Direct Testimony and Schedules
Daniel S. Dane

Before the South Dakota Public Utilities Commission
State of South Dakota

In the Matter of the Application of Northern States Power Company,
a Minnesota corporation
for Authority to Increase Rates for Electric Service in South Dakota

Docket No. EL11-___
Exhibit___ (DSD-1)

Rate of Return and
Return on Equity

June 30, 2011

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Daniel S. Dane. I am a Senior Project Manager at Concentric Energy Advisors, Inc. ("Concentric"), located at 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752. I also serve as the Financial and Operations Principal of CE Capital Advisors, a FINRA-member firm and a subsidiary of Concentric.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this testimony on behalf of Northern States Power Company, a Minnesota corporation operating in South Dakota ("NSP" or the "Company"). NSP is a wholly owned subsidiary of Xcel Energy Inc. ("XEI").

Q. PLEASE DESCRIBE CONCENTRIC'S ACTIVITIES IN ENERGY AND UTILITY ENGAGEMENTS.

A. Concentric provides financial and economic advisory services to a large number of energy and utility clients across North America. Our regulatory, economic and market analysis services include utility ratemaking and regulatory advisory services, energy market assessments, market entry and exit analysis, corporate and business unit strategy development, and energy contract negotiations. Our financial advisory activities include merger, acquisition, and divestiture assignments; due diligence and valuation assignments; project and corporate finance services; and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues for clients throughout North America.

Q. WHAT ARE YOUR RESPONSIBILITIES IN YOUR CURRENT POSITION?

A. As a consultant, my responsibilities include assisting clients in identifying and addressing business issues. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of those assignments have included the determination of the cost of capital for valuation purposes. I have included my résumé as Exhibit__(DSD-1), Schedule 1.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I have an MBA from Boston College in Chestnut Hill, Massachusetts and a BA in Economics from Colgate University in Hamilton, New York. I am a certified public accountant, and am a member of the Massachusetts Society of Certified Public Accountants. I am also a licensed securities professional (Series 7, 28, 63, and 79).

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to present evidence and provide an opinion regarding the proposed return on equity ("ROE") for the Company, as well as the Company's proposed capital structure and cost of debt for ratemaking purposes. My analysis and conclusions are supported by the data presented in Exhibit__(DSD-1), Schedules 2 through 8, which have been prepared by me or under my direction in connection with my Direct Testimony.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF NSP'S SOUTH DAKOTA OPERATIONS.

A. NSP's South Dakota operations serve electric residential and business customers in eastern South Dakota. The Company's customer base is largely comprised of commercial and industrial customers. NSP's credit ratings are A-, A3, and A- from Standard & Poor's ("S&P"), Moody's, and Fitch Ratings ("Fitch"), respectively. Table 1 (below) provides operating and financial results for NSP's South Dakota operations from 2008 through 2010.

Table 1: NSP - 2008 to 2010 Electric Operating and Financial Results, South Dakota Operations[1]

	2008	2009	2010
Operating Revenues ($000s)	$183,384	$175,581	$196,286
Regulated Operating Income ($000s)	$16,085	$13,632	$13,697
Average Electric Customers	80,585	82,037	83,182
Total Electric (kWh) (000s)	1,942,545	1,918,434	2,000,289

Q. PLEASE SUMMARIZE YOUR PRINCIPLE CONCLUSIONS REGARDING THE APPROPRIATE COST OF CAPITAL FOR THE COMPANY.

A. Based on the analyses I have performed and that are discussed herein, I find a reasonable range for the ROE for NSP to be from 10.75 percent to 11.25 percent. Within that range, I recommend that the South Dakota Public Utilities Commission (the "Commission") authorize the Company the opportunity to earn an ROE of 11.00 percent. As described in greater detail later in my testimony, that recommendation is based on the use of several

[1] South Dakota Jurisdictional reports; Company data.

well-accepted methodologies, and reflects market data from companies directly comparable to NSP. I also have concluded that the Company's proposed cost of debt, and NSP's proposed capital structure of 52.48 percent common equity and 47.52 percent long-term debt, are reasonable. The proposed overall rate of return is summarized in Table 2:

Table 2: Capital Structure and Cost of Capital

	Percent	Cost Rate	Weighted Cost
Common Equity	52.48%	11.00%	5.77%
Long-term debt	47.52%	6.33%	3.01%
Total Capitalization	100.00%		8.78%

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSIS THAT LED TO YOUR CONCLUSIONS.

A. My recommendation of the appropriate ROE for the Company is based primarily on the results of the Discounted Cash Flow ("DCF") approach, adjusted for flotation costs, and is corroborated by the results of a risk premium approach. I also considered current economic trends and business risks specific to the Company in making my recommendation, although I did not make an explicit adjustment for those factors.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my Direct Testimony is organized into six sections. Section III discusses the regulatory guidelines and financial considerations pertinent to the development of the cost of capital, as well as current underlying economic conditions and their effect on the cost of capital; Section IV explains my selection of a proxy group of integrated electric utilities; Section V explains my analysis and the analytical basis for my recommendation of the appropriate ROE for the Company; Section VI provides a discussion of specific business risks and other factors that have a direct bearing on the ROE to be authorized for the Company in this proceeding; Section VII provides a discussion of the analysis that supports the Company's proposed capital structure and cost of long-term debt; and Section VIII summarizes my conclusions and recommendations.

III. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS

Q. PLEASE DESCRIBE THE GUIDING PRINCIPLES TO BE USED IN ESTABLISHING THE ROE FOR A REGULATED UTILITY.

A. The United States Supreme Court's *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. In those cases the Court established standards: (1) that authorized returns be consistent with other businesses having similar or comparable risks; (2) that the return be adequate to support credit quality and access to capital; and (3) that the means of arriving at a fair return are not important, only that the end result leads to just and reasonable rates.[2]

Based on the standards established in *Hope* and *Bluefield*, the Commission's order in this proceeding should provide the Company with the opportunity to earn an ROE that is:

- Adequate to allow the Company to attract the capital that is necessary to provide safe and reliable service;

[2] *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

- Sufficient to ensure the Company's ability to maintain its financial integrity; and
- At a level that is comparable to returns required on investments of similar risk.

Q. WHY IS IT IMPORTANT FOR A UTILITY TO BE ALLOWED THE OPPORTUNITY TO EARN A RETURN ADEQUATE TO ATTRACT EQUITY CAPITAL AT REASONABLE TERMS?

A. The allowed ROE should be sufficient to enable the Company to finance capital expenditures and working capital requirements at reasonable rates and maintain financial integrity during a variety of economic and capital market conditions. A return that is adequate to attract capital at reasonable terms enables the subject company to provide safe, reliable service while maintaining its financial integrity. While the "capital attraction" and "financial integrity" standards are important principles in normal economic conditions, the practical implications of those standards are even more pronounced when, as discussed in more detail below and in the Direct Testimony of Ms. Laura McCarten, the Company is making very substantial capital investments and when considered in the context of the recent financial environment.

In addition, the rates set in this case, including the ROE and capital structure, will directly affect the Company's cash flows during the period in which rates are in effect. Since credit ratings are intended to reflect a company's ability to fund financial obligations, the ability to generate internally the cash flows required to meet those obligations (and to provide an additional amount for unexpected events) is of critical importance to debt investors; thus, cash flows have a bearing on credit quality, which in turn affects the terms at which a company can raise capital.

Lastly, the deemed supportiveness of the regulatory environment within which a utility operates is a key consideration for ratings agencies such as Moody's, S&P, and Fitch, as well as equity investors. As stated by S&P, "[t]he assessment of regulatory risk is perhaps the most important factor in Standard & Poor's Ratings Services' analysis of a U.S. regulated, investor-owned utility's business risk."[3] Further, as noted by Moody's, "the predictability and supportiveness of the regulatory framework in which a regulated utility operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors."[4] From the equity investor's viewpoint, Barclays Capital stated, "[t]he heightened importance of regulatory lag throughout the capital investment cycle continues to increase the importance of which regulatory jurisdiction a utility operates within and how its cost of capital is impacted as a result."[5]

Q. WHAT ARE YOUR CONCLUSIONS REGARDING REGULATORY GUIDELINES AND CAPITAL MARKET EXPECTATIONS?

A. The Company's ability to fund capital investments will be dependent on its ability to access external capital on reasonable terms. Consequently, it is important for the ROE authorized in this proceeding to take into consideration not only returns required on investments of comparable risk, but also the Company's substantial capital investment plans, the economic

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3 Standard & Poor's, *Assessing U.S. Utility Regulatory Environments*, March 11, 2010, at 2.

4 Moody's Global Infrastructure Finance, *Regulated Electric and Gas Utilities*, August 2009, at 6.

5 Barclays Capital, *Capital Appreciation*, June 24, 2010, at 21.

environment in which it operates, and investors' expectations relative to both risks and returns.

Q. DO YOU HAVE ANY OBSERVATIONS REGARDING CURRENT ECONOMIC CONDITIONS AND THEIR INFLUENCE ON THE COST OF CAPITAL AND THE COST OF EQUITY?

A. Yes, I do. The U.S. economy is currently recovering from an 18-month recession that saw several high profile bankruptcies, a sharp drop off in lending, a historically high degree of investor uncertainty and risk aversion, and an unprecedented level of government intervention in the markets. Although the recent market turmoil seen in 2008 and 2009 has moderated, we are still in a period of elevated uncertainty that pervades both debt and equity markets. As stated by the Federal Open Market Committee ("FOMC") in the minutes to its March 2011 meeting:

> The staff's estimate of the spread between the expected real equity return for S&P 500 firms and the real 10-year Treasury yield—a measure of the equity risk premium—narrowed a bit more over the intermeeting period *but continued to be quite elevated relative to longer-term norms*.[6]

In addition, while current interest rates are at historic lows due to federal policies as well as a flight to quality due to the recent market turmoil, economists expect long-term interest rates to rise over the next few years, putting upwards pressure on borrowers.[7] Costs in the electric utility sector

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6 Federal Open Market Committee, Minutes of the Meeting of March 15, 2011, at 4. Emphasis added.

7 The Blue Chip Financial Forecasts projects the 30-year Treasury bond to yield 5.40 percent by 2014 (*see*, Blue Chip Financial Forecasts, Vol. 29, No. 12, December 1, 2010, at 14). Since the 30-day average yield on 30-year Treasury securities was approximately 4.34 percent as of May 31, 2011, the consensus estimate reported by Blue Chip Financial Forecasts projects an increase of approximately 106 basis points.

are threatened by inflation and are also on an increasing trajectory due to the replacement of aging infrastructure, environmental spending, reliability projects, and investments in "smart grid," energy efficiency, and transmission projects. These trends have a bearing on the risks faced by utilities as well as on investors' required returns.

Consistent with the *Hope* and *Bluefield* decisions, the authorized ROE for a public utility should allow the company to attract investor capital at a reasonable cost under a variety of economic and financial market conditions. Thus, the conditions discussed above need to be considered not only in the context of their effect on investors' return requirements, but also for their effect on the results of traditionally accepted methodologies for estimating the cost of equity.

IV. PROXY GROUP SELECTION

Q. PLEASE EXPLAIN WHY YOU HAVE USED A GROUP OF PROXY COMPANIES TO DETERMINE THE COST OF EQUITY FOR NSP.

A. Consistent with the *Hope* and *Bluefield* decisions, the authorized ROE for a public utility should be commensurate with the equity return required on investments of similar risk. Investments in enterprises of similar risk thus represent opportunity costs with a direct bearing on the ROE of the subject utility.

In addition, in this proceeding we are focused on estimating the cost of equity for the South Dakota operations of NSP, a rate-regulated, wholly-owned subsidiary of XEI. Since the ROE is a market-based concept, and given that the Company is not publicly traded, it is necessary to establish a group of companies that are both publicly traded and comparable to the Company in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process.

Q. HOW DID YOU SELECT THE COMPANIES INCLUDED IN YOUR PROXY GROUP?

A. I began with the companies that Value Line classifies as "Electric Utilities," which comprise a group of 53 domestic U.S. utilities. I then simultaneously applied the following screening criteria:

- I excluded companies that do not pay consistent quarterly cash dividends.
- I excluded companies that have not been covered by at least two generally recognized utility industry equity analysts.
- All of the companies in my proxy group had investment grade senior bond and/or corporate ratings from S&P (*i.e.*, BBB- to AAA).
- I excluded companies that do not own regulated generation assets.
- I excluded companies whose average regulated net income for the period 2008 through 2010 comprised less than 60.00 percent of the total for the company.
- To ensure a focus on companies whose net income is derived primarily from electric operations, I excluded companies whose average regulated electric net income for the period 2008 though 2010 represented less than 90 percent of total regulated net income.
- Finally, I eliminated any companies that are currently known to be party to a merger or other transforming transaction.

Q. DID YOU INCLUDE XEI IN YOUR ANALYSIS?

A. No. In order to avoid the circular logic that otherwise would occur, I excluded XEI from the proxy group.

Q HOW MANY COMPANIES MET YOUR SCREENING CRITERIA?

A. The criteria discussed above resulted in a group of the following 13 companies:

Table 3: Screening Results

Company	**Ticker**
American Electric Power Company, Inc.	AEP
Cleco Corp.	CNL
Edison International	EIX
Empire District Electric	EDE
Great Plains Energy Inc.	GXP
Hawaiian Electric	HE
IDACORP, Inc.	IDA
Integrys/WPS Resources	TEG
Otter Tail Corp.	OTTR
Pinnacle West Capital Corp.	PNW
Portland General Electric Company	POR
Southern Company	SO
Westar Energy, Inc.	WR

Q. DO THOSE 13 COMPANIES CONSTITUTE YOUR FINAL PROXY GROUP?

A. No, they do not. As discussed above, to ensure that the proxy group contains companies with significant rate-regulated electric operations, I set a minimum threshold in my screening criteria for net income derived from that segment. While strict adherence to those screening criteria resulted in the group of 13 companies in Table 3, events at some of the companies' non-regulated or non-electric operations segments potentially skew the relative ratio of regulated electric operations to total company performance, and make it difficult to discern the long-term contribution of those operations to each company's results. For the reasons discussed below, I have excluded Edison International ("EIX"), Integrys/WPS Resources ("Integrys") and Otter Tail Corp. ("Otter Tail") from the final proxy group.

First, EIX reported significant unregulated losses in 2009; those losses were in excess of 45.00 percent of EIX's regulated utility operating income. According to EIX's 2009 Securities and Exchange Commission ("SEC") Form 10-K, those significant operating losses were the result of a global tax settlement with the Internal Revenue Service and termination of cross-border leases, which caused EIX's unregulated competitive power and financial services segment to record an approximately $920 million pre-tax loss.[8] Given the extent of those losses, it is difficult to assess the relative degree to which regulated electric utility operations would be expected to contribute to the company's consolidated financial performance in the near and longer terms. Consequently, I have excluded EIX from my final proxy group.

Second, Integrys also experienced significant losses during the three year period that I relied on to develop my proxy group. In 2008, the company posted operating losses of $118.30 million in Integrys Energy Services Non-regulated Segment Operations.[9] In 2009, the Natural Gas Utility Segment reported an operating loss of $114.6 million that was primarily the result of a

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[8] Edison International, 2009 SEC Form 10-K, at 71, 104.
[9] Integrys 2010 SEC Form 10-K, at 40.

non-cash goodwill impairment loss of $284.6 million.[10] The company noted that:

> Key factors contributing to the impairment charge included disruptions in the global credit and equity markets and the resulting increase in the weighted-average cost of capital used to value the natural gas utility operations, and the negative impact that the global decline in equity markets had on the valuation of natural gas distribution companies in general.[11]

This large accounting loss reported by an affiliate potentially skews the relative contribution of the company's electric operations. For this reason, I have excluded Integrys from the final proxy group.

Lastly, Otter Tail reported significant losses in the operating income of several non-regulated business segments in 2009 and 2010. In fact, Otter Tail reported operating losses in its non-electric business segments in 2010 that, in total, exceeded 75.00 percent of its regulated electric operating income.[12] As a consequence, operating income from regulated operations constituted the majority of the reported operating income in those years. Reviewing Otter Tail's SEC Form 10-K, the $14.3 million operating loss experienced in 2010 in the Manufacturing segment was due to economic conditions and a $19.7 million asset impairment.[13] In addition, the Wind Energy segment, which is engaged in the manufacturing of wind towers and trucking, experienced an operating loss of $14.2 million in 2010.[14] Looking forward, Value Line projects a significant increase in the earnings from the

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[10] Integrys 2009 SEC Form 10-K, at 35.
[11] *Ibid.*, at 107.
[12] Otter Tail Corporation, SEC Form 10-K, February 28, 2011, at 44.
[13] *Ibid.*, at 48.
[14] *Ibid.*, at 47.

Manufacturing subsidiary in 2011, noting that the backlog for this business is 37.00 percent higher than the year prior.[15] Value Line also projects growth in Otter Tail's Construction segment, with a backlog that is nearly double that of the prior year.

Given the extent of the 2010 losses, and analyst projections for 2011, it is difficult to assess the degree to which regulated electric utility operations would be expected to contribute to Otter Tail's consolidated financial performance in the near and longer terms. Therefore, as with EIX and Integrys, I have excluded Otter Tail from the final proxy group.

Q. WHAT IS YOUR FINAL PROXY GROUP?

A. Excluding EIX, Integrys, and Otter Tail from the group results in a proxy group of the following ten companies (also presented in Exhibit__(DSD-1), Schedule 2):

[15] Value Line Report on Otter Tail Corp, March 25, 2011.

Table 4: Final Proxy Group

Company	Ticker
American Electric Power Company, Inc.	AEP
Cleco Corp.	CNL
Empire District Electric	EDE[16]
Great Plains Energy Inc.	GXP
Hawaiian Electric	HE
IDACORP, Inc.	IDA
Pinnacle West Capital Corp.	PNW
Portland General Electric Company	POR
Southern Company	SO
Westar Energy, Inc.	WR

V. DETERMINATION OF THE APPROPRIATE COST OF EQUITY

Q. HOW IS THE REQUIRED ROE DETERMINED?

A. The cost of equity is not directly observable, and, therefore, must be inferred by using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Informed judgment is applied, based on the results of those analyses, to determine where within the range of results the cost of equity for the Company falls. The resulting adjusted cost of equity serves as the recommended ROE for ratemaking purposes. As a general proposition, the key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors'

[16] On May 22, 2011, Empire District Electric ("EDE") sustained significant storm damage in its service territory. While EDE subsequently paid its dividend on May 27, 2011, it also announced a two-quarter temporary dividend suspension for the remainder of the year on May 26, 2011 (*see*, Empire District Electric press release, "The Empire District Electric Company Announces Temporary Suspension of Dividend," May 26, 2011). Given that there were only three trading days within my study period (*i.e.*, the 30, 90, and 180 trading days through May 31, 2011, as discussed below) following EDE's announcement, these events did not have a significant effect on the overall results of my analyses.

view of the financial markets as well as the subject company's common stock.

Q. WHAT METHODS DID YOU USE TO DETERMINE THE COMPANY'S ROE?

A. I primarily relied on the results of the DCF model corroborated by the results of a risk premium approach. I also considered the Capital Asset Pricing Model ("CAPM"). However, as discussed further below, the historical assumptions commonly relied on in the CAPM do not adequately reflect current market conditions and investor sentiment. As such, I did not rely on the CAPM in developing my recommendation.

A. Constant Growth DCF Model

Q. ARE DCF MODELS WIDELY USED TO DETERMINE THE ROE FOR REGULATED UTILITIES?

A. Yes. DCF models are widely used in regulatory proceedings and have sound theoretical bases, although neither the DCF model nor any other model can be applied without considerable judgment in the selection of data and the interpretation of results. In its simplest form, the DCF model expresses the cost of equity as the sum of the expected dividend yield and long-term growth rate.

Q. PLEASE DESCRIBE THE CONSTANT GROWTH DCF APPROACH.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows, which, for purposes of the model, are assumed to be equal to all expected future dividends. Thus, the return required by investors is implied by the per share price of a company's common stock. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + ... + \frac{D_\infty}{(1+k)^\infty} \quad [1]$$

Where P_0 represents the current stock price, D_1 … D_∞ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation, which can be simplified and rearranged into the following formula:

$$k = \frac{D(1+g)}{P_0} + g \quad [2]$$

Equation [2] is often referred to as the "Constant Growth DCF" model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. WHAT ASSUMPTIONS ARE REQUIRED FOR THE CONSTANT GROWTH DCF MODEL?

A. The Constant Growth DCF model requires the following assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate that is greater than the expected growth rate. To the extent that any of these assumptions do not hold true, considered judgment and/or specific adjustments should be made to the results.

B. Dividend Yield for the DCF Model

Q. WHAT DATA DID YOU USE TO CALCULATE THE DIVIDEND YIELD IN YOUR DCF MODEL?

A. I used readily available market data to calculate the dividend yield component of the DCF model. Specifically, the dividend yield is based on the proxy companies' current annualized dividend, and average closing stock prices over the 30-, 90-, and 180-trading days ended May 31, 2011.

Q. WHY DID YOU USE 30-DAY, 90-DAY, AND 180-DAY AVERAGING PERIODS?

A. I used multi-day averaging periods to calculate the term P_0 in the DCF model to ensure that the calculated ROE is not skewed by anomalous events that may affect stock prices on any given trading day. In addition, the averaging period should be reasonably representative of expected capital market conditions over the long term while at the same time reflecting the extraordinary conditions that have defined the financial markets over the recent past. In my view, the use of the 30, 90, and 180-day averaging periods reasonably balances those concerns.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE DIVIDEND YIELD TO ACCOUNT FOR PERIODIC GROWTH IN DIVIDENDS?

A. Yes, I did. Since current dividend data reflects the last dividend paid (*i.e.*, D_0) by each proxy company, the dividend must be adjusted to reflect the next dividend expected by investors (*i.e.*, D_1). Since utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, I applied one-half of the expected annual dividend growth for the purposes of calculating the expected dividend yield component of the DCF model, as shown in Exhibit__(DSD-1), Schedule 2. This adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period and does not overstate the aggregate dividends to be paid during that time.

C. Growth Rates for the DCF Model

Q. WHAT GROWTH RATE ASSUMPTION DID YOU USE IN THE DCF ANALYSIS?

A. I used analysts' expected earnings growth rates for each proxy group company. Since the cost of equity is a forward-looking concept, and since the DCF model is based on the premise that today's stock price is based on expected cash flows, it is important to use forecasted, as opposed to historical, estimates of proxy company growth. Analysts' expected earnings-per-share growth rates are widely relied upon by investors and likely incorporate all the public information available to the investment community. In addition, over the long run, dividend growth can only be sustained by earnings growth. Thus, it is common to use the long-term expected earnings growth rate as the measure of growth in the constant growth DCF model. There is also academic research supporting the use of analysts' forecasts as the source of DCF growth rates.[17]

[17] *See*, *e.g.*, Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts*, Financial Management, 21 (Summer 1992), and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988, at 81. Please note that while the original study was published in 1988, it was updated in 2004 under the direction of Dr. Vander Weide. The results of this updated study are consistent with the Vander Weide and Carlton's original conclusions.

D. Summary of Application of the Constant Growth DCF Model

Q. PLEASE SUMMARIZE YOUR APPLICATION OF THE CONSTANT GROWTH DCF MODEL.

A. I applied the DCF model to the proxy group of ten electric utility companies, using the following inputs for the price and dividend terms:

1. The average daily closing prices for the 30-trading days, 90-trading days, and 180-trading days ended May 31, 2011 for the term P_0; and
2. The annualized dividend per share as of May 31, 2011, for the term D_0.

I then calculated the DCF results using each of the following growth terms:

1. The Zacks consensus long-term earnings growth estimates;
2. The First Call consensus long-term earnings growth estimates; and
3. The Value Line earnings per share growth estimates.

Q. HOW DID YOU CALCULATE THE RANGE OF DCF RESULTS?

A. I used the mean of all three growth rates in combination with the dividend yield to determine the mean DCF result. I calculated the mean high DCF result using the maximum growth rate (*i.e.*, the maximum of the Value Line, Zack's, and First Call EPS growth rates) in combination with the dividend yield for each of the proxy group companies. Thus, the mean high result reflects the average maximum DCF result for the proxy group. I used a similar approach to calculate the mean low results, using the minimum growth rate for each proxy group company.

Q. ARE THE RESULTS OF THE DCF ANALYSIS PRESENTED IN THE SCHEDULES TO YOUR DIRECT TESTIMONY?

A. Yes. The results of the Constant Growth DCF analysis are presented in Exhibit_(DSD-1), Schedule 2.

E. Flotation Cost Recovery

Q. DID YOUR ANALYSIS PROVIDE FOR RECOVERY OF FLOTATION COSTS?

A. Yes. My analysis provided for recovery of flotation costs.

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include underwriter discounts; audit, legal and listing fees; printing costs; and other direct issuance expenses. Such flotation costs are similar to debt issuance costs in that they are necessary for the issuance of the securities, and they reduce the net proceeds available to the issuing company. As an example, whereas a company's share price at the time of a stock issuance may be $22.00, if flotation costs are equal to $0.50 per share, the Company will receive only $21.50 per share. In order to compensate investors for the return they require (implied by the $22.00 price at the time of the issuance), the enterprise must earn a higher ROE on the reduced proceeds.

Q. SHOULD FLOTATION COSTS BE REFLECTED IN THE ALLOWED ROE?

A. Yes. Flotation costs are not expenses that flow through the income statement, but instead reduce the proceeds of the issuance, resulting in a permanent net reduction to the common equity portion of the balance sheet.

As a result, flotation costs should be recovered through a return adjustment, regardless of whether an issuance occurs during, or is planned for, the test year. Recovery of investments is not limited to the year in which the investment is made, and neither should the recovery of legitimately incurred, direct flotation costs. According to Dr. Shannon Pratt:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[18]

In addition, in order to attract and retain new investors, a regulated utility must have the opportunity to earn a return that is both competitive and compensatory. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diminishing the company's ability to attract adequate capital on reasonable terms.

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[18] Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-221.

Q. ARE FLOTATION COSTS PART OF THE UTILITY'S INVESTED COSTS OR PART OF THE UTILITY'S EXPENSES?

A. Flotation costs are part of the invested cost of the utility, which are reflected on the balance sheet under "paid in capital." As a result, the great majority of a utility's flotation costs is incurred prior to the test year, but remain part of the cost structure that exists during the test year and beyond, and as such, should be recognized for ratemaking purposes. Therefore, this adjustment is appropriate even if no new issuances are planned in the near future because failure to allow such an adjustment may deny the Company the opportunity to earn its required rate of return in the future.

Q. HAS XEI RECENTLY ISSUED COMMON EQUITY?

A. Yes, it has. As shown in Exhibit_(DSD-1), Schedule 3, XEI issued 21,850,000 equity shares on August 3, 2010.

Q. WILL THE COMPANY NEED ACCESS TO THE EQUITY MARKET IN THE NEXT SEVERAL YEARS?

A. Yes. In addition, the Company will need to access the equity market in the next several years in order to finance its capital investment plan.

Q. IS THE NEED TO CONSIDER FLOTATION COSTS ELIMINATED BECAUSE THE COMPANY IS A SUBSIDIARY OF XEI?

A. No. Although the Company is a subsidiary of XEI, it is appropriate to consider flotation costs because the source of capital used by the Company was the result of a public issuance by its parent organization, which led to the issuance costs. To deny recovery of issuance costs associated with the capital that is invested in the utility ultimately will penalize the investors that fund the utility operations and will inhibit the utility's ability to obtain new equity capital at a reasonable cost.

Q. DOES THE DCF MODEL ALREADY INCORPORATE INVESTOR EXPECTATIONS OF A RETURN THAT COMPENSATES FOR FLOTATION COSTS?

A. No. All the models used to estimate the appropriate ROE assume no "friction" or transaction costs, as these costs are not reflected in the market price (in the case of the DCF model). Therefore, it is appropriate to consider flotation costs when estimating the Company's ROE.

Q. HAVE YOU CALCULATED THE EFFECT OF FLOTATION COSTS ON THE ROE?

A. Yes, I have. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. Based on the issuance costs provided in Exhibit__(DSD-1), Schedule 3, an adjustment of 0.26 percent (*i.e.*, 26 basis points) is reflective of flotation costs for the Company.

Q. DO THE RESULTS IN EXHIBIT_(DSD-1), SCHEDULE 2 INCLUDE AN ADJUSTMENT FOR FLOTATION COST RECOVERY?

A. Yes. The results presented in Exhibit_(DSD-1), Schedule 2 include an adjustment for flotation cost recovery.

F. Results for Constant Growth Model

Q. WHAT ARE THE RESULTS OF YOUR DCF ANALYSIS?

A. Table 5 (below) provides the results of my DCF analysis, including flotation costs. As shown in Table 5, the mean DCF results for my proxy group range from 10.97 percent to 11.22 percent.

Table 5: Mean DCF Results

	Mean Low	Mean	Mean High
Constant Growth DCF – including Flotation Costs			
30-Day Average	9.84%	10.97%	12.13%
90-Day Average	9.97%	11.10%	12.26%
180-Day Average	10.09%	11.22%	12.38%

Q. DID YOU UNDERTAKE ANY ADDITIONAL ANALYSES TO SUPPORT YOUR DCF MODEL RESULTS?

A. Yes. As noted earlier, I used the Bond Yield plus Risk Premium approach as a means of assessing the reasonableness of my DCF results. I also considered the use of the CAPM, as also noted previously, but did not rely on that model due for the reasons discussed below.

G. Bond Yield plus Risk Premium Analysis

Q. PLEASE PROVIDE AN OVERVIEW OF THE BOND YIELD PLUS RISK PREMIUM APPROACH YOU EMPLOYED.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with ownership and therefore must be compensated for bearing that additional risk. That is, since returns to equity holders are more risky than returns to bondholders, equity investors require a premium over the return on less risky bonds. Risk premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I used actual authorized returns for electric utilities as the historical measure of the cost of equity to determine the risk premium.

Q. PLEASE FURTHER DESCRIBE THE ANALYSIS.

A. I developed the analysis based on a regression of the risk premium (*i.e.*, authorized ROEs less Treasury yields) as a function of Treasury yields. More specifically, I let authorized ROEs serve as the measure of required equity returns and defined the yield on the long-term Treasury bond as the relevant measure of interest rates. The risk premium is simply the difference between those two points.

Q. ARE THERE OTHER FACTORS THAT SHOULD BE CONSIDERED?

A. Yes. In addition, it is important to recognize both academic literature and market evidence indicating that the equity risk premium is inversely related to the level of interest rates.[19] That is, as interest rates increase (decrease), the equity risk premium decreases (increases). My analysis thus reflects the inverse relationship between interest rates and the equity risk premium and applies that relationship to expected market conditions.

Q. WHAT DID YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS REVEAL?

A. As shown on Chart 1, from 1992 through May 31, 2011, there was, in fact, a strong negative relationship between risk premia and interest rates for electric utilities. To estimate that relationship, I conducted a regression analysis for electric utilities using the following equation:

$$RP = a + b\,(T) \qquad [3]$$

where:

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[19] *See*, *e.g.*, S. Keith Berry, *Interest Rate Risk and Utility Risk Premia during 1982-93*, Managerial and Decision Economics, Vol. 19, No. 2 (March, 1998), in which the author used a methodology similar to the regression approach described here, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between risk premia and interest rates. *See* also Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return*, Financial Management, Spring 1986, at 66.

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year Treasuries)

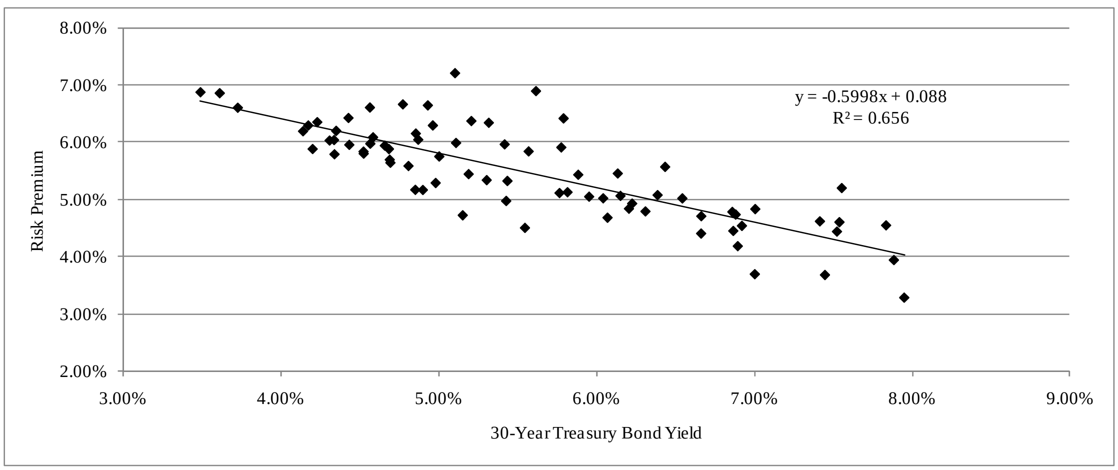
a = Intercept term

b = Slope term

T = 30-year Treasury Bond Yield

Data regarding allowed ROEs were derived from 498 rate cases from 1992 through May 31, 2011 as reported by Regulatory Research Associates. That equation's coefficients were statistically significant at the 99.00 percent level.

Chart 1: Electric Utilities Risk Premium vs. Interest Rates



As shown on Exhibit__(DSD-1), Schedule 4, based on the near-term (2011-2012) projections of the 30-year Treasury bond yield (*i.e.*, 4.88 percent), the risk premium would be 5.87 percent, resulting in an estimated ROE of 10.76 percent. Based on longer-term (2012-2016) projections of the 30-year Treasury Bond yield (*i.e.*, 5.45 percent), the risk premium would be 5.53 percent, resulting in an estimated ROE of 10.98 percent. The mean of these estimated ROE results is 10.87 percent. These results corroborate the DCF results discussed earlier, and further support my recommended ROE of 11.00 percent.

Q. DID YOU CONSIDER ANY ADDITIONAL ANALYSES AS PART OF YOUR DETERMINATION OF A REASONABLE ROE FOR THE COMPANY?

A. Yes. As noted earlier, I also considered the CAPM. The CAPM is a risk premium model that is based on a required return that compensates the investor for the time value of money (indicated by a risk free rate of return) as well as for bearing systematic, non-diversifiable risk. However since the financial market dislocation that began in 2008, the underlying assumptions used in the traditional application of this model are not indicative of market expectations and therefore the results from the traditional application of the model are not representative of current market conditions. Therefore, I did not rely on the CAPM in developing my recommended ROE.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE TRADITIONAL APPLICATION OF THE CAPM.

A. As shown in Equation [4], the CAPM estimate of the cost of equity is calculated using three theoretically forward-looking inputs:

$$K_e = r_f + \beta(r_m - r_f) \qquad [4]$$

where:

k_e = the current required market ROE

β = the expected Beta coefficient of an individual security

r_f = the expected risk free rate of return

r_m = the required return on the market as a whole.

The risk premium term of the CAPM, $(r_m - r_f)$, represents the expected risk premium that investors currently require the market to provide in the future. However, because the currently-expected risk premium is unknown, or difficult to measure, the expected Market Risk Premium ("MRP") is commonly estimated by subtracting the risk free rate from the returns in the market during a historical time period. As a result of the extraordinary loss in equity values during 2008, the historical MRP decreased from the prior year despite the significant elevation in the degree of uncertainty in the market as well as high levels of risk aversion indicating a higher required rate of return. That result is somewhat counter-intuitive. As noted earlier, the FOMC currently estimates the equity risk premium to be, "quite elevated relative to longer-term norms."[20] While the market rally of 2009 and 2010 resulted in a somewhat higher historical MRP, the current estimate of the MRP based on historical data still remains below its pre-financial crisis level.

In addition, the third term in the CAPM, the Beta coefficient, measures the systematic risk of a particular stock relative to a broader market index, the S&P 500. Beta coefficients are estimated for an individual stock by regressing the company's stock price against a market index. The Beta coefficient estimates reported by Value Line and Bloomberg are calculated over historical periods of 60 and 24 months, respectively. The use of such longer-term measurement periods includes data from the recent financial market dislocation as well as the period prior to the market dislocation and results in Beta coefficient estimates based on recent history that may not be

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[20] Federal Open Market Committee, Minutes of the Meeting of March 15, 2011, at 4.

reasonable measures of the level of systematic risk currently perceived by investors.

Therefore, since the underlying historical market data used to develop the key assumptions of the CAPM may not be reflective of current market conditions and investors' current expectations, I did not rely on that model to establish my recommended ROE.

VI. BUSINESS RISKS

Q. DO THE MEAN DCF RESULTS FOR THE PROXY GROUP PROVIDE AN APPROPRIATE ESTIMATE OF THE COST OF EQUITY FOR THE COMPANY?

A. No, the mean DCF results do not necessarily provide an appropriate estimate of the Company's cost of equity. There are several factors that have a direct bearing on the Company's ability to earn a fair return and on the Company's relative riskiness when compared to the proxy group. These include the Company's planned capital investment program and risks related to the Company's customer concentration. These factors should be considered in terms of their overall effect on the Company's ability to earn its allowed return and on its business risk when compared with the proxy group.

Q. WHAT ARE THE PRIMARY BUSINESS RISKS THAT THE COMPANY CURRENTLY FACES?

A. The principle business risks facing the Company are: (1) the need for a very substantial level of capital expenditures; and (2) a high dependence on commercial customers.

Capital Expenditures

Q. PLEASE SUMMARIZE THE COMPANY'S CAPITAL EXPENDITURE PLAN.

A. The Company estimates that during the five-year period 2011-2015 it will invest approximately $6.2 billion,[21] averaging over $1.2 billion per year over that five-year period. These expenditures represent approximately 82.65 percent of the Company's total net utility plant in service as of December 31, 2010.[22]

Q. HOW IS THE COMPANY'S RISK PROFILE AFFECTED BY THE SUBSTANTIAL INCREASE IN ITS PLANNED CAPITAL EXPENDITURES?

A. The Company's risk profile is adversely affected because the heightened level of investment increases the risk of under-recovery, or the delayed recovery of the invested capital, which is known as regulatory lag.

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[21] SEC Form 10-K, Xcel Energy, Inc, for the year ending December 31, 2010, at 75. Includes Minnesota and North Dakota jurisdictions.

[22] NSP's net utility plant at December 31, 2010 was $7.5 billion, as reported in its FERC Form 1 at 110 for the period ended December 31, 2010.

Q. IS THAT RISK ELIMINATED BY THE COMPANY'S TRANSMISSION COST RECOVERY ("TCR") AND ENVIRONMENTAL COST RECOVERY ("ECR") RIDERS?

A. No, it is not. While the TCR and ECR's designs reduce regulatory lag, these mechanisms only cover costs incurred for NSP's transmission and environmental measure expenditures. In addition, it is important to note that even with these mechanisms in place, regulatory lag remains a significant concern, putting pressure on working capital balances, straining cash flows, and creating financial risk for vertically integrated utilities.

Q. DOES THE INVESTMENT COMMUNITY RECOGNIZE THE RISKS ASSOCIATED WITH INCREASED CAPITAL EXPENDITURES?

A. Yes, it does. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. S&P has noted several long term challenges for utilities' financial health, including: heavy construction programs to address demand growth, declining capacity margins, aging infrastructure, and regulatory responsiveness to mounting requests for rate increases.[23] S&P specifically identified the risks associated with NSP's capital expenditure plan in its July 2010 rating of the Company. In that report, S&P noted that its credit rating reflects in part the full cost recovery of larger construction projects. In addition, S&P notes that the current stable outlook could be revised to negative if construction

[23] Standard & Poor's RatingsDirect, *Industry Report Card: Utility Sectors In the Americas Remain Stable, While Challenges Beset European, Australian, and New Zealand Counterparts*, June 27, 2008, at 4.

projects are not completed on time and budget or if rate recovery is less than expected.[24]

Equity investors also recognize the pressure on cash flows and earnings associated with relatively high levels of capital expenditures. KeyBanc, for example, noted that:

> Credit and liquidity concerns have driven many companies to revisit capital spending plans and reassess operational efficiencies. The primary response has generally been to delay projects, as opposed to outright cancellation. Initially, reductions in capital programs were a function of lower growth, which eliminated the need for growth-related capital spending on items such as line extensions and new substations. However, as difficult economic conditions persist, the cuts have grown more extensive, with deferrals in non-core maintenance spending, reevaluating the cost-effectiveness of running older inefficient power plants, and pursuing company restructurings or mergers.[25]

Q. WILL THE COMPANY NEED CONTINUED ACCESS TO THE CAPITAL MARKETS IN ORDER TO FINANCE ITS CAPITAL EXPENDITURE PLAN?

A. Yes. Given the magnitude and long-term nature of the anticipated capital expenditures, the Company will require continued access to the capital markets, at reasonable terms, in order to finance its capital expenditure plan.

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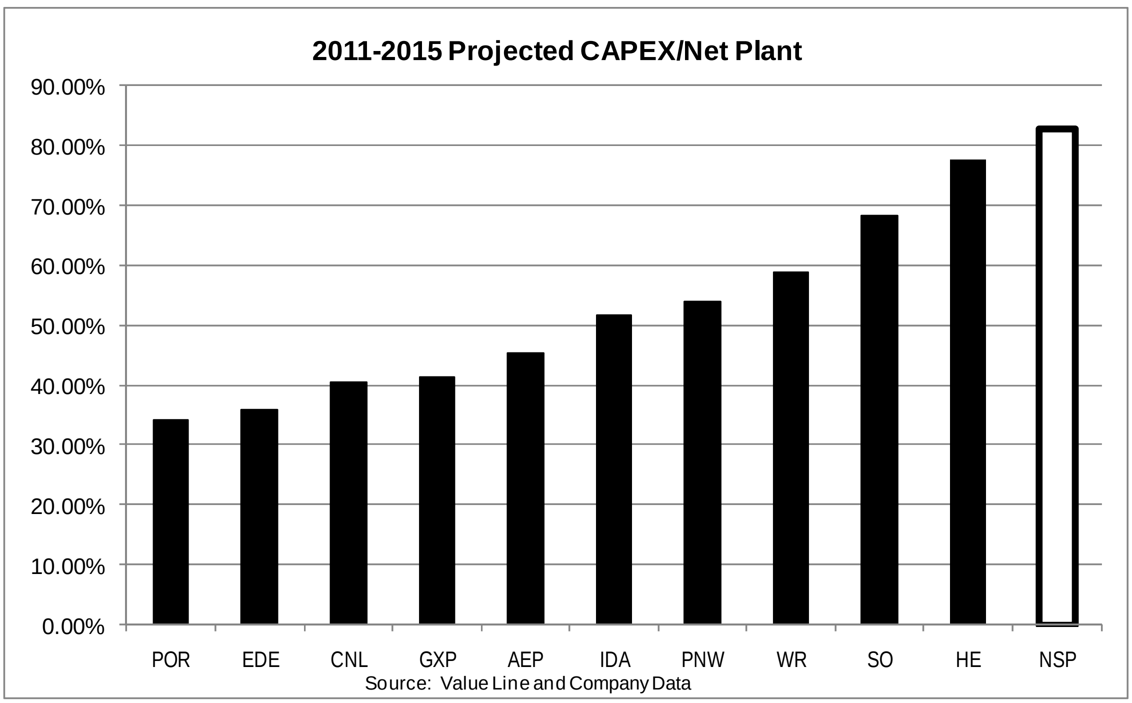
[24] Standard & Poor's Global Credit Portal RatingsDirect, Northern States Power Co., July 14, 2010, at 2-3.

[25] KeyBanc Capital Markets Inc. Equity Research, *Electric Utilities Quarterly 1Q10*, June 2010, at 7.

Q. HOW DOES THE LEVEL OF THE COMPANY'S EXPECTED CAPITAL EXPENDITURES COMPARE TO THE PROXY GROUP?

A. As shown in Exhibit__(DSD-1), Schedule 5, I calculated the ratio of expected capital expenditures to net assets for each of the companies in the proxy group. For the projected period from 2011 to 2015, I performed that calculation using the Company's projected capital expenditures and its total net assets as of December 31, 2010. As shown in Schedule 5, the Company's relative level of capital expenditures is 1.6 times the average projected investments of the proxy group companies. Chart 2 below compares the projected capital expenditures of the Company and my electric utility proxy group.

Chart 2: Comparison of Capital Expenditures[26]



[26] Sources: Value Line, SEC Form 10-K, Xcel Energy, Inc, for the year ending December 31, 2010, at 75, and FERC Form 1, Northern States Power Company (Minnesota), for the period ending December 31, 2010, at 110. The capital expenditure estimate for Empire District Electric excludes any restoration costs that may be required within its service territory as a result of the tornado damage suffered in May 2011.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF THE COMPANY'S CAPITAL INVESTMENT PLAN ON ITS RISK PROFILE AND COST OF CAPITAL?

A. It is clear that the Company is projecting a substantial capital expenditure program over the next five years that will require continued access to the capital markets. It also is clear that equity investors and credit rating agencies recognize the additional risks associated with substantial capital expenditures. Therefore, the relative size of the Company's capital expenditure plan suggests an above average risk profile for the Company as compared to the proxy group.

Customer Concentration

Q. HOW DOES THE COMPANY'S CUSTOMER CONCENTRATION AFFECT ITS BUSINESS RISK?

A. The Company's customer base is largely comprised of commercial and industrial customers. Approximately 62.31 percent of its total revenues, excluding sales for resale, are attributable to sales to commercial and industrial customers.[27] The Company has the second highest commercial customer concentration by percent of revenues relative to the proxy group, which has an average of 53.73 percent of revenues, excluding sales for resale, attributable to sales to commercial and industrials customers.[28] The Company's dependence on sales to commercial users subjects its operations to greater cash flow volatility and risk of demand destruction and bypass. Although the Company currently believes its rates are sufficiently

[27] Source: SNL Financial Energy Service. Includes Minnesota and North Dakota jurisdictions.
[28] The proxy group's concentration of commercial and industrial customers ranges from 48.20 percent to 63.75 percent.

competitive to retain its commercial customers, it remains highly exposed to these risks.

Q. BASED ON THE BUSINESS RISKS IDENTIFIED ABOVE, HOW WOULD YOU CLASSIFY THE COMPANY'S RISK LEVEL RELATIVE TO THE OTHERS IN THE PROXY GROUP?

A. As discussed above, the Company faces a higher than average level of business risk relative to the companies in the proxy group associated with substantially higher capital investment levels and, to a lesser extent, its dependence on commercial customers. Consequently, I believe that the Company has somewhat greater business risks relative to the proxy group.

VII. CAPITAL STRUCTURE AND COST OF DEBT

A. Capital Structure

Q. WHAT IS THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. The Company's proposed capital structure consists of 52.48 percent common equity and 47.52 percent long-term debt, which is based on the thirteen month average historical test period ended December 31, 2010. The calculation of the proposed capital structure is provided on Exhibit__(DSD-1), Schedule 6.

Q. HAVE YOU ASSESSED THE REASONABLENESS OF THE COMPANY'S CAPITAL STRUCTURE?

A. Yes. In order to assess the reasonableness of the Company's proposed capital structure, I reviewed the average capitalization ratios for the past eight quarters of the individual utility operating companies owned and operated by the respective proxy group companies. As shown in Exhibit__(DSD-1), Schedule 7 the Company's proposed 52.48 percent equity ratio is well within the range of equity ratios for that group, and is only slightly above the mean equity ratio of 51.21 percent.

B. Cost of Long-Term Debt

Q. WHAT IS THE COMPANY'S PROPOSED LONG-TERM COST OF DEBT?

A. The Company is proposing to use its actual long-term cost of debt of 6.33 percent. The calculation of the long-term cost of debt is provided on Exhibit__(DSD-1), Schedule 8.

Q. IS THE COMPANY'S LONG-TERM COST OF DEBT REASONABLE?

A. Yes. The proposed cost of long-term debt reflects the Company's actual debt costs. In addition, Exhibit__(DSD-1), Schedule 8, compares the cost of each issuance to the Moody's A Utility Index (the "Moody's Index") at the times of the Company's debt issuances. The weighted Moody's Index based on those issuance dates was 6.53 percent, further indicating that the Company's debt cost of 6.33 percent is reasonable.

VIII. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CALCULATED COST OF EQUITY, TAKING INTO CONSIDERATION THE ISSUES DISCUSSED ABOVE.

A. Table 6 summarizes the results of the DCF analyses, as well as the Bond Yield plus Risk Premium analyses. Based on these results, I find a reasonable range of ROE results for the Company to be from 10.75 percent to 11.25 percent.

Table 6: ROE Estimate Summary

	Mean Low	Mean	Mean High
Constant Growth DCF – including Flotation Costs			
30-Day Average	9.84%	10.97%	12.13%
90-Day Average	9.97%	11.10%	12.26%
180-Day Average	10.09%	11.22%	12.38%
Bond Yield plus Risk Premium			
Based on Blue Chip 2011-2012 30-Year Treasury Projections		10.76%	
Based on Blue Chip 2012-2016 30-Year Treasury Projections		10.98%	
Mean		10.87%	

Q. WHAT IS YOUR CONCLUSION REGARDING A FAIR ROE FOR NSP?

A. Within the range of 10.75 percent to 11.25 percent, I recommend an ROE of 11.00 percent for the Company. This recommendation is well within the bounds of the DCF results presented in Table 6, is corroborated by the Bond Yield plus Risk Premium analysis, and takes into consideration the current market environment as well as risks attendant to NSP's South Dakota operations.

Q. WHAT IS YOUR CONCLUSION REGARDING THE APPROPRIATE CAPITAL STRUCTURE FOR THE COMPANY?

A. I conclude that the Company's capital structure for the 13 month average test period ending December 31, 2010 which includes a 52.48 percent equity ratio, a 47.52 percent long-term debt, and an embedded debt cost of 6.33 percent are reasonable.

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED OVERALL COST OF CAPITAL?

A. Given the recommended ROE of 11.00 percent, a cost of debt of 6.33 percent, and the capital structure noted above, the requested rate of return for the Company is 8.78 percent, as shown in Table 7, below.

Table 7: Overall Rate of Return

	Percent	Cost Rate	Weighted Cost
Common Equity	52.48%	11.00%	5.77%
Long-term debt	47.52%	6.33%	3.01%
Total Capitalization	100.00%		8.78%

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does

Daniel S. Dane, CPA
Senior Project Manager

Daniel S. Dane is a consultant with 10 years of experience in the energy and financial services industries. Mr. Dane has provided advisory services in the areas of litigation support, generating asset divestitures, utility regulation and ratemaking, valuation, financial statement audits and analysis, and the examination of financial reporting systems and controls. He also has provided expert testimony on regulated ratemaking matters for an investor-owned utility. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, and is a licensed securities professional (Series 7, 28, 63, and 79). Mr. Dane also serves as the Financial and Operations Principal of CE Capital Advisors, a FINRA-Member firm and a subsidiary of Concentric.

REPRESENTATIVE PROJECT EXPERIENCE

Litigation Advisory Assignments

Prepared analyses and reports in a variety of proceedings related to energy, economic, and litigation issues. Clients in these matters have included international diversified energy companies and electric distribution companies. Representative engagements have included:

- For a diversified energy company involved in litigation related to the lease-leaseback of a gas-fired combined heat and power plant, performed appraisal review services, created an economic model to test the sensitivity of the plant's valuation model to changes in economic drivers, and supported the development of expert testimony.
- Spent nuclear fuel litigation. For three utilities involved in litigation with the U.S. Department of Energy regarding breach of contract for the removal of spent nuclear fuel from nuclear reactor sites, performed pro-forma valuations of generating facilities to quantify diminished sale value due to breach and supported the development of written testimony regarding the analyses.

Financial Advisory Assignments

As part of electric generating and transmission asset divestitures, responsibilities have included marketing, due diligence support, drafting of transaction agreements, bid evaluation, and closing/regulatory approval assistance. Transactions included nuclear, coal, gas-fired, and hydroelectric generating assets. Performed independent valuations, appraisals, and market analyses in support of asset and equity acquisitions and divestitures. Performed financial statement audits for public and private companies. Performed attestation services for a global public company as part of the implementation of Sarbanes-Oxley Section 404 regulations.

Representative engagements have included:

- Transaction team member for the following asset divestitures:
  - Wisconsin Electric's $998 million sale of the 1,036 MW Point Beach Nuclear Power Plant
  - Consumers Energy's $380 million sale of the 798 MW Palisades Nuclear Power Plant
  - Interstate Power & Light's $373 million sale of the 583 MW Duane Arnold Energy Center
  - Atlantic City Electric's $173 million sale of its ownership interest in the 1,712 MW Keystone and Conemaugh coal-fired stations
  - The equity holders' sale of the MASSPOWER station, a 258 MW gas-fired facility

- Participated in or managed the development of fairness opinions issued by CE Capital Advisors, Inc. to Boards of Directors of companies entering into asset purchases and sales.
- Provided buy-side support to an international developer of wind generation targeting investment in U.S. wind properties. Engagement included valuing wind assets in various stages of development and evaluating multiple ownership/tax-equity structures.
- For a desalination plant developer, appraised desalination facilities in California for corporate accounting purposes. Appraisal included providing a going concern valuation and opinion.
- For a hedge fund, performed a valuation of a generating company to provide support for investment decision making.
- For the developer of a multi-billion dollar Greenfield natural gas pipeline, provided research and advice related to accounting treatment of construction and financing costs, and developed a cost of service and revenue requirements model for use in the open season process.
- For an international diversified company investing in a Texas pipeline and natural gas marketer, performed accounting-related due diligence, developed an opening balance sheet in accordance with U.S. GAAP, and performed subsequent tests for impairment of Goodwill and intangible assets.
- For a confidential Transmission & Distribution ("T&D") company, developed an application for Department of Energy loan guarantees pursuant to the American Recovery and Reinvestment Act of 2009.

Ratemaking and Utility Regulation Assignments

Performed financial and other analyses and drafted expert testimony and reports related to multiple regulatory proceedings. Representative engagements have included:

- Submitted expert direct and rebuttal testimony on behalf of Ameren's Illinois utilities regarding ratemaking policy issues specifically related to regulated rate base (Illinois Commerce Commission Docket No. 09-0306 through 09-0311 (Cons.)).
- Performed analyses and supported development of cost of capital expert testimony for electric, gas LDC, pipeline, and steam utilities.
- For utilities developing decoupling proposals, developed financial models to back-cast and forecast the effects of various types of decoupling mechanisms, capital expenditure tracking mechanisms, and inflation tracking mechanisms.
- Supported expert testimony related to corporate cost allocations on behalf of Constellation Energy Group as part of the Maryland Public Service Commission's 2009 review of the merger between Constellation Energy Nuclear Group and E.D.F. International SA.
- Preparation of multiple rounds of testimony in support of a group of utilities, including Oncor Electric Delivery Company, AEP and MidAmerican Energy, seeking to construct over $5 billion of new transmission in Texas as part of the state's Competitive Renewable Energy Zone process.
- For Oncor Electric Delivery Company's 2008 rate case, supported the development of written direct and rebuttal testimony and analyses regarding the return of and on capital, as well as the effects of recent merger activity, the 2008/2009 credit crisis, and changing business and operating environments thereon.
- For NSTAR, on two separate occasions reviewed the company's cost of service calculations to determine and certify to the Massachusetts Attorney General that the calculations were performed in accordance with NSTAR's tariff.
- For the Ontario Energy Board ("OEB"), contributed to a report comparing authorized equity returns for natural gas utilities in Canada and the U.S., including an analysis of cross-border differences in access to capital and the effect of firm size on required returns on equity. Presented findings to the OEB and the Ontario Energy Association ("OEA") at the 2007 OEA ROE Seminar.

Management and Operations Consulting Assignments

Representative engagements have included:

- For the owners of the Palo Verde Nuclear Generating Station, performed a comprehensive study of the costs being incurred by Arizona Public Service to support operations of the plant, including a benchmarking study.
- For We Energies, performed a synergies analysis to quantify benefits of a recent merger.

Research Assignments

Reviewed and summarized accounting guidance and tax law to assist clients in interpreting and applying U.S. GAAP and provisions of the Internal Revenue Code.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2004 – Present)
CE Capital Advisors, Inc.
Senior Project Manager (Concentric)/Financial and Operations Principal (CE Capital)
Project Manager
Senior Consultant
Consultant

Ernst & Young (2000 – 2001, 2003 – 2004)
Staff Auditor
Database Management Associate

ZIA Information Analysis Group (1997 – 2000)
Senior Consultant
Consultant

EDUCATION AND CERTIFICATIONS

M.B.A., Boston College, 2003
B.A., Economics, Colgate University, 1996
Licensed Securities Professional: NASD Series 7, 28, 63, and 79 Licenses

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DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant, 2004
Massachusetts Society of Certified Public Accountants, 2004

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30 DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	Value Line EPS Growth	First Call	Average Growth Rate	Low DCF	Mean DCF	High DCF
American Electric Power	AEP	$1.84	$37.12	4.96%	5.05%	4.00%	3.50%	3.71%	3.74%	8.54%	8.79%	9.06%
Cleco Corp.	CNL	$1.12	$34.84	3.21%	3.31%	7.00%	8.00%	3.00%	6.00%	6.26%	9.31%	11.34%
Empire District Electric	EDE	$1.28	$22.12	5.79%	5.97%	NA	7.00%	6.00%	6.50%	11.96%	12.47%	12.99%
Great Plains Energy Inc.	GXP	$0.83	$20.64	4.02%	4.17%	9.00%	6.00%	7.50%	7.50%	10.14%	11.67%	13.20%
Hawaiian Electric	HE	$1.24	$25.33	4.90%	5.12%	8.90%	11.00%	7.90%	9.27%	12.99%	14.39%	16.17%
IDACORP, Inc.	IDA	$1.20	$39.01	3.08%	3.14%	4.70%	4.00%	4.67%	4.46%	7.14%	7.60%	7.85%
Pinnacle West Capital	PNW	$2.10	$44.24	4.75%	4.89%	5.00%	6.00%	6.98%	5.99%	9.87%	10.88%	11.89%
Portland General	POR	$1.06	$25.10	4.22%	4.34%	5.00%	7.50%	4.38%	5.63%	8.70%	9.97%	11.88%
Southern Co.	SO	$1.89	$39.57	4.78%	4.91%	5.00%	6.00%	5.51%	5.50%	9.90%	10.41%	10.92%
Westar Energy	WR	$1.28	$27.08	4.73%	4.89%	5.50%	8.50%	6.28%	6.76%	10.36%	11.65%	13.43%
		PROXY GROUP MEAN		4.44%	4.58%	6.01%	6.75%	5.59%	6.13%	9.58%	10.71%	11.87%
									Flotation Adjustment	0.26%	0.26%	0.26%
									Adjusted Mean ROE	9.84%	10.97%	12.13%

Notes

[1] Source: Bloomberg
[2] Source: Bloomberg. Based on indicated number of days historical average, as of May 31, 2011.
[3] Equals Col. [1]/Col. [2]
[4] Equals (Col. [1] x (1+(0.5 x Col. [8])))/Col. [2]
[5] Source: Zacks
[6] Source: Value Line
[7] Source: First Call
[8] Equals Avg (Col. [5], [6], [7])
[9] Equals (Col. [3] x (1 + (0.5 x Minimum (Col. [5], [6], [7])))) + Minimum (Col. [5], [6], [7])
[10] Equals Col. [4] + Col. [8]
[11] Equals (Col. [3] x (1 + (0.5 x Maximum (Col. [5], [6], [7])))) + Maximum (Col. [5], [6], [7])

90 DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company		Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	Value Line EPS Growth	First Call	Average Growth Rate	Low DCF	Mean DCF	High DCF
American Electric Power	AEP	$1.84	$36.00	5.11%	5.21%	4.00%	3.50%	3.71%	3.74%	8.70%	8.94%	9.21%
Cleco Corp.	CNL	$1.12	$33.45	3.35%	3.45%	7.00%	8.00%	3.00%	6.00%	6.40%	9.45%	11.48%
Empire District Electric	EDE	$1.28	$21.73	5.89%	6.08%	NA	7.00%	6.00%	6.50%	12.07%	12.58%	13.10%
Great Plains Energy Inc.	GXP	$0.83	$20.03	4.14%	4.30%	9.00%	6.00%	7.50%	7.50%	10.27%	11.80%	13.33%
Hawaiian Electric	HE	$1.24	$24.86	4.99%	5.22%	8.90%	11.00%	7.90%	9.27%	13.09%	14.49%	16.26%
IDACORP, Inc.	IDA	$1.20	$38.23	3.14%	3.21%	4.70%	4.00%	4.67%	4.46%	7.20%	7.67%	7.91%
Pinnacle West Capital	PNW	$2.10	$42.88	4.90%	5.04%	5.00%	6.00%	6.98%	5.99%	10.02%	11.04%	12.05%
Portland General	POR	$1.06	$23.85	4.44%	4.57%	5.00%	7.50%	4.38%	5.63%	8.92%	10.20%	12.11%
Southern Co.	SO	$1.89	$38.43	4.92%	5.05%	5.00%	6.00%	5.51%	5.50%	10.04%	10.56%	11.07%
Westar Energy	WR	$1.28	$26.36	4.86%	5.02%	5.50%	8.50%	6.28%	6.76%	10.49%	11.78%	13.56%
		PROXY GROUP MEAN		4.57%	4.72%	6.01%	6.75%	5.59%	6.13%	9.72%	10.85%	12.01%
									Flotation Adjustment	0.26%	0.26%	0.26%
									Adjusted Mean ROE	9.97%	11.10%	12.26%

Notes
[1] Source: Bloomberg
[2] Source: Bloomberg. Based on indicated number of days historical average, as of May 31, 2011.
[3] Equals Col. [1]/Col. [2]
[4] Equals (Col. [1] x (1+(0.5 x Col. [8])))/Col. [2]
[5] Source: Zacks
[6] Source: Value Line
[7] Source: First Call
[8] Equals Avg (Col. [5], [6], [7])
[9] Equals (Col. [3] x (1 + (0.5 x Minimum (Col. [5], [6], [7])))) + Minimum (Col. [5], [6], [7])
[10] Equals Col. [4] + Col. [8]
[11] Equals (Col. [3] x (1 + (0.5 x Maximum (Col. [5], [6], [7])))) + Maximum (Col. [5], [6], [7])

180 DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks EPS Growth	[6] Value Line EPS Growth	[7] First Call	[8] Average Growth Rate	[9] Low DCF	[10] Mean DCF	[11] High DCF
American Electric Power	AEP	$1.84	$36.11	5.10%	5.19%	4.00%	3.50%	3.71%	3.74%	8.68%	8.93%	9.20%
Cleco Corp.	CNL	$1.12	$32.04	3.50%	3.60%	7.00%	8.00%	3.00%	6.00%	6.55%	9.60%	11.64%
Empire District Electric	EDE	$1.28	$21.51	5.95%	6.14%	NA	7.00%	6.00%	6.50%	12.13%	12.64%	13.16%
Great Plains Energy Inc.	GXP	$0.83	$19.59	4.24%	4.40%	9.00%	6.00%	7.50%	7.50%	10.36%	11.90%	13.43%
Hawaiian Electric	HE	$1.24	$23.82	5.21%	5.45%	8.90%	11.00%	7.90%	9.27%	13.31%	14.71%	16.49%
IDACORP, Inc.	IDA	$1.20	$37.44	3.21%	3.28%	4.70%	4.00%	4.67%	4.46%	7.27%	7.73%	7.98%
Pinnacle West Capital	PNW	$2.10	$42.09	4.99%	5.14%	5.00%	6.00%	6.98%	5.99%	10.11%	11.13%	12.14%
Portland General	POR	$1.06	$22.54	4.70%	4.84%	5.00%	7.50%	4.38%	5.63%	9.19%	10.46%	12.38%
Southern Co.	SO	$1.89	$38.17	4.95%	5.09%	5.00%	6.00%	5.51%	5.50%	10.07%	10.59%	11.10%
Westar Energy	WR	$1.28	$25.67	4.99%	5.16%	5.50%	8.50%	6.28%	6.76%	10.62%	11.92%	13.70%
		PROXY GROUP MEAN		4.68%	4.83%	6.01%	6.75%	5.59%	6.13%	9.83%	10.96%	12.12%
									Flotation Adjustment	0.26%	0.26%	0.26%
									Adjusted Mean ROE	10.09%	11.22%	12.38%

Notes
[1] Source: Bloomberg
[2] Source: Bloomberg. Based on indicated number of days historical average, as of May 31, 2011.
[3] Equals Col. [1]/Col. [2]
[4] Equals (Col. [1] x (1+(0.5 x Col. [8])))/Col. [2]
[5] Source: Zacks
[6] Source: Value Line
[7] Source: First Call
[8] Equals Avg (Col. [5], [6], [7])
[9] Equals (Col. [3] x (1 + (0.5 x Minimum (Col. [5], [6], [7])))) + Minimum (Col. [5], [6], [7])
[10] Equals Col. [4] + Col. [8]
[11] Equals (Col. [3] x (1 + (0.5 x Maximum (Col. [5], [6], [7])))) + Maximum (Col. [5], [6], [7])

FLOTATION COST ADJUSTMENT

Flotation Costs from Inception to Date

Date	Shares Issued	Market Price	Offering Price	Underwriting Discount	Offering Expense	Net Proceeds	Total Flotation Costs	Gross Equity Issue before Costs	Net Proceeds	Flotation Cost Percentage
11/16/1949	1,584,238	$10.750	$10.250	$0.124	$0.137	$9.989	$1,205,605	$17,030,559	$15,824,953	7.079%
6/4/1952	1,108,966	$10.500	$10.500	$0.098	$0.162	$10.240	$288,331	$11,644,143	$11,355,812	2.476%
4/14/1954	1,219,856	$15.250	$14.000	$0.060	$0.124	$13.816	$1,749,274	$18,602,804	$16,853,530	9.403%
2/29/1956	670,920	$17.825	$16.750	$0.050	$0.221	$16.479	$903,058	$11,959,149	$11,056,091	7.551%
7/22/1959	952,033	$23.375	$22.000	$0.069	$0.191	$21.740	$1,556,574	$22,253,771	$20,697,197	6.995%
7/28/1965	772,008	$35.250	$33.000	$0.092	$0.225	$32.683	$1,981,745	$27,213,282	$25,231,537	7.282%
1/22/1969	1,080,811	$29.000	$27.000	$0.119	$0.187	$26.694	$2,492,350	$31,343,519	$28,851,169	7.952%
10/21/1970	1,729,298	$23.125	$21.500	$0.175	$0.149	$21.176	$3,370,402	$39,990,016	$36,619,614	8.428%
7/26/1972	1,902,228	$25.000	$23.500	$0.129	$0.166	$23.205	$3,414,499	$47,555,700	$44,141,201	7.180%
10/10/1973	2,092,451	$25.825	$24.500	$0.128	$0.153	$24.219	$3,360,476	$54,037,547	$50,677,071	6.219%
11/20/1974	2,300,000	$17.625	$17.500	$0.910	$0.069	$16.521	$2,539,200	$40,537,500	$37,998,300	6.264%
8/14/1975	1,750,000	$23.000	$23.000	$0.740	$0.077	$22.183	$1,429,750	$40,250,000	$38,820,250	3.552%
6/3/1976	2,000,000	$24.000	$24.000	$0.720	$0.064	$23.216	$1,568,000	$48,000,000	$46,432,000	3.267%
5/31/1993	3,041,955	$44.125	$43.625	$1.200	$0.048	$42.377	$5,317,337	$134,226,264	$128,908,927	3.961%
9/23/1997	4,500,000	$49.938	$49.563	$1.230	$0.133	$48.200	$7,821,000	$224,721,000	$216,900,000	3.480%
9/29/1997	400,000	$50.500	$49.563	$1.230	$0.133	$48.200	$920,000	$20,200,000	$19,280,000	4.554%
2/25/2002	20,000,000	$22.950	$22.500	$0.730	$0.015	$21.755	$23,900,000	$459,000,000	$435,100,000	5.207%
9/9/2008	17,250,000	$20.860	$20.200	$0.100	$0.006	$20.094	$13,218,352	$359,835,000	$346,616,648	3.673%
8/3/2010	21,850,000	$22.100	$21.500	$0.645	$0.013	$20.571	$33,407,927	$482,885,000	$449,477,073	6.918% [1]
Weighted Average Flotation Costs							$110,443,880	$2,091,285,255	$1,980,841,375	5.281%

The flotation adjustment is derived by dividing the dividend yield by 1-F (where F = flotation costs expressed in percentage terms), or by 0.9472, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + .5g)}{P \times (1 - F)} + g$$

Source: Company data.

[1] This issuance was structured as a forward equity sale. The spread between the initial forward sale price (*i.e.* , $20.855) and the actual forward settle price (*i.e.* , $20.584) is reflected in the net proceeds.

FLOTATION COST ADJUSTMENT

		[1] Stock Price	[2] Annualized Dividend	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Expected Dividend Yield Adjusted for Flotation Costs	[6] Proj EPS Growth (Zacks)	[7] Proj EPS Growth (V.L.)	[8] Proj EPS Growth (First Call)	[9] Average Growth Estimate	[10] DCF k(e)	[11] Flotation Adjusted DCF k(e)
Americai	AEP	$37.12	$1.84	4.96%	5.05%	5.33%	4.00%	3.50%	3.71%	3.74%	8.79%	9.07%
Cleco Cc	CNL	$34.84	$1.12	3.21%	3.31%	3.50%	7.00%	8.00%	3.00%	6.00%	9.31%	9.50%
Empire [	EDE	$22.12	$1.28	5.79%	5.97%	6.31%	NA	7.00%	6.00%	6.50%	12.47%	12.81%
Great Pl	GXP	$20.64	$0.83	4.02%	4.17%	4.41%	9.00%	6.00%	7.50%	7.50%	11.67%	11.91%
Hawaiiar	HE	$25.33	$1.24	4.90%	5.12%	5.41%	8.90%	11.00%	7.90%	9.27%	14.39%	14.68%
IDACOR	IDA	$39.01	$1.20	3.08%	3.14%	3.32%	4.70%	4.00%	4.67%	4.46%	7.60%	7.78%
Pinnacle	PNW	$44.24	$2.10	4.75%	4.89%	5.16%	5.00%	6.00%	6.98%	5.99%	10.88%	11.15%
Portland	POR	$25.10	$1.06	4.22%	4.34%	4.58%	5.00%	7.50%	4.38%	5.63%	9.97%	10.21%
Southerr	SO	$39.57	$1.89	4.78%	4.91%	5.18%	5.00%	6.00%	5.51%	5.50%	10.41%	10.68%
Westar E	WR	$27.08	$1.28	4.73%	4.89%	5.16%	5.50%	8.50%	6.28%	6.76%	11.65%	11.92%
		PROXY GROUP MEAN		4.44%	4.58%	4.84%	6.01%	6.75%	5.59%	6.13%	10.71%	10.97%

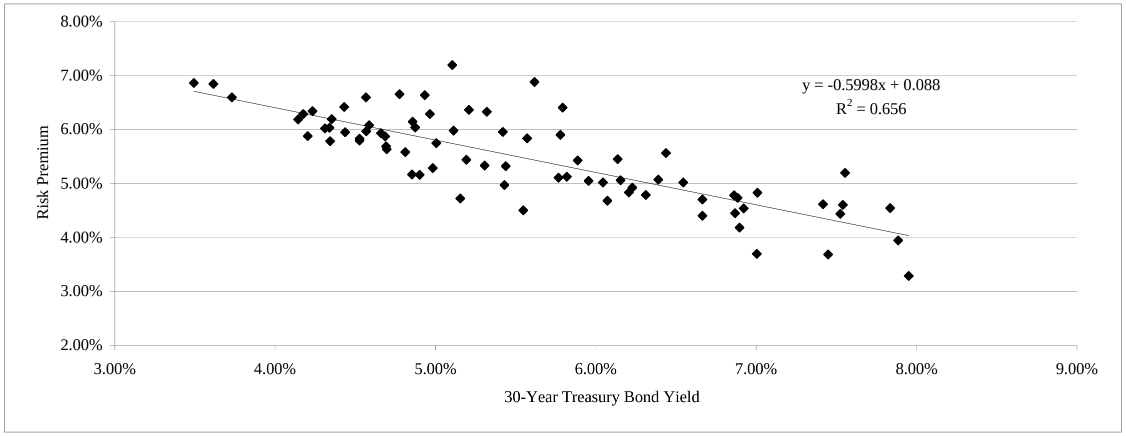
MEAN		10.97%
UNADJUSTED CONSTANT GROWTH DCF MEAN		10.71%
DIFFERENCE (FLOTATION COST ADJUSTMENT)	[12]	0.26%

[1] Source: Bloomberg, 30 day average price
[2] Bloomberg
[3] = Col. [1] / Col. [2] or [Annualized Dividend] / [Price]
[4] = Col. [3] x [1+ (.5 x Col. [9])] or [Dividend Yield] x [1 + (.5 x average growth rate)]
[5] = [Expected Dividend Yield] / [1- Flotation Cost Percentage]
[6] Source: Zacks
[7] Source Value Line
[8] Source: First Call
[9] Average of columns [6], [7], [8]
[10] = Column [4] + Column [9]
[11] = Column [5] + Column [9]
[12] = Col. [11] - Col. [10] or [Mean Adjusted DCF] - [Mean Unadjusted DCF]

TREASURY BOND YIELD RISK PREMIUM

Quarter	Average Authorized Electric Utility ROE [1]	Average 30-Yr. Treasury Yield [2]	Risk Premium (ROE-Treasury Yield)
1992.1	12.38%	7.84%	4.55%
1992.2	11.83%	7.88%	3.94%
1992.3	12.03%	7.42%	4.62%
1992.4	12.14%	7.54%	4.60%
1993.1	11.84%	7.01%	4.83%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.23%	4.92%
1993.4	11.04%	6.21%	4.84%
1994.1	11.07%	6.66%	4.40%
1994.2	11.13%	7.45%	3.68%
1994.3	12.75%	7.55%	5.20%
1994.4	11.24%	7.95%	3.29%
1995.1	11.96%	7.52%	4.44%
1995.2	11.32%	6.87%	4.45%
1995.3	11.37%	6.66%	4.71%
1995.4	11.58%	6.14%	5.45%
1996.1	11.46%	6.39%	5.07%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	7.00%	3.70%
1996.4	11.56%	6.54%	5.02%
1997.1	11.08%	6.90%	4.18%
1997.2	11.62%	6.88%	4.73%
1997.3	12.00%	6.44%	5.56%
1997.4	11.06%	6.04%	5.02%
1998.1	11.31%	5.89%	5.43%
1998.2	12.20%	5.79%	6.41%
1998.3	11.65%	5.32%	6.33%
1998.4	12.30%	5.11%	7.20%
1999.1	10.40%	5.43%	4.97%
1999.2	10.94%	5.82%	5.12%
1999.3	10.75%	6.07%	4.68%
1999.4	11.10%	6.31%	4.79%
2000.1	11.21%	6.15%	5.06%
2000.2	11.00%	5.95%	5.05%
2000.3	11.68%	5.78%	5.90%
2000.4	12.50%	5.62%	6.88%
2001.1	11.38%	5.42%	5.96%
2001.2	10.88%	5.77%	5.11%
2001.3	10.76%	5.44%	5.32%
2001.4	11.57%	5.21%	6.36%
2002.1	10.05%	5.55%	4.50%
2002.2	11.41%	5.57%	5.83%
2002.3	11.25%	4.96%	6.29%
2002.4	11.57%	4.93%	6.63%
2003.1	11.43%	4.78%	6.65%
2003.2	11.16%	4.57%	6.60%
2003.3	9.88%	5.15%	4.72%
2003.4	11.09%	5.11%	5.98%
2004.1	11.00%	4.86%	6.14%
2004.2	10.64%	5.31%	5.33%
2004.3	10.75%	5.01%	5.74%
2004.4	10.91%	4.87%	6.04%
2005.1	10.56%	4.69%	5.87%
2005.2	10.13%	4.34%	5.78%
2005.3	10.85%	4.43%	6.41%
2005.4	10.59%	4.66%	5.93%
2006.1	10.38%	4.69%	5.69%
2006.2	10.63%	5.19%	5.44%
2006.3	10.06%	4.90%	5.16%
2006.4	10.33%	4.70%	5.64%
2007.1	10.39%	4.81%	5.58%
2007.2	10.27%	4.98%	5.28%
2007.3	10.02%	4.85%	5.16%
2007.4	10.36%	4.53%	5.83%
2008.1	10.37%	4.34%	6.03%
2008.2	10.54%	4.57%	5.97%
2008.3	10.38%	4.44%	5.95%
2008.4	10.36%	3.49%	6.86%
2009.1	10.46%	3.62%	6.85%
2009.2	10.58%	4.23%	6.34%
2009.3	10.46%	4.18%	6.28%
2009.4	10.54%	4.35%	6.19%
2010.1	10.66%	4.59%	6.08%
2010.2	10.08%	4.20%	5.87%
2010.3	10.32%	3.73%	6.59%
2010.4	10.33%	4.14%	6.18%
2011.1	10.32%	4.53%	5.80%
2011.2	10.33%	4.31%	6.02%
Mean	11.03%	5.57%	5.47%

TREASURY BOND YIELD RISK PREMIUM



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.80996605
R Square	0.656045002
Adjusted R Square	0.651519278
Standard Error	0.004907308
Observations	78

ANOVA

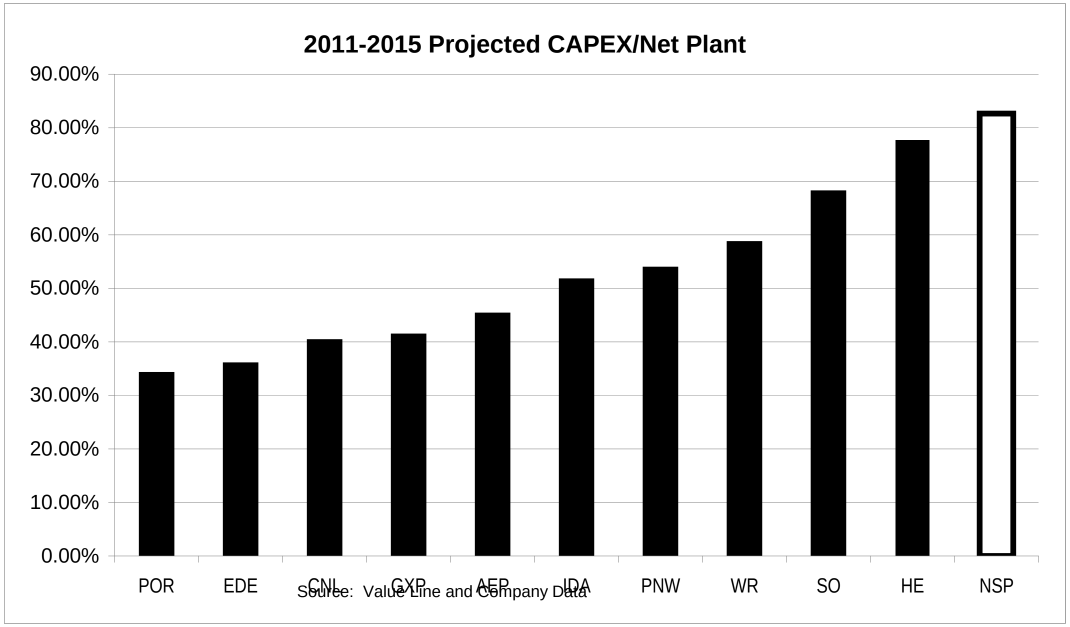
	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.003490859	0.003490859	144.9591383	2.72789E-19
Residual	76	0.001830207	2.40817E-05		
Total	77	0.005321066			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.088037347	0.002827666	31.13427887	5.18963E-45	0.082405562	0.0936691	0.082405562	0.093669133
X Variable 1	-0.599781768	0.049816184	-12.03989777	2.72789E-19	-0.698999297	-0.5005642	-0.698999297	-0.50056424

30-Year Treasury Yield	30-Year Treasury	Risk Prem [3]	ROE
Blue Chip Consensus Forecast (Q2 2011- Q3 2012) [4]	4.88%	5.87%	10.76%
Blue Chip Consensus Forecast (2012 - 2021) [5]	5.45%	5.53%	10.98%
MEAN		5.70%	10.87%

Notes

[1] Source: Regulatory Research Associates, *Rate Case Statistics*, accessed June 8, 2011.
[2] Source: Bloomberg Professional Service. Quarterly T-bond yields are the average of the last trading day of each month in the quarter.
[3] Equals intercept + regression coefficient x 30-year Treasury
[4] Source: Aspen Publishers, *Blue Chip Financial Forecasts*, Vol. 30, No. 5 May 1, 2011, p. 2.
[5] Source: Aspen Publishers, *Blue Chip Financial Forecasts*, Vol. 29 No. 12 December 1, 2010 p.14.



Projected CAPEX / 2010 Net Plant

Company		**2011-2015**
Portland General	POR	34.19%
Empire District	EDE	35.98%
Cleco Corp.	CNL	40.31%
Great Plains Energy	GXP	41.37%
American Electric Power	AEP	45.29%
IDACORP, Inc.	IDA	51.68%
Pinnacle West	PNW	53.88%
Westar Gas	WR	58.66%
Southern Company	SO	68.11%
Hawaiian Electric	HE	77.67%
NSP	NSP	82.65%
Proxy Group Average (ex. NSP)		50.71%
NSP/Proxy Group		1.6

Notes

Source: Value Line, SEC Form 10-K, Xcel Energy, Inc, for the year ending December 31, 2010, at 75, and FERC Form 1, Northern States Power Company (Minnesota), for the period ending December 31, 2010, at 110.

COMPANY PROPOSED CAPITAL STRUCTURE

Nothern States Power Company Minnesota - South Dakota
Capital Structure
13 Month Average for 2010
($000's)

Line No	(A) Description	(B) Amount	(C) Percentage Of Total
1	Long Term Debt	3,086,733	47.52%
2	Common Equity	3,408,561	52.48%
		6,495,294	100.00%

Line Notes:
1 Statement G Working Papers Page 2 of 5 (see Exhibit___(DSD-1), Schedule 8)
2 Statement G Working Papers Page 3 of 5 (reproduced below)

Northern States Power Company Minnesota - South Dakota
Proposed Test Year - Cost of Capital
13 Month Average for 2010
Common Equity
($000's)

Month	Common Equity Outstanding	Non-Regulated Subsidiaries*	Net Common Equity
ACTUAL YEAR 2010			
2009 Dec	$3,241,209	$1,188	$3,240,021
2010 Jan	$3,322,862	$1,180	$3,321,682
Feb	$3,342,017	$1,166	$3,340,851
Mar	$3,298,019	$1,157	$3,296,862
Apr	$3,302,151	$1,145	$3,301,006
May	$3,315,686	$1,129	$3,314,557
Jun	$3,445,044	$1,116	$3,443,928
Jul	$3,492,094	$1,103	$3,490,991
Aug	$3,547,496	$1,091	$3,546,405
Sep	$3,496,587	$1,078	$3,495,509
Oct	$3,505,951	$1,066	$3,504,885
Nov	$3,520,521	$1,053	$3,519,468
Dec	$3,496,169	$1,040	$3,495,129
13 Month Average	$3,409,677	$1,116	$3,408,561

* Subsidiaries include United Power and Land.

Equity Ratio

Summary Data

Company Name	Ticker	2011Q1	2010Q4	2010Q3	2010Q2	2010Q1	2009Q4	2009Q3	2009Q2	Overall Average
American Electric Power	AEP	48.61%	50.05%	53.10%	52.55%	52.51%	48.47%	49.05%	48.94%	50.41%
Cleco Power LLC	CNL	46.98%	47.33%	51.14%	50.52%	50.69%	45.45%	47.08%	46.43%	48.20%
Empire District Electric	EDE	51.03%	50.93%	50.99%	50.50%	51.88%	50.80%	48.49%	46.88%	50.19%
Great Plains Energy Inc.	GXP	53.59%	52.23%	52.34%	54.19%	53.82%	53.70%	52.96%	52.39%	53.15%
Hawaiian Electric Company, Inc.	HE	55.86%	55.83%	55.62%	55.42%	55.31%	55.26%	53.41%	56.88%	55.45%
IDACORP, Inc.	IDA	48.84%	46.61%	46.22%	48.20%	47.56%	47.45%	48.15%	46.98%	47.50%
Pinnacle West	PNW	52.57%	52.97%	52.98%	51.49%	49.78%	50.37%	50.74%	48.18%	51.14%
Portland General	POR	47.74%	46.83%	46.73%	46.26%	46.47%	46.94%	49.37%	49.17%	47.44%
Southern Co.	SO	50.59%	49.27%	48.75%	50.45%	50.71%	50.01%	50.38%	48.99%	49.89%
Westar Energy	WR	59.24%	59.37%	59.48%	58.67%	58.41%	58.73%	58.86%	57.04%	58.72%
Proxy Group Average		51.50%	51.14%	51.73%	51.82%	51.71%	50.72%	50.85%	50.19%	51.21%

Underlying Data

		Equity Ratio							
Company Name	Ticker	2011Q1	2010Q4	2010Q3	2010Q2	2010Q1	2009Q4	2009Q3	2009Q2
AEP Texas Central Company	AEP	44.99%	44.85%	44.76%	43.79%	43.89%	43.79%	43.67%	46.13%
AEP Texas North Company	AEP	45.88%	45.52%	45.18%	45.09%	45.73%	45.58%	46.63%	46.51%
Alabama Power Company	SO	46.46%	46.54%	47.06%	46.45%	46.16%	45.80%	45.75%	43.43%
Appalachian Power Company	AEP	41.53%	44.21%	43.87%	43.52%	45.05%	44.35%	44.82%	44.58%
Arizona Public Service Company	PNW	52.57%	52.97%	52.98%	51.49%	49.78%	50.37%	50.74%	48.18%
Cleco Power LLC	CNL	46.98%	47.33%	51.14%	50.52%	50.69%	45.45%	47.08%	46.43%
Columbus Southern Power Company	AEP	50.87%	50.81%	48.47%	47.05%	46.48%	46.95%	46.18%	46.81%
Empire District Electric Company	EDE	51.03%	50.93%	50.99%	50.50%	51.88%	50.80%	48.49%	46.88%
Georgia Power Company	SO	51.17%	51.32%	50.22%	50.69%	50.99%	49.77%	51.57%	49.55%
Gulf Power Company	SO	47.52%	46.71%	45.40%	47.46%	48.46%	47.25%	46.75%	46.23%
Hawaiian Electric Company, Inc.	HE	55.86%	55.83%	55.62%	55.42%	55.31%	55.26%	53.41%	56.88%
Idaho Power Co.	IDA	48.84%	46.61%	46.22%	48.20%	47.56%	47.45%	48.15%	46.98%
Indiana Michigan Power Company	AEP	48.86%	48.47%	46.80%	46.29%	46.44%	45.85%	45.74%	45.30%
Kansas City Power & Light Company	GXP	52.66%	52.90%	53.16%	52.29%	51.98%	51.97%	51.93%	51.33%
Kansas Gas and Electric Company	WR	56.52%	57.00%	57.24%	56.49%	56.24%	57.15%	57.23%	56.43%
KCP&L Greater Missouri Operations Company	GXP	54.52%	51.55%	51.52%	56.09%	55.66%	55.43%	53.99%	53.44%
Kentucky Power Company	AEP	45.50%	44.84%	44.21%	43.59%	44.27%	44.04%	44.00%	43.94%
Kingsport Power Company	AEP	59.12%	57.96%	100.00%	100.00%	100.00%	51.61%	55.30%	54.84%
Mississippi Power Company	SO	57.21%	52.51%	52.30%	57.20%	57.23%	57.24%	57.45%	56.74%
Ohio Power Company	AEP	54.52%	53.43%	52.37%	52.33%	49.41%	49.94%	50.14%	53.32%
Portland General Electric Company	POR	47.74%	46.83%	46.73%	46.26%	46.47%	46.94%	49.37%	49.17%
Public Service Company of Oklahoma	AEP	45.21%	46.45%	46.65%	45.41%	45.33%	45.61%	48.55%	47.44%
Southwestern Electric Power Company	AEP	49.58%	49.15%	49.07%	47.81%	47.41%	51.71%	51.52%	48.17%
Westar Energy (KPL)	WR	61.96%	61.74%	61.72%	60.84%	60.58%	60.31%	60.48%	57.65%
Wheeling Power Co	AEP	NA	64.89%	62.73%	63.16%	63.54%	63.72%	62.98%	61.25%

Notes
Source: SNL Financial

Long Term Debt Ratio

Summary Data

Company Name	Ticker	2011Q1	2010Q4	2010Q3	2010Q2	2010Q1	2009Q4	2009Q3	2009Q2	Overall Average
American Electric Power	AEP	51.39%	49.95%	46.90%	47.45%	47.49%	51.53%	50.95%	51.06%	49.59%
Cleco Power LLC	CNL	53.02%	52.67%	48.86%	49.48%	49.31%	54.55%	52.92%	53.57%	51.80%
Empire District Electric	EDE	48.97%	49.07%	49.01%	49.50%	48.12%	49.20%	51.51%	53.12%	49.81%
Great Plains Energy Inc.	GXP	46.41%	47.77%	47.66%	45.81%	46.18%	46.30%	47.04%	47.61%	46.85%
Hawaiian Electric Company, Inc.	HE	44.14%	44.17%	44.38%	44.58%	44.69%	44.74%	46.59%	43.12%	44.55%
IDACORP, Inc.	IDA	51.16%	53.39%	53.78%	51.80%	52.44%	52.55%	51.85%	53.02%	52.50%
Pinnacle West	PNW	47.43%	47.03%	47.02%	48.51%	50.22%	49.63%	49.26%	51.82%	48.86%
Portland General	POR	52.26%	53.17%	53.27%	53.74%	53.53%	53.06%	50.63%	50.83%	52.56%
Southern Co.	SO	49.41%	50.73%	51.25%	49.55%	49.29%	49.99%	49.62%	51.01%	50.11%
Westar Energy	WR	40.76%	40.63%	40.52%	41.33%	41.59%	41.27%	41.14%	42.96%	41.28%
Proxy Group Average		48.50%	48.86%	48.27%	48.18%	48.29%	49.28%	49.15%	49.81%	48.79%

Underlying Data

		Long Term Debt Ratio							
Company Name	Ticker	2011Q1	2010Q4	2010Q3	2010Q2	2010Q1	2009Q4	2009Q3	2009Q2
AEP Texas Central Company	AEP	55.01%	55.15%	55.24%	56.21%	56.11%	56.21%	56.33%	53.87%
AEP Texas North Company	AEP	54.12%	54.48%	54.82%	54.91%	54.27%	54.42%	53.37%	53.49%
Alabama Power Company	SO	53.54%	53.46%	52.94%	53.55%	53.84%	54.20%	54.25%	56.57%
Appalachian Power Company	AEP	58.47%	55.79%	56.13%	56.48%	54.95%	55.65%	55.18%	55.42%
Arizona Public Service Company	PNW	47.43%	47.03%	47.02%	48.51%	50.22%	49.63%	49.26%	51.82%
Cleco Power LLC	CNL	53.02%	52.67%	48.86%	49.48%	49.31%	54.55%	52.92%	53.57%
Columbus Southern Power Company	AEP	49.13%	49.19%	51.53%	52.95%	53.52%	53.05%	53.82%	53.19%
Empire District Electric Company	EDE	48.97%	49.07%	49.01%	49.50%	48.12%	49.20%	51.51%	53.12%
Georgia Power Company	SO	48.83%	48.68%	49.78%	49.31%	49.01%	50.23%	48.43%	50.45%
Gulf Power Company	SO	52.48%	53.29%	54.60%	52.54%	51.54%	52.75%	53.25%	53.77%
Hawaiian Electric Company, Inc.	HE	44.14%	44.17%	44.38%	44.58%	44.69%	44.74%	46.59%	43.12%
Idaho Power Co.	IDA	51.16%	53.39%	53.78%	51.80%	52.44%	52.55%	51.85%	53.02%
Indiana Michigan Power Company	AEP	51.14%	51.53%	53.20%	53.71%	53.56%	54.15%	54.26%	54.70%
Kansas City Power & Light Company	GXP	47.34%	47.10%	46.84%	47.71%	48.02%	48.03%	48.07%	48.67%
Kansas Gas and Electric Company	WR	43.48%	43.00%	42.76%	43.51%	43.76%	42.85%	42.77%	43.57%
KCP&L Greater Missouri Operations Company	GXP	45.48%	48.45%	48.48%	43.91%	44.34%	44.57%	46.01%	46.56%
Kentucky Power Company	AEP	54.50%	55.16%	55.79%	56.41%	55.73%	55.96%	56.00%	56.06%
Kingsport Power Company	AEP	40.88%	42.04%	0.00%	0.00%	0.00%	48.39%	44.70%	45.16%
Mississippi Power Company	SO	42.79%	47.49%	47.70%	42.80%	42.77%	42.76%	42.55%	43.26%
Ohio Power Company	AEP	45.48%	46.57%	47.63%	47.67%	50.59%	50.06%	49.86%	46.68%
Portland General Electric Company	POR	52.26%	53.17%	53.27%	53.74%	53.53%	53.06%	50.63%	50.83%
Public Service Company of Oklahoma	AEP	54.79%	53.55%	53.35%	54.59%	54.67%	54.39%	51.45%	52.56%
Southwestern Electric Power Company	AEP	50.42%	50.85%	50.93%	52.19%	52.59%	48.29%	48.48%	51.83%
Westar Energy (KPL)	WR	38.04%	38.26%	38.28%	39.16%	39.42%	39.69%	39.52%	42.35%
Wheeling Power Co	AEP	NA	35.11%	37.27%	36.84%	36.46%	36.28%	37.02%	38.75%

Notes

Source: SNL Financial

Proposed Test Year
13 Month Average for 2010
Composite Cost of Long-term Debt
($000's)

ACTUAL YEAR 2010 1/

Description	Coupon Rate	Issue Date	Maturity Date	13 Month Avg. Bal. Amount	Hedge/ Premium	Discount	Expense	/ 5 Capital Employed	Total 4/ Interest Charge	Premium Amortization	Discount Amortization	Expense Amortization	Cost of Capital	Capital Cost %	Moody's Utility A-Rated Bond Index	Weighted Moody's Utility A-Rated Bond Index
First Mortgage Bonds																
Series Due August 1, 2010 (FMB) 2/	4.7500	Aug-03	Aug-10	107,692	-	262	983	106,447	4,849	-	37	140	5,026	4.72%	6.79%	0.23%
Series Due August 28, 2012 (FMB)	8.0000	Aug-02	Aug-12	450,000	-	-	5,687	444,313	36,000	-	450	119	36,569	8.23%	7.17%	1.03%
Becker (92A) due March 1, 2019 (PC) (FMB) Series N 1/	6.5430	Mar-92	Mar-19	27,900	-	-	993	26,907	1,825	-	-	52	1,878	6.98%	8.97%	0.08%
Becker (93A) due September 1, 2019 (PC) (FMB) Series O 1/	6.5430	Sep-93	Sep-19	50,000	-	-	1,073	48,927	3,272	-	-	55	3,327	6.80%	7.04%	0.11%
Becker (93B) due September 1, 2019 (PC) (FMB) Series P 1/	6.5430	Sep-93	Sep-19	50,000	-	-	1,057	48,943	3,272	-	-	55	3,326	6.80%	7.04%	0.11%
City of Becker due April 1, 2030 (PC) 1/	6.5430	Apr-00	Apr-30	69,000	-	-	348	68,652	4,515	-	-	45	4,560	6.64%	8.29%	0.18%
Series due July 1, 2025 (FMB)	7.1250	Jul-95	Jul-25	250,000	-	2,330	1,898	245,772	17,813	-	78	63	17,953	7.30%	7.70%	0.61%
Series due March 1, 2028 (FMB)	6.5000	Mar-98	Mar-28	150,000	-	1,761	1,475	146,764	9,750	-	59	49	9,858	6.72%	7.16%	0.34%
Series Due July 15, 2035 (FMB)	5.2500	Jul-05	Jul-35	250,000	-	485	3,032	246,483	13,125	-	16	101	13,242	5.37%	5.51%	0.44%
Series Due June 1, 2036 (FMB)	6.2500	May-06	Jun-36	400,000	16,202	1,404	4,877	409,921	25,000	545	35	174	24,665	6.02%	6.42%	0.85%
Series Due July 1, 2037 (FMB)	6.2000	Jun-07	Jul-37	350,000	1,894	1,988	4,337	345,569	21,700	189	66	144	21,721	6.29%	6.30%	0.71%
Series Due March 1, 2018 (FMB)	5.2500	Mar-08	Mar-18	500,000	(5,167)	1,520	4,815	488,497	26,250	(518)	153	484	27,405	5.61%	6.21%	0.98%
Series Due November 1, 2039 (FMB)	5.3500	Nov-09	Nov-39	300,000	(3,209)	570	4,154	292,067	16,050	(107)	19	139	16,315	5.59%	5.63%	0.53%
Series Due August 15, 2015 (FMB) 3/	1.9500	Aug-10	Aug-15	96,154	-	207	969	94,977	1,896	-	39	178	2,113	2.22%	5.01%	0.15%
Series Due August 15, 2040 (FMB) 3/	4.8500	Aug-10	Aug-40	96,154	-	295	1,256	94,603	4,715	-	9	39	4,763	5.03%	5.01%	0.15%
Seeley & Right of Way Notes	var	var	var	43	-	-	-	43	1	-	-	-	1	2.33%		
TOTAL DEBT				3,146,943	9,721	10,822	36,954	3,108,887	190,032	109	961	1,838	192,722	6.20%		
Unamortized Loss on Reacquired Debt								(22,155)					2,417			
Fees on 5-year Credit Facility 4/								-					199			
GRAND TOTAL								3,086,733					195,339	6.33%		6.53%

COST OF DEBT

1/ Long Term Debt not adjusted for MERP, Becker Bond Interest Rate adjusted from 8.500% to 6.543% (1.957% Adjustment).
2/ NSPM maturity on 8/1/2010 a $175M First Mortgage Bond. The $107.692MM balance represents 8 of 13 months average balance.
3/ NSPM issued two $250M First Mortgage Bond tranches totaling $500M on 8/11/2010. Average Balance represents 5 of 13 Months.
4/ Up Front Fees associated with the 5 Year Credit Facility are amortized over the life of the facility and are incorporated into the long-term debt rate.
5/ Capital Employed is based on the Premium / Discount / Expense Balances representing the initial balances. New and Maturing Debt averaged on number of months in the year.

Source: Statement G
Working Papers
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