BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION	)	
OF OKLAHOMA GAS AND ELECTRIC	)	
COMPANY FOR AN ORDER OF THE	)	CAUSE NO. PUD 201800140
COMMISSION AUTHORIZING APPLICANT	)	
TO MODIFY ITS RATES, CHARGES, AND	)	
TARIFFS FOR RETAIL ELECTRIC	)	
SERVICE IN OKLAHOMA	)	

Direct Testimony

of

Roger A. Morin, PhD

on behalf of

Oklahoma Gas and Electric Company

December 31, 2018

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I. INTRODUCTION AND SUMMARY OF RECOMMENDATION

Q. **Please state your name, business 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. I am testifying on behalf of Oklahoma Gas and Electric Company.

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, The Management Exchange Inc., Exnet, Inc. I am now a faculty member of S&P Global Intelligence (formerly SNL Knowledge Center or SNL), where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last 30 years, I have conducted numerous national seminars on “Utility Finance,” “Utility Cost of Capital,” “Alternative Regulatory Frameworks,” and “Utility Capital Allocation,” which I have developed on behalf of the aforementioned institutions.

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 <u>The Journal of Finance</u>, <u>The Journal of Business</u>

Administration, International Management Review, and Public Utilities Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984. In late 1994, the same publisher released my book, Regulatory Finance, a voluminous treatise on the application of finance to regulated utilities. A revised and expanded edition of this book, The New Regulatory Finance, was published in 2006. I have been engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation.

Please see Exhibit RAM-1 for my professional qualifications.

Q. **Have you previously testified on cost of capital before utility regulatory commissions?**

A. Yes, I have been a cost of capital witness before nearly 50 regulatory bodies in North America, including the Oklahoma Corporation Commission ("OCC" or "Commission") and the Federal Energy Regulatory Commission. I have testified before the following state, provincial, and other local regulatory commissions:

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

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

Q. **What is the purpose of your testimony in this proceeding?**

A. The purpose of my testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on common equity (ROE) on the common equity capital invested in Oklahoma Gas and Electric Company's electric utility operations in the State of Oklahoma. Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would:

(1) be fair to ratepayers;

(2) allow OG&E to attract the capital needed for infrastructure and reliability investments on reasonable terms;

(3) maintain OG&E's financial integrity; and

(4) be comparable to returns offered on comparable risk investments.

Q. **Please briefly identify the exhibits and appendices accompanying your testimony.**

A. I have attached to my testimony Exhibit RAM-1 through Exhibit RAM-10, and Appendices A and B. These Exhibits and appendices relate directly to points in my testimony, and are described in further detail in connection with the discussion of those points in my testimony.

Q. **Please summarize your results and recommendations.**

A. My testimony demonstrates the following:

1) In order to arrive at my final recommended ROE, I applied several traditional financial models to a group of electric utilities comparable in risk to OG&E, including Discounted Cash Flow (DCF) analyses, Capital Asset Pricing Model (CAPM) analyses, and Risk Premium analyses. I use the average result of 9.9% obtained from these multiple analyses as my recommended ROE for OG&E.

A ROE of 9.9% for OG&E is required in order for the Company to: (i) attract capital on reasonable terms, (ii) maintain its financial integrity, and (iii) earn a return commensurate with returns on comparable risk investments.

2) I demonstrate that the Company's test year capital structure consisting of approximately 53% common equity capital is reasonable for ratemaking purposes for two reasons. First, it is consistent with the actual capital structures of the operating electric utility companies in my comparable group of electric utilities. The average common equity ratio of these companies in 2018 is 53%, the same as the Company's. Second, it is consistent with the credit agencies' financial ratio benchmarks for a single A bond rating which I consider optimal and cost efficient for ratepayers.

3) I describe the negative consequences of imputing a capital structure different from the company's actual capital structure and consisting of more debt.

4) I demonstrate the need for both the Company and its ratepayers to regain the Company's single A bond rating which is predicated in part on its robust balance sheet. A strong single A bond rating minimizes the pre-tax cost of capital to ratepayers.

5) I describe the concerns expressed by several members of the investment community regarding their perception of the regulatory climate in Oklahoma. Moody's downgrade of the Company's credit rating is noteworthy in that regard. I discuss the consequences of a downgrade of the Company's bonds, and the crucial role of my recommended ROE in avoiding such a downgrade. The consequences include a substantial increase in ratepayer burden, an increase in both the cost of debt and common equity, and a capital loss incurred by existing bondholders. I stress the importance through supportive regulation of avoiding these consequences and the need to regain the Company's solid single A bond rating which I consider cost efficient for both ratepayers and investors.

Q. **Would it be in the best interests of ratepayers for the Commission to approve a ROE of 9.9% for OG&E electric utility operations?**

A. Yes. My analysis shows that this return fairly compensates investors, maintains

OG&E's credit strength, and attracts the capital needed for utility infrastructure and reliability capital investments. Adopting a lower ROE would increase costs for ratepayers.

Q. **Please explain how low allowed ROEs can increase both the future cost of equity and debt financing.**

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

As a company relies more on debt financing, its capital structure becomes more leveraged. Because debt payments are a fixed financial obligation to the utility, and income available to common equity is subordinate to fixed charges, this decreases the operating income available for dividend and earnings growth. Consequently, equity investors face greater uncertainty about future dividends and earnings from the firm. As a result, the firm's equity becomes a riskier investment. The risk of default on a 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 a company will not have access to the capital markets for its outside financing needs. Ultimately, to ensure that OG&E has access to capital markets for its capital needs, a fair and reasonable authorized ROE of 9.9% is required.

OG&E 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. Thus, rate relief requirements and supportive regulatory treatment, including approval of my recommended ROE, are essential requirements.

II. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. Please explain how a regulated company's rates should be set under traditional cost of service regulation.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company recovers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's required 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 a 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 (i.e., investors' required rate of return) is more difficult to estimate. It is the purpose of the next section of my testimony to estimate a fair and reasonable ROE for OG&E's cost of common equity capital.

Q. **What fundamental principles underlie the determination of a fair and reasonable ROE?**

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

1. *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923); and
2. *Federal Power Commission v. Hope Natural Gas Co.*, 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.

Bluefield Water Works & Improvement Co., 262 U.S. at 692 (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*.

Hope Natural Gas Co., 320 U.S. at 603 (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. v. Barasch*, 488 U.S. 299 (1989). In the *Permian Basin Rate 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.

Permian Basin Rate Cases, 390 U.S. at 792.

Therefore, the "end result" of this Commission's decision should be to allow OG&E the opportunity to earn a return on equity that is:

(i) commensurate with returns on investments in other firms having corresponding risks;

(ii) sufficient to assure confidence in OG&E's financial integrity; and

(iii) sufficient to maintain OG&E's creditworthiness and ability to attract capital on reasonable terms.

Q. **How is the fair rate of return determined?**

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the utility. It is the composite weighted cost of the various classes of capital (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.

Although utilities like OG&E enjoy varying degrees of monopoly in the sale of public utility services, they (or their parent companies) must compete with everyone else in the free, open market for the input factors of production, whether labor, materials, machines, or capital, including the capital investments required to support the utility infrastructure. 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 (e.g., the interest on debt capital or the expected return on equity). In order to attract the necessary capital, utilities must compete with alternative uses of capital and offer a return commensurate with the associated risks.

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. The capital markets translate these differences in risk 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. **What economic and financial concepts have guided your assessment of OG&E's cost of common equity?**

A. Two fundamental economic principles underlie the appraisal of OG&E's cost of equity, one relating to the supply side of capital markets, the other to the demand side.

On the supply side, the first principle asserts that rational investors maximize the performance of their portfolios only if they expect the returns on investments of comparable risk to be the same. If not, rational investors will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract capital funds 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 equals, or exceeds, a company's cost of capital. This principle suggests that a regulatory board should set rates at a level sufficient to create equality between the return on physical asset investments and a company's cost of capital.

Q. **How does OG&E obtain its capital and how is its overall cost of capital determined?**

A. The funds employed by OG&E are obtained in two general forms, debt capital and equity capital. The cost of debt funds 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 (overall rate of return).

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.

Q. **What must be considered in estimating a fair ROE?**

A. The basic premise is that the allowable ROE should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness and 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 DCF, CAPM, or risk premium 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.

III. COST OF EQUITY CAPITAL ESTIMATES

Q. **How did you estimate a fair ROE for OG&E?**

A. To estimate a fair ROE for OG&E, I employed three methodologies:

(i) DCF methodology;

(ii) CAPM methodology; and

(iii) Risk Premium methodology.

All three methodologies are market-based methodologies designed to estimate the return required by investors on the common equity capital committed to OG&E.

Q. **Why did you use more than one approach for estimating the cost of equity?**

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

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

As I have stated, there are three broad generic methods available to measure the cost of equity: DCF, CAPM, and risk premium. All three of these methods are accepted and used by the financial community and firmly supported in the financial literature. The weight accorded to any one method may vary depending on unusual circumstances in capital market conditions.

Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the method and on the reasonableness of the proxies used to validate the theory and apply the method. Each method has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or risk premium result constitutes the perfect explanation of a stock's price or the cost of equity.

Q. **Are there any practical difficulties in applying cost of capital methodologies in environments of volatility in capital markets and economic uncertainty?**

A. Yes, there are. The traditional cost of equity estimation methodologies are difficult to implement when you are dealing with instability and volatility in the capital markets and the uncertain economy both in the U.S. and abroad. This is not only because stock prices are volatile at this time, but also because utility company historical data have become less meaningful for an industry experiencing substantial change, for example, the transition to stringent renewable standards and the need to secure vast amounts of external capital over the next decade, regardless of capital market conditions. Past earnings and dividend trends may simply not be indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including the sluggish economy, declining customer usage, restructuring, historically low interest rates and falling margins. 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 necessarily 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.

In short, given volatility in capital markets and economic uncertainties, the utilization of multiple methodologies is critical, and reliance on a single methodology is highly hazardous.

A. 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:

$$K_e = D_1/P_0 + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend at the end of the coming year

P_0 = current stock price

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

The traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return (K_e) can be viewed as the sum of an expected dividend yield (D_1/P_0) 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 8 of my reference text, *The New Regulatory Finance*. The standard DCF model requires the following main assumptions:

(i) a constant average growth trend for both dividends and earnings;

(ii) a stable dividend payout policy;

(iii) a discount rate in excess of the expected growth rate; and

(iv) a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends.

The standard DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. **How did you estimate OG&E's cost of equity with the DCF model?**

A. In estimating OG&E's cost of equity, I applied the DCF model to a group of investment-grade, dividend-paying, vertically integrated electric utilities with the majority of their revenues from regulated operations that are covered in the Value Line database.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/P_0), and the expected long-term growth (g). The expected dividend (D_1) in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

Q. **How did you estimate the dividend yield component of the DCF model?**

A. In implementing the DCF model, I have used the dividend yields reported on the Zacks Investment Research ("Zacks") web site for each company in the peer group[1]. 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. **Why did you multiply the spot dividend yield by (1 + g) rather than by (1 + 0.5g)?**

A. Some analysts multiply the spot dividend yield by one plus one half the expected growth rate (1 + 0.5g) rather than the conventional one plus the expected growth rate (1 + g). This procedure understates the return expected by the investor.

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[1] Value Line reports for each company in the peer group are available in my workpapers.

The fundamental assumption of the basic annual DCF model is that dividends are received annually at the end of each year and that the first dividend is to be received one year from now. Thus, the appropriate dividend to use in a DCF model is the full prospective dividend to be received at the end of the year. Since the appropriate dividend to use in a DCF model is the prospective dividend one year from now rather than the dividend one-half year from now, multiplying the spot dividend yield by (1 + 0.5g) understates the proper dividend yield.

Moreover, the basic annual DCF model ignores the time value of quarterly dividend payments and assumes dividends are paid once a year at the end of the year. Multiplying the spot dividend yield by (1 + g) is actually a conservative attempt to capture the reality of quarterly dividend payments. Use of this method is conservative in the sense that the annual DCF model fully ignores the more frequent compounding of quarterly dividends.

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. 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 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 and Yahoo Finance. I used Value Line's growth forecasts as well as analysts' long-term growth forecasts reported in Zacks as proxies for investors' growth expectations in applying the DCF model.

Q. **Why did you reject the use of historical growth rates in applying the DCF model to utilities?**

A. I have rejected historical growth rates as proxies for expected growth in the DCF calculation for two reasons. First, historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model, and are therefore redundant. Second, published studies in the academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations, and that investors rely on analysts' forecasts. This considerable literature is summarized in Chapter 9 of my most recent textbook, *The New Regulatory Finance*.

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

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

$$g = b \times ROE$$

where: g = expected growth rate in earnings/dividends

b = expected retention ratio

ROE = expected return on book equity

Q. **Do you have any reservations in regards to the sustainable growth method?**

A. Yes, I do. First, the sustainable method of predicting growth contains a logic trap: the method requires an estimate of expected return on book equity to be implemented. But if the expected return on book equity input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Second, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock prices and price/earnings ratios, as analysts' growth forecasts. I therefore chose not to rely on this method.

Q. **Did you consider dividend growth in applying the DCF model?**

A. No, not at this time. The reason is that as a practical matter, while there is an abundance of earnings growth forecasts, there are very few forecasts of dividend growth. Moreover, it is widely expected that some utilities will continue to lower their dividend payout ratios over the next several years in response to heightened business risk and the need to fund very large construction programs over the next decade. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks and finance large infrastructure investments. As a result, investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations. Indeed, it is growth in earnings that will support future dividends and share prices.

Q. **Is there any empirical evidence documenting the importance of earnings in evaluating investors' expectations?**

A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. First, the sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. To illustrate, Value Line, Yahoo Finance, Zacks Investment, First Call Thompson, Reuters, and Multex provide comprehensive compilations of investors' earnings forecasts. 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. **How did you approach the composition of comparable groups in order to estimate OG&E's cost of equity with the DCF method?**

A. Because OG&E is a wholly-owned subsidiary of OGE Energy Corp. and is not publicly traded, the DCF model cannot be applied to OG&E, and proxies must be used. There are two possible approaches in forming proxy groups of companies.

The first approach is to apply cost of capital estimation techniques to a select group of companies directly comparable in risk to OG&E. These companies are chosen by the application of stringent screening criteria to a universe of utility stocks in an attempt to identify companies with the same investment risk as OG&E. Examples of screening criteria include bond rating, beta risk, size, percentage of revenues from utility operations, and common equity ratio. The end result is a small sample of companies with a risk profile similar to that of OG&E, provided the screening criteria are defined and applied correctly.

The second approach is to apply cost of capital estimation techniques to a large group of utilities representative of the utility industry average and then make adjustments to account for any difference in investment risk between the company and the industry average, if any. As explained below, in view of substantial changes in circumstances in the utility industry, I have chosen the latter approach.

In the uncertain capital market and industry environment, it is important to select relatively large sample sizes representative of the utility industry as a whole, as opposed to small sample sizes consisting of a handful of companies. This is because the equity market as a whole and utility industry capital market data are volatile. As a result of this volatility, the composition of small groups of companies is very fluid, with companies exiting the sample due to dividend suspensions or reductions, insufficient or unrepresentative historical data due to recent mergers, impending merger or acquisition, and changing corporate identities due to restructuring activities.

From a statistical standpoint, confidence in the reliability of the DCF model result is considerably enhanced when applying the DCF model to a large group of companies. Any distortions introduced by measurement errors in the two DCF components of equity return for individual companies, namely dividend yield and growth are mitigated. Utilizing a large portfolio of companies reduces the influence of either overestimating or underestimating the cost of equity for any one individual company. For example, in a large group of companies, positive and negative deviations from the expected growth will tend to cancel out owing to the law of large numbers, provided that the errors are independent.[2] The average growth rate of several companies is less likely to diverge from expected growth than is the estimate of growth for a single firm. More generally, the assumptions of the DCF model are more likely to be fulfilled for a large group of companies than for any single firm or for a small group of companies.

Moreover, small samples are subject to measurement error, and in violation of the Central Limit Theorem of statistics.[3] From a statistical standpoint, reliance on robust sample sizes mitigates the impact of possible measurement errors and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due to a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring.

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2 If σ_i^2 represents the average variance of the errors in a group of N companies, and σ_{ij} the average covariance between the errors, then the variance of the error for the group of N companies, σ_N^2 is:

$$\sigma_N^2 = \frac{1}{N}\bar{\sigma}_i^2 + \frac{N-1}{N}\bar{\sigma}_{ij}$$

If the errors are independent, the covariance between them (σ_{ij}) is zero, and the variance of the error for the group is reduced to:

$$\sigma_N^2 = \frac{1}{N}\sigma_i^2$$

As N gets progressively larger, the variance gets smaller and smaller.

3 The Central Limit Theorem describes the characteristics of the distribution of values we would obtain if we were able to draw an infinite number of random samples of a given size from a given population and we calculated the mean of each sample. The Central Limit Theorem asserts: [1] The mean of the sampling distribution of means is equal to the mean of the population from which the samples were drawn. [2] The variance of the sampling distribution of means is equal to the variance of the population from which the samples were drawn divided by the size of the samples. [3] If the original population is distributed normally, the sampling distribution of means will also be normal. If the original population is not normally distributed, the sampling distribution of means will increasingly approximate a normal distribution as sample size increases.

The point of all this is that the use of a handful of companies in a highly fluid and unstable industry produces fragile and statistically unreliable results. A far safer procedure is to employ large sample sizes representative of the industry as a whole and apply subsequent risk adjustments to the extent that the company's risk profile differs from that of the industry average.

Q. **Can you describe the proxy group for OG&E's electric utility business?**

A. As proxies for OG&E, I examined a group of investment-grade dividend-paying vertically integrated electric utilities covered in Value Line's Electric Utility industry group, meaning that these companies all possess utility assets similar to OG&E's. I began with all the parent companies of those electric utility operating companies designated as vertically integrated electric utilities by Moody's[4] that are also covered in the Value Line Survey. These companies are shown on Page 1 of Exhibit RAM-2. Page 2 of Exhibit RAM-2 shows the relative importance of electric and gas utility operations for each company. Given that OG&E has no reveniues from natural gas operations, companies with natural gas operations were eliminated as well as companies below investment-grade. Westar and Great Plains Energy were eliminated following their merger to form Evergy Corp. SCANA was eliminated on account of its purchase by Southern Company. PG&E was eliminated since it has suspended dividends. DP&L is not investment-grade and was thus removed from the sample. Empire District was acquitted by Liberty Utilities, a private company. Entergy was remove on account of its nuclear exposure and corporate reorganization. Finally, AES was removed, given its international exposure in several countries and generation intensity. The remaining companies are shown on Page 3 of Exhibit RAM-2.

The final group of seventeen companies that comprises the OG&E proxy group is shown on Exhibit RAM-3. I stress that this proxy group must be viewed

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[4] Moody's Investor Service: "2017 Outlook – Timely Cost-Recovery Drives Stable Outlook," November 4th, 2016.

as a portfolio of comparable risk. It would be inappropriate to select any particular company or subset of companies from this group and infer the cost of common equity from that company or subset alone.

Q. **What DCF results did you obtain for OG&E using Value Line growth projections?**

A. Exhibit RAM-4 displays the DCF analysis using Value Line growth projections for the nineteen companies in OG&E's proxy group. Please note that the growth forecasts for Evergy was drawn from the Zacks since the Value Line growth forecast was not available for that company. Value Line's dividend growth forecast was used for Emera, and the latter's dividend yield was obtained from Value Line.

As shown on column 3, line 19 of Exhibit RAM-4, the average long-term earnings per share growth forecast obtained from Value Line is 5.34% for OG&E's proxy group. Combining this growth rate with the average expected dividend yield of 3.62% shown on column 4, line 19 of Exhibit RAM-4 produces an estimate of equity costs of 8.96% for OG&E's proxy group, as shown on column 5, line 19 of Exhibit RAM-4. Recognition of flotation costs brings the cost of equity estimate to 9.15% for the group, shown in Column 6. The need for a flotation cost allowance is discussed at length later in my testimony. Please note that IDACORP's cost of equity estimate is only 5.59% and barely exceeds its cost of debt. If we remove this estimate from computation of the average, the cost of equity estimate for the group becomes 9.4%.

Q. **What DCF results did you obtain for OG&E using analysts' consensus growth forecasts?**

A. Exhibit RAM-5 displays the DCF analysis using analysts' consensus growth forecasts for the nineteen companies in OG&E's proxy group. Please note that the growth forecasts for Emera, Otter Tail, and Hawaiian Electric were drawn from Yahoo Finance as the Zacks growth forecast were not available for these three companies.

As shown on column 3, line 19 of Exhibit RAM-5, the average long-term earnings per share growth forecast obtained from analysts is 5.65% for OG&E's proxy group. Combining this growth rate with the average expected dividend yield of 3.65% shown on column 4, line 19, produces an estimate of equity costs of 9.30% for OG&E's proxy group unadjusted for flotation cost, as shown on column 5, line 19, of Exhibit RAM-5. Recognition of flotation costs brings the cost of equity estimate to 9.49%, shown in Column 6, line 21. If we remove the IDACORP estimate for reasons discussed earlier, the average becomes 9.8%.

Q. **Please summarize the DCF estimates for OG&E.**

A. Table 1 below summarizes the DCF estimates for OG&E:

Table 1. DCF Estimates for OG&E

DCF STUDY	ROE
Electric Utilities Value Line Growth	9.4%
Electric Utilities Analysts Growth	9.8%

B. CAPM Estimates

Q. **Please describe your application of the CAPM risk premium approach.**

A. My first two risk premium estimates are based on the CAPM and on an empirical approximation to the CAPM (ECAPM). The CAPM is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta (β). 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:

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

where: K = investors' expected return on equity

R_F = risk-free rate

R_M = return on the market as a whole

β = systematic risk (i.e., change in a security's return relative to that of the market)

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium determined by $\beta \times (R_M - R_F)$. The bracketed expression $(R_M - R_F)$ expression is known as the market risk premium (MRP). To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the MRP, $(R_M - R_F)$.

For the risk-free rate (R_F), I used 4.3%, based on forecast interest rates on long-term U.S. Treasury bonds.

For beta (β), I used 0.66 based on Value Line estimates.

For the MRP ($(R_M - R_F)$), I used 7.0% based on historical market risk premium studies.

These inputs to the CAPM are explained below.

Q. **How did you arrive at your risk-free rate estimate of 4.3% in your CAPM analyses?**

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. I relied on noted economic forecasts which call for a rising trend in interest rates in response to the recovering economy, renewed inflation, and record high federal deficits. Value Line, Global Insight, the Congressional Budget Office, the Bureau of Labor Statistics, the Economic Report of the President, and the U.S. Energy Information Administration all project higher long-term Treasury bond rates in the future.

Q. **Why did you rely on long-term bonds instead of short-term bonds?**

A. 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 Treasury bills 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.

While long-term Treasury bonds are potentially subject to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (e.g., pension funds and 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 yields on 30-year Treasury bonds will more closely incorporate within their yields the inflation expectations that influence the prices of common stocks than do short-term Treasury bills or intermediate-term U.S. Treasury notes.

Among U.S. Treasury securities, 30-year Treasury bonds have the longest term to maturity and the yields on such securities should be used as proxies for the risk-free rate in applying the CAPM. Therefore, I have relied on the yield on 30-year Treasury bonds in implementing the CAPM and risk premium methods.

Q. **Are there other reasons why you reject short-term interest rates as proxies for the risk-free rate in implementing the CAPM?**

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

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

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

Q. **What is your estimate of the risk-free rate in applying the CAPM?**

A. All the noted interest rate forecasts that I am aware of point to significantly higher interest rates over the next several years. The table below reports the forecast yields on 30-year US Treasury bonds from several prominent sources, including the Congressional Budget Office, Bureau of Labor Statistics, U.S. Energy Information Administration, HIS (formerly Global Insight), Value Line, and the Economic Report of the President.

The average 30-year long-term bond yield forecast from the seven sources is 4.3%, and the individual forecasts are quite consistent as they are closely clustered around the average. Based on this evidence, a long-term bond yield forecast of 4.3% is a reasonable estimate of the expected risk-free rate for purposes of forward-looking CAPM/ECAPM and Risk Premium analyses in the current economic environment.

Table 2 Forecast Yields on
30-year U.S. Treasury Bonds

Value Line Economic Forecast	3.80
U.S. Energy Information Administration	4.57
Bureau of Labor Statistics	5.68
Congressional Budget Office	4.20
Economic Report of the President	4.20
White House Budget 2018	4.10
IHS (Global Insight)	3.76
AVERAGE	**4.33**

Q. **Dr. Morin, why did you ignore the current level of interest rates in developing your proxy for the risk-free rate in a CAPManalysis?**

A. I relied on projected long-term Treasury interest rates for three reasons. First, investors price securities on the basis of long-term expectations, including interest rates. Cost of capital models, including both the CAPM and DCF models, are prospective (i.e., forward-looking) in nature and must take into account current market expectations for the future because investors price securities on the basis of long-term expectations, including interest rates. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflects the expectations of actual investors in the market. While investors examine history as a guide to the future, it is the expectations of future events that influence security values and the cost of capital.

Second, investors' required returns can and do shift over time with changes in capital market conditions, hence the importance of considering interest rate forecasts. The fact that organizations such as Value Line, IHS (Global Insight), EIA, and CBO among many others devote considerable expertise and resources to developing an informed view of the future, and the fact that investors are willing to purchase such expensive services confirm the importance of economic/financial forecasts in the minds of investors. Moreover, the empirical evidence demonstrates that stock prices do indeed reflect prospective financial input data.

Third, given that this proceeding is to provide ROE estimates for future proceedings, forecast interest rates are far more relevant. The use of interest rate forecasts is no different than the use of projections of other financial variables in DCF analyses.

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" (β), 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. It indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation that are reflected in investors' return requirements.

OG&E is not publicly traded, and therefore, proxies must be used. In the discussion of DCF estimates of the cost of common equity earlier, I examined a sample of investment-grade dividend-paying vertically integrated electric utilities covered by Value Line that have at least 50% of their revenues from regulated electric utility operations. The average beta for this group is 0.66. Please see Exhibit RAM-6 for the beta estimates of the proxy group for OG&E. Based on these results, I shall use 0.66, as an estimate for the beta applicable to OG&E. I note that OG&E has the highest beta risk measure in the group.

Q. **What MRP did you use in your CAPM analysis?**

A. For the MRP, I used 7.0%. This estimate was based on the results of historical studies of long-term market risk premiums and on one additional check.

Q. **Can you describe the historical MRP study used in your CAPM analysis?**

A. Yes. The historical MRP estimate is based on the results obtained in Duff & Phelps' 2017 Valuation Handbook (formerly published by Morningstar and earlier by Ibbotson Associates), which compiles historical returns from 1926 to 2016. This well-known study shows that a very broad market sample of common stocks outperformed long-term U.S. Government bonds by 6.0%. The historical MRP over the income component of long-term Government bonds rather than over the total return is 7.0%. 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 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), because both realized capital gains and realized losses are largely unanticipated by bond investors. The long-horizon (1926-2015) MRP (based on income returns, as required) is 7.0%.

As a check on my 7.0% MRP estimate, I examined the historical return on common stocks in real terms (inflation-adjusted) over the 1926-2016 period and added current inflation expectations to arrive at a current inflation-adjusted common stock return. According to the Duff & Phelps study, the average historical return on common stocks averaged 12.0% over the 1926-2016 period while inflation averaged 3.0% over the same period, implying a real return of 9.0% (12.0% - 3.0% = 9.0%). With current long-term inflation expectations of 2.0%[5], the inflation-adjusted return on common stock becomes 11.0% (9.0% + 2.0% = 11.0%). Given the current yield on 30-year U.S. Treasury bonds of 2.8%, the implied MRP is therefore 8.0% (11.0% - 2.8% = 8.2%). Using the forecast yield of 4.4%, the implied MRP is 6.6% (11.0% - 4.4% = 6.6%). The average of the two estimates is 7.4% which is makes my 7.0% estimate conservative.

Q. **On what maturity bond does the Duff & Phelps historical risk premium data rely?**

A. Because 30-year bonds were not always traded or even available throughout the entire 1926-2016 period covered in the Duff & Phelps study of historical returns, the latter study relied on bond return data based on 20-year Treasury bonds. Given that the normal yield curve is virtually flat above maturities of 20 years over most of the period covered in the Duff & Phelps study, the difference in yield is not material.

Q. **Why did you use long time periods in arriving at your historical MRP estimate?**

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

[5] 30-year U.S. Treasury bonds are currently trading at a 2.8% yield while 30-year inflation-adjusted bonds are trading at a yield of 0.8% implying a long-term inflation rate expectation of 2.0%.

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. 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, one should expect the equity risk premium to remain at its historical mean. Since I found no evidence that the MRP in common stocks has changed over time, at least prior to the onslaught of the financial crisis of 2008-2009 which has now partially subsided, that is, no significant serial correlation in the Duff & Phelps study prior to that time, it is reasonable to assume that these quantities will remain stable in the future.

Q. **Should studies of historical risk premiums rely on arithmetic average returns or geometric average returns?**

A. Whenever relying on historical risk premiums, only arithmetic average returns over long periods are appropriate for forecasting and estimating the cost of capital, and geometric average returns are not.[6]

Q. **Please explain how the issue of what is the proper "mean" arises in the context of analyzing the cost of equity?**

A. The issue arises in applying methods that derive estimates of a utility's cost of

[6] See Roger A. Morin, Regulatory Finance: Utilities' Cost of Capital, Chapter 11 (1994); Roger A. Morin, The New Regulatory Finance: Utilities' Cost of Capital, Chapter 4 (2006); Richard A Brealey, et al., Principles of Corporate Finance (8th ed. 2006).

equity from historical relationships between bond yields and earned returns on equity for individual companies or portfolios of several companies. Those methods produce series of numbers representing the annual difference between bond yields and stock returns over long historical periods. The question is how to translate those series into a single number that can be added to a current bond yield to estimate the current cost of equity for a stock or a portfolio. Calculating geometric and arithmetic means are two ways of converting series of numbers to a single, representative figure.

Q. **If both are "representative" of the series, what is the difference between the two means?**

A. Each mean represents different information about the series. The geometric mean of a series of numbers is the value which, if compounded over the period examined, would have made the starting value to grow to the ending value. The arithmetic mean is simply the average of the numbers in the series. Where there is any annual variation (volatility) in a series of numbers, the arithmetic mean of the series, which reflects volatility, will always exceed the geometric mean, which ignores volatility. Because investors require higher expected returns to invest in a company whose earnings are volatile than one whose earnings are stable, the geometric mean is not useful in estimating the expected rate of return which investors require to make an investment.

Q. **Can you provide a numerical example to illustrate this difference between geometric and arithmetic means?**

A. Yes. Table 3 below compares the geometric and arithmetic mean returns of a hypothetical Stock A, whose yearly returns over a ten-year period are very volatile, with those of a hypothetical Stock B, whose yearly returns are perfectly stable during that period. Consistent with the point that geometric returns ignore volatility, the geometric mean returns for the two series are identical (11.6% in both cases), whereas the arithmetic mean return of the volatile stock (26.7%) is much higher than the arithmetic mean return of the stable stock (11.6%).

If relying on geometric means, investors would require the same expected return to invest in both of these stocks, even though the volatility of returns in Stock A is very high while Stock B exhibits perfectly stable returns. That is clearly contrary to the most basic financial theory, that is, the higher the risk the higher the expected return.

Chapter 4 Appendix A of my book The New Regulatory Finance contains a detailed and rigorous discussion of the impropriety of using geometric averages in estimating the cost of capital. Briefly, the disparity between the arithmetic average return and the geometric average return raises the question as to what purposes should these different return measures be used. The answer is that the geometric average return should be used for measuring historical returns that are compounded over multiple time periods. The arithmetic average return should be used for future-oriented analysis, where the use of expected values is appropriate. It is inappropriate to average the arithmetic and geometric average return; they measure different quantities in different ways.

Q. **Is your MRP estimate of 7.0% consistent with the academic literature on the subject?**

A. Yes, it is, although in the upper portion of the range. In their authoritative corporate finance textbook, Professors Brealey, Myers, and Allen[7] conclude from their review of the fertile literature on the MRP that a range of 5% to 8% is reasonable for the MRP in the United States. My own survey of the MRP literature, which appears in Chapter 5 of my latest textbook, The New Regulatory Finance, is also quite consistent with this range.

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7 Richard A. Brealey, Stewart C. Myers, and Paul Allen, Principles of Corporate Finance, 8th Edition, Irwin McGraw-Hill, 2006.

Table 3. Arithmetic vs Geometric Mean Returns

Year	*Stock A*	*Stock B*
2008	50.0%	11.6%
2009	-54.7%	11.6%
2010	98.5%	11.6%
2011	42.2%	11.6%
2012	-32.3%	11.6%
2013	-39.2%	11.6%
2014	153.2%	11.6%
2015	-10.0%	11.6%
2016	38.9%	11.6%
2017	20.0%	11.6%
Std. Deviation	64.9%	0.0%
Arith Mean	26.7%	11.6%
Geom Mean	11.6%	11.6%

Q. **What is your estimate of OG&E's cost of equity using the CAPM approach?**

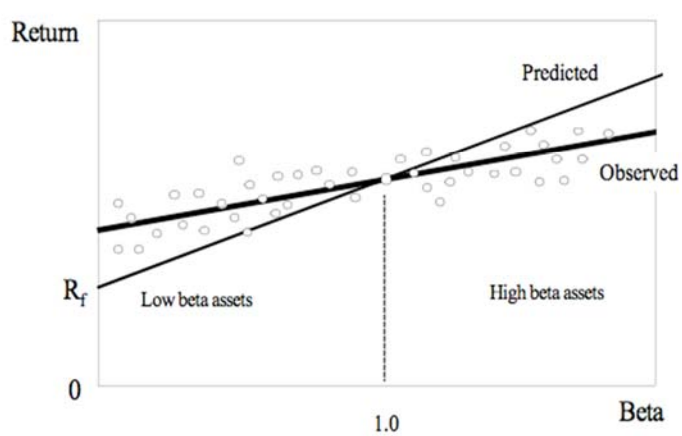
A. Inserting those input values into the CAPM equation, namely a risk-free rate of 4.3%, a beta of 0.66, and a MRP of 7.0%, the CAPM estimate of the cost of common equity is: 4.3% + 0.66 x 7.0% = 8.92%. This estimate becomes 9.12% with flotation costs, discussed later in my testimony.

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

A. There have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 6 of my latest book, <u>The New Regulatory Finance</u>. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.

A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. This is one of the most well-known results in finance, and it is displayed graphically below.

CAPM: Predicted vs Observed Returns



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

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

where the symbol alpha, α, represents the "constant" of the risk-return line, MRP is the market risk premium ($R_M - R_F$), and the other symbols are defined as usual.

Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following more tractable ECAPM expression:

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

An alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. In other words, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version 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.[8] Thus, it is reasonable to apply a conservative alpha adjustment.

Please see Appendix A for a 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:

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

Inserting the risk-free rate (R_F) of 4.3%, a MRP (($R_M - R_F$)) of 7.0% for ($R_M - R_F$) and a beta of 0.66 in the above equation, the return on common equity is 9.52%. This estimate becomes 9.72% with flotation costs, discussed later in my testimony.

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

$$\beta_{adjusted} = 0.33 + 0.66\,\beta_{raw}$$

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

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease in beta. 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 comprise two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to the previous graph, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

Q. **Please summarize your CAPM estimates.**

A. Table 4 below summarizes the common equity estimates obtained from the CAPM studies.

Table 4. CAPM Results

CAPM Method	**ROE**
Traditional CAPM	9.1%
Empirical CAPM	9.7%

C. Historical Risk Premium Estimates

Q. Please describe your historical risk premium analysis of the electric utility industry using treasury bond yields.

A. A historical risk premium for the utility industry was estimated with an annual time series analysis applied to the utility industry as a whole over the 1930-2016 period, using Standard and Poor's Utility Index (S&P Utility Index) as an industry proxy. The risk premium was estimated by computing the actual realized return on equity capital for the S&P Utility Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term Treasury bond return for that year. Please see Exhibit RAM-7 for this analysis

As shown on Exhibit RAM-7, the average risk premium over the period was 5.6% over long-term Treasury bond yields and 6.2% over the income component of bond yields. As discussed previously, the latter is the appropriate risk premium to use. Given the risk-free rate of 4.3%, and using the historical estimate of 6.2% for bond returns, the implied cost of equity is

4.3% + 6.2% = 10.5% without flotation costs and 10.7% with the flotation cost allowance.

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 be reluctant to invest money.

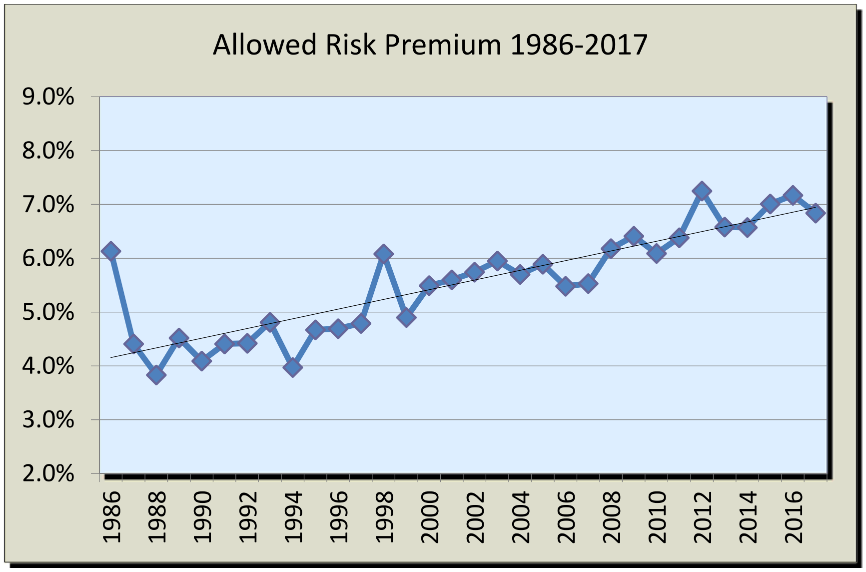
D. <u>Allowed Risk Premium Estimates</u>

Q. **Please describe your analysis of allowed risk premiums in the electric utility industry.**

A. To estimate the electric utility industry'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 1986-2017 period for which data were available, relative to the contemporaneous level of the long-term Treasury bond yield. Please see Exhibit RAM-8 for this analysis.

This variation of the risk premium approach is reasonable because allowed risk premiums are presumably based on the results of market-based methodologies (DCF, CAPM, Risk Premium, *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 (now S&P Global Intelligence) and easily verifiable from prior issues of that same publication and past commission decision archives.

The average ROE spread over long-term Treasury yields was 5.55% over the entire 1986-2017 period for which data were available from SNL. The graph below shows the year-by-year allowed risk premium. The escalating trend of the risk premium in response to lower interest rates and rising competition is noteworthy.

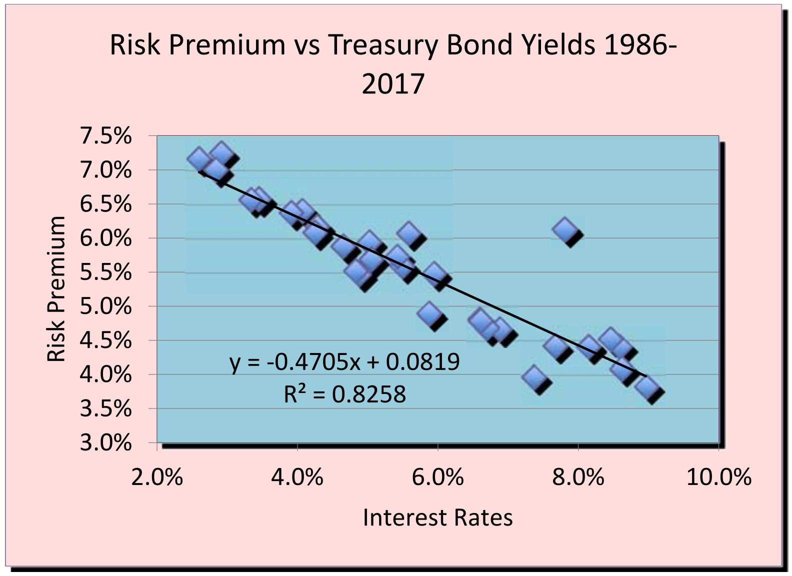


A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the 1986-2016 period:

$$RP = 8.1900 - 0.4705 \text{ YIELD} \qquad R^2 = 0.83$$

The relationship is highly statistically significant[9] as indicated by the very high R^2. The graph below shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.

[9] The coefficient of determination R^2, sometimes called the "goodness of fit measure," is a measure of the degree of explanatory power of a statistical relationship. It is simply the ratio of the explained portion to the total sum of squares. The higher R^2 the higher is the degree of the overall fit of the estimated regression equation to the sample data.



Inserting the long-term Treasury bond yield of 4.30% in the above equation suggests a risk premium estimate of 6.17%, implying a cost of equity of 10.47%. The latter result is reasonably close to the result of the historical risk premium study.

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

A. Yes, they do. Investors do indeed 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 SNL (formerly Regulatory Research Associates). Allowed returns, while certainly not a precise indication of a particular company's cost of equity capital, are nevertheless important determinants of investor growth perceptions and investor expected returns.

Q. **Please summarize your risk premium estimates.**

A. Table 5 below summarizes the ROE estimates obtained from the two risk premium studies.

Table 5. Risk Premium Estimates

Risk Premium Method	ROE
Historical Risk Premium Electric	10.7%
Allowed Risk Premium	10.5%

E. <u>Need for Flotation Cost Adjustment</u>

Q. **Please 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 issuing common equity capital is not free. Flotation costs associated with stock issues are similar to 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 (e.g., printing, legal, prospectus). 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 costs 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 10.53%.

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 20 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 4.0% for utility stocks by 0.95 yields 4.2%, which is 20 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, as the argument goes, 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.

In theory, flotation costs could be expensed and recovered through rates as they are incurred. This procedure, although simple in implementation, is not considered appropriate, however, because the equity capital raised in a given stock issue remains on the utility's common equity account and continues to provide benefits to ratepayers indefinitely. It would be unfair to burden the current generation of ratepayers with the full costs of raising capital when the benefits of that capital extend indefinitely. The common practice of capitalizing rather than expensing eliminates the intergenerational transfers that would prevail if today's ratepayers were asked to bear the full burden of flotation costs of bond/stock issues in order to finance capital projects designed to serve future as well as current generations. Moreover, expensing flotation costs requires an estimate of the market pressure effect for each individual issue, which is likely to prove unreliable. A more reliable approach is to estimate market pressure for a large sample of stock offerings rather than for one individual issue.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plans, employees' savings plans, 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 with and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. **Dr. Morin, can you please elaborate on the market pressure component of flotation cost?**

A. The indirect component, or market pressure component of flotation costs represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue, reflecting the basic economic fact that when the supply of securities is increased following a stock or bond issue, the price falls. The market pressure effect is real, tangible, measurable, and negative. According to the empirical finance literature cited in Appendix B, the market pressure component of the flotation cost adjustment is approximately 1% of the gross proceeds of an issuance. The announcement of the sale of large blocks of stock produces a decline in a company's stock price, as one would expect given the increased supply of common stock.

Q. **Is a flotation cost adjustment required for an operating subsidiary like OG&E that does not trade publicly?**

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

IV. CONCLUSION

Q. **Please summarize your results and recommendation.**

A. To arrive at my final recommendation, I performed

(i) a DCF analysis on a group of investment-grade dividend-paying vertically integrated electric utilities using Value Line's growth forecasts;

(ii) a DCF analysis on a group of investment-grade dividend-paying vertically integrated electric utilities using analysts' growth forecasts;

(iii) a traditional CAPM using current market data;

(iv) an empirical approximation of the CAPM using current market data;

(v) historical risk premium data from electric utility industry aggregate data, using the yield on long-term US Treasury bonds; and

(vi) allowed risk premium data from electric utility industry aggregate data, using the current yield on long-term US Treasury bonds.

Table 6 below summarizes the ROE estimates for OG&E.

Table 6. Summary of ROE Estimates

STUDY	ROE
Integrated Utilities Value Line Growth	9.4%
Integrated Utilities Analysts Growth	9.8%
CAPM	9.1%
Empirical CAPM	9.7%
Historical Risk Premium Electric	10.7%
Allowed Risk Premium	10.5%

The average result is 9.9%. The results range from 9.1% to 10.7%, with a midpoint of 9.9%. Based on all those results, I use 9.9% as my recommended ROE for OG&E.

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 Table 6 above must be viewed as a whole rather than each as a stand-alone. It would be inappropriate to select any particular number from Table 6 and infer the cost of common equity from that number alone.

Q. **Dr. Morin, what is your final conclusion regarding OG&E's return on common equity capital?**

A. Based on the results of all my analyses, the application of my professional judgment, and the risk circumstances of OG&E, it is my opinion that a just and reasonable ROE for OG&E's electric utility operations in the State Oklahoma is 9.9%.

V. CAPITAL STRUCTURE

Q. **Dr. Morin, what capital structure assumption underlies your recommended return on OG&E's common equity capital?**

A. My recommended return on common equity for OG&E is predicated on the adoption of a test year capital structure consisting of approximately 53% common equity capital, which is the Company's actual capital structure.

Q. **Is the Company's actual capital structure reasonable for ratemaking purposes?**

A. Yes, it is for several reasons. First, I have examined the actual capital structures of the operating utility companies in my comparable group of electric utilities. Direct Exhibit RAM-9 displays the common equity ratios for the operating electric utilities in my peer group of companies as reported in SNL Financial in 2018. The average common equity ratio reported for 2018 is 54%, slightly higher than the Company's.

Second, I have examined the credit agencies' financial ratio benchmarks for various bond rating categories for utilities. Moody's publishes a matrix of financial ratios that correspond to their respective assessment of the investment risk of utility companies and related bond rating.

Table 7 below reproduces Moody's range for a utility company's debt ratio and related bond rating, one of its four primary financial ratios that it uses as guidance in its credit review for utility companies[10]. For a single A bond rating, which was OG&E's bond rating, prior to the downgrade, and which I consider optimal and cost efficient for ratepayers, the debt ratio range is 35%-45%, implying a common equity ratio range of 55% - 65%. Even for a Baa bond rating, the corresponding debt ratio range is 45% - 55%, implying a common equity range of 45% - 55%, consistent with OG&E's 53% ratio.

Table 7 Moody's Debt Ratio Benchmark

Bond Rating	Debt/capital %
Aaa	<25
Aa	25-35
A	**35-45**
Baa	**45-55**
Ba	55-65
B	>65

It is clear from these multiple perspectives that OG&E's 53% common equity ratio is appropriate. I show below why it is essential for both the Company and its ratepayers to retain the Company's single A bond rating which is predicated

10 Moody's Investors Service, "Electric & Gas Utilities: Assessing Their Credit Quality and Outlook", Jan. 2013.

in part on its robust balance sheet. The Commission's regulatory support is required in order to maintain a financially healthy OG&E, including retaining its existing bond rating which I show to be optimal below. Given that ROE exerts a direct impact on the determinants of a credit rating, approval of my recommended ROE certainly increases the probability that OG&E will retain its single A bond rating which is cost efficient for ratepayers as discussed below.

Q. **What would be the consequences of imputing a capital structure different from the company's actual capital structure and consisting of more debt?**

A. The first consequence is that the Commission would endanger the retention of the Company's single A bond rating and increase the probability of a downgrade. A higher cost of capital is likely to follow suit as I show below. Secondly, if the Commission imputes a capital structure consisting of more debt than the Company's test year capital structure, the higher common equity cost rate related to a changed common equity ratio should be reflected in the approach. It is a fundamental tenet of finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing. In other words, the greater the debt ratio, the greater is the return required by equity investors. The cost of equity must be adjusted to reflect the additional risk associated with the more debt-heavy capital structure.

Several researchers have studied the empirical relationship between the cost of capital, capital-structure changes, and the value of the firm's securities.[11] The empirical studies suggest an average increase of 76 basis points, or 7.6 basis points per one percentage point increase in the debt ratio. The theoretical studies suggest an average increase of 138 basis points, or 13.8 basis points per one percentage point increase in the debt ratio. In other words, equity return requirements increase between 7.6 and 13.8 basis points with a midpoint of approximately 10 basis points

[11] *See* Roger A. Morin, *The New Regulatory Finance* (2006) Chapter 16 section 16-4 for a summary of the literature on the relationship between cost of capital and leverage for public utilities.

for each one percentage point increase in the debt ratio, and more recent studies indicate that the upper end of that range is more indicative of the repercussions on required equity returns.

As discussed above, for every 1% downward change in the common equity ratio, the required ROE adjustment increases by 10 basis points. For example, taking the 10 basis points benchmark, to go from 50% to 45% common equity, the increase in ROE would be 50 basis points, that is, (50-45) = 5, and 5 x 10 = 50 basis points. The simple fact of the matter is that lower common equity ratios imply greater risk and higher capital cost.

VI. OPTIMAL BOND RATING AND CAPITAL STRUCTURE

Q. **Dr. Morin, what is the optimal bond rating for a regulated electric utility?**

A. A single A bond rating generally results in the lowest pre-tax cost of capital for electric utilities, and therefore the lowest ratepayer burden, especially under adverse economic conditions, which are far more relevant to the question of capital structure. This result prevails over a wide range of cost of common equity models and estimates utilized, and remains robust to changes in key assumptions.

As I showed in the optimal capital structure simulation model developed in Chapter 19 of my book The New Regulatory Finance, a strong single A bond rating will minimize the pre-tax cost of capital to ratepayers. Long-term achievement/retention of a single A bond rating is in both the electric utility company's and ratepayers' best interests. If the company maintains its debt ratio within the optimal range discussed earlier for an A-rated company, its overall cost of capital should be minimized. If the company reduces its debt ratio below that point, it would be giving up the tax benefits associated with debt but would not reap the benefits from a lower cost of debt and equity. If the company operates at a debt ratio beyond that point, the cost of debt and equity will rise, and therefore so will the cost of service.

Q. **Dr. Morin, can you provide a simple numerical example showing what happens to ratepayers when a company's bonds are downgraded from single A to BBB.**

A. The following example shows that the ratepayer burden and the cost of capital would increase significantly. Let's say the Company issues a 20-year $100 million bond. The difference in cost between being a single A-rated company and being a BBB-rated company is approximately 50 basis points (0.50%) based on historical spreads between A and BBB bonds, that is, the cost of debt increases by 50 basis points. So, every year for 20 years, the additional cost to ratepayers is $500,000 (0.50% times $100). Over the entire 20-year period the total additional cost to ratepayers is therefore $10 million (20 times $500,000). This example is conservative, for it does not even consider the increase in common equity capital costs.

In short, for every $100 millions of bonds issued by the company, the cost to ratepayers of being a BBB company instead of being a single A company is $10 million.

Q. **Besides the increase costs to ratepayers, are there other consequences if the Company's bonds were further downgraded?**

A. Yes, there are. Besides the aforementioned substantial increase in ratepayer burden, existing bondholders would incur a capital loss with the attendant rise in the cost of debt, and the cost of common equity capital would rise as well. Thus, it is imperative that the Commission remains supportive in order to maintain the Company's single A rating and avoid the aforementioned consequences. Approval of my recommended ROE would certainly substantially increase the probability of maintaining the Company's financial integrity and its existing optimal bond rating.

Q. **Does the financial community's reaction to the regulatory climate have an impact on the Company's credit rating?**

A. Yes, it does. The investment community closely monitors the Commission's decisions and interprets the effects those decisions will have on the Company.

Changes to the Company's credit rating can directly affect the Company's cost of capital for the reasons I have previously described.

Q. **Can you provide examples of how the investment community has monitored and interpreted recent Commission actions with respect to OG&E?**

A. Yes, I can. The following are recent statements and actions published by members of the investment community with regards with Oklahoma regulation.

On August 1st 2018 Fitch downgraded OG&E to A- and stated:

"*Fitch believes that the regulatory environment in Oklahoma has become challenging underscored by the unfavorable rate case outcomes in 2017 and 2018 and the uncertain treatment of environmental compliance investment resulting in higher operating risks and weaker financial metrics…..*"

Fitch continues:

"Following the unfavorable 2017 rate case order the 2018 rate case order continues to be below Fitch's expectations…… The order specified the return on equity to be 9.5%... The ROE is lower than the three-year industry average of 9.7%....."

On July 11th 2018, Moody's placed OG&E's bonds on Negative Outlook following the previous downgrade to A2. Moody's stated the following:

With nearly 80% of OG&E's rate regulated operations in Oklahoma, the degree of support received from the Oklahoma Corporation Commission (OCC) is a key credit driver. We view OG&E's regulatory relationships in the state as generally constructive; however, following OG&E's March 2017 rate order, we took a more negative view of the timeliness of cost recovery for the utility

These and similar comments, from the investment community reflect circumspection in response to the recent Oklahoma regulatory decisions and anticipation that a decision in this cause can relieve apprehension over the Company's risk profile and financial metrics. The Commission could address these concerns by a credit supportive decision in this case which includes authorizing a ROE equal to my recommendation. I reiterate the importance through supportive regulation of reinstating and solidifying the Company's single A bond rating which

I consider cost efficient for both ratepayers and investors.

Q. **Were Direct Exhibits RAM-1 through RAM-10 and Appendices A and B prepared by you and/or under your direction and control?**

A. Yes, they were.

Q. **Does this conclude your pre-filed direct testimony?**

A. Yes.

RESUME OF ROGER A. MORIN

(Fall 2018)

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(404) 229-2857 cellular
(902) 823-0000 summer office

E-MAIL ADDRESS: profmorin@mac.com

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University Plaza
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RANK: Emeritus Professor of Finance

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

EDUCATIONAL HISTORY

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

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

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

EMPLOYMENT HISTORY

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

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

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

- Professor of Finance, Georgia State University, 1979-2012
- Emeritus Professor of Finance, Georgia State University 2012-present

- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, Robinson College of Business, Georgia State University, 1985-2009

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

- Emeritus Professor of Finance, Georgia State University, 2007-18

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.

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

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

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

- Member Board of Directors, Executive Visions Inc., 1985-2016

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

- Member Board of Directors, Hotel Equities Inc., 2009-2018

PROFESSIONAL CLIENTS

AGL Resources
AT & T Communications
Alagasco - Energen
Alaska Anchorage Municipal Light & Power
Alberta Power Ltd.
Allete
Alliant Energy
AmerenUE
American Water
Ameritech
Arkansas Western Gas
ATC Transmission
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
California Pacific
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.
CH Energy
Chattanooga Gas Company
Cincinnatti Gas & Electric
Cinergy Corp.
Citizens Utilities
City Gas of Florida
CN-CP Telecommunications
Commonwealth Telephone Co.
Columbia Gas System
Consolidated Edison
Consolidated Natural Gas
Constellation Energy
Delmarva Power & Light Co
Deerpath Group
Detroit Edison Company
Dayton Power & Light Co.
DPL Energy
Duke Energy Indiana
Duke Energy Kentucky
Duke Energy Ohio
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.
Federal Energy Regulatory Commission
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
Interstate Power & Light
Illinois Commerce Commission
Island Telephone
ITC Holdings
Jersey Central Power & Light
Kansas Power & Light
KeySpan Energy
Maine Public Service
Manitoba Hydro
Maritime Telephone
Maui Electric Co.
Metropolitan Edison Co.
Minister of Natural Resources Province of Quebec
Minnesota Power & Light
Mississippi Power Company
Missouri Gas Energy
Mountain Bell
National Grid PLC
Nevada Power Company
New Brunswick Power
Newfoundland Power Inc. - Fortis Inc.
New Market Hydro
New Tel Enterprises Ltd.

New York Telephone Co.
NextEra Energy
Niagara Mohawk Power Corp
Norfolk-Southern
Northeast Utilities
Northern Telephone Ltd.
Northwestern Bell
Northwestern Utilities Ltd.
Nova Scotia Power
Nova Scotia Utility and Review Board
NUI Corp.
NV Energy
NYNEX
Oklahoma Gas & Electric
Ontario Telephone Service Commission
Orange & Rockland
PNM Resources
PPL Corp
Pacific Northwest Bell
People's Gas System Inc.
People's Natural Gas
Pennsylvania Electric Co.
Pepco Holdings
Potomac Electric Power Co.
Price Waterhouse
PSI Energy
Public Service Electric & Gas
Public Service of New Hampshire
Public Service of New Mexico
Puget Sound Energy
Quebec Telephone
Regie de l'Energie du Quebec
Rockland Electric
Rochester Telephone
SNL Center for Financial Execution
San Diego Gas & Electric
SaskPower
Sempra
Sierra Pacific Power Company
Source Gas
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.
Wisconsin Power & Light

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73

- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75

- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78

- Investment Dealers Association of Canada, 1977-78

- Financial Research Foundation, bi-annual seminar, 1975-79

- Advanced Management Research (AMR), faculty member, 1977-80

- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar

- The Management Exchange Inc., faculty member 1981-2008:

  National Seminars: *Risk and Return on Capital Projects*
  Cost of Capital for Regulated Utilities
  Capital Allocation for Utilities
  Alternative Regulatory Frameworks
  Utility Directors' Workshop
  Shareholder Value Creation for Utilities
  Fundamentals of Utility Finance
  Contemporary Issues in Utility Finance

- SNL Center for Financial Education faculty member 2008-2018

- S&P Global Intelligence, faculty member 2015 -2018
  National Seminars: *Essentials of Utility Finance*

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

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Corporate Finance
Rate of Return
Capital Structure
Generic Cost of Capital
Costing Methodology
Depreciation
Flow-Through vs Normalization
Revenue Requirements Methodology
Utility Capital Expenditures Analysis
Risk Analysis
Capital Allocation
Divisional Cost of Capital, Unbundling
Incentive Regulation & Alternative Regulatory Plans
Shareholder Value Creation
Value-Based Management

REGULATORY BODIES

Alabama Public Service Commission
Alaska Regulatory 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.
City of New Orleans Council
Colorado Public Utilities Commission
Delaware Public Service 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 Utilities Commission
Illinois Commerce Commission
Indiana Utility Regulatory Commission
Iowa Utilities Board
Kentucky Public Service Commission
Louisiana Public Service Commission
Maine Public Utilities Commission
Manitoba Board of Public Utilities
Maryland Public Service Commission
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
Nebraska Public Service Commission
Nevada Public Utilities Commission
New Brunswick Board of Public Commissioners
New Hampshire Public Utilities Commission
New Jersey Board of Public Utilities
New Mexico Public Regulation Commission
New Orleans City Council
New York Public Service Commission
Newfoundland Board of Commissioners of Public Utilities
North Carolina Utilities Commission
Nova Scotia Board of Public Utilities
Ohio Public Utilities Commission
Oklahoma Corporation Commission
Ontario Telephone Service Commission
Ontario Energy Board
Oregon Public Utility Service Commission
Pennsylvania Public Utility Commission
Quebec Regie de l'Energie
Quebec Telephone Service Commission
South Carolina Public Service Commission
South Dakota Public Utilities Commission
Tennessee Regulatory Authority
Texas Public Utility Commission
Utah Public Service Commission
Vermont Department of Public Services
Virginia State Corporation Commission
Washington Utilities & Transportation Commission
West Virginia Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C
Southern Bell, So. Carolina PSC, Docket #82-294C
Southern Bell, North Carolina PSC, Docket #P-55-816
Metropolitan Edison, Pennsylvania PUC, Docket #R-822249
Pennsylvania Electric, Pennsylvania PUC, Docket #R-822250
Georgia Power, Georgia PSC, Docket # 3270-U, 1981
Georgia Power, Georgia PSC, Docket # 3397-U, 1983
Georgia Power, Georgia PSC, Docket # 3673-U, 1987
Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327
Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731

Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731
Bell Canada, CRTC 1987
Northern Telephone, Ontario PSC
GTE-Quebec Telephone, Quebec PSC, Docket 84-052B
Newtel., Nfld. Brd of Public Commission PU 11-87
CN-CP Telecommunications, CRTC
Quebec Northern Telephone, Quebec PSC
Edmonton Power Company, Alberta Public Service Board
Kansas Power & Light, F.E.R.C., Docket # ER 83-418
NYNEX, FCC generic cost of capital Docket #84-800
Bell South, FCC generic cost of capital Docket #84-800
American Water Works - Tennessee, Docket #7226
Burlington-Northern - Oklahoma State Board of Taxes
Georgia Power, Georgia PSC, Docket # 3549-U
GTE Service Corp., FCC Docket #84-200
Mississippi Power Co., Miss. PSC, Docket U-4761
Citizens Utilities, Ariz. Corp. Comm., Docket U2334-86020
Quebec Telephone, Quebec PSC, 1986, 1987, 1992
Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991
Northwestern Bell, Minnesota PSC, Docket P-421/CI-86-354
GTE Service Corp., FCC Docket #87-463
Anchorage Municipal Power & Light, Alaska PUC, 1988
New Brunswick Telephone, N.B. PUC, 1988
Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92
Gulf Power Co., Florida PSC, Docket #88-1167-EI
Mountain States Bell, Montana PSC, #88-1.2
Mountain States Bell, Arizona CC, #E-1051-88-146
Georgia Power, Georgia PSC, Docket # 3840-U, l989
Rochester Telephone, New York PSC, Docket # 89-C-022
Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89
GTE Northwest, Washington UTC, #U-89-3031
Orange & Rockland, New York PSC, Case 89-E-175
Central Illinois Light Company, ICC, Case 90-0127
Peoples Natural Gas, Pennsylvania PSC, Case
Gulf Power, Florida PSC, Case # 891345-EI
ICG Utilities, Manitoba BPU, Case 1989
New Tel Enterprises, CRTC, Docket #90-15
Peoples Gas Systems, Florida PSC
Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J
Alabama Gas Co., Alabama PSC, Case 890001
Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board
Mountain Bell, Utah PSC,
Mountain Bell, Colorado PUB
South Central Bell, Louisiana PS
Hope Gas, West Virginia PSC
Vermont Gas Systems, Vermont PSC

Alberta Power Ltd., Alberta PUB
Ohio Utilities Company, Ohio PSC
Georgia Power Company, Georgia PSC
Sun City Water Company
Havasu Water Inc.
Centra Gas (Manitoba) Co.
Central Telephone Co. Nevada
AGT Ltd., CRTC 1992
BC GAS, BCPUB 1992
California Water Association, California PUC 1992
Maritime Telephone 1993
BCE Enterprises, Bell Canada, 1993
Citizens Utilities Arizona gas division 1993
PSI Resources 1993-5
CILCORP gas division 1994
GTE Northwest Oregon 1993
Stentor Group 1994-5
Bell Canada 1994-1995
PSI Energy 1993, 1994, 1995, 1999
Cincinnati Gas & Electric 1994, 1996, 1999, 2004
Southern States Utilities, 1995
CILCO 1995, 1999, 2001
Commonwealth Telephone 1996
Edison International 1996, 1998
Citizens Utilities 1997
Stentor Companies 1997
Hydro-Quebec 1998
Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003
Detroit Edison, 1999, 2003
Entergy Gulf States, Texas, 2000, 2004
Hydro Quebec TransEnergie, 2001, 2004
Sierra Pacific Company, 2000, 2001, 2002, 2007, 2010
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, 2012, 2014
New Brunswick Power, 2002
Entergy New Orleans, 2002, 2008
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, 2008, 2009
Delmarva Power & Light Company 2005, 2009
Union Heat Power & Light 2005
Puget Sound Energy 2006, 2007, 2009
Cascade Natural Gas 2006
Entergy Arkansas 2006-7
Bangor Hydro 2006-7
Delmarva 2006, 2007, 2009
Potomac Electric Power Co. 2006, 2007, 2009
Duke Energy Ohio, 2007, 2008, 2009
Duke Energy Kentucky 2009
Consolidated Edison 2007 Docket 07-E-0523
Duke Energy Ohio Docket 07-589-GA-AIR
Hawaiian Electric Company Docket 05-0315
Sierra Pacific Power Docket ER07-1371-000
Public Service New Mexico Docket 06-00210-UT
Detroit Edison Docket U-15244
Potomac Electric Power Docket FC-1053
Delmarva, Delaware, Docket 09-414
Atlantic City Electric, New Jersey, Docket ER-09080664
Maui Electric Co, Hawaii, Docket 2009-0163, 2011
Niagara Mohawk, New York, Docket 10E-0050
Sierra Pacific Power Docket No. 10-06001
Gaz Metro, Regie de l'Energie (Quebec), Docket 2012 R-3752-2011
California Pacific Electric Co., LLC, California PUC, Docket A-12-02-014
Duke Energy Ohio, Ohio Case No. 11-XXXX-EL-SSO
San Diego Gas & Electric, FERC, 2012, 2014, 2018
San Diego Gas & Electric, California PUC, 2012, Docket A-12-04
Southern California Gas, California PUC, 2012, Docket A-12-04
Puget Sound Electric 2016
Puget Sound Electric 2017
Duke Energy of Ohio 2015, 2018
Duke Energy of Kentucky 2017. 2018
Duke Energy of Ohio 2017
Dayton Power & Light 2016-2018
Missouri American Water
California Power Electric Company
Interstate Power & Light Iowa 2017, 2018
Wisconsin Power & Light 2016

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 Fl, 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, l978.

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

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

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977
- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975
- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976
- Member, New Product Development Committee, Financial Management Association, 1985-1986
- Reviewer: Journal of Financial Research
Financial Management
Financial Review
Journal of Finance

PUBLICATIONS

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

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

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

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

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

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

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

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

BOOKS

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

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

	VERTICALLY INTEGRATED ELECTRIC UTILITIES (1)	PARENT CO. (2)	ELEC	GAS
1	Indiana Michigan Power Company Baa1 Stable	AEP	Y	
2	Indianapolis Power & Light Co. Baa1 Stable	AES Corp	Y	
3	ALLETE, Inc. A3 Stable	ALLETE	Y	
4	Interstate Power and Light Co. Baa1 Stable	Alliant	Y	Y
5	Union Electric Company Baa1 Stable	Ameren	Y	Y
6	Avista Corp. Baa1 Stable	Avista	Y	Y
7	Black Hills Power, Inc. A3 Stable	Black Hills	Y	Y
8	Consumers Energy Company (P)A3 Positive	CMS Energy	Y	Y
9	Virginia Electric and Power Co. A2 Stable	Dominion Energy	Y	Y
10	Dayton Power & Light Company Ba2	DP&L	Y	
11	DTE Electric Company A2 Stable	DTE Energy	Y	Y
12	Duke Energy Carolinas, LLC A1 Stable	Duke Energy	Y	Y
13	Southern California Edison Co. A2 Stable	Edison	Y	
14	El Paso Electric Company Baa1 Stable	El Paso Elec	Y	
15	Tampa Electric Company A3 Stable	Emera	Y	
16	Empire District Electric Company Baa1 Stable	Empire District	Y	Y
17	Entergy Arkansas, Inc. Baa1 Stable	Entergy	Y	Y
18	Public Service Company of New Hampshire A3 Stable	Eversource Energy	Y	Y
19	Monongahela Power Company Baa2 Stable	First Energy	Y	
20	Tucson Electric Power Company A3 Stable	Fortis	Y	
21	Kansas City Power & Light Co. Baa1 Stable	Great Plains	Y	
22	Hawaiian Electric Company, Inc. Baa2 Stable	Hawaian Electric	Y	
23	Idaho Power Company A3 Stable	IDACORP	Y	
24	Madison Gas and Electric Company A1 Stable	MGE Energy	Y	Y
25	Florida Power & Light Company A1 Stable	Next Era	Y	
26	Northern Indiana Public Service Co Baa1 Stable	NiSource	Y	Y
27	NorthWestern Corporation A3 Negative	Northwestern Corp	Y	Y
28	Oklahoma Gas & Electric Company A1 Stable	OG&E	Y	
29	Otter Tail Power Company A3 Stable	Otter Tail	Y	
30	Pacific Gas & Electric Company A3 Positive	PG&E	Y	Y
31	Arizona Public Service Company A2 Stable	Pinnacle West	Y	
32	Public Service Company of New Mexico Baa2 Stable	PNM Resources	Y	
33	Portland General Electric Company A3 Stable	Portland General	Y	
34	Kentucky Utilities Company A3 Stable	PPL Corp	Y	
35	South Carolina Electric & Gas Co. Baa2 Stable	SCANA	Y	Y
36	Alabama Power Company A1 Stable	Southern Co	Y	
37	Southern Indiana Gas & Electric A2 Stable	Vectren	Y	Y
38	Wisconsin Electric Power Company A1 Negative	WEC Energy	Y	Y
39	Westar Energy, Inc. Baa1 Stable	Westar	Y	
40	Northern States Power Company (Minnesota) A2 Stable	Xcel	Y	Y

Source: Moody's Investor Service, "2017 Outlook - Timely Cost-Recovery Drives Stable Outlook", 11/16
Value Line Investment Survey Investment Reports 9/2017

	VERTICALLY INTEGRATED ELECTRIC UTILITIES (1)	PARENT CO. (2)	ELEC	GAS
1	Indiana Michigan Power Company Baa1 Stable	AEP	Y	
2	ALLETE, Inc. A3 Stable	ALLETE	Y	
3	Interstate Power and Light Co. Baa1 Stable	Alliant	Y	Y
4	Union Electric Company Baa1 Stable	Ameren	Y	Y
5	Avista Corp. Baa1 Stable	Avista	Y	Y
6	Black Hills Power, Inc. A3 Stable	Black Hills	Y	Y
7	Consumers Energy Company (P)A3 Positive	CMS Energy	Y	Y
8	Virginia Electric and Power Co. A2 Stable	Dominion Energy	Y	Y
9	DTE Electric Company A2 Stable	DTE Energy	Y	Y
10	Duke Energy Carolinas, LLC A1 Stable	Duke Energy	Y	Y
11	Southern California Edison Co. A2 Stable	Edison	Y	
12	El Paso Electric Company Baa1 Stable	El Paso Elec	Y	
13	Tampa Electric Company A3 Stable	Emera	Y	
14	Public Service Company of New Hampshire A3 Stable	Eversource Energy	Y	Y
15	Monongahela Power Company Baa2 Stable	First Energy	Y	
16	Tucson Electric Power Company A3 Stable	Fortis	Y	
17	Hawaiian Electric Company, Inc. Baa2 Stable	Hawaian Electric	Y	
18	Idaho Power Company A3 Stable	IDACORP	Y	
19	Madison Gas and Electric Company A1 Stable	MGE Energy	Y	Y
20	Florida Power & Light Company A1 Stable	Next Era	Y	
21	Northern Indiana Public Service Co Baa1 Stable	NiSource	Y	Y
22	NorthWestern Corporation A3 Negative	Northwestern Corp	Y	Y
23	Oklahoma Gas & Electric Company A1 Stable	OG&E	Y	
24	Otter Tail Power Company A3 Stable	Otter Tail	Y	
25	Arizona Public Service Company A2 Stable	Pinnacle West	Y	
26	Public Service Company of New Mexico Baa2 Stable	PNM Resources	Y	
27	Portland General Electric Company A3 Stable	Portland General	Y	
28	Kentucky Utilities Company A3 Stable	PPL Corp	Y	
29	Alabama Power Company A1 Stable	Southern Co	Y	Y
30	Southern Indiana Gas & Electric A2 Stable	Vectren	Y	Y
31	Wisconsin Electric Power Company A1 Negative	WEC Energy	Y	Y
32	Northern States Power Company (Minnesota) A2 Stable	Xcel	Y	Y

Companies Eliminated	Reason
Great Plains, Westar	Merged into Evergy
SCANA	Acquired by Southern Company
PG&E	Dividends suspended
AES	International diversification, generation intensive
DP&L	Non-investment grade
Empire District	Acquired by Liberty Utilities
Entergy	Nuclear exposure and ongoing restructuring

	VERTICALLY INTEGRATED ELECTRIC UTILITI	PARENT CO.
	(1)	(2)
1	Indiana Michigan Power Company Baa1 Stable	AEP
2	ALLETE, Inc. A3 Stable	ALLETE
3	Southern California Edison Co. A2 Stable	Edison
4	El Paso Electric Company Baa1 Stable	El Paso Elec
5	Tampa Electric Company A3 Stable	Emera
6	Kansas City P & L and Westar Energy Baa1 Stable	Evergy
7	Monongahela Power Company Baa2 Stable	First Energy
8	Tucson Electric Power Company A3 Stable	Fortis
9	Hawaiian Electric Company, Inc. Baa2 Stable	Hawaian Electric
10	Idaho Power Company A3 Stable	IDACORP
11	Florida Power & Light Company A1 Stable	Next Era
12	Oklahoma Gas & Electric Company A1 Stable	OG&E
13	Otter Tail Power Company A3 Stable	Otter Tail
14	Arizona Public Service Company A2 Stable	Pinnacle West
15	Public Service Company of New Mexico Baa2 Stable	PNM Resources
16	Portland General Electric Company A3 Stable	Portland General
17	Kentucky Utilities Company A3 Stable	PPL Corp

Utilities with natural gas operations excluded
Evergy the new parent of Great Plains & Westar added

Proxy Group for OG&E

	Company	Ticker
1	AEP	AEP
2	ALLETE	ALE
3	Edison	EIX
4	El Paso Elec	EE
5	Emera	EMA.TO
6	Evergy	EVRG
7	First Energy	FE
8	Fortis	FTS.TO
9	Hawaiian Electric	HE
10	IDACORP	IDA
11	Next Era	NEE
12	OG&E	OGE
13	Otter Tail	OTTR
14	Pinnacle West	PNW
15	PNM Resources	PNM
16	Portland General	POR
17	PPL Corp	PPL

Vertically Integrated Electric Utilities
DCF Analysis Value Line Growth Rates

Line No.	(1) Company Name	(2) Dividend Yield	(3) Projected EPS Growth	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	AEP	3.39	4.50	3.54	8.04	8.23
2	ALLETE	2.92	5.00	3.07	8.07	8.23
3	Edison	3.46	4.50	3.62	8.12	8.31
4	El Paso Elec	2.42	4.50	2.53	7.03	7.16
5	Emera	5.80	6.00	6.15	12.15	12.47
6	Evergy	3.24	7.70	3.49	11.19	11.37
7	First Energy	3.73	3.00	3.84	6.84	7.04
8	Fortis	4.03	8.00	4.35	12.35	12.58
9	Hawaian Electric	3.46	3.50	3.58	7.08	7.27
10	IDACORP	2.39	3.00	2.46	5.46	5.59
11	Next Era	2.47	9.00	2.69	11.69	11.83
12	OG&E	3.91	6.00	4.14	10.14	10.36
13	Otter Tail	2.94	7.50	3.16	10.66	10.83
14	Pinnacle West	3.27	5.00	3.43	8.43	8.61
15	PNM Resources	2.66	7.50	2.86	10.36	10.51
16	Portland General	3.10	4.00	3.22	7.22	7.39
17	PPL Corp	5.36	2.00	5.47	7.47	7.75
19	**AVERAGE**	**3.44**	**5.34**	**3.62**	**8.96**	**9.15**
20	**AVERAGE w/o IDACORP**					**9.40**

Notes:

23 Column 1, 3: Value Line Investment Reports 10/2018
24 Column 2; Zacks Investment Research 10/2018
25 Column 4 = Column 2 times (1 + Column 3/100)
26 Column 5 = Column 4 + Column 3
27 Column 6 = Column 4/0.95 + Column 3

29 Growth forecast for Evergy unavailable from Value Line. Used Zacks forecast.
Dividend Yield for Emera from Value Line
Emera growth forecast used Value Line DPS forecast

Vertically Integrated Electric Utilities
DCF Analysis Analysts' Growth Forecasts

Line No.	(1) Company Name	(2) Dividend Yield	(3) Analysts' Growth Forecast	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	AEP	3.39	5.60	3.58	9.18	9.37
2	ALLETE	2.92	6.00	3.10	9.10	9.26
3	Edison	3.46	5.90	3.66	9.56	9.76
4	El Paso Elec	2.42	4.70	2.53	7.23	7.37
5	Emera	5.98	4.57	6.25	10.82	11.15
6	Evergy	3.24	7.70	3.49	11.19	11.37
7	First Energy	3.73	6.00	3.95	9.95	10.16
8	Fortis	4.03	5.00	4.23	9.23	9.45
9	Hawaian Electric	3.46	8.10	3.74	11.84	12.04
10	IDACORP	2.39	2.80	2.46	5.26	5.39
11	Next Era	2.47	8.30	2.68	10.98	11.12
12	OG&E	3.91	5.20	4.11	9.31	9.53
13	Otter Tail	2.94	9.00	3.20	12.20	12.37
14	Pinnacle West	3.27	4.50	3.42	7.92	8.10
15	PNM Resources	2.66	4.60	2.78	7.38	7.53
16	Portland General	3.10	3.10	3.20	6.30	6.46
17	PPL Corp	5.36	5.00	5.63	10.63	10.92
19	**AVERAGE**	**3.45**	**5.65**	**3.65**	**9.30**	**9.49**
20	**AVERAGE w/o IDACORP**					**9.80**

Notes:

23 Column 2, 3: Zacks Investment Research growth forecast 10/2018
24 Column 4 = Column 2 times (1 + Column 3/100)
25 Column 5 = Column 4 + Column 3
26 Column 6 = Column 4/0.95 + Column 3
27 Growth forecast for Emera, Otter Tail, Hawaian Elec from Yahoo Finance

Integrated Electric Utilities Beta Estimates

	(1)	(2)
Line No.	**Company Name**	**Beta**
1	AEP	0.60
2	ALLETE	0.70
3	Edison	0.60
4	El Paso Elec	0.70
5	Emera	0.60
6	Evergy	0.70
7	First Energy	0.60
8	Fortis	0.65
9	Hawaiian Electric	0.60
10	IDACORP	0.60
11	Next Era	0.60
12	OG&E	0.90
13	Otter Tail	0.80
14	Pinnacle West	0.60
15	PNM Resources	0.65
16	Portland General	0.60
17	PPL Corp	0.70
19	**AVERAGE**	**0.66**
21	Source: Value Line Investment Reports 10/2018	

2018 Utility Industry Historical Risk Premium

Line No	Year	(1) Long-Term Government Bond Yield	Long-Term Government Income Component Bond Yield	(2) 20 year Maturity Bond Value	(3) Gain/Loss	(4) Interest	(5) Bond Total Return	(6) S&P Utility Index Return	(7) Utility Equity Risk Premium Over Bond Returns	(8) Utility Equity Risk Premium Over Bond Return Income Component
1	1931	4.07%	3.33%	1,000.00						
2	1932	3.15%	3.69%	1,135.75	135.75	40.70	17.64%	-0.54%	-18.18%	-4.23%
3	1933	3.36%	3.12%	969.60	-30.40	31.50	0.11%	-21.87%	-21.98%	-24.99%
4	1934	2.93%	3.10%	1,064.73	64.73	33.60	9.83%	-20.41%	-30.24%	-23.51%
5	1935	2.76%	2.81%	1,025.99	25.99	29.30	5.53%	76.63%	71.10%	73.82%
6	1936	2.56%	2.77%	1,031.15	31.15	27.60	5.88%	20.69%	14.81%	17.92%
7	1937	2.73%	2.66%	973.93	-26.07	25.60	-0.05%	-37.04%	-36.99%	-39.70%
8	1938	2.52%	2.64%	1,032.83	32.83	27.30	6.01%	22.45%	16.44%	19.81%
9	1939	2.26%	2.40%	1,041.65	41.65	25.20	6.68%	11.26%	4.58%	8.86%
10	1940	1.94%	2.23%	1,052.84	52.84	22.60	7.54%	-17.15%	-24.69%	-19.38%
11	1941	2.04%	1.94%	983.64	-16.36	19.40	0.30%	-31.57%	-31.87%	-33.51%
12	1942	2.46%	2.46%	933.97	-66.03	20.40	-4.56%	15.39%	19.95%	12.93%
13	1943	2.48%	2.44%	996.86	-3.14	24.60	2.15%	46.07%	43.92%	43.63%
14	1944	2.46%	2.46%	1,003.14	3.14	24.80	2.79%	18.03%	15.24%	15.57%
15	1945	1.99%	2.34%	1,077.23	77.23	24.60	10.18%	53.33%	43.15%	50.99%
16	1946	2.12%	2.04%	978.90	-21.10	19.90	-0.12%	1.26%	1.38%	-0.78%
17	1947	2.43%	2.13%	951.13	-48.87	21.20	-2.77%	-13.16%	-10.39%	-15.29%
18	1948	2.37%	2.40%	1,009.51	9.51	24.30	3.38%	4.01%	0.63%	1.61%
19	1949	2.09%	2.25%	1,045.58	45.58	23.70	6.93%	31.39%	24.46%	29.14%
20	1950	2.24%	2.12%	975.93	-24.07	20.90	-0.32%	3.25%	3.57%	1.13%
21	1951	2.69%	2.38%	930.75	-69.25	22.40	-4.69%	18.63%	23.32%	16.25%
22	1952	2.79%	2.68%	984.75	-15.25	26.90	1.17%	19.25%	18.08%	16.57%
23	1953	2.74%	2.84%	1,007.66	7.66	27.90	3.56%	7.85%	4.29%	5.01%
24	1954	2.72%	2.79%	1,003.07	3.07	27.40	3.05%	24.72%	21.67%	21.93%
25	1955	2.95%	2.75%	965.44	-34.56	27.20	-0.74%	11.26%	12.00%	8.51%
26	1956	3.45%	2.99%	928.19	-71.81	29.50	-4.23%	5.06%	9.29%	2.07%
27	1957	3.23%	3.44%	1,032.23	32.23	34.50	6.67%	6.36%	-0.31%	2.92%
28	1958	3.82%	3.27%	918.01	-81.99	32.30	-4.97%	40.70%	45.67%	37.43%
29	1959	4.47%	4.01%	914.65	-85.35	38.20	-4.71%	7.49%	12.20%	3.48%
30	1960	3.80%	4.26%	1,093.27	93.27	44.70	13.80%	20.26%	6.46%	16.00%
31	1961	4.15%	3.83%	952.75	-47.25	38.00	-0.92%	29.33%	30.25%	25.50%
32	1962	3.95%	4.00%	1,027.48	27.48	41.50	6.90%	-2.44%	-9.34%	-6.44%
33	1963	4.17%	3.89%	970.35	-29.65	39.50	0.99%	12.36%	11.37%	8.47%
34	1964	4.23%	4.15%	991.96	-8.04	41.70	3.37%	15.91%	12.54%	11.76%
35	1965	4.50%	4.20%	964.64	-35.36	42.30	0.69%	4.67%	3.98%	0.47%
36	1966	4.55%	4.49%	993.48	-6.52	45.00	3.85%	-4.48%	-8.33%	-8.97%
37	1967	5.56%	4.59%	879.01	-120.99	45.50	-7.55%	-0.63%	6.92%	-5.22%
38	1968	5.98%	5.50%	951.38	-48.62	55.60	0.70%	10.32%	9.62%	4.82%
39	1969	6.87%	5.96%	904.00	-96.00	59.80	-3.62%	-15.42%	-11.80%	-21.38%
40	1970	6.48%	6.74%	1,043.38	43.38	68.70	11.21%	16.56%	5.35%	9.82%
41	1971	5.97%	6.32%	1,059.09	59.09	64.80	12.39%	2.41%	-9.98%	-3.91%
42	1972	5.99%	5.87%	997.69	-2.31	59.70	5.74%	8.15%	2.41%	2.28%
43	1973	7.26%	6.51%	867.09	-132.91	59.90	-7.30%	-18.07%	-10.77%	-24.58%
44	1974	7.60%	7.27%	965.33	-34.67	72.60	3.79%	-21.55%	-25.34%	-28.82%
45	1975	8.05%	7.99%	955.63	-44.37	76.00	3.16%	44.49%	41.33%	36.50%
46	1976	7.21%	4.89%	1,088.25	88.25	80.50	16.87%	31.81%	14.94%	26.92%
47	1977	8.03%	7.14%	919.03	-80.97	72.10	-0.89%	8.64%	9.53%	1.50%
48	1978	8.98%	7.90%	912.47	-87.53	80.30	-0.72%	-3.71%	-2.99%	-11.61%
49	1979	10.12%	8.86%	902.99	-97.01	89.80	-0.72%	13.58%	14.30%	4.72%
50	1980	11.99%	9.97%	859.23	-140.77	101.20	-3.96%	15.08%	19.04%	5.11%
51	1981	13.34%	11.55%	906.45	-93.55	119.90	2.63%	11.74%	9.11%	0.19%
52	1982	10.95%	13.50%	1,192.38	192.38	133.40	32.58%	26.52%	-6.06%	13.02%
53	1983	11.97%	10.38%	923.12	-76.88	109.50	3.26%	20.01%	16.75%	9.63%
54	1984	11.70%	11.74%	1,020.70	20.70	119.70	14.04%	26.04%	12.00%	14.30%
55	1985	9.56%	11.25%	1,189.27	189.27	117.00	30.63%	33.05%	2.42%	21.80%
56	1986	7.89%	8.98%	1,166.63	166.63	95.60	26.22%	28.53%	2.31%	19.55%
57	1987	9.20%	7.92%	881.17	-118.83	78.90	-3.99%	-2.92%	1.07%	-10.84%
58	1988	9.19%	8.97%	1,000.91	0.91	92.00	9.29%	18.27%	8.98%	9.30%
59	1989	8.16%	8.10%	1,100.73	100.73	91.90	19.26%	47.80%	28.54%	39.70%
60	1990	8.44%	8.19%	973.17	-26.83	81.60	5.48%	-2.57%	-8.05%	-10.76%
61	1991	7.30%	8.22%	1,118.94	118.94	84.40	20.33%	14.61%	-5.72%	6.39%
62	1992	7.26%	7.26%	1,004.19	4.19	73.00	7.72%	8.10%	0.38%	0.84%
63	1993	6.54%	7.17%	1,079.70	79.70	72.60	15.23%	14.41%	-0.82%	7.24%
64	1994	7.99%	6.59%	856.40	-143.60	65.40	-7.82%	-7.94%	-0.12%	-14.53%
65	1995	6.03%	7.60%	1,225.98	225.98	79.90	30.59%	42.15%	11.56%	34.55%
66	1996	6.73%	6.18%	923.67	-76.33	60.30	-1.60%	3.14%	4.74%	-3.04%
67	1997	6.02%	6.64%	1,081.92	81.92	67.30	14.92%	24.69%	9.77%	18.05%

		(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No	Year	Long-Term Government Bond Yield	Long-Term Government Income Component Bond Yield	20 year Maturity Bond Value	Gain/Loss	Interest	Bond Total Return	S&P Utility Index Return	Utility Equity Risk Premium Over Bond Returns	Utility Equity Risk Premium Over Bond Return Income Component
68	1998	5.42%	5.83%	1,072.71	72.71	60.20	13.29%	14.82%	1.53%	8.99%
69	1999	6.82%	5.57%	848.41	-151.59	54.20	-9.74%	-8.85%	0.89%	-14.42%
70	2000	5.58%	6.50%	1,148.30	148.30	68.20	21.65%	59.70%	38.05%	53.20%
71	2001	5.75%	5.53%	979.95	-20.05	55.80	3.57%	-30.41%	-33.98%	-35.94%
72	2002	4.84%	5.59%	1,115.77	115.77	57.50	17.33%	-30.04%	-47.37%	-35.63%
73	2003	5.11%	4.80%	966.42	-33.58	48.40	1.48%	26.11%	24.63%	21.31%
74	2004	4.84%	5.02%	1,034.35	34.35	51.10	8.54%	24.22%	15.68%	19.20%
75	2005	4.61%	4.69%	1,029.84	29.84	48.40	7.82%	16.79%	8.97%	12.10%
76	2006	4.91%	4.68%	962.06	-37.94	46.10	0.82%	20.95%	20.13%	16.27%
77	2007	4.50%	4.86%	1,053.70	53.70	49.10	10.28%	19.36%	9.08%	14.50%
78	2008	3.03%	4.45%	1,219.28	219.28	45.00	26.43%	-28.99%	-55.42%	-33.44%
79	2009	4.58%	3.47%	798.39	-201.61	30.30	-17.13%	11.94%	29.07%	8.47%
80	2010	4.14%	4.25%	1,059.45	59.45	45.80	10.52%	5.49%	-5.03%	1.24%
81	2011	2.48%	3.81%	1,260.50	260.50	41.40	30.19%	19.88%	-10.31%	16.07%
82	2012	2.41%	2.40%	1,011.06	11.06	24.80	3.59%	1.99%	-1.60%	-0.41%
83	2013	3.67%	2.86%	822.57	-177.43	24.10	-15.33%	13.26%	28.59%	10.40%
84	2014	2.40%	3.12%	1,200.79	200.79	36.70	23.75%	28.61%	4.86%	25.49%
85	2015	2.60%	2.84%	968.96	-31.04	24.00	-0.70%	1.38%	2.08%	-1.46%
86	2016	2.60%	2.63%	1,000.00	0.00	26.00	2.60%	11.93%	9.33%	9.30%
87	2017	2.90%	2.89%	954.71	-45.29	26.00	-1.93%	12.11%	14.04%	9.22%
89	**Mean**								**5.6%**	**6.2%**

91 Source Bloomberg Web site: Standard & Poors Utility Stock Index % Annual Change, Jan. to Dec.
92 Bond yields from Duff & Phelps Classic Yearbooks Table A-9 Long-Term Government Bonds Yields
92 and Fed Reserve H-15 Data Release

Equity Risk Premium - Treasury Bond

Line	Date	Treasury Bond Yield[1]	Authorized Electric Returns[2]	Indicated Risk Premium
		(1)	(2)	(3)
1	1986	7.80%	13.93%	6.1%
2	1987	8.58%	12.99%	4.4%
3	1988	8.96%	12.79%	3.8%
4	1989	8.45%	12.97%	4.5%
5	1990	8.61%	12.70%	4.1%
6	1991	8.14%	12.55%	4.4%
7	1992	7.67%	12.09%	4.4%
8	1993	6.60%	11.41%	4.8%
9	1994	7.37%	11.34%	4.0%
10	1995	6.88%	11.55%	4.7%
11	1996	6.70%	11.39%	4.7%
12	1997	6.61%	11.40%	4.8%
13	1998	5.58%	11.66%	6.1%
14	1999	5.87%	10.77%	4.9%
15	2000	5.94%	11.43%	5.5%
16	2001	5.49%	11.09%	5.6%
17	2002	5.42%	11.16%	5.7%
18	2003	5.02%	10.97%	6.0%
19	2004	5.05%	10.75%	5.7%
20	2005	4.65%	10.54%	5.9%
21	2006	4.88%	10.36%	5.5%
22	2007	4.83%	10.36%	5.5%
23	2008	4.28%	10.46%	6.2%
24	2009	4.07%	10.48%	6.4%
25	2010	4.25%	10.34%	6.1%
26	2011	3.91%	10.29%	6.4%
27	2012	2.92%	10.17%	7.3%
28	2013	3.45%	10.03%	6.6%
29	2014	3.34%	9.91%	6.6%
30	2015	2.84%	9.85%	7.0%
31	2016	2.60%	9.77%	7.2%
32	2017	2.90%	9.74%	6.8%
34	**Average**	**5.61%**	**11.16%**	**5.55%**

Sources:
1 Fed Reserve Board of Governors H.15 Release, 30-Yr Treasury rate

2 S&P Global Intelligence (Regulatory Research Associates)
Major Rate Case Decisions 1986-2017

Operating Company Capital Structure

Operating Company	Parent	2018Q2
Appalachian Power Company	AEP	48.93%
Indiana Michigan Power Company	AEP	44.15%
Kentucky Power Company	AEP	44.89%
Kingsport Power Company	AEP	47.69%
Ohio Power Company	AEP	57.11%
Public Service Company of Oklahoma	AEP	48.59%
Southwestern Electric Power Company	AEP	47.91%
Wheeling Power Company	AEP	54.19%
ALLETE (Minnesota Power)	ALE	60.33%
Superior Water, Light and Power Company	ALE	57.34%
El Paso Electric Company	EE	47.32%
Southern California Edison Company	EIX	50.05%
Tampa Electric Company	EMA	58.81%
Kansas Gas and Electric Company	EVRG	74.45%
KCP&L Greater Missouri Operations Company	EVRG	52.03%
Kansas City Power & Light Company	EVRG	48.88%
Westar Energy (KPL)	EVRG	58.68%
Cleveland Electric Illuminating Company	FE	56.31%
Jersey Central Power & Light Company	FE	68.81%
Metropolitan Edison Company	FE	53.10%
Monongahela Power Company	FE	51.53%
Ohio Edison Company	FE	67.33%
Pennsylvania Electric Company	FE	53.90%
Potomac Edison Company	FE	52.65%
Toledo Edison Company	FE	62.25%
West Penn Power Company	FE	52.09%
Tucson Electric Power Company	FTS	54.39%
Hawaiian Electric Company, Inc.[1]	HE	56.01%
Idaho Power Co.	IDA	53.44%
Florida Power & Light Company	NEE	60.84%
OG&E	OGE	54.25%
Otter Tail Power Company	OTTR	53.11%
Public Service Company of New Mexico	PNM	46.69%
Texas-New Mexico Power Company[1]	PNM	54.56%
Arizona Public Service Company	PNW	53.71%
Portland General Electric Company	POR	50.29%
Kentucky Utilities Company	PPL	54.51%
Mean		54.35%

Source: SNL Financial

1) Equity percentages for Texas-New Mexico Power Company and Hawaiian Electric Company, Inc derived from their 10Q filings, all others - from FERC Form No. 3-Q

Moody's Financial Risk Indicators

Financial Risk Ratios			
	Financial Risk Benchmarks		
	CFO/debt %	CFO/interest x	Tot debt/capital %
Aaa	>40	>8.0	<25
Aa	30-50	6.0-8.0	25-35
A	22-30	4.5-6.0	35-45
Baa	13-22	2.7-4.5	45-55
Ba	21-6	1.5-2.7	55-65
B	<5	<1.5	>65

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:

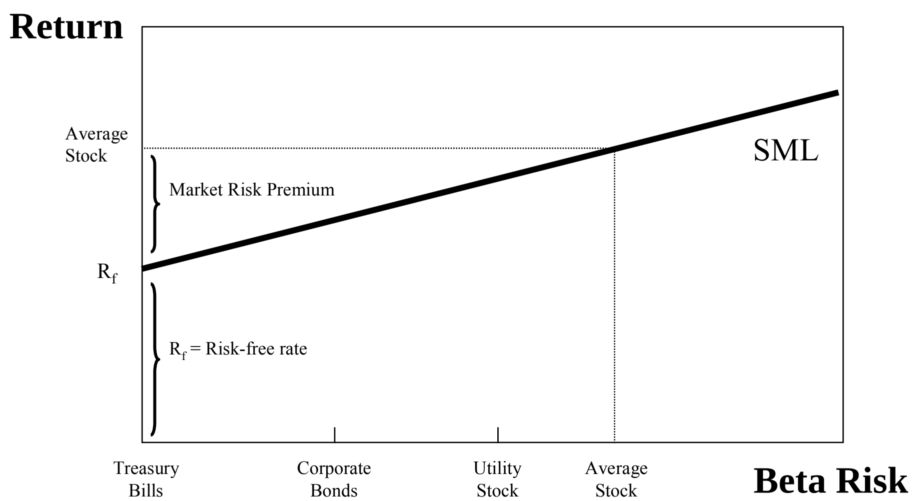
$$K = R_F + \beta(R_M - R_F) \qquad (1)$$

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.

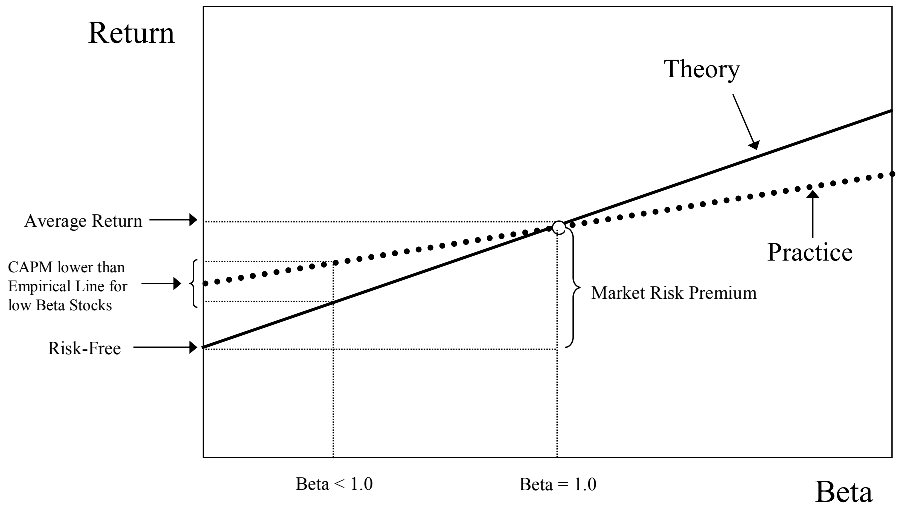
CAPM and Risk - Return
in Capital Markets



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:

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

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 (2003)	2.0%	1983-1998

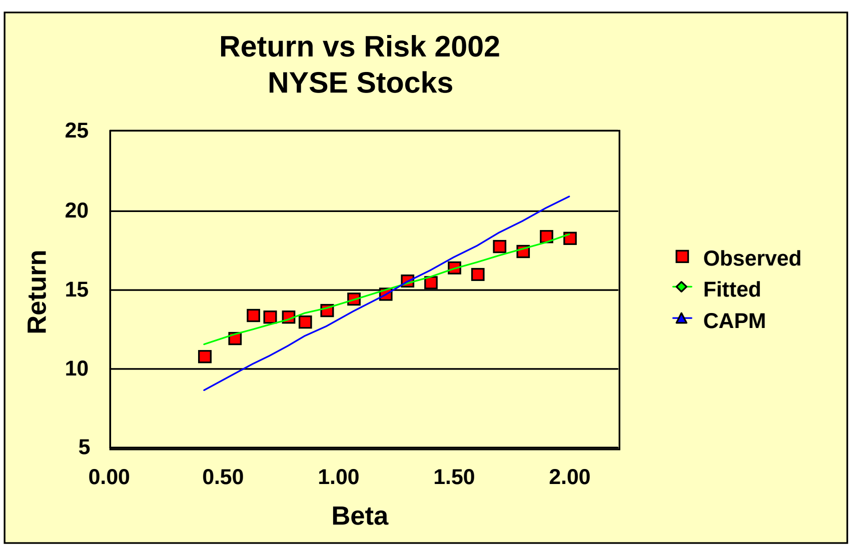
Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1989) over the period 1926-1984 indicating that the observed expected return on a security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

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

Given that the risk-free rate over the estimation period was approximately 6 percent, this relationship implies that the intercept of the risk-return relationship is higher than the 6 percent risk-free rate, contrary to the CAPM's prediction. Given that the average return on an average risk stock exceeded the risk-free rate by about 8.0 percent in that period, that is, the market risk premium (R_M - R_F) = 8 percent, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2 percent, suggesting an alpha factor of 2 percent.

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

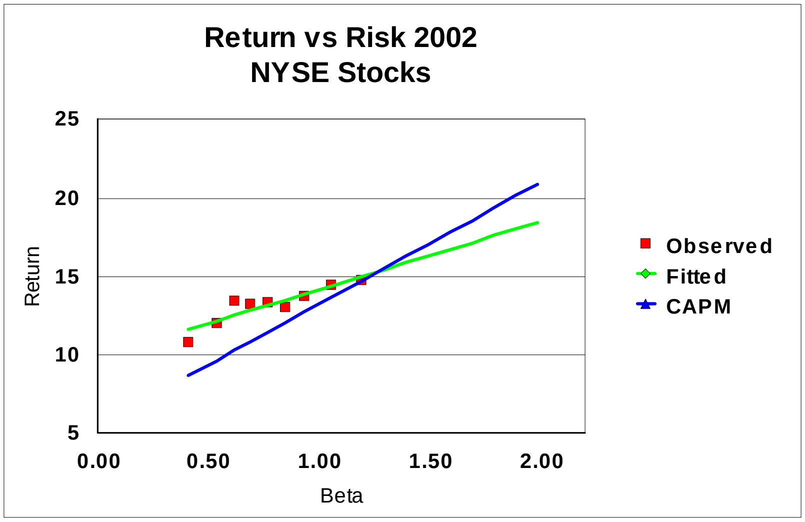
CAPM vs ECAPM



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

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

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



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

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

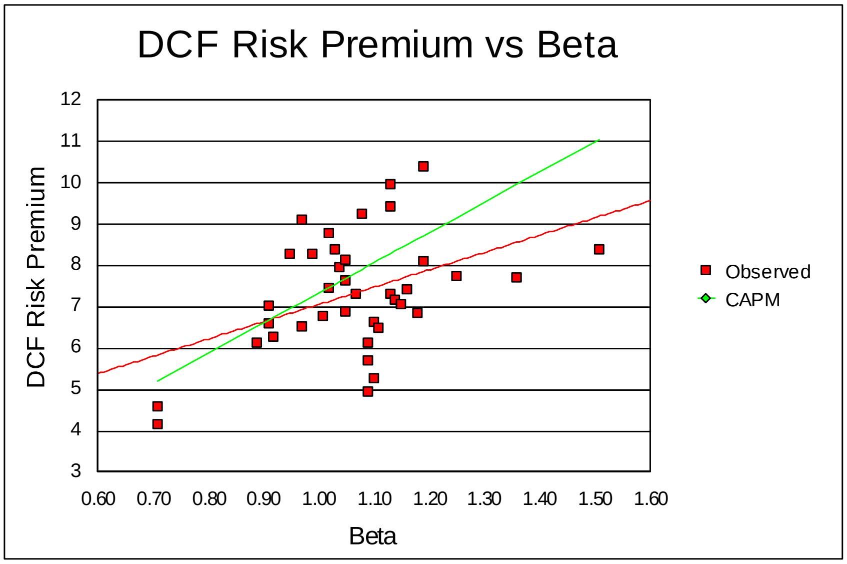
Table A-1 Risk Premium and Beta Estimates by Industry

	Industry (1)	**DCF Risk Premium** (2)	Raw Industry Beta (3)	Adjusted Industry Beta (4)
1	Aero	6.63	1.15	1.10
2	Autos	5.29	1.15	1.10
3	Banks	7.16	1.21	1.14

[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.

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]:

[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

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

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

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

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

[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-f) + g = .09/.95 + .05 = 14.47%.

The initial book value (rate base) is the net proceeds from the stock issue, which are \$23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at $2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from $26.25 to $26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

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

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