose not to rely on dividend growth at this time. The reason is that it is widely expected that utilities will continue to lower their dividend payout ratio over the next several years in response to heightened business risk. 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 core DCF 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 is because utilities' dividend policies have become increasingly conservative as business risks in the industry have intensified steadily. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks. 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' growth 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 accounts for 65% of the ranking.

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. No growth forecast was available for Portland General. As shown on Column 3, line 27 of page 2 of Schedule RAM-E5, the average long-term growth forecast obtained from Value Line is 5.8% for this group. Adding this growth rate to the average expected dividend yield of 4.4% shown in Column 4 produces an estimate of equity costs of 10.2% for the group. Recognition of flotation costs brings the cost of equity estimate to 10.4%, shown in Column 6.

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, MGE Energy, and UniSource were eliminated as no analysts' growth forecasts were available from Zacks. For the remaining 26 companies shown on page 2 of Schedule RAM-E6, using the consensus analysts' earnings growth forecast published by Zacks of 7.0% instead of the Value Line forecast, the cost of equity for the group is 11.3% unadjusted for flotation cost. Recognition of flotation costs brings the cost of equity estimate to 11.6%, shown in Column 6, line 28.

Q. What DCF results did you obtain for Moody's electric utilities group?

A. Page 1 of Schedule RAM-E7 displays the electric utilities that make up Moody's Electric Utility Index. No growth forecast was available for Duke Energy from Value Line. As shown on Column 3 of page 2 of Schedule RAM-E7, the average long-term growth forecast obtained from Value Line is 6.6% for this group. Coupling this growth rate with the average expected dividend yield of 4.3% shown in Column 4 for each company produces an estimate of equity costs of 10.9% 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 11.1%, shown in Column 6.

Using the consensus analysts' growth forecast from Zacks instead of the Value Line growth forecast, the cost of equity for the Moody's group is 12.1%. This analysis is displayed on Pages 1 and 2 of Schedule RAM-E8. No growth projection was available for CH Energy and that company was therefore eliminated from the group. If we eliminate the two companies with outlying growth rates of 18% (Constellation Energy and Public Service Enterprise), the average ROE result for the remaining companies is 11.0%

Q. Please summarize your DCF estimates.

A. The table below summarizes the DCF estimates:

DCF STUDY	ROE
Vertically Integrated Elec Utilities Value Line Growth	10.4%
Vertically Integrated Elec Utilities Zacks Growth	11.6%
Moody's Elec Utilities Value Line Growth	11.1%
Moody's Elec Utilities Zacks Growth	11.0%

Q. Do these DCF results understate the cost of equity for UE?

A. Yes, they do. As shown earlier, application of the standard DCF model to utility stocks understates the investor's expected return when the M/B ratio of a given stock exceeds unity.

Q. Did you check your DCF results with any other variation of the DCF model?

A. Yes, I did. Although the constant growth DCF model does have a long history, analysts, practitioners, academics, and regulators including FERC, have come to recognize that it is not applicable in all situations. A reasonable alternative to the constant growth DCF model is the multiple-stage DCF model that more appropriately captures the path of future earnings/dividend growth than inserting a constant growth rate into the plain vanilla DCF equation. The two-stage DCF model is based on the premise that investors expect the growth rate for the utilities to be equal to the company-specific growth rates for the next 5 years, known as Stage 1 Growth, and to converge to an expected steady-state long-run rate of growth from year 6 onward, known as Stage 2 Growth.

One way to account for the two stages of growth is to modify the single-stage DCF model by specifying the growth rate as a weighted average of short-term and long-term growth rates. The blended growth rate is calculated as a weighted average giving two-thirds weight to the analysts' five-year growth projections (Zacks) and one-third to historical long-term growth of the economy as a whole and/or the long-range projections of growth in Gross Domestic Product

("GDP") projected for the very long term. FERC, among others, has adopted such a method in the past for determining the return on equity for energy utilities.

It turns out in this instance that two-stage DCF estimates for the two benchmark groups of electric utilities previously discussed are nearly identical to those obtained from the ordinary single-stage DCF model. Recall from page 2 of Schedules RAM-E5 to RAM-E8 that the analysts' and Value Line growth forecasts for the two groups of companies range from 5.8% to 7.5% with a midpoint of 6.2%. As shown below, a reasonable long-range GDP forecast for the U.S. economy is approximately 6.1% at this time, almost the same estimate as in the first stage. Clearly, given that the two stages of growth are close in magnitude, giving 2/3 weight to the first stage estimate of 5.8% - 6.8%, and 1/3 weight to the second stage estimate of 6.1%, produces DCF results close to the results obtained using the plain vanilla DCF model.

Q. How do you estimate the long-term growth rate for the U.S. economy?

A. A long-term forecast of nominal growth in GDP for the U.S. economy can be obtained from commercial sources such as Standard & Poor's Global Insight and Blue Chip Forecast or can be formulated by combining a long-term inflation estimate with a long-term real growth rate forecast as follows:

GDP Nominal growth = GDP Real Growth + Expected Inflation

The growth rate in U.S. real GDP has been reasonably stable over time. Therefore, its historical performance is a reasonable estimate of expected long-term future performance. The growth in real GDP for the 1929-2006 period was approximately 3.5%. The long-term expected inflation rate can be obtained by comparing the yield on long-term U.S. Treasury bonds with the yield on inflation-adjusted bonds of the same maturity. Given that the current nominal yield on 20-year Treasury bonds is 4.83% while the yield on inflation-adjusted bonds ("Treasury Inflation Protected Securities," or "TIPS") for the same maturity is 2.26%, one can surmise that investors expect a long-term 2.6% inflation rate, that is, 4.83% - 2.26% = 2.57%, rounded to 2.6%. Long-term expected GDP nominal growth is then 3.5% + 2.6% = 6.1%.

E. Need for Flotation Cost Adjustment

Q. Can you describe 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 around 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 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.

IV. SUMMARY AND RECOMMENDATION ON COST OF EQUITY

Q. Can you summarize your results and recommendation?

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

STUDY	ROE
CAPM	11.2%
Empirical CAPM	11.5%
Risk Premium Electric	10.5%
Allowed Risk Premium	10.1%
DCF Vert. Integrated Electric Utilities Value Line Growth	10.4%
DCF Vert. Integrated Electric Utilities Zacks Growth	11.6%
DCF Moody's Elec Utilities Value Line Growth	11.1%
DCF Moody's Elec Utilities Zacks Growth	11.0%

The central tendency of the results is 10.9% for the average risk utility, as indicated by the mean and midpoint results of 10.9%. I note that the various results are closely clustered around 10.9%. From a broader methodological perspective, the average result from the three principal methodologies is also 10.9%:

CAPM	11.4%
Risk Premium	10.3%
DCF	11.0%
AVERAGE	10.9%

I stress that no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is hazardous when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others. Thus, the results shown in the above table must be viewed as a whole rather than each as a stand-alone. It would be inappropriate to select any particular number from the summary table and infer the cost of common equity from that number alone.

A. Risk Associated with Energy Cost Recovery

Q. Dr. Morin, can you please comment on the impact of the Company's proposed fuel adjustment clause ("FAC"), which recovers fuel and purchased energy expenses, on the Company's business risk?

A. Yes, certainly. Rider FAC serves to reimburse UE for prudently-incurred fuel and purchased energy expenses in a manner that minimizes the negative financial effects caused by regulatory lag. Consideration of these energy expenses in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. Accordingly, the financial community relies on the presence of energy cost recovery mechanisms to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility. Rider FAC mitigates a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection would be factored into the Company's credit profile as a negative element that, in turn, would raise the Company's cost of capital. The approval of energy cost recovery mechanisms by regulatory commissions is widespread in the utility business. Approval of fuel adjustment clauses, purchased water adjustment clauses, and purchased gas adjustment clauses has become the norm for regulated industries. All else remaining constant, such clauses reduce investment risk on an absolute basis and constitute sound regulatory policy. To wit, the vast majority of the companies that make up my comparable group possess such clauses.

My assessment of UE's business risk, hence of the Company's cost of common equity, is dependent on the adoption of the FAC. I believe that the absence of a FAC harms UE's financial condition, causes deterioration in its credit metrics (and thus puts downward pressure on its credit ratings), and puts its customers at risk of having to pay higher rates due to access to capital becoming more expensive for UE. Because of the magnitude of the energy cost component in its cost of service, these effects could be significant. I note that the Company's bonds are already under review for possible downgrade by Moody's and under "negative outlook" by Fitch.

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

I very strongly encourage the Commission to approve UE's request for implementation of FAC, as it is fair to UE, its customers, and investors. I believe that the FAC deals with the cost of fuel and purchased energy, as well as with the mix of resources, which can vary month-to-month and which can represent a considerable financial outlay, on a consistent basis.

Q. Does the absence of an energy cost adjustment mechanism have any impact on the Company's cost of common equity?

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

If the proposed Rider FAC were not approved, with no provision for recovery of on-going fuel and purchased power costs, the resulting increase in UE's cost of common equity would be substantive, at least 25 basis points in my view. Given the proportion of fuel and purchased power costs as compared to total revenue requirement in this proceeding, the Company faces higher financing costs for incremental financing and would be expected to be at substantial risk for material financial deterioration. The absence of an energy cost recovery mechanism subjects the Company to significantly increased risks, and thus a significantly higher cost of common equity, than it would incur under the timely application of Rider FAC. Only if an alternative mechanism to Rider FAC were approved that allowed for timely recovery of on-going fuel and purchased power costs, with carrying charges equal to the Company's overall required rate of return, would there be no impact on the cost of common equity.

My recommended return is predicated on the assumption that the Commission will approve the Company's proposed FAC, thus avoiding significantly increased risk to investors vis-à-vis the risk they face with an FAC. Absent this mechanism, the Company's risk with regard to volatile fuel prices is significantly enhanced versus operating with an FAC and the investor-required rate of return on common equity correspondingly significantly higher.

Q. Are there any other elements of risk that influence the Company's cost of capital?

A. Yes, there are. The risk associated with the absence of a fuel adjustment clause is further heightened by UE's reliance on coal-based generation because there are uncertainties with regard to new state and federal regulations to reduce the impact of greenhouse gas emissions. Such regulations are likely to increase power supply costs for companies with coal-based generation, such as UE, where coal is the primary fuel in 76% of the energy produced. UE is thus at a risk for potential environmental compliance cost increases. UE also faces additional risks because rates in Missouri are based on an historical rather than projected test year and because Missouri law prohibits the inclusion of construction work in progress ("CWIP") for electric plant in rates until the electric plant is in service.

Q. Have you adjusted the cost of equity estimates to account for the fact that UE is riskier than the average electric utility?

A. Yes, I have. The testimony provided by Company witnesses Thomas R. Voss and Martin J. Lyons, Jr. outline UE's business risks in greater detail. The risks identified in their respective testimonies are individually and collectively material and unique. As I discussed above, at the most basic level, UE's business risk is above the risk level of the average utility due primarily to the absence of an energy cost recovery mechanism.

The appropriate determination of UE's cost of equity should include a reasonable risk adjustment relative to the average utility to account for this additional risk. The cost of equity estimates derived from the various comparable groups reflect the risk of the average electric utility. To the extent that these estimates are drawn from a less risky group of companies, the expected equity return applicable to the riskier UE is downward-biased. In my judgment, a reasonable estimate of the risk differential is on the order of 25 basis points and I have adjusted my result of 10.9% for the average risk utility upward to 11.15% in order to account for UE's higher relative risks. The risk adjustment was based on the difference in yield between utility long-term bonds rated Baa and A. The historical difference in yield is of the order of 20-40 basis points.

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 test year capital structure consistent with the recommended capital structure for UE consisting of 51.12% common equity capital.

Q. Did you examine the reasonableness of the Company's test year capital structure?

A. Yes, I did. I examined the actual common equity ratios of my comparable group of companies. The average common equity ratio for the group is 48%, which is reasonably close to the Company's test year common equity ratio. The Company's slightly stronger capital structure partially offsets the Company's greater than average business risk, as discussed above.

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.

Q. 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 business at this time is 11.15% and 10.9% with the adoption of a fuel adjustment clause.

B. 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. As I discuss elsewhere in my direct testimony, 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 2007, the average allowed ROE for integrated electric utilities was 10.56%. This means that the appropriate zone of reasonableness for the Commission to use in this case is 9.56% - 11.56%. My recommendations for an ROE for the Company, 10.9% if an FAC is approved, and 11.15% if an FAC is not approved, fall well within this zone of reasonableness.

Q. If capital market conditions change significantly between the date of filing your prepared testimony and the date oral testimony is presented, would this cause you to revise your estimated cost of equity?

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

Q. Does this conclude your direct testimony?

A. Yes, it does.

BEFORE THE 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-2008-____

AFFIDAVIT OF ROGER A. MORIN

STATE OF GEORGIA)
) ss
COUNTY OF GLYNN)

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 73 pages, Attachment A, Appendices A and B, and Schedules RAM-E1 through RAM-E8, 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 3 day of April, 2008.

Notary Public

My commission expires:

Notary Public, Glynn County, Georgia
My Commission Expires April 19, 2009

EXECUTIVE SUMMARY

Dr. Roger A. Morin

Emeritus Professor of Finance at the Robinson College of Business in Atlanta, Georgia

* * * * * * * * * *

To arrive at my final return on equity ("ROE") recommendation, I performed four risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other two risk premium analyses were performed on historical and allowed risk premium data from electric utility industry aggregate data, using the current yield on long-term Treasury bonds. I also performed DCF analyses on two surrogates for UE's electric utility business: a group of investment-grade vertically integrated electric utilities, and a group of companies that make up Moody's Electric Utility Index.

The central tendency of the results is 10.9% for the average risk utility, as indicated by the mean and midpoint results of 10.9%. I note that the various results are closely clustered around 10.9%.

I stress that no one individual method provides an exclusive foolproof formula for determining a fair return, but each method provides useful evidence so as to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is hazardous when dealing with investor expectations. Moreover, the advantage of using several different approaches is that the results of each one can be used to check the others.

Rider FAC serves to reimburse UE for prudently-incurred fuel and purchased energy expenses in a manner that minimizes the negative financial effects caused by regulatory lag.

Consideration of these energy expenses in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. Accordingly, the financial community relies on the presence of energy cost recovery mechanisms to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility. Rider FAC mitigates a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection would be factored into the Company's credit profile as a negative element that, in turn, would raise the Company's cost of capital. The approval of energy cost recovery mechanisms by regulatory commissions is widespread in the utility business. Approval of fuel adjustment clauses, purchased water adjustment clauses, and purchased gas adjustment clauses has become the norm for regulated industries. All else remaining constant, such clauses reduce investment risk on an absolute basis and constitute sound regulatory policy. To wit, the vast majority of the companies that make up my comparable group possess such clauses.

My assessment of UE's business risk, hence of the Company's cost of common equity, is dependent on the adoption of the FAC. I believe that the absence of a FAC harms UE's financial condition, causes deterioration in its credit metrics (and thus puts downward pressure on its credit ratings), and puts its customers at risk of having to pay higher rates due to access to capital becoming more expensive for UE. Because of the magnitude of the energy cost component in its cost of service, these effects could be significant. I note that the Company's bonds are already under review for possible downgrade by Moody's and under "negative outlook" by Fitch.

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

I very strongly encourage the Commission to approve UE's request for implementation of FAC, as it is fair to UE, its customers, and investors. I believe that the FAC deals with the cost of fuel and purchased energy, as well as with the mix of resources, which can vary month-to-month and which can represent a considerable financial outlay, on a consistent basis.

If the proposed Rider FAC were not approved, with no provision for recovery of on-going fuel and purchased power costs, the resulting increase in UE's cost of common equity would be substantive, at least 25 basis points in my view. Given the proportion of fuel and purchased power costs as compared to total revenue requirement in this proceeding, the Company faces higher financing costs for incremental financing and would be expected to be at substantial risk for material financial deterioration. The absence of an energy cost recovery mechanism subjects the Company to significantly increased risks, and thus a significantly higher cost of common equity, than it would incur under the timely application of Rider FAC. Only if an alternative mechanism to Rider FAC were approved that allowed for timely recovery of on-going fuel and purchased power costs, with carrying charges equal to the Company's overall required rate of return, would there be no impact on the cost of common equity.

My recommended return is predicated on the assumption that the Commission will approve the Company's proposed FAC, thus avoiding significantly increased risk to investors vis-à-vis the risk they face with an FAC. Absent this mechanism, the Company's risk with regard to volatile fuel prices is significantly enhanced versus operating with an FAC and the investor-required rate of return on common equity correspondingly significantly higher.

The risk associated with the absence of a fuel adjustment clause is further heightened by UE's reliance on coal-based generation because there are uncertainties with regard to new state and federal regulations to reduce the impact of greenhouse gas emissions. Such regulations are likely to increase power supply costs for companies with coal-based generation, such as UE, where coal is the primary fuel in 76% of the energy produced. UE is thus at a risk for potential environmental compliance cost increases. UE also faces additional risks because rates in Missouri are based on an historical rather than projected test year and because Missouri law prohibits the inclusion of construction work in progress ("CWIP") for electric plant in rates until the electric plant is in service.

The appropriate determination of UE's cost of equity should include a reasonable risk adjustment relative to the average utility to account for this additional risk. The cost of equity estimates derived from the various comparable groups reflect the risk of the average electric utility. To the extent that these estimates are drawn from a less risky group of companies, the expected equity return applicable to the riskier UE is downward-biased. In my judgment, a reasonable estimate of the risk differential is on the order of 25 basis points and I have adjusted my result of 10.9% for the average risk utility upward to 11.15% in order to account for UE's higher relative risks. The risk adjustment was based on the difference in yield between utility long-term bonds rated Baa and A. The historical difference in yield is of the order of 20-40 basis points.

My recommended return on common equity for UE is predicated on the adoption of a test year capital structure consistent with the recommended capital structure for UE consisting of 51.12% common equity capital.

I examined the actual common equity ratios of my comparable group of companies. The average common equity ratio for the group is 48%, which is reasonably close to the Company's test year common equity ratio. The Company's slightly stronger capital structure partially offsets the Company's greater than average business risk, as discussed above.

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.

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 business at this time is 11.15% and 10.9% with the adoption of a fuel adjustment clause

Using RRA reported data for calendar year 2007, the average allowed ROE for integrated electric utilities was 10.56%. This means that the appropriate zone of reasonableness for the Commission to use in this case is 9.56% - 11.56%. My recommendations for an ROE for the Company, 10.9% if an FAC is approved, and 11.15% if an FAC is not approved, fall well within this zone of reasonableness.

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:

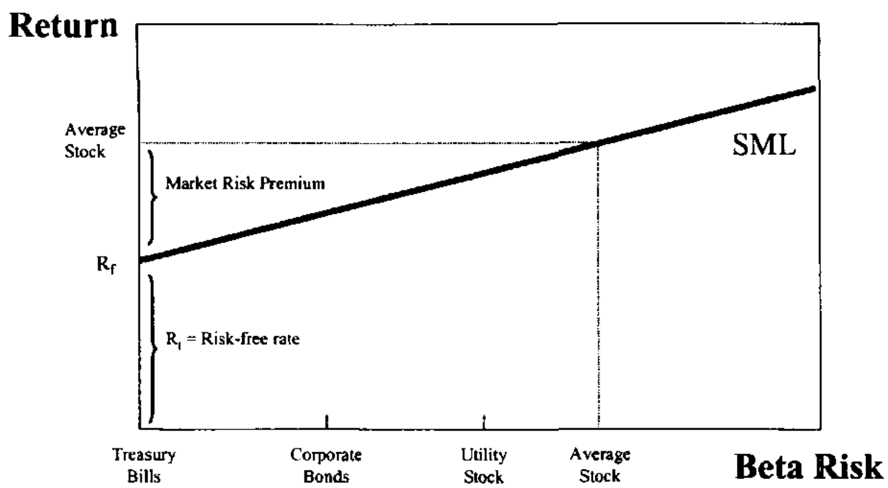
$$K = R_F + \beta(R_M - R_F) \qquad (1)$$

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.

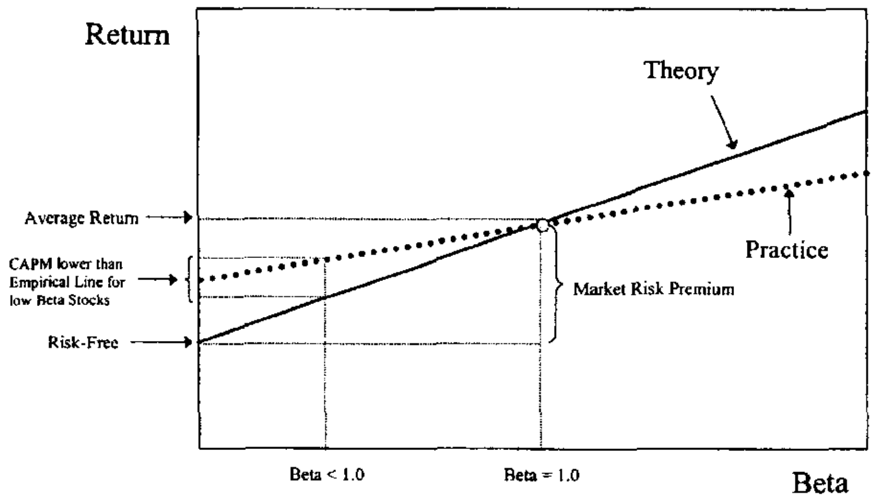
CAPM and Risk - Return in Capital Markets



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:

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

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

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

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

Theoretical Underpinnings

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

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

Empirical studies by Litzenberger and Ramaswamy (1979) 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	2.0%	1983-1998

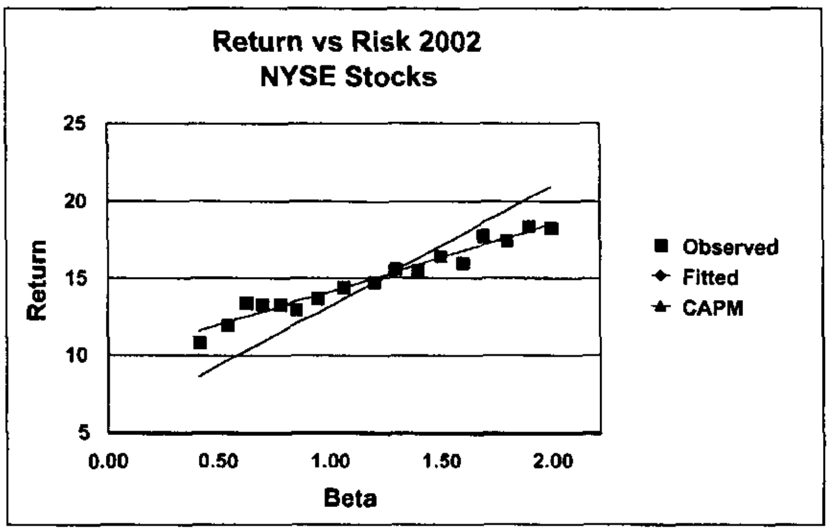
Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1989) over the period 1926-1984 indicating that the observed expected return on a security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

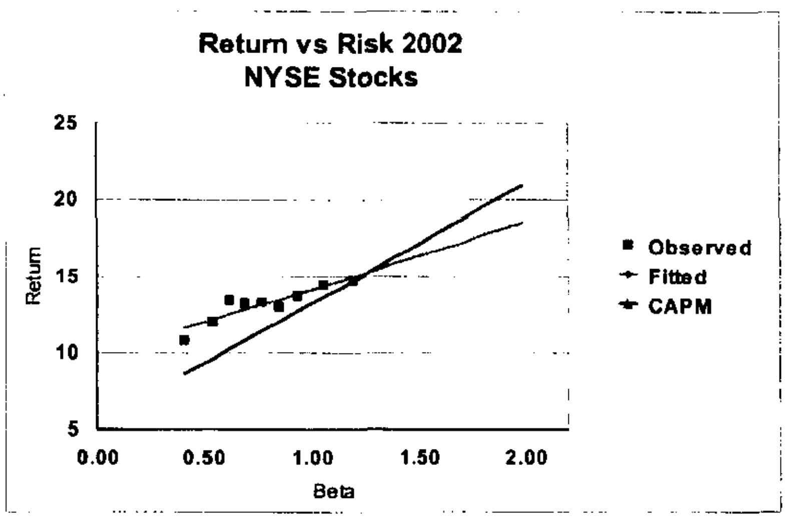
CAPM vs ECAPM



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 by using the constant growth DCF model. They then investigate the relation between the risk premium (expected return over the 20-year U.S. Treasury Bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

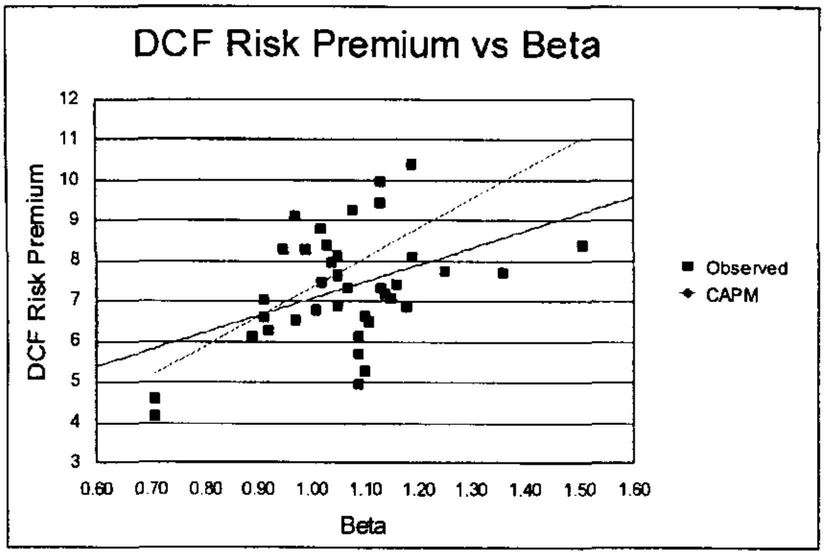
The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill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

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

Table A-1 Risk Premium and Beta Estimates by Industry

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

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



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

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

Practical Implementation of the ECAPM

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

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

or, alternatively by the following equivalent relationship:

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

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

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

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

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

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]:

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

[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

[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

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].

[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 = (D/P + g)	**14.00%**
ALLOWED RETURN ON EQUITY = (D/P(1-f) + g)	**14.47%**

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

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

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- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.
- Executive Visions Inc., Board of Directors, Member
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PROFESSIONAL CLIENTS

AGL Resources

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

Allete

Ameren

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

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

Nevada Power Company

New Brunswick Power

Newfoundland Power Inc. - Fortis Inc.

New Market Hydro

New Tel Enterprises Ltd.

New York Telephone Co.

Norfolk-Southern

Northeast Utilities

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Power – Emera Inc.

Nova Scotia Utility and Review Board

NUI Corp.

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

Pacific Northwest Bell

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Pepco Holdings

Potomac Electric Power Co.

Price Waterhouse

PSI Energy

Public Service Electric & Gas

Public Service of New Hampshire

Puget Sound Electric Co.

Quebec Telephone

Regie de l'Energie du Quebec

Rochester Telephone

San Diego Gas & Electric

SaskPower

Sierra Pacific Power Company

Southern Bell

Southern States Utilities

Southern Union Gas

South Central Bell

Sun City Water Company

TECO Energy

The Southern Company

Touche Ross and Company

TransEnergie

Trans-Quebec & Maritimes Pipeline

TXU Corp

US WEST Communications

Union Heat Light & Power

Utah Power & Light

Vermont Gas Systems Inc.

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- 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

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  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

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EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

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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 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

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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, 207

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 Electric Co 2006

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

Nevada Power Co. 2007

Hawaiian Electric Co. 2006-7

Hawaii Elec & Light Co. 2007

Maui Electric Co. 2007

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.

S&P Integrated Elec Utilities

Line No.	(1) Company Name	(2) Beta
1	ALLETE	0.95
2	Alliant Energy	0.80
3	Amer. Elec. Power	0.95
4	Ameren Corp.	0.80
5	Cleco Corp.	1.15
6	CMS Energy Corp.	1.35
7	DPL Inc.	0.85
8	DTE Energy	0.80
9	Edison Int'l	0.85
10	Empire Dist. Elec.	0.85
11	Energy East Corp.	0.80
12	Entergy Corp.	0.85
13	FPL Group	0.75
14	Hawaiian Elec.	0.75
15	IDACORP Inc.	0.95
16	MGE Energy	0.95
17	Northeast Utilities	0.80
18	PG&E Corp.	0.85
19	Pinnacle West Capital	0.80
20	PNM Resources	0.90
21	Portland General	
22	Progress Energy	0.85
23	Puget Energy Inc.	0.90
24	Southern Co.	0.70
25	TECO Energy	0.95
26	UniSource Energy	0.60
27	Westar Energy	0.85
28	Wisconsin Energy	0.85
29	Xcel Energy Inc.	0.80
31	**AVERAGE**	**0.87**

Source: VLIA 02/2008

Moody's Electric Utilities

Line No.	(1) Company Name	(2) Beta
1	Amer. Elec. Power	0.95
2	CH Energy Group	0.90
3	Consol. Edison	0.75
4	Constellation Energy	0.85
5	Dominion Resources	0.75
6	DPL Inc.	0.85
7	DTE Energy	0.80
8	Duke Energy	
9	Energy East Corp.	0.80
10	Exelon Corp.	0.90
11	FirstEnergy Corp.	0.85
12	IDACORP Inc.	0.95
13	NiSource Inc.	0.90
14	OGE Energy	0.85
15	PPL Corp.	0.90
16	Progress Energy	0.85
17	Public Serv. Enterprise	0.95
18	Southern Co.	0.70
19	TECO Energy	0.95
20	Xcel Energy Inc.	0.80

Electric Industry Historical Risk Premium

Line No.	Year	(1) Long-Term Government Bond Yield	(2) 20 year Maturity Bond Value	(3) Gain/Loss	(4) Interest	(5) Bond Total Return	(6) Moody's Electric Utility Stock Index	(7) Dividend	(8) Capital Gain/(Loss) % Growth	(9) Yield	(10) Stock Total Return	(11) Equity Risk Premium Over Bond Returns	(12) Equity Risk Premium Over Bond Yields
1	1931	4.07%	1,000.00				43.23						
2	1932	3.15%	1,135.75	135.75	40.70	17.64%	39.42	2.22	-8.81%	5.14%	-3.68%	-21.32%	-6.83%
3	1933	3.36%	969.60	-30.40	31.50	0.11%	28.73	1.75	-27.12%	4.44%	-22.68%	-22.79%	-26.04%
4	1934	2.93%	1,064.73	64.73	33.60	9.83%	21.06	1.42	-26.70%	4.94%	-21.75%	-31.59%	-24.68%
5	1935	2.76%	1,025.99	25.99	29.30	5.53%	36.06	1.33	71.23%	6.32%	77.54%	72.01%	74.78%
6	1936	2.55%	1,032.74	32.74	27.60	6.03%	41.60	1.78	15.36%	4.94%	20.30%	14.27%	17.75%
7	1937	2.73%	972.40	-27.60	25.50	-0.21%	24.24	1.68	-41.73%	4.04%	-37.69%	-37.48%	-40.42%
8	1938	2.52%	1,032.83	32.83	27.30	6.01%	27.55	1.45	13.66%	5.98%	19.64%	13.62%	17.12%
9	1939	2.26%	1,041.65	41.65	25.20	6.68%	28.85	1.51	4.72%	5.48%	10.20%	3.51%	7.94%
10	1940	1.94%	1,052.84	52.84	22.60	7.54%	22.22	1.57	-22.98%	5.44%	-17.54%	-25.08%	-19.48%
11	1941	2.04%	983.64	-16.36	19.40	0.30%	13.45	1.27	-39.47%	5.72%	-33.75%	-34.06%	-35.79%
12	1942	2.46%	933.97	-66.03	20.40	-4.56%	14.29	1.28	6.25%	9.52%	15.76%	20.33%	13.30%
13	1943	2.48%	996.86	-3.14	24.60	2.15%	21.01	1.46	47.03%	10.22%	57.24%	55.10%	54.76%
14	1944	2.46%	1,003.14	3.14	24.80	2.79%	21.09	1.35	0.38%	6.43%	6.81%	4.01%	4.35%
15	1945	1.99%	1,077.23	77.23	24.60	10.18%	31.14	1.37	47.65%	6.50%	54.15%	43.97%	52.16%
16	1946	2.12%	978.90	-21.10	19.90	-0.12%	32.71	1.48	5.04%	4.75%	9.79%	9.91%	7.67%
17	1947	2.43%	951.13	-48.87	21.20	-2.77%	25.60	1.58	-21.74%	4.83%	-16.91%	-14.14%	-19.34%
18	1948	2.37%	1,009.51	9.51	24.30	3.38%	26.20	1.63	2.34%	6.37%	8.71%	5.33%	6.34%
19	1949	2.09%	1,045.58	45.58	23.70	6.93%	30.57	1.68	16.68%	6.41%	23.09%	16.16%	21.00%
20	1950	2.24%	975.93	-24.07	20.90	-0.32%	30.81	1.85	0.79%	6.05%	6.84%	7.15%	4.60%
21	1951	2.69%	930.75	-69.25	22.40	-4.69%	33.85	1.90	9.87%	6.17%	16.03%	20.72%	13.34%
22	1952	2.79%	984.75	-15.25	26.90	1.17%	37.85	1.92	11.82%	5.67%	17.49%	16.32%	14.70%
23	1953	2.74%	1,007.66	7.66	27.90	3.56%	39.61	2.09	4.65%	5.52%	10.17%	6.62%	7.43%
24	1954	2.72%	1,003.07	3.07	27.40	3.05%	47.56	2.14	20.07%	5.40%	25.47%	22.43%	22.75%
25	1955	2.95%	965.44	-34.56	27.20	-0.74%	49.35	2.27	3.76%	4.77%	8.54%	9.27%	5.59%
26	1956	3.45%	928.19	-71.81	29.50	-4.23%	48.96	2.37	-0.79%	4.80%	4.01%	8.24%	0.56%
27	1957	3.23%	1,032.23	32.23	34.50	6.67%	50.30	2.46	2.74%	5.02%	7.76%	1.09%	4.53%
28	1958	3.82%	918.01	-81.99	32.30	-4.97%	66.37	2.57	31.95%	5.11%	37.06%	42.03%	33.24%
29	1959	4.47%	914.65	-85.35	38.20	-4.71%	65.77	2.64	-0.90%	3.98%	3.07%	7.79%	-1.40%
30	1960	3.80%	1,093.27	93.27	44.70	13.80%	76.82	2.74	16.80%	4.17%	20.97%	7.17%	17.17%
31	1961	4.15%	952.75	-47.25	38.00	-0.92%	99.32	2.86	29.29%	3.72%	33.01%	33.94%	28.86%
32	1962	3.95%	1,027.48	27.48	41.50	6.90%	96.49	3.07	-2.85%	3.09%	0.24%	-6.66%	-3.71%
33	1963	4.17%	970.35	-29.65	39.50	0.99%	102.31	3.33	6.03%	3.45%	9.48%	8.50%	5.31%
34	1964	4.23%	991.96	-8.04	41.70	3.37%	115.54	3.68	12.93%	3.60%	16.53%	13.16%	12.30%
35	1965	4.50%	964.64	-35.36	42.30	0.69%	114.86	4.02	-0.59%	3.48%	2.89%	2.20%	-1.61%
36	1966	4.55%	993.48	-6.52	45.00	3.85%	105.99	4.18	-7.72%	3.64%	-4.08%	-7.93%	-8.63%
37	1967	5.56%	879.01	-120.99	45.50	-7.55%	98.19	4.44	-7.36%	4.19%	-3.17%	4.38%	-8.73%
38	1968	5.98%	951.38	-48.62	55.60	0.70%	104.04	4.58	5.96%	4.66%	10.62%	9.92%	4.64%
39	1969	6.87%	904.00	-96.00	59.80	-3.62%	84.62	4.63	-18.67%	4.45%	-14.22%	-10.60%	-21.09%
40	1970	6.48%	1,043.38	43.38	68.70	11.21%	88.59	4.73	4.69%	5.59%	10.28%	-0.93%	3.80%
41	1971	5.97%	1,059.09	59.09	64.80	12.39%	85.56	4.81	-3.42%	5.43%	2.01%	-10.38%	-3.96%
42	1972	5.99%	997.69	-2.31	59.70	5.74%	83.61	4.92	-2.28%	5.75%	3.47%	-2.27%	-2.52%
43	1973	7.26%	867.09	-132.91	59.90	-7.30%	60.87	5.04	-27.20%	6.03%	-21.17%	-13.87%	-28.43%
44	1974	7.60%	965.33	-34.67	72.60	3.79%	41.17	4.83	-32.36%	7.93%	-24.43%	-28.22%	-32.03%
45	1975	8.05%	955.63	-44.37	76.00	3.16%	55.66	4.99	35.20%	12.12%	47.32%	44.15%	39.27%
46	1976	7.21%	1,088.25	88.25	80.50	16.87%	66.29	5.25	19.10%	9.43%	28.53%	11.66%	21.32%
47	1977	8.03%	919.03	-80.97	72.10	-0.89%	68.19	5.68	2.87%	8.57%	11.43%	12.32%	3.40%
48	1978	8.98%	912.47	-87.53	80.30	-0.72%	59.75	5.98	-12.38%	8.77%	-3.61%	-2.88%	-12.59%
49	1979	10.12%	902.99	-97.01	89.80	-0.72%	56.41	6.34	-5.59%	10.61%	5.02%	5.74%	-5.10%
50	1980	11.99%	859.23	-140.77	101.20	-3.96%	54.42	6.67	-3.53%	11.82%	8.30%	12.25%	-3.69%
51	1981	13.34%	906.45	-93.55	119.90	2.63%	57.20	7.16	5.11%	13.16%	18.27%	15.63%	4.93%

52	1982	10.95%	1,192.38	192.38	133.40	32.58%	70.26	7.64	22.83%	13.36%	36.19%	3.61%	25.24%
53	1983	11.97%	923.12	-76.88	109.50	3.26%	72.03	8.00	2.52%	11.39%	13.91%	10.64%	1.94%
54	1984	11.70%	1,020.70	20.70	119.70	14.04%	80.16	8.37	11.29%	11.62%	22.91%	8.87%	11.21%
55	1985	9.56%	1,189.27	189.27	117.00	30.63%	94.98	8.71	18.49%	10.87%	29.35%	-1.27%	19.79%
56	1986	7.89%	1,166.63	166.63	95.60	26.22%	113.66	8.97	19.67%	9.44%	29.11%	2.89%	21.22%
57	1987	9.20%	881.17	-118.83	78.90	-3.99%	94.24	9.12	-17.09%	8.02%	-9.06%	-5.07%	-18.26%
58	1988	9.18%	1,001.82	1.82	92.00	9.38%	100.94	8.71	7.11%	9.24%	16.35%	6.97%	7.17%
59	1989	8.16%	1,099.75	99.75	91.80	19.16%	122.52	8.85	21.38%	8.77%	30.15%	10.99%	21.99%
60	1990	8.44%	973.17	-26.83	81.60	5.48%	117.77	8.76	-3.88%	7.15%	3.27%	-2.20%	-5.17%
61	1991	7.30%	1,118.94	118.94	84.40	20.33%	144.02	9.02	22.29%	7.66%	29.95%	9.61%	22.65%
62	1992	7.26%	1,004.19	4.19	73.00	7.72%	141.06	8.82	-2.06%	6.12%	4.07%	-3.65%	-3.19%
63	1993	6.54%	1,079.70	79.70	72.60	15.23%	146.70	9.04	4.00%	6.41%	10.41%	-4.82%	3.87%
64	1994	7.99%	856.40	-143.60	65.40	-7.82%	115.50	9.01	-21.27%	6.14%	-15.13%	-7.31%	-23.12%
65	1995	6.03%	1,225.98	225.98	79.90	30.59%	142.90	9.06	23.72%	7.84%	31.57%	0.98%	25.54%
66	1996	6.73%	923.67	-76.33	60.30	-1.60%	136.00	9.06	-4.83%	6.34%	1.51%	3.11%	-5.22%
67	1997	6.02%	1,081.92	81.92	67.30	14.92%	155.73	9.06	14.51%	6.66%	21.17%	6.25%	15.15%
68	1998	5.42%	1,072.71	72.71	60.20	13.29%	181.84	8.01	16.77%	5.14%	21.91%	8.62%	16.49%
69	1999	6.82%	848.41	-151.59	54.20	-9.74%	137.30	8.06	-24.49%	4.43%	-20.06%	-10.32%	-26.88%
70	2000	5.58%	1,148.30	148.30	68.20	21.65%	227.09	8.71	65.40%	6.34%	71.74%	50.09%	66.16%
71	2001	5.75%	979.95	-20.05	55.80	3.57%	200.50	8.95	-11.71%	3.94%	-7.77%	-11.34%	-13.52%
72	2002	4.84%	1,115.77	115.77	57.50	17.33%	169.50	8.83	-15.46%	4.40%	-11.06%	-28.38%	-15.90%
73	2003	5.11%	966.42	-33.58	48.40	1.48%	201.21	8.52	18.71%	5.03%	23.73%	22.25%	18.62%
74	2004	4.84%	1,034.35	34.35	51.10	8.54%	249.70	9.98	24.10%	4.96%	29.06%	20.51%	24.22%
75	2005	4.61%	1,029.84	29.84	48.40	7.82%	285.86	10.72	14.48%	4.29%	18.77%	10.95%	14.16%
76	2006	4.91%	962.06	-37.94	46.10	0.82%	326.19	11.31	14.11%	3.96%	18.06%	17.25%	13.15%
78	**Mean**											**5.7%**	**5.8%**

Source: Mergent Public Utility Manual December stock prices and dividends

Dec. Bond yields from Ibbotson Associates 2007 Valuation Yearbook Table B-9 Long-Term Government Bonds Yields

Electric Utility Industry Historical Growth Rates

Line No.	(1) Company Name	(2) Earnings Growth 5-Year	(3) Dividend Growth 5-Year	(4) Book Value Growth 5-Year
1	ALLETE			
2	Allegheny Energy	-16.5		-9.0
3	Alliant Energy	-3.0	-11.5	-2.5
4	Amer. Elec. Power	3.0	-9.5	-2.5
5	Ameren Corp.	-2.0		5.5
6	Aquila Inc.			-27.0
7	Avista Corp.	0.5	2.5	3.5
8	Black Hills	-4.0	3.5	11.0
9	CH Energy Group	-2.5		1.5
10	CMS Energy Corp.	-18.0		-10.5
11	Cen. Vermont Pub. Serv.	-2.5	1.0	2.0
12	CenterPoint Energy	-11.0	-21.0	-28.0
13	Cleco Corp.		1.0	5.5
14	Consol. Edison	-2.0	1.0	3.0
15	Constellation Energy	9.0	1.0	4.5
16	DPL Inc.	-3.5	0.5	0.5
17	DTE Energy	-1.0		3.0
18	Dominion Resources	7.5	1.0	3.5
19	Duke Energy			
20	Edison Int'l		8.5	14.0
21	El Paso Electric	-3.5		8.0
22	Empire Dist. Elec.	1.0		2.0
23	Energy East Corp.	-3.0	5.0	6.0
24	Entergy Corp.	10.5	11.0	4.0
25	Evergreen Energy Inc			
26	Exelon Corp.	11.5		3.5
27	FPL Group	4.5	5.5	6.5
28	FirstEnergy Corp.	3.5	4.0	4.5
29	Florida Public Utilities	3.5	3.5	9.5
30	G't Plains Energy	5.0		3.0
31	Hawaiian Elec.	-1.0		2.0
32	IDACORP Inc.	-8.5	-8.5	2.5
33	Integrys Energy	9.5	2.0	9.0
34	MDU Resources	13.0	5.5	11.5
35	MGE Energy	2.5	1.0	7.0
36	Maine & Maritimes Corp	-31.0	-9.0	2.0
37	NSTAR	3.5	3.0	2.5
38	NiSource Inc.	0.5	-1.5	4.0
39	NorthWestern Corp			
40	Northeast Utilities		16.5	3.0
41	OGE Energy	3.5		3.5
42	Otter Tail Corp.	1.0	2.0	8.0
43	PG&E Corp.		-1.5	9.5
44	PNM Resources	-2.5	7.5	4.5
45	PPL Corp.	6.5	13.0	14.0
46	Pepco Holdings	-5.0		0.5
47	Pinnacle West Capital	-5.0	6.0	4.0
48	Portland General			
49	Progress Energy	-0.5	2.5	5.0
50	Public Serv. Enterprise	-1.5	0.5	5.0
51	Puget Energy Inc.	-4.5	-11.5	1.5
52	SCANA Corp.	7.0	5.0	2.5
53	Sempra Energy	13.0	-1.0	14.0
54	Sierra Pacific Res.	29.5		-8.0
55	Southern Co.	3.0	2.0	1.0
56	TECO Energy	-13.0	-10.5	-9.5
57	U.S. Energy Sys Inc			-6.5
58	UIL Holdings	-8.5		1.0
59	UNITIL Corp.	-1.5		1.0
60	UniSource Energy	1.5	25.5	9.5
61	Vectren Corp.	4.5	4.0	4.5
62	Westar Energy	21.0	-11.0	-9.0
63	Wisconsin Energy	8.0	-6.5	6.0
64	Xcel Energy Inc.	-6.5	-10.5	-4.5
66	**AVERAGE**	**0.5**	**0.8**	**2.1**

Source: Value Line Investment Analyzer 02/2008

Schedule RAM-E4

S&P Integrated Electric Utilities: DCF Analysis Value Line Growth Rates

	(1)	(2)	(3)
Line No.	Company Name	Current Dividend Yield	Projected EPS Growth
1	ALLETE	4.5	8.0
2	Alliant Energy	4.0	5.5
3	Amer. Elec. Power	3.9	6.5
4	Ameren Corp.	5.7	3.0
5	Cleco Corp.	3.5	6.5
6	CMS Energy Corp.	2.6	8.5
7	DPL Inc.	4.0	10.5
8	DTE Energy	5.1	4.0
9	Edison Int'l	2.4	6.5
10	Empire Dist. Elec.	5.8	8.5
11	Energy East Corp.	5.0	0.5
12	Entergy Corp.	2.9	9.5
13	FPL Group	2.8	11.0
14	Hawaiian Elec.	5.5	1.5
15	IDACORP Inc.	3.7	2.0
16	MGE Energy	4.3	6.5
17	Northeast Utilities	3.0	17.0
18	PG&E Corp.	3.8	4.5
19	Pinnacle West Capital	5.5	1.5
20	PNM Resources	5.0	2.5
21	Portland General	4.0	
22	Progress Energy	5.4	3.5
23	Puget Energy Inc.	3.8	6.0
24	Southern Co.	4.6	3.0
25	TECO Energy	4.8	4.5
26	UniSource Energy	3.3	4.0
27	Westar Energy	4.7	4.5
28	Wisconsin Energy	2.4	8.0
29	Xcel Energy Inc.	4.6	5.5

S&P 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	ALLETE	4.5	8.0	4.8	12.8	13.1
2	Alliant Energy	4.0	5.5	4.2	9.7	9.9
3	Amer. Elec. Power	3.9	6.5	4.2	10.7	10.9
4	Ameren Corp.	5.7	3.0	5.8	8.8	9.1
5	Cleco Corp.	3.5	6.5	3.7	10.2	10.4
6	CMS Energy Corp.	2.6	8.5	2.8	11.3	11.4
7	DPL Inc.	4.0	10.5	4.4	14.9	15.1
8	DTE Energy	5.1	4.0	5.3	9.3	9.6
9	Edison Int'l	2.4	6.5	2.5	9.0	9.2
10	Empire Dist. Elec.	5.8	8.5	6.3	14.8	15.1
11	Energy East Corp.	5.0	0.5	5.0	5.5	5.7
12	Entergy Corp.	2.9	9.5	3.1	12.6	12.8
13	FPL Group	2.8	11.0	3.1	14.1	14.2
14	Hawaiian Elec.	5.5	1.5	5.6	7.1	7.4
15	IDACORP Inc.	3.7	2.0	3.8	5.8	6.0
16	MGE Energy	4.3	6.5	4.6	11.1	11.4
17	Northeast Utilities	3.0	17.0	3.5	20.5	20.6
18	PG&E Corp.	3.8	4.5	4.0	8.5	8.7
19	Pinnacle West Capital	5.5	1.5	5.6	7.1	7.4
20	PNM Resources	5.0	2.5	5.1	7.6	7.9
21	Progress Energy	5.4	3.5	5.6	9.1	9.4
22	Puget Energy Inc.	3.8	6.0	4.0	10.0	10.3
23	Southern Co.	4.6	3.0	4.7	7.7	7.9
24	TECO Energy	4.8	4.5	5.0	9.5	9.8
25	UniSource Energy	3.3	4.0	3.4	7.4	7.6
26	Westar Energy	4.7	4.5	4.9	9.4	9.6
27	Wisconsin Energy	2.4	8.0	2.6	10.6	10.7
28	Xcel Energy Inc.	4.6	5.5	4.8	10.3	10.6
30	**AVERAGE**	**4.1**	**5.8**	**4.4**	**10.2**	**10.4**

Notes:

Column 1, 2, 3: Value Line Investment Analyzer, 02/2008

Column 4 = Column 2 times (1 + Column 3/100)

Column 5 = Column 4 + Column 3

Column 6 = (Column 4 /0.95) + Column 3

No growth forecast is available for Portland General

S&P Integrated Electric Utilities: DCF Analysis Analysts'Growth Forecasts

	(1)	(2)	(3)
Line No.	Company Name	Current Dividend Yield	Analysts' Growth Forecast
1	ALLETE	4.5	5.0
2	Alliant Energy	4.0	6.0
3	Amer. Elec. Power	3.9	5.4
4	Ameren Corp.	5.7	5.0
5	Cleco Corp.	3.5	9.5
6	CMS Energy Corp.	2.6	7.3
7	DPL Inc.	4.0	8.0
8	DTE Energy	5.1	6.0
9	Edison Int'l	2.4	10.3
10	Empire Dist. Elec.	5.8	
11	Energy East Corp.	5.0	3.0
12	Entergy Corp.	2.9	13.3
13	FPL Group	2.8	10.6
14	Hawaiian Elec.	5.5	4.5
15	IDACORP Inc.	3.7	5.0
16	MGE Energy	4.3	
17	Northeast Utilities	3.0	12.7
18	PG&E Corp.	3.8	8.5
19	Pinnacle West Capital	5.5	6.7
20	PNM Resources	5.0	5.8
21	Portland General	4.0	7.0
22	Progress Energy	5.4	4.6
23	Puget Energy Inc.	3.8	5.5
24	Southern Co.	4.6	4.6
25	TECO Energy	4.8	7.3
26	UniSource Energy	3.3	
27	Westar Energy	4.7	4.5
28	Wisconsin Energy	2.4	9.4
29	Xcel Energy Inc.	4.6	5.2

Notes:
Column 1, 2: Value Line Investment Analyzer, 02/2008
Column 3: Zacks long-term earnings growth forecast,02/2008

S&P 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	4.5	5.0	4.7	9.7	10.0
2	Alliant Energy	4.0	6.0	4.2	10.2	10.4
3	Amer. Elec. Power	3.9	5.4	4.1	9.5	9.7
4	Ameren Corp.	5.7	5.0	6.0	11.0	11.3
5	Cleco Corp.	3.5	9.5	3.8	13.3	13.5
6	CMS Energy Corp.	2.6	7.3	2.7	10.0	10.2
7	DPL Inc.	4.0	8.0	4.3	12.3	12.5
8	DTE Energy	5.1	6.0	5.4	11.4	11.7
9	Edison Int'l	2.4	10.3	2.6	12.9	13.1
10	Energy East Corp.	5.0	3.0	5.1	8.1	8.4
11	Entergy Corp.	2.9	13.3	3.2	16.5	16.7
12	FPL Group	2.8	10.6	3.1	13.7	13.8
13	Hawaiian Elec.	5.5	4.5	5.8	10.3	10.6
14	IDACORP Inc.	3.7	5.0	3.9	8.9	9.1
15	Northeast Utilities	3.0	12.7	3.3	16.0	16.2
16	PG&E Corp.	3.8	8.5	4.1	12.6	12.8
17	Pinnacle West Capital	5.5	6.7	5.9	12.6	12.9
18	PNM Resources	5.0	5.8	5.3	11.1	11.3
19	Portland General	4.0	7.0	4.3	11.3	11.5
20	Progress Energy	5.4	4.6	5.7	10.3	10.6
21	Puget Energy Inc.	3.8	5.5	4.0	9.5	9.7
22	Southern Co.	4.6	4.6	4.8	9.4	9.6
23	TECO Energy	4.8	7.3	5.1	12.4	12.7
24	Westar Energy	4.7	4.5	4.9	9.4	9.6
25	Wisconsin Energy	2.4	9.4	2.6	12.0	12.1
26	Xcel Energy Inc.	4.6	5.2	4.8	10.0	10.3
28	**AVERAGE**	**4.1**	**7.0**	**4.4**	**11.3**	**11.6**

Notes:

Column 1, 2: Value Line Investment Analyzer, 02/2008

Column 3: Zacks long-term earnings growth forecast, 02/2008

Column 4 = Column 2 times (1 + Column 3/100)

Column 5 = Column 4 + Column 3

Column 6 = (Column 4 /0.95) + Column 3

Moody's Electric Utilities: DCF Analysis Value Line Growth

	(1)	(2)	(3)
Line No.	Company Name	Current Dividend Yield	Projected EPS Growth
1	Amer. Elec. Power	3.9	6.5
2	CH Energy Group	5.6	3.0
3	Consol. Edison	5.4	4.0
4	Constellation Energy	2.1	15.5
5	Dominion Resources	3.8	9.5
6	DPL Inc.	4.0	10.5
7	DTE Energy	5.1	4.0
8	Duke Energy	4.8	
9	Energy East Corp.	5.0	0.5
10	Exelon Corp.	2.6	10.5
11	FirstEnergy Corp.	3.1	9.0
12	IDACORP Inc.	3.7	2.0
13	NiSource Inc.	4.9	2.5
14	OGE Energy	4.3	5.5
15	PPL Corp.	2.7	14.0
16	Progress Energy	5.4	3.5
17	Public Serv. Enterprise	2.7	11.5
18	Southern Co.	4.6	3.0
19	TECO Energy	4.8	4.5
20	Xcel Energy Inc.	4.6	5.5

Notes:
Column 1, 2, 3: Value Line Investment Analyzer, 02/2008

Moody's Electric Utilities: DCF Analysis Value Line Growth

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Amer. Elec. Power	3.9	6.5	4.2	10.7	10.9
2	CH Energy Group	5.6	3.0	5.8	8.8	9.1
3	Consol. Edison	5.4	4.0	5.6	9.6	9.9
4	Constellation Energy	2.1	15.5	2.5	18.0	18.1
5	Dominion Resources	3.8	9.5	4.1	13.6	13.8
6	DPL Inc.	4.0	10.5	4.4	14.9	15.1
7	DTE Energy	5.1	4.0	5.3	9.3	9.6
8	Energy East Corp.	5.0	0.5	5.0	5.5	5.7
9	Exelon Corp.	2.6	10.5	2.9	13.4	13.5
10	FirstEnergy Corp.	3.1	9.0	3.4	12.4	12.5
11	IDACORP Inc.	3.7	2.0	3.8	5.8	6.0
12	NiSource Inc.	4.9	2.5	5.0	7.5	7.7
13	OGE Energy	4.3	5.5	4.5	10.0	10.3
14	PPL Corp.	2.7	14.0	3.1	17.1	17.2
15	Progress Energy	5.4	3.5	5.6	9.1	9.4
16	Public Serv. Enterprise	2.7	11.5	3.0	14.5	14.6
17	Southern Co.	4.6	3.0	4.7	7.7	7.9
18	TECO Energy	4.8	4.5	5.0	9.5	9.8
19	Xcel Energy Inc.	4.6	5.5	4.8	10.3	10.6
21	**AVERAGE**	**4.1**	**6.6**	**4.3**	**10.9**	**11.1**

Notes:

Column 1, 2, 3: Value Line Investment Analyzer, 02/2008
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3
No Value Line growth forecasts available for Duke Energy

Moody's Electric Utilities: DCF Analysis Analysts Growth Forecasts

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Analysts' Growth Forecast
1	Amer. Elec. Power	3.9	5.4
2	CH Energy Group	5.6	
3	Consol. Edison	5.4	3.2
4	Constellation Energy	2.1	18.0
5	Dominion Resources	3.8	11.5
6	DPL Inc.	4.0	8.0
7	DTE Energy	5.1	6.0
8	Duke Energy	4.8	6.0
9	Energy East Corp.	5.0	3.0
10	Exelon Corp.	2.6	12.0
11	FirstEnergy Corp.	3.1	7.5
12	IDACORP Inc.	3.7	5.0
13	NiSource Inc.	4.9	2.8
14	OGE Energy	4.3	4.0
15	PPL Corp.	2.7	10.3
16	Progress Energy	5.4	4.6
17	Public Serv. Enterprise	2.7	18.5
18	Southern Co.	4.6	4.6
19	TECO Energy	4.8	7.3
20	Xcel Energy Inc.	4.6	5.2

Notes:
Column 1, 2: Value Line Investment Analyzer, 10/2007
Column 3: Zacks long-term earnings growth forecast, 10/2007
No growth forecast available for CH Energy Group

Moody's Electric Utilities: DCF Analysis Analysts Growth Forecasts

	(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Company Name	Current Dividend Yield	Analysts' Growth Forecast	% Expected Divid Yield	Cost of Equity	ROE
1	Amer. Elec. Power	3.9	5.4	4.1	9.5	9.7
2	Consol. Edison	5.4	3.2	5.5	8.7	9.0
3	Constellation Energy	2.1	18.0	2.5	20.5	20.6
4	Dominion Resources	3.8	11.5	4.2	15.7	15.9
5	DPL Inc.	4.0	8.0	4.3	12.3	12.5
6	DTE Energy	5.1	6.0	5.4	11.4	11.7
7	Duke Energy	4.8	6.0	5.1	11.1	11.4
8	Energy East Corp.	5.0	3.0	5.1	8.1	8.4
9	Exelon Corp.	2.6	12.0	2.9	14.9	15.1
10	FirstEnergy Corp.	3.1	7.5	3.3	10.8	11.0
11	IDACORP Inc.	3.7	5.0	3.9	8.9	9.1
12	NiSource Inc.	4.9	2.8	5.0	7.8	8.0
13	OGE Energy	4.3	4.0	4.5	8.5	8.7
14	PPL Corp.	2.7	10.3	3.0	13.3	13.4
15	Progress Energy	5.4	4.6	5.7	10.3	10.6
16	Public Serv. Enterprise	2.7	18.5	3.2	21.7	21.8
17	Southern Co.	4.6	4.6	4.8	9.4	9.6
18	TECO Energy	4.8	7.3	5.1	12.4	12.7
19	Xcel Energy Inc.	4.6	5.2	4.8	10.0	10.3
21	**AVERAGE**	**4.1**	**7.5**	**4.3**	**11.9**	**12.1**
23	**AVERAGE without Constellation Energy and Public Service**					**11.0**

Notes:
Column 1, 2: Value Line Investment Analyzer, 02/2008
Column 3: Zacks long-term earnings growth forecast, 02/2008
Column 4 = Column 2 times (1 + Column 3/100)
Column 5 = Column 4 + Column 3
Column 6 = (Column 4 /0.95) + Column 3
No growth forecast available for CH Energy Group.