EXHIBIT NO. ___(RAM-1T)
DOCKET NO. UE-06___/UG-06___
2006 PSE GENERAL RATE CASE
WITNESS: DR. ROGER A. MORIN

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-06____** **Docket No. UG-06____**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
DR. ROGER A. MORIN
ON BEHALF OF PUGET SOUND ENERGY, INC.

FEBRUARY 15, 2006

PUGET SOUND ENERGY, INC.

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CONTENTS

PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

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 Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(RAM-2).

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

A. As a principal in Utility Research International, I regularly serve as a cost of capital witness before regulatory bodies in North America, including the Washington Utilities and Transportation Commission ("WUTC", or "Commission"), the Federal Energy Regulatory Commission, and the Federal Communications Commission. Exhibit No. ___(RAM-2) describes my participation in regulatory proceedings in more detail.

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

A. My testimony presents an independent appraisal of the just, fair, reasonable and sufficient rate of return on the combined gas and electric utility operations of the Puget Sound Energy, Inc. ("PSE," or "Company") in the State of Washington, with particular emphasis on the fair return on the Company's common equity capital committed to that business. Based upon this appraisal, I have formed my professional judgment as to a return on equity ("ROE") that would: (i) be fair to the Company's ratepayers, (ii) allow the Company to attract capital on reasonable terms, (iii) maintain the Company's financial integrity, and (iv) be comparable to returns offered on comparable risk investments.

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

A. I have examined PSE's risks and concluded that PSE's risk environment slightly exceeds the industry average. It is my opinion that a just, fair, reasonable and sufficient ROE for PSE is 11.25%.

Q. What methodologies have you employed in arriving at such opinion?

A. My opinion derives from studies I performed using the Capital Asset Pricing Model ("CAPM"), Risk Premium, and Discounted Cash Flow ("DCF") methodologies.

I performed two CAPM analyses:

(i) a "traditional" CAPM and

(ii) a methodology using an empirical approximation of the CAPM ("ECAPM").

I performed three risk premium analyses:

(i) a historical risk premium analysis on the electric utility industry;

(ii) a historical risk premium analysis on the natural gas distribution utility industry, which I consider to be a conservative proxy for the Company; and

(iii) a study of the risk premiums reflected in ROEs allowed in the utility industry between 1996-2005.

I also performed DCF analyses on three surrogates for the Company's gas and electric utility business:

(i) Puget Energy, Inc. ("Puget Energy"), PSE's parent company;

(ii) a group of investment-grade combination gas and electric utilities; and

(iii) a group of natural gas distribution utilities.

Q. Have you considered factors other than the above-listed methodologies in arriving at your recommended ROE?

A. Yes, I slightly adjusted the results of the methodologies listed above to account for the slightly above average risks faced by PSE relative to the industry. In other words, the recommended ROE reflects the application of my professional judgment to the results in light of the indicated returns from my Risk Premium, CAPM, and DCF analyses. Moreover, I have based my recommended ROE on the assumption that the Commission will approve the Company's proposed revisions to the Company's power cost adjustment ("PCA") mechanism.

Q. Please describe how your testimony is organized.

A. The remainder of my testimony consists of four sections. The first section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The second section contains the application of CAPM, Risk Premium, and DCF tests. The third section summarizes the results from the various approaches used in determining a fair return and the factors that contribute to the slightly above average risks faced by PSE relative to the industry. The final section contains the conclusion.

II. REGULATORY FRAMEWORK AND RATE OF RETURN

A. Legal and Regulatory Concepts Regarding Rate of Return

Q. Under traditional cost of service regulation, please explain how a regulated company's rates should be set.

A. Under the traditional regulatory process, a regulated company's rates should enable the company to recover its costs (including taxes and depreciation) and earn 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.

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

A. The heart of utility regulation is the setting of just, fair, reasonable and sufficient rates by way of a fair and reasonable ROE. Two landmark U.S. Supreme Court cases 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:

(i) *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923), and

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

The *Bluefield* case set the standard against which just, fair, reasonable and sufficient 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. v. Pub. Serv. Comm'n of W. Va., 262 U.S. at 692 (emphasis added).

The *Hope* case expanded on the guidelines for assessing 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.

Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. at 603 (emphasis added).

The U.S. Supreme Court reiterated the criteria set forth in *Hope* in *Federal Power Commission v. Memphis Light, Gas and 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 PSE 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 the Company's financial integrity, and (iii) sufficient to maintain the Company's creditworthiness and ability to attract capital on reasonable terms.

B. <u>Economic and Financial Concepts Regarding Rate of Return</u>

Q. How is the fair rate of return determined?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the Company. It is the composite weighted cost of the various classes of capital (e.g., bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents.

While utilities like PSE enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free, open market for the input factors of production, whether labor, materials, or machines. 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. Utilities and other investor-owned businesses must (i) access capital on the open capital market and (ii) pay a market price for the capital they require (i.e., interest on debt capital and expected return on equity).

Q. How does the concept of a fair return relate to the concept of opportunity cost?

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

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

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

A. Two fundamental economic principles underlie the appraisal of the Company's cost of equity--one relating to the supply side and the other to the demand side of capital markets.

On the supply side, the first principle asserts that rational investors maximize the performance of their portfolios only if they expect 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, the company's cost of capital. This principle suggests that a regulatory commission should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital.

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

A. The funds employed by the Company are obtained in two general forms--debt capital and equity capital, which consists of preferred equity capital and common equity capital. The cost of debt funds and preferred stock funds can be ascertained easily from an examination of the contractual interest payments and preferred dividends. The cost of common equity funds--that is, equity investors' required rate of return--is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments.

Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded costs of debt and preferred stock, based on the utility's capital structure, in order to arrive at the overall cost of capital (overall 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 to maintain creditworthiness and ability to attract capital on reasonable terms.

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

Q. How does PSE's cost of capital relate to that of its parent company, Puget Energy?

A. I treat PSE as a separate stand-alone entity--distinct from Puget Energy--because the cost of capital to measure in this proceeding is the cost of capital for PSE and not the cost of capital for Puget Energy's consolidated activities.

Financial theory establishes that the cost of equity is the risk-adjusted opportunity cost to the investor--in this case, Puget Energy. The true cost of capital depends on the use to which the capital is put--in this case PSE's combined gas and electric utility operations in the State of Washington. The specific source of funding for an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at an after-tax cost of 8% and invests the funds in a speculative oil extraction venture, the required return on the investment is not the cost of 8% but rather the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return on PSE is the return foregone in comparable risk electricity utility operations and not the cost of capital of Puget Energy. In other words, the cost of capital is governed by the risk to which the capital is exposed and not by the source of funds.

III. COST OF EQUITY CAPITAL ESTIMATES

A. <u>Three Market-Based Methodologies: CAPM, Risk Premium and DCF</u>

Q. How did you estimate the fair ROE for PSE?

A. I employed three methodologies: (i) the CAPM, (ii) the Risk Premium, and (iii) the DCF methodologies. All three are market-based methodologies and estimate the return required by investors on the common equity capital committed to PSE.

1. Use of More Than One Market-Based Methodology

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

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

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

Q. Are there any difficulties in applying cost of capital methodologies in the current environment of change?

A. Yes, there are. All the traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the fast-changing circumstances of the electric and natural gas utility industry. This is because utility company historical data have become less meaningful for an industry in a state of profound change.

Past earnings and dividend trends are simply not indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including corporate structural transformation and the transition to a more competitive environment. As a result, these historical indicators are not representative of the future long-term earning power of these companies.

Moreover, historical growth rates are not representative of future trends for utilities involved in mergers and acquisitions, as these companies going forward would not be the same companies for which historical data are available.

Q. Are you aware that some regulatory commissions (and some analysts) have placed principal reliance on DCF-based analyses to determine costs of equity for public utilities?

A. Yes, I am.

Q. Do you agree with this approach?

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

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

There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor.

Absent any hard evidence, which does not exist as far as I am concerned, as to which method outperforms the other, all relevant evidence should be used to minimize judgmental error, measurement error, and conceptual infirmities. A regulatory body should rely on the results of a variety of methods applied to a variety of comparable groups. It is unwarranted to conclude that the DCF model, standing alone, is necessarily the ideal or best predictor of the stock price and of the cost of equity reflected in that price, just as it should not be concluded that the CAPM or Risk Premium models, standing alone, produce the perfect or best explanation of that stock price or the cost of equity. As a result, all the various methodologies to estimate the cost of equity should be considered.

Q. Does the financial literature support the use of more than a single method?

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

> [i]n practical work, it is often best to use all three methods - CAPM, bond yield plus risk premium, and DCF - and then apply judgement when the methods produce different results. People experienced in estimating capital costs recognize that both careful analysis and some very fine judgements are required. It would be nice to pretend that these judgements are unnecessary and to

> specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible.

E. F. Brigham & L. C. Gapenski, Financial Management Theory and Practice, at 256 (4th ed., Dryden Press, Chicago, 1985). In a subsequent edition of his best-selling corporate finance textbook, Dr. Brigham discusses the various methods used in estimating the cost of common equity capital, and states:

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

Id. at 348.

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

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

R. A. Brealey & S. C. Myers, Principles of Corporate Finance, at 182 (3rd ed., McGraw Hill, New York, 1988). In an earlier article, Professor Myers explains that one should

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

S. C. Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," Financial Management, at 67 (Autumn 1978).

Q. Does the broad usage of the DCF methodology in past regulatory proceedings indicate that it is superior to other methods?

A. No, uncritical acceptance of the standard DCF equation vests the model with a degree of reliability that is simply not justified. One of the leading experts on regulation, Dr. Charles F. Phillips discussed the dangers of relying solely on the DCF model as follows:

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

> reasons, the DCF model suggests a degree of precision which is in fact not present and leaves wide room for controversy about the level of k [cost of equity].

C. F. Phillips, The Regulation of Public Utilities Theory and Practice, at 376-77 (Public Utilities Reports, Inc., 1988) (footnotes omitted). Dr. Charles F. Phillips also discusses the dangers of relying solely on the CAPM model because of the lack of realism of certain of its stringent assumptions, as is the case for any model in the social sciences.

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

2. Caution Regarding the DCF Methodology

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

A. Yes, particularly in today's rapidly changing utility industry. Even ignoring the fundamental thesis that several methods and/or variants of such methods should be used in measuring equity costs, the DCF methodology is problematic for use in estimating cost of equity at this time.

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

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

A. No, not always. Caution must be exercised when implementing the standard DCF model in a mechanistic fashion because it may fail to recognize changes in relative market valuations over time. The traditional DCF model is not equipped to deal with surges in price-earnings (P/E) and market-to-book (M/B) ratios.

The standard DCF model assumes a constant market valuation multiple, that is, a constant P/E ratio and a constant M/B ratio. Stated another way, the model assumes (i) that investors expect the ratio of market price to dividends (or earnings) in any given year to be the same as the current ratio of market price to dividend (or earnings) and (ii) that the stock price will grow at the same rate as the book value. This is a necessary result of the infinite growth assumption. This assumption is unrealistic under current conditions. The DCF model is not equipped to deal with sudden surges in P/E and M/B ratios, as was experienced by a number of utility stocks in recent years.

In short, caution and judgment are required in interpreting the results of the DCF model because of (i) the effect of changes in risk and growth on electric utilities, (ii) the disconnect between the tenets of the DCF model and the characteristics of utility stocks in the current capital market environment, and (iii) the practical difficulties associated with the growth component of the DCF model. Hence, there is a clear need to go beyond the DCF results and take into account the results produced by alternate methodologies in arriving at an ROE recommendation.

3. Caution Regarding the CAPM

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

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

B. CAPM Estimates

1. Background

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. The fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta.

According to the CAPM, securities are priced such that:

Expected Return = Risk-Free Rate + Risk Premium

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

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

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium given by β times (R_M - R_F). To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, (R_M - R_F). For the risk-free rate, I used a range of 4.7% - 5.3%, based on current and forecast long-term interest rates. For beta, I used 0.83. For the market risk premium I used 7.5%. These inputs to the CAPM are explained below.

2. <u>Risk-Free Rate</u>

Q. What risk-free rate did you use in your CAPM and risk premium analyses?

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

The appropriate proxy for the risk-free rate in the CAPM is the return on the longest term Treasury bond possible. This is because common stocks are very long-term instruments more akin to very long-term bonds rather than to short-term or intermediate-term Treasury notes, for example, 10-year 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 (i.e., 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, insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

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

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

Q. Dr. Morin, why did you reject short-term interest rates as a proxies for the risk-free rate in implementing the CAPM?

A. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, Treasury bills are used by the Federal Reserve Board 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 little sense to match the return on common stock to the yield on 90-day Treasury Bills. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

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

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

A. The level of U.S. Treasury 30-year long-term bond yields prevailing in December 2005 as reported in the Value Line Investment Analyzer ("VLIA") December 2005 edition was 4.7%. In response to the robust economic growth ongoing and forecast for 2006 recovery and in response to Federal Reserve Board policy, long-term yields are projected to be higher in 2006.

The consensus forecast for the yield on 10-year U. S. Treasury bonds in December 2006 reported in the December 2005 edition of Consensus Economics Inc.'s "Consensus Forecast" is 5.1%, an increase of 70 basis points (0.7%) over the current level of 4.4%. The consensus forecast reported in the Business Week Economists Survey published in the January 2nd 2006 edition of Business Week is 5.0%, an increase of 60 basis points over the current level of 4.4%, virtually the same forecast reported by Consensus Economics Inc.

Since long-term interest rates generally move in unison, an increase (decrease) in the yield on 10-year Treasury bonds should be accompanied by a parallel increase (decrease) in the yield on 30-year bonds. Given the prevailing level of 4.7% for 30-year Treasury bonds, the implied forecast for 30-year U. S. Treasury securities was therefore a mirror increase of at least 60 basis points from 4.7% to 5.3%. The forecast increase in long-term yields is not surprising in view of the solid economic growth of the U.S. economy, declining unemployment, and rising core inflation. I used a range of 4.7% - 5.3% as my estimate of the risk-free rate component of the CAPM.

3. <u>Beta</u>

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

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

As a wholly-owned subsidiary of Puget Energy, PSE is not publicly traded, and therefore, proxies must be used. I examined the betas of combination gas and electric utilities as proxies for PSE. As displayed on Exhibit No. ___(RAM-3), the average beta for investment-grade combination gas and electric utilities covered by AUS Utility Reports and Value Line and whose utility revenues constitute at least 50% of total revenues is 0.83.

As a check on the magnitude of PSE's beta, I examined the weighted average beta of PSE's natural gas business and vertically integrated electric utility business which constitute approximately one-third and two thirds of PSE's business, respectively.[1] Given that the average beta of investment-grade widely-traded natural gas and vertically integrated electric utilities is 0.81 and 0.85, respectively, and that these two segments constitute approximately one third and two-thirds of PSE's business, the weighted average beta of PSE is 1/3 x 0.81 + 2/3 x 0.85 = 0.84, virtually the same estimate obtained with the combination gas and electric proxy group. Based on these results, I used 0.83 as a reasonable estimate for the beta applicable to PSE.

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[1] The risk of PSE, as measured by beta, is a weighted average of the risks (betas) associated with the risk of each of its two principal business segments, that is, PSE's beta (β_p) is equal to the weighted average of the betas of its natural gas and electricity business segments:

$$\boldsymbol{\beta_P = w_{gas}\beta_{gas} + w_{elec}\beta_{elec}}$$

where, w_{gas} and w_{elec} represent the weight of the gas and electric business segments, and

β_{gas} and β_{elec} the betas of those business segments.

4. <u>Market Risk Premium</u>

Q. What market risk premium estimate did you use in your CAPM analysis?

A. For the market risk premium, I used 7.5%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums. First, the Ibbotson Associates study, *Stocks, Bonds, Bills, and Inflation, 2004 Yearbook,* compiling historical returns from 1926 to 2004, shows that a broad market sample of common stocks outperformed long-term U. S. Treasury bonds by 6.6%. The historical market risk premium over the income component of long-term Treasury bonds rather than over the total return is 7.2%. Ibbotson Associates recommend the use of the latter as a more reliable estimate of the historical market risk premium, and I concur with this viewpoint. This is because the income component of total bond return (*i.e.* the coupon rate) is a far better estimate of expected return than the total return (*i.e.* the coupon rate + capital gain), as realized capital gains/losses are largely unanticipated by bond investors.

Second, a DCF analysis applied to the aggregate equity market using Value Line's aggregate stock market index and growth forecasts indicates a prospective market risk premium of 7.7%. I have used the average of the historical and prospective estimates, 7.5%, as a reasonable estimate of the market risk premium.

Q. Why did you use long time periods in arriving at your historical market risk premium estimate?

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

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

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

Q. Please describe your prospective approach in deriving the market risk premium in the CAPM analysis.

A. For my prospective estimate of the market risk premium, I applied a DCF analysis to the aggregate equity market using Value Line's VLIA software. The dividend yield on the dividend-paying stocks that make up the S & P 500 index is currently 2.1% (VLIA 12/2005 edition), and the projected dividend and earnings growth rates for the more than 5000 stocks covered by Value Line are 8.6% and 12.4%, respectively. (Companies with projected growth and projected negative growth in excess of 20% were eliminated.) Adding the dividend yield to the growth component produces an expected return on the aggregate equity market in the range of 10.7% to 14.5%, with a midpoint of 12.6%.

Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 12.8%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings the market risk premium estimate to approximately 13.0%. Subtracting the risk-free rate from the latter, the implied risk premium is therefore 7.7% over long-term U.S. Treasury bonds that are expected to yield 5.3% in December 2006. The average of the historical and prospective market risk premium estimate is 7.5%.

As a check on my market risk premium estimate, I examined a recent 2003 comprehensive article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") that provides estimates of the ex ante expected returns for S & P 500 companies over the period 1983-1998. R. S. Harris, *et al.*, "*Ex Ante* Cost of Equity Estimates of S & P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, at 51-66 (Autumn 2003). 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. The prevailing risk-free rate for each year was then subtracted from the expected rate of return for the overall market to arrive at the market risk premium for that year. The table below, drawn from HMMO Table 2, displays the average prospective risk premium estimate (Column 2) for each year from 1983 to 1998. The average market risk premium estimate for the overall period is 7.2%, which is very close to my own estimate of 7.5%:

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

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

A. Inserting those input values in the CAPM equation, namely a risk-free rate of 4.7%, a beta of 0.83, and a market risk premium of 7.5%, the CAPM estimate of the cost of common equity is: 4.7% + 0.83 x 7.5% = 10.9%. This estimate becomes 11.2% with flotation costs, discussed later in my testimony. Using the forecast risk-free rate of 5.7%, the CAPM estimate becomes 11.8%, that is, 5.3% + 0.83 x 7.5% = 11.5%, without flotation costs and 11.8% with flotation costs.

Q. What is your risk premium estimate using the empirical version of the CAPM?

A. With respect to the empirical validity of the plain vanilla CAPM, there have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 13 of my book, <u>Regulatory Finance</u>, published by Public Utilities Report Inc. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.

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

$$\mathbf{K = R_F + \acute{\alpha} + \beta \times (MRP - \acute{\alpha})}$$

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

Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha 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 ECAPM expression:

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

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. That is, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. This is also because the use of adjusted betas rather than raw betas also incorporate some of the desired effect of using the ECAPM. Thus, it is reasonable to apply a conservative alpha adjustment.

Exhibit No. ___(RAM-4) contains a full discussion of the ECAPM, including its theoretical and empirical underpinnings. In short, the following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

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

Inserting 4.7% for the risk-free rate R_F, a market risk premium of 7.5% for (R_M - R_F) and a beta of 0.83 in the above equation, the return on common equity is 11.2% without flotation costs and 11.5% with flotation costs. The corresponding estimates using the forecast risk-free rate of 5.3% are 11.8% and 12.1%.

5. CAPM Estimates

Q. Please summarize your CAPM estimates.

A. The table below summarizes the ROE estimates obtained from the CAPM studies. The average CAPM result is 11.7%.

CAPM	ROE
CAPM Risk-free rate 4.7%	11.2%
CAPM Risk-free rate 5.3%	11.8%
Empirical CAPM Risk-free rate 4.7%	11.5%
Empirical CAPM Risk-free rate 5.3%	12.1%
AVERAGE	11.7%

C. Risk Premium Analyses

1. Historical Risk Premium Analysis of the Electric Utility Industry

Q. Please describe your historical risk premium analysis of the electric utility industry.

A. An historical risk premium for the electric utility industry was estimated with an annual time series analysis applied to the electric utility industry as a whole, using

Moody's Electric Utility Index as an industry proxy. The analysis is depicted on Exhibit No. ___(RAM-5). The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year from 1931 to 2001 using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. Data beyond 2001 were not readily available following the acquisition of Moody's by Mergent.

The average risk premium over the period was 5.6% over long-term Treasury bonds. Given that long-term Treasury bonds were yielding 4.7% in December 2005, the implied cost of equity for the average electric utility from this particular method is 4.7% + 5.6% = 10.3% without flotation costs and 10.6% with flotation costs. The need for a flotation cost allowance is discussed at length later in my testimony. Given that long-term Treasury bonds are expected to yield 5.3% in 2006, the implied cost of equity for the average electric utility is 5.3% + 5.6% = 10.9% without flotation costs and 11.2% with flotation costs.

2. Historical Risk Premium Analysis of the Natural Gas Distribution Industry

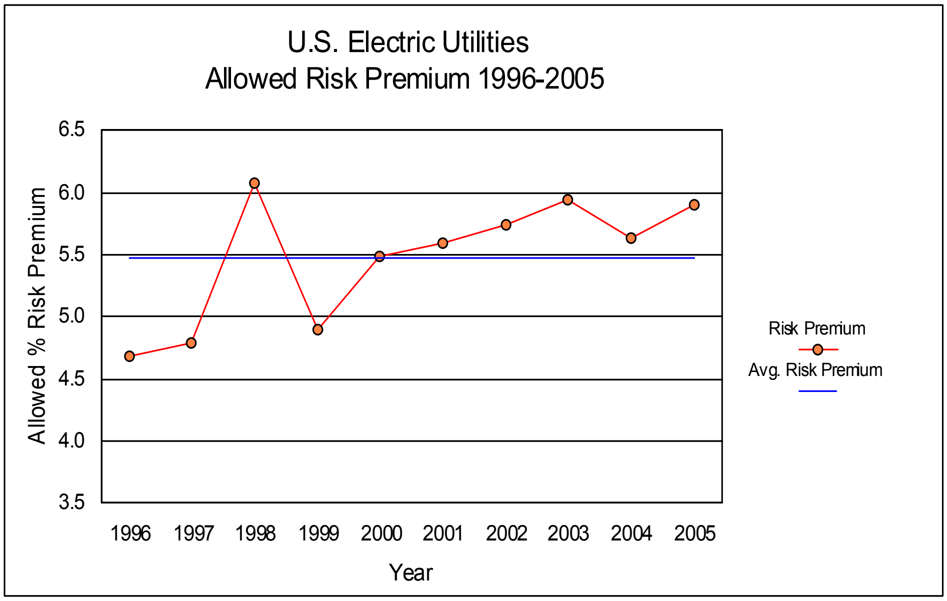
Q. Please describe your historical risk premium analysis of the natural gas distribution industry.

A. Given that PSE is a combination gas and electric utility, the same risk premium analysis was also applied to the natural gas utility industry. Moreover, the natural gas distribution business provides a reasonable proxy for PSE's energy delivery business. A historical risk premium for the natural gas distribution utility industry was estimated with an annual time series analysis from 1955 to 2001 applied to the natural gas distribution industry as a whole, using Moody's Natural Gas Distribution Index as an industry proxy. Data for this particular index was unavailable for periods prior to 1955. The analysis is depicted on Exhibit No. ___(RAM-6). The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. The average risk premium over the period was 5.7% over long-term Treasury bonds. Given that long-term Treasury bond yields were 4.7% in December 2005, the implied cost of equity from this particular method is 4.7% + 5.7% = 10.4% without flotation costs and 10.7% with flotation costs. Given that long-term Treasury bonds are expected to yield 5.3% in 2006, the implied cost of equity for the average electric utility is 5.3% + 5.7% = 11.0% without flotation costs and 11.3% with flotation costs.

3. <u>Allowed Risk Premiums in the Utility Industry (1996-2005)</u>

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

A. To estimate the Company's cost of common equity, I also examined the historical risk premiums implied in the returns on equity ("ROE") allowed by regulatory commissions for electric utilities over the last decade relative to the contemporaneous level of the long-term Treasury bond yield[2]. The average ROE spread over long-term Treasury yields was 5.5% for the 1996-2005 time period, as shown by the horizontal line in the graph below. The graph also shows the year-by-year allowed risk premium. The steady escalating trend of the risk premium in response to lower interest rates and rising competition and restructuring 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 last decade:

$$\mathbf{RP = 8.9291 - 0.6137\ YIELD} \qquad \mathbf{R^2 = 0.69}$$

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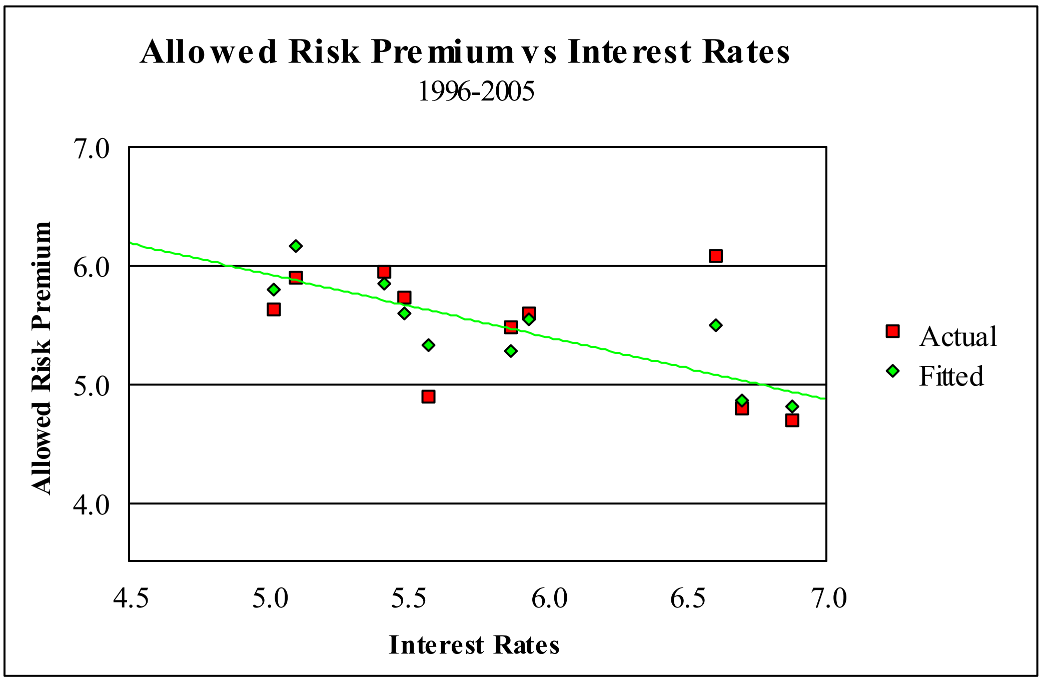
[2] Historical Allowed ROE data is available on a quarterly basis from Regulatory Research Associates.

(t = 4.3)

The relationship is statistically significant[3] as indicated by the high R^2 and statistically significant t-value of the slope coefficient. The following graph shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.



Inserting the current long-term Treasury bond yield of 4.7% in the above equation suggests that a risk premium estimate of 6.0% should be allowed for the average

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

risk electric utility, implying a cost of equity of 10.7% for the average risk utility. Using the projected bond yield of 5.3%, the risk premium is 5.7%, implying a cost of equity of 11.0%. Virtually identical results are obtained using allowed returns for natural gas utilities instead of electric utilities.

4. Risk Premium Estimates

Q. Please summarize your risk premium estimates.

A. The following table summarizes the ROE estimates obtained from the risk premium studies and the average risk premium of 10.9%:

Risk Premium	**ROE**
Risk Premium Electric Utility at 4.7%	10.6%
Risk Premium Electric Utility at 5.3%	11.2%
Risk Premium Natural Gas at 4.7%	10.7%
Risk Premium Natural Gas at 5.3%	11.3%
Allowed Risk Premium at 4.7%	10.7%
Allowed Risk Premium at 5.3%	11.0%
AVERAGE	**10.9%**

D. DCF Estimates

1. Background

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:

$$\mathbf{K_e = D_1/P_o + g}$$

where:

K_e = investors' expected return on equity
D_1 = expected dividend at the end of the coming year
P_o = current stock price
g = expected growth rate of dividends, earnings, book value, stock price

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

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

2. The Growth Component

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

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

As proxies for expected growth, I examined growth estimates developed by professional analysts employed by large investment brokerage institutions. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available to investors and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model.

Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. ("Zacks"). I used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. I also used Value Line's growth forecast as an additional proxy.

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

A. Columns 1, 2, and 3 of Exhibit No. ___(RAM-7) display the historical growth in earnings, dividends, and book value per share over the last five years for the combination gas and electric proxy group. The average historical growth rates in earnings, dividends, and book value for the group are 1.1%, -2.5%, and 2.6% over the past 5 years, respectively. Several companies have experienced a negative earnings growth rate, as evidenced by the numerous historical growth rates reported on the table that are negative.

These historical growth rates have little relevance as proxies for future long-term growth. They are downward-biased by the sluggish earnings performance in the last five years, due to the structural transformation of the electric utility industry from a regulated monopoly to a more competitive environment. These anemic historical growth rates are certainly not representative of these companies' long-term earning power, and produce unreasonably low DCF estimates, well outside reasonable limits of probability and common sense. To illustrate, adding the historical growth rates of 1.1%, -2.5%, and 2.6% to the average dividend yield of approximately 3.9% prevailing currently for those same companies, produces preposterous cost of equity estimates of 5.0%, 1.4%, and 6.5%, using earnings, dividends, and book value growth rates, respectively. Of course, these estimates of equity costs are outlandish as they are less than the cost of long-term debt for these companies.

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

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

A. No, I did not. This is because it is widely expected that electric utilities will continue to lower their dividend payout ratio over the next several years in response to the gradual penetration of competition and its potential impact on the revenue stream. In other words, earnings and dividends are not expected to grow at the same rate in the future. According to the latest edition of Value Line, the expected dividend growth of 4.6% for the proxy group is substantially less than the expected earnings growth of 6.5% over the next few years.

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

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

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

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

3. <u>DCF Analysis</u>

a. <u>Use of Three Proxies for PSE</u>

Q. How did you estimate the Company's cost of equity with the DCF model?

A. I applied the DCF model to three proxies for PSE: (1) PSE's parent company, Puget Energy; (2) a group of investment-grade combination gas and electric utilities that derive the majority of their revenues from regulated operations, and (3) a group of actively-traded dividend-paying natural gas distribution companies drawn from the Value Line Gas Distribution Group.

In order to apply the DCF model, two components are required: the expected dividend yield (D1/Po) and the expected long-term growth (g). The expected dividend D1 in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

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

In implementing the DCF model, I have used the dividend yields reported in the December 2005 edition of Value Line's VLIA. Basing dividend yields on average results from a large group of companies reduces the concern that vagaries of individual company stock prices will produce an unreliable dividend yield.

b. <u>DCF Results for Puget Energy</u>

Q. What DCF results did you obtain for PSE's parent company?

A. The DCF results for PSE's parent company can be gleaned from Exhibit No. ___(RAM-8) and Exhibit No. ___(RAM-10). As shown on line 16 Column 2 of Exhibit No. ___(RAM-10) Page 2, the long-term growth forecast obtained from the Zacks corporate earnings database is 5.3% for Puget Energy. Combining this growth rate with the expected dividend yield of 5.1% shown in Column 3 produces an estimate of equity costs of 10.4%. Recognition of flotation costs brings the cost of equity estimate to 10.7%, shown in Column 5.

Repeating the exact same procedure, only this time using Value Line's long-term earnings growth forecast of 5.5% instead of the Zacks consensus growth forecast, the cost of equity for Puget Energy is 10.6%, unadjusted for flotation costs. Adding an allowance for flotation costs brings the cost of equity estimate to 10.9%. This analysis is displayed on Page 2 of Exhibit No. ___(RAM-8), line 16.

c. <u>DCF Results for the Combination Gas and Electric Group</u>

Q. What DCF results did you obtain for the combination gas and electric group?

A. Exhibit No. ___(RAM-8) displays the DCF analysis for the group of 22 companies using the Value Line growth forecast for each company in the group. Exhibit No. ___(RAM-9) shows the current dividend yield and Value Line growth forecast for each company in the group. Three companies were removed from the group: (i) TECO Energy had no Value Line growth forecast available, (ii) PG&E's forecast growth rate of 26.5% is unduly high and unsustainable, and (iii) Public Service Enterprise's DCF estimate of about 4% is far less than the cost of debt. Page 2 shows the final DCF analysis for the remaining 19 companies.

As shown on Column 2, the average long-term growth forecast from Value Line is 5.7% for this group. Adding this growth rate to the average expected dividend yield of 4.2% shown in Column 3 produces an estimate of equity costs of 9.9% for the group, unadjusted for flotation costs. Adding an allowance for flotation costs to the results of Column 4 brings the cost of equity estimate to 10.1%, shown in Column 5.

Using the Zacks analysts' consensus forecast of long-term earnings growth instead of the Value Line forecast, the cost of equity for the group is coincidentally the same at 10.1%. Exhibit No. ___(RAM-10) displays the DCF analysis for the group of 22 companies using the Zacks growth forecast for each company in the group. Exhibit No. ___(RAM-11) shows the current dividend yield and Zacks growth forecast for each company in the group. No growth projections were available for CH Energy, MGE Energy, and Unisource, and these three companies were therefore eliminated from the group.

d. DCF Results for the Natural Gas Utilities

Q. What DCF results did you obtain for the natural gas utilities?

A. The natural gas distribution utility business comprises a significant portion of PSE's total business and provides a reasonable proxy for PSE's electricity delivery business as well. Accordingly, I have examined the expected returns of dividend-paying natural gas distribution utilities contained in Value Line's natural gas distribution universe with a market value in excess of $500 million. The group is shown in Exhibit No. ___(RAM-12).

As shown on Column 3 of Exhibit No. ___(RAM-12), the average long-term growth forecast obtained from the Zacks corporate earnings database is 5.1% for the gas distribution group. Combining this growth rate with the average expected dividend yield of 4.3% shown in Column 4 produces an estimate of equity costs of 9.4% for the gas distribution group. Recognition of flotation costs brings the cost of equity estimate to 9.6%, shown in Column 6.

Repeating the exact same procedure, only this time using Value Line's long-term earnings growth forecast of 6.6% instead of the Zacks consensus growth forecast, the cost of equity for gas distribution group is 11.0%, unadjusted for flotation costs. Adding an allowance for flotation costs brings the cost of equity estimate to 11.2%. This analysis is displayed on Exhibit No. ___(RAM-13).

4. DCF Estimates

Q. Please summarize your DCF estimates.

A. The table below summarizes the DCF estimates. The average result is 10.4%.

DCF Study	ROE
Puget Energy Inc. Zacks Growth	10.9%
Puget Energy Inc. Value Line Growth	10.7%
Combination Gas and Electric Zacks Growth	10.1%
Combination Gas and Electric Value Line Growth	10.1%
Natural Gas Distribution Zacks Growth	9.6%
Natural Gas Distribution Value Line Growth	11.2%
AVERAGE	**10.4%**

E. Flotation Cost Adjustment

Q. Please describe the need for a flotation cost allowance.

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

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

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. Exhibit No. ___(RAM-14) discusses flotation costs in detail, and shows: (i) 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 (iii) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

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

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.52%.

According to the empirical finance literature discussed in Exhibit No. ___(RAM-14), total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 30 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 5.0% for utility stocks by 0.95 yields 5.3%, which is 30 basis points higher.

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

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

Q. Is a flotation cost adjustment required for an operating subsidiary like PSE that does not trade publicly?

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

IV. SUMMARY AND RECOMMENDATION ON COST OF EQUITY

A. Summary of Results of the Three Market-Based Methodologies

Q. Please summarize your results and recommendation.

A. To arrive at my final recommendation, I performed five risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other three risk premium analyses were performed on historical and allowed risk premium data from both electric utility and natural gas distribution industry aggregate data, using both the current and forecast yields on long-term Treasury bonds. I also performed DCF analyses on three surrogates for PSE: the parent company, a group representative of the combination gas and electric utility industry, and a group representative of the natural gas distribution utility industry.

The results are summarized in the table below.

STUDY	ROE
CAPM Risk-free rate 4.7%	11.2%
CAPM Risk-free rate 5.3%	11.8%
Empirical CAPM Risk-free rate 4.7%	11.5%
Empirical CAPM Risk-free rate 5.3%	12.1%
Risk Premium Electric at 4.7%	10.6%
Risk Premium Electric at 5.3%	11.2%
Risk Premium Natural Gas at 4.7%	10.7%
Risk Premium Natural Gas at 5.3%	11.3%
Allowed Risk Premium at 4.7%	10.7%
Allowed Risk Premium at 5.3%	11.0%
DCF Puget Energy Value Line Growth	10.7%
DCF Puget Energy Zacks Growth	10.9%
DCF Combination Gas and Electric Utilities Zacks Growth	10.1%
DCF Combination Gas and Electric Utilities Value Line Growth	10.1%
DCF Natural Gas Distribution Value Line Growth	11.2%
DCF Natural Gas Distribution Zacks Growth	9.6%

The central tendency of the results is 10.9% for the average risk utility, as indicated by the mean, truncated mean, and midpoint result. Yet another way of presenting the results is on a methodological basis. The average result from the three principal methodologies is as follows:

CAPM	11.7%
Risk Premium	10.9%
DCF	10.4%
Average	11.0%

The overall average result is 11.0% for the average risk utility.

B. Adjustment to the Estimated ROE to Account for the Fact that PSE is Riskier than the Average Electric Utility

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

A. Yes, I have. The cost of equity estimates derived from the various comparable groups reflect the risk of the average electric and natural gas utility. To the extent that these estimates are drawn from a less risky group of companies, the expected equity return applicable to the riskier PSE is downward-biased. In my judgment, a reasonable estimate of the risk differential is on the order of 25 basis points and I have adjusted my result of 11.0% for the average risk utility upward to 11.25% in order to account for PSE's higher relative risks. As explained in detail below, PSE's distinguishing risk features relative to its peers is related mainly, but not exclusively, to PSE's gargantuan capital spending program for the next several years and the various risks associated with such an ambitious construction program. The risk increment of 25 basis points is based on the differences in yield between utility long-term bonds rated Baa and those rated single A and by differences between PSE's debt ratio adjusted for the presence of purchased power obligations and that of the electric utility industry.

Q. Please comment on PSE's investment risks relative to other electric and natural gas utilities.

A. Four major factors drive PSE's higher risk profile relative to other utilities: construction risk, power costs risks and the Company's PCA Mechanism, regulatory lag, and financial risk.

1. <u>Construction Risk</u>

Q. Please comment on the construction risks faced by PSE.

A. The term construction risk refers to the financial risks caused by the magnitude of a company's capital budget. Capital expenditures to meet anticipated increases in demand, refurbish old infrastructure, and increase internal power generation to reduce power cost volatility represent an important source of risk. On the one hand, anticipated increases in demand are more difficult to forecast than existing demand. Because of the relatively long lead times associated with utility planning and construction of new plant, there is significant risk that demand will be less than the level forecasted when the new capital investment was planned. On the other hand, a large construction program increases both financial and regulatory risks.

PSE has a massive construction program relative to its size, some estimated $1.4 billion scheduled capital spending for the next two years alone. To place this number in perspective, that represents an increase of some 25% in its rate base for the next two years alone. The Company's ability (through its parent) to tap capital markets and attract funds on reasonable terms occurs at a crucial point in time when the Company has an ambitious capital expenditures program and requires external financing. PSE's large capital expenditure program over the next several years, relative to its size, increases its dependence on capital markets which have become volatile and more unpredictable.

PSE's massive construction requirements also have a substantial impact on its financial risk. The Company will require substantial external financing over the next few years. It is imperative the Company have access to capital funds at reasonable terms and conditions. The Company must secure outside funds from capital markets to finance new required capacity, irrespective of capital market conditions, interest rate conditions and the quality consciousness of market participants. Construction is one of the key determinants of credit quality, and hence capital costs. The construction budget relative to internal cash generation is a key quantitative determinant of financial risk. The Company will need to rely heavily on capital markets to finance its construction program.

On debt markets, construction is one of several key determinants of credit quality and, hence, of capital costs. Company future construction plans are scrutinized by bond rating agencies before assessing credit quality. The construction budget in relation to internal cash generation is a key quantitative determinant of credit quality, along with construction expenditures as a proportion of capitalization. Construction to capitalization and common equity ratios are also analyzed by investors and become key determinants of capital costs and funds availability. More generally, the empirical finance literature has demonstrated clearly that construction is a key determinant of a utility's capital costs.

Because of PSE's large construction program over the next few years, rate relief requirements and regulatory treatment uncertainty will increase regulatory risks as well. Generally, regulatory risks include approval risks, lags and delays, potential rate base exclusions, and potential disallowances. Continued regulatory support from the Commission will be required. Reviews of the economic and environmental aspects of new construction can consume as much as one year before approval or denial. Uncertainty of approval increases forecasting and planning risks and complicates the utility's ability to devise an optimum transmission/distribution system. Regulatory approval for financings required for new construction may also be required, injecting additional risks.

2. <u>Power Costs Risks and the Company's PCA Mechanism</u>

Q. Dr. Morin, can you please comment on the Company's power cost risk?

A. Yes. Because of the Company's predominantly hydro-based generating capacity, a dominant element of business risk peculiar to PSE is a significant reliance on a volatile water supply and on replacement power. Hydroelectric production for

PSE was below average in 2005, although the revised power cost sharing bands proposed by the Company, assuming they are approved by the Commission, should help protect the Company from the cost of procuring more expensive replacement power in the future. My ROE recommendation is predicated on the Commission's adoption of the revisions to the PCA Mechanism proposed by the Company in this proceeding.

Q. Dr. Morin, can you please comment on the impact of the PCA Mechanism on the Company's investment risk?

A. Yes, certainly. The PCA Mechanism serves to reimburse PSE for prudently-incurred energy costs in a manner that minimizes the negative financial effects caused by regulatory lag. Consideration of energy costs in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. This is certainly the case for PSE although the specifics of the PCA Mechanism are such that the risks inherent in the mechanism are higher than the norm. The financial community relies on the presence of energy cost recovery mechanisms such as the PCA Mechanism to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility, even when prudently managed. To illustrate, it is my understanding that bond rating agencies would place considerably more weight on the Company's purchased power contracts as debt equivalents in the absence of PCA Mechanism, thus weakening the Company's financial integrity. The PCA Mechanism mitigates a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection is factored into the Company's credit profile as a negative element which in turn raises its cost of capital, as discussed above.

The approval of cost recovery mechanisms (fuel adjustment clauses, purchased water adjustment clauses, environmental riders, and purchased gas adjustment clauses) by regulatory commissions is widespread in the utility business. All else remaining constant, such clauses reduce investment risk on an absolute basis and constitute sound regulatory policy.

The PCA Mechanism's $40 million cap is scheduled to expire at the end of June 2006. I believe that in the absence of the Commission's adoption of the Company's proposed revisions to the PCA Mechanism to mitigate this additional risk, PSE's financial condition would deteriorate, its credit ratings would likely be under review for possible downgrade, and its customers would be at risk of having to pay higher rates due to access to capital becoming more expensive for PSE. This situation would have a substantial effect on PSE and its customers because of the magnitude of the energy cost component in its cost of service. The Company's bond rating is already marginal at Baa3, only one notch above junk bond territory, and any further deterioration in the Company's credit rating would have serious negative consequences for both ratepayers and investors.

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

I strongly encourage the Commission to adopt the Company's proposed revisions to the PCA Mechanism, and I believe that such proposed revisions are fair to PSE, its customers, and investors. I believe that the PCA Mechanism, as revised, will better deal with the cost of fuel and purchased energy, as well as with the mix of resources, which can vary month-to-month and which can represent a considerable financial outlay, on a consistent basis, without need for recurring regulatory proceedings that are time-consuming, costly, and, significantly, create uncertainty within the financial community.

3. <u>Regulatory Lag</u>

Q. Is the Company's exposure to regulatory lag significant?

A. Yes, it is relative to other utilities. Although the state's regulatory climate has been restrictive in the past, the Commission's more recent orders have generally been fair and reasonable. It is crucial that the supportive regulatory climate continue given that strong regulatory relief is critical to the Company's future. As evidenced from several investment research and credit agency reports on the Company, investors are keenly aware of the need for strong regulatory support. In the current environment of volatile and rising fuel and purchased power costs, of record-high capital spending to procure new generation resources, timely and adequate regulatory support is critical to the Company's future. However, because rate decisions cannot be implemented retroactively, the Company's exposure to regulatory lag remains substantial relative to other utilities.

The problem of regulatory lag is well-known in the utility industry and is particularly acute in the case of PSE. Its presence makes it difficult to earn a reasonable rate of return, especially in an inflationary environment. In fact, PSE has been unable to earn its allowed return for the past five years. Regulatory lag exerts a significant drag on the Company's ability to earn its allowed rate of return and creates mismatches between regulatory rates and supply-demand-costs so that prices are either too high or too low. Inefficient resource allocation and distorted consumer pricing signals may result. One expedient solution to the regulatory lag issue is the use of forward test years rather than historical test years. Another solution is to pass through to ratepayers external power costs on a dollar-to-dollar basis without deadbands, subject to audit.

Notwithstanding the regulatory lag issue, there are material regulatory challenges ahead, not the least of which is the uncertainty surrounding revisions to the PCA Mechanism and the need for very large capital investments in the near future.

4. Financial Risk

Q. Dr. Morin, what do you mean by financial risks?

A. Financial risk stems from the method used by the firm to finance its investments and is reflected in its capital structure. It refers to the additional variability imparted to income available to common shareholders by the employment of fixed cost financing, that is, debt capital. Although the use of fixed cost capital (debt and preferred stock) can offer financial advantages through the possibility of leverage of earnings, it creates additional risk due to the fixed contractual obligations associated with such capital. Debt carries fixed charge burdens which must be supported by the Company's earnings before any return can be made available to the common shareholder. The greater the percentage of fixed charges to the total income of the Company, the greater the financial risk. The use of fixed cost financing introduces additional variability into the pattern of net earnings over and above that already conferred by business risk.

a. Effect of Imputed Debt On Capital Structure

Q. Dr. Morin, how do purchased power contracts affect an electric utility's financial risk profile?

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

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

[[*See* Exhibit No. ___(DEG-3)]]. The risk perceptions of the investment community and bond rating agencies are such that incremental long-term fixed obligations associated with acquiring energy through off-system purchases increase a utility's financial risk. Clearly, if a company's purchased power contract obligations are converted to a debt equivalent, that company's effective debt ratio increases, and so does its risk.

Q. Does financial theory provide a reasonable and consistent method of adjusting for the increased risk and return associated with purchased power contracts?

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

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

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

Q. Can you provide a numerical example of the manner in which debt equivalents increase the cost of equity?

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

Q. How does the inclusion of purchased power contracts affect PSE's common equity ratio?

A. PSE's 2005 year-end capital structure consisted of approximately 45% common equity and 55% debt, unadjusted for purchased power contracts. According to Standard and Poor's debt equivalent calculations, the inclusion of PSE's purchased power contracts as debt equivalent lowers PSE's common equity ratio from 45% to approximately 43%, a decrease of 2%. Based on the above calculation, an upward adjustment of approximately 25 basis points to the initial cost of common equity estimate of 11.0% would be required to reflect this additional risk alone.

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

A. Yes, I did. I have compared PSE's requested capital structure with: 1) the capital structures adopted by regulators for electric and gas utilities, 2) the capital structure benchmark contained in Standard and Poor's ("S&P") Rating Criteria for electric and gas utilities, and 3) the capital structures of comparable risk investor-owned gas and electric utilities.

The October 2005 edition of Regulatory Research Associates' "*Regulatory Focus: Major Rate Case Decisions*" reports an average percentage of common equity in the adopted capital structure of 45% and 48% for electric and gas utilities, respectively, for 2005, versus the Company's unadjusted 45%. The latter figure does not account for the Company's higher than average debt equivalent on account of its purchased power contracts that brings its effective equity ratio below 43%.

I have also compared the Company's test year debt ratio of 55% to the capital structure benchmark contained in Standard and Poor's ("S&P") Rating Criteria for electric and gas utilities. PSE is assigned a Business Risk Position of 4.0 by S&P on a scale of 1.0 to 10.0, with 1.0 being the least risky and 10.0 the most risky. For a utility with a Business Risk Position of 4.0, the debt ratio benchmark for a single "A" bond rating, which I consider optimal for both ratepayers and utility investors, is 45% – 52% versus the Company's 55% debt ratio unadjusted for purchased power debt equivalence. The Company's 55% debt ratio lies well outside the range for a single "A" bond rating. The benchmark for a BBB bond rating is 52% – 62%, again unadjusted for purchased power debt equivalence. For a BBB bond rating, the Company's adjusted debt ratio lies at the midpoint of the range.

Finally, I have examined the actual capital structures of comparable risk electric utility operating companies reported in Moody's Power Source Book 2005. The average common equity ratio for U.S. A-rated operating electric utility companies is 48%, 50%, and 49% for 2004, 2003, and 2002, respectively. This exceeds the Company's 45% common equity ratio.

Moreover, given the Company's small size relative to other combination gas and electric utilities[4], a stronger capital structure, that is, one consisting of a higher

[4] The average common equity market capitalization reported by Value Line for the comparable gas and electric utilities on Exhibit No. ___(RAM-3) is $7.3 billion compared to Puget Energy's $2.1 billion.

proportion of common equity capital, is generally required by investors to offset the small capitalization. It is well documented in the finance literature that investment risk increases as company size diminishes, all else remaining constant. Small firms experience average returns greater than those of large firms that are of equivalent systematic risk (beta) and produce greater returns than could be explained by their risks. Empirically, stocks of small firms earn higher risk-adjusted abnormal returns than those of large firms. Ibbotson Associates' widely-used annual historical return series publication covering the period 1926 to the present reinforces this evidence; the average small stock premium is approximately 6% over the average stock, more than could be expected by risk differences alone, suggesting that the cost of equity for small stocks is considerably larger than for large capitalization stocks. In addition to earning the highest average rates of return, small stocks also have the highest volatility, as measured by the standard deviation of returns.

I conclude that the Company's common equity ratio of 45% is weak relative to its peers, its small size, the S&P bond rating benchmarks, and especially in light of the chronic need for massive external financing over the next several years.

If the Commission imputes a capital structure consisting of substantially more (less) debt than the requested capital structure, the higher (lower) common equity cost rate related to a changed common equity ratio should be reflected in the approach. If the Commission ascribes a capital structure different from the requested capital structure, which imputes a higher debt amount for example, the repercussions on equity costs must be recognized. It is a rudimentary tenet of basic finance that the greater the amount of financial risk borne by common shareholders, the greater the return required by shareholders in order to be compensated for the added financial risk imparted by the greater use of senior debt financing. In other words, the greater the debt ratio, the greater is the return required by equity investors. Both the cost of incremental debt and the cost of equity must be adjusted to reflect the additional risk associated with the more debt-heavy capital structure. Lower common equity ratios imply greater risk and higher capital cost, and conversely.

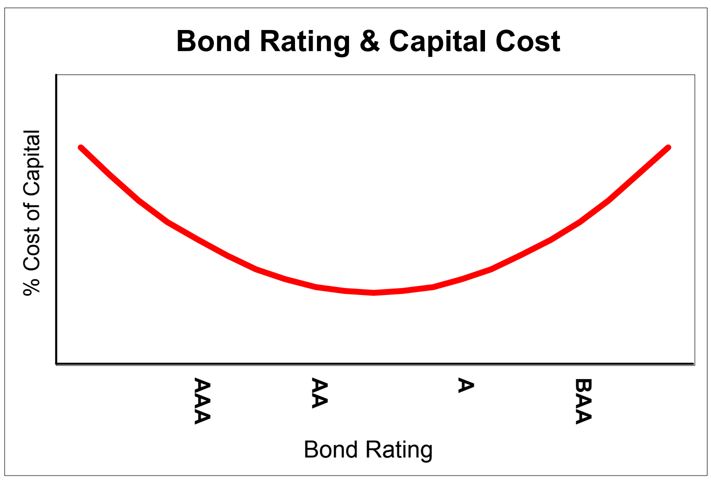
b. <u>Credit Ratings</u>

Q. Dr. Morin, you mentioned earlier the need for an optimal bond rating of at least single A. Could you elaborate on that point?

A. Yes, certainly. It is in both ratepayers' and investors' interest that a regulated utility be financially sound and have the credit rating and financial flexibility needed to (i) cope with the increased operational challenges in today's much more volatile industry environment; (ii) pursue initiatives to further increase performance, and (iii) finance in a timely and cost effective fashion the significant infrastructure investment needs faced in PSE's service territory.

In the utility regulation context, the idea of an optimal strong "A" bond rating for a utility's senior securities is widely supported. That is why the vast majority of utilities in North America migrate to such a bond rating.

I have performed several studies and I have frequently testified on the optimal capital structure for various utilities. One common theme in these studies and testimonies is the desirability of a strong "A" bond rating from both the ratepayers' and investors' standpoint. Chapter 19 of my book Regulatory Finance describes a capital structure simulation model for electric utilities using market data prior to industry restructuring. The graph below illustrates the major finding of the model, and demonstrates how the cost of capital changes as the debt ratio increases and the bond rating declines.



The horizontal axis shows that as the company substitutes debt for equity, the bond rating progressively deteriorates from "AAA" all the way down to "BAA" and beyond. The vertical axis shows what happens to overall capital costs, hence to rates, as the company continues to substitute debt for equity and its bond rating deteriorates. With each successive substitution of lower-cost debt for higher-cost equity, the average cost of capital declines as the weight of low-cost debt in the weighted average cost of capital increases. An optimal point is reached where the cost advantage of debt is exactly offset by the increased cost of equity. This is the optimal capital structure point. Beyond that point, the cost disadvantage of equity outweighs the cost advantage of debt, and the weighted cost of capital rises accordingly. The message from the graph is clear: over the long run, a strong "A" bond rating will minimize the cost of capital to ratepayers.

Several intangible costs and distress costs associated with a low bond rating cannot be readily accommodated into a mathematical simulation model without the model becoming computationally prohibitive. Thus, the case for a strong "A" bond rating is understated in these studies. Several examples of such costs follow.

The need to maintain borrowing capacity is well known. During normal times, a utility company should conserve enough unused borrowing capacity so that during adverse capital market periods it can use this capacity to avoid foregoing investment opportunities, selling stock at confiscatory prices, or jeopardizing its mandated obligation to serve. The yield advantage of a higher bond rating increases dramatically in adverse capital market conditions.

Bond flotation costs, which must be borne by ratepayers, increase also as bond ratings decline, particularly in years of difficult financial markets. Not only is lower bond quality associated with higher yields, but lower-rated utility bonds also carry shorter maturities, especially in poor years. The result is a maturity mismatch between the firm's long-term capital assets and its liabilities.

Moreover, lower bond quality is associated with more years of call protection, particularly during difficult financial markets; since bonds are frequently called after a decrease in interest rates, bonds which carry call protection for a greater number of years are more costly to utility companies. Finally, as bond ratings decline, the probability that a company will reduce the dollar amount or shorten the maturity of their bond issues increases dramatically; this in turn reduces the marketability of a bond issue, and hence increases its yield. Any reasonable quantification of such implicit costs reinforces the case for a strong "A" rating.

The implication for PSE is very clear. Long-term achievement and maintenance of a strong "A" rating is in investors' and ratepayers' best interests. Capital structure targets should be therefore set so as to achieve such ratings.

Q. Dr. Morin, in light of your discussion of an optimal bond rating, please comment on PSE's capital structure.

A. Long-term achievement and maintenance of a strong "A" rating is in investors' and ratepayers' best interests. Capital structure targets should be therefore set so as to achieve such ratings. Moreover, the average bond rating for the electric utility is also in the single A range. In addition, although the legal definition of investment grade is "BBB", the actual practical definition of investment grade is "A". This is because a large majority of institutional investors are precluded from investing in bonds rated below "A". For all these reasons, sound public policy requires that the Commission establish rates so as to create financial conditions conducive to an optimal bond rating of at least single “A”.

As discussed earlier, the Company’s financial condition is not consistent with a single “A” credit rating. The Company’s common equity ratio of 45% is weak relative to its peers, its small size, the S&P bond rating benchmarks, and especially in light of its chronic need for external financing over the next several years. In light of PSE’s massive capital expenditure requirements and the critical importance of preserving access to capital markets, PSE’s goal is to achieve strong single “A” credit ratings. Consequently, PSE’s credit profile with the two major credit rating agencies needs to improve in order to support an upgrade from its current unsecured rating levels to a Single “A” rated level. This goal implies continued improvement in reducing debt, reducing interest expense and increasing cash flows.

The existence of a strong equity base favorably impacts the cost of debt by virtue of superior credit ratings, allows the company to absorb operating deficits without violating debt servicing obligations, and provides flexibility and freedom in timing new debt issues, in that capital can be raised with discretion under favorable capital market conditions.

V. CONCLUSION

Q. Dr. Morin, what is your final conclusion regarding PSE's cost of equity capital?

A. In conclusion, in my judgment, PSE's total investment risk is slightly higher than the industry at this time. This is corroborated by the Company's below average bond rating in the utility industry. I have therefore increased my recommended return slightly from 11.0% to 11.25% in order to recognize PSE's higher relative risk. The conservative 25 basis points upward adjustment is based on utility bond yield spread differentials between A-rated and Baa-rated bonds and on observed beta differentials. Based on the results of all my analyses and the application of my professional judgment, it is my opinion that a just and reasonable return on common equity is 11.25%. My recommended return is predicated on the assumption that the Commission will approve the Company's proposed revisions to the PCA Mechanism. Absent such revisions to this mechanism, the Company's risk with regard to volatile fuel prices would be significantly enhanced and the rate of return on common equity correspondingly significantly higher. My recommendation is also predicated on the adoption of the Company's capital structure consisting of 45% common equity capital.

Q. Is there a relationship between financial risk and the authorized return on equity?

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

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

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

As the company relies more on debt financing, its capital structure becomes more leveraged. Because (i) debt payments are a fixed financial obligation to the utility and (ii) income available to common equity is subordinate to fixed charges, additional leverage decreases the operating income available for dividend and earnings growth. Consequently, equity investors face greater uncertainty about future dividends and earnings from the firm. As a result, the firm's equity becomes a riskier investment.

The risk of default on the company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility the company will not have access to the capital markets for its outside financing needs.

Ultimately, to ensure that PSE has access to capital markets for its capital needs, a fair and reasonable authorized ROE of 11.25% is required.

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

A. Yes. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes occur between the time my appraisal of the Company's ROE was done and the time rebuttal testimony or my oral summary testimony is presented, I will update my testimony accordingly.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

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