

Direct Testimony and Schedules
Ann E. Bulkley

Before the North Dakota Public Service Commission

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

Case No. PU-10-____
Exhibit____(AEB-1)

Return on Equity

December 20, 2010

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1 **I. INTRODUCTION AND QUALIFICATIONS**

2
3 Q. PLEASE STATE YOUR NAME, EMPLOYER, AND BUSINESS ADDRESS.

4 A. My name is Ann E Bulkley. I am employed by Concentric Energy Advisors
5 (“Concentric”) as a Vice President. My business address is 293 Boston Post
6 Road West, Suite 500, Marlborough, Massachusetts 01752.

7
8 Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

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

12
13 Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

14 A. I have approximately 15 years of experience consulting to the energy industry.
15 I have advised numerous energy and utility clients on a wide range of financial
16 and economic issues with primary concentrations in valuation and utility rate
17 matters. Many of those assignments have included the determination of the
18 cost of capital for valuation purposes. I have included my résumé as Exhibit
19 __ (AEB-1), Schedule 1, and a summary of testimony that I have filed in other
20 proceedings as Exhibit __ (AEB-1), Schedule 2.

21
22 **II. PURPOSE AND OVERVIEW OF TESTIMONY**

23
24 Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

25 A. The purpose of my Direct Testimony is to present evidence and provide a
26 recommendation regarding the Company’s return on equity (“ROE”), and to
27 provide an assessment of the capital structure to be used for ratemaking
28 purposes, as proposed in the Direct Testimony of Company Witness Mr. John

1 M. Felling. My analyses and recommendations are supported by the data
2 presented in Exhibit __ (AEB-1), Schedules 3 through 7.

3
4 Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE APPROPRIATE COST OF
5 EQUITY AND OVERALL RATE OF RETURN FOR THE COMPANY?

6 A. The Company is requesting an ROE of 11.25 percent in this proceeding.
7 Based on the analyses discussed throughout the balance of my testimony, it is
8 my view that the cost of equity for the Company is in the 50 basis point range
9 of 11.30 percent to 11.80 percent. As a result, I find the Company's requested
10 11.25 percent ROE is conservative, and I recommend that the North Dakota
11 Public Service Commission (the "Commission") authorize the Company the
12 opportunity to earn an ROE of 11.25 percent. I also conclude that the
13 Company's projected test year capital structure, which includes 52.56 percent
14 common equity, 46.30 percent long-term debt, and 1.14 percent short-term
15 debt, is reasonable.

16
17 Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSIS THAT LED TO YOUR
18 CONCLUSIONS.

19 A. My recommended ROE is based primarily on the results of the Constant
20 Growth Discounted Cash Flow ("DCF") model. However, I also considered
21 the results of the Risk Premium approach.

22
23 In applying and assessing the results of my DCF and Risk Premium analyses, I
24 considered and made an adjustment for the flotation costs associated with
25 equity issuances. I also considered general industry trends and the effect of
26 the Company's substantial capital expenditure plan, although I did not make a
27 specific adjustment for these factors.

1
2 Finally, I reviewed the Company's proposed capital structure within the
3 context of its pending capital expenditures, general industry trends, and proxy
4 group norms. Based on that review, I concluded that the Company's
5 proposed capital structure is reasonable.
6

7 Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

8 A. The remainder of my testimony is organized in seven sections. In Section III,
9 I discuss the regulatory guidelines and financial considerations pertinent to the
10 development of the ROE. Section IV provides an overview of current market
11 conditions and the affect of these conditions on the recommended ROE.
12 Section V explains my selection of a proxy group of integrated electric utilities.
13 Section VI explains my analysis and recommendation of the appropriate ROE
14 for the Company. Section VII provides a discussion of the business and
15 economic risks to which the Company is exposed. Section VIII provides my
16 assessment of the Company's proposed capital structure, and Section IX
17 summarizes my conclusions and recommendations.
18

19 **III. REGULATORY GUIDELINES AND FINANCIAL**
20 **CONSIDERATIONS**

21
22 Q. PLEASE DESCRIBE THE GUIDING PRINCIPLES TO BE USED IN ESTABLISHING THE
23 ROE FOR A REGULATED UTILITY.

24 A. The United States Supreme Court's *Hope* and *Bluefield* cases established the
25 standards for determining the fairness or reasonableness of a utility's allowed
26 ROE. Among the standards established by the Court in those cases are: (1)
27 consistency with other businesses having similar or comparable risks; (2)

1 adequacy of the return to support financial soundness and access to capital;
2 and (3) that the end result, as opposed to the methodology employed, is the
3 controlling factor in arriving at just and reasonable rates.¹

4
5 Based on those widely recognized standards, the Commission's order in this
6 case should provide the Company with the opportunity to earn an ROE that
7 is:

- 8 • Adequate to attract capital on favorable terms, thereby enabling the
9 Company to provide safe, reliable service;
- 10 • Sufficient to ensure the financial soundness of the Company's
11 operations; and
- 12 • Commensurate with returns on investments in enterprises having
13 comparable risks.

14
15 The allowed ROE, therefore, should enable the Company to finance capital
16 expenditures on reasonable terms and optimize its financial flexibility over the
17 period during which rates are expected to remain in effect.

18
19 Q. WHY IS IT IMPORTANT FOR A UTILITY TO BE ALLOWED THE OPPORTUNITY TO
20 EARN AN ROE THAT IS ADEQUATE TO ATTRACT CAPITAL AT REASONABLE
21 TERMS?

22 A. An ROE that is adequate to attract capital at reasonable terms enables the
23 Company to provide safe, reliable electric service while maintaining its
24 financial integrity. To the extent the Company is provided the opportunity to
25 earn its market-based cost of capital, neither customers nor shareholders are

¹ *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).

1 disadvantaged. While the “capital attraction” and “financial integrity”
2 standards are important principles in normal economic conditions, the
3 practical implications of those standards are even more pronounced when
4 considered in the context of the recent financial environment.

5
6 Q. WHAT ARE YOUR CONCLUSIONS REGARDING REGULATORY GUIDELINES AND
7 CAPITAL MARKET EXPECTATIONS?

8 A. It is important for the ROE authorized in this proceeding to take into
9 consideration the capital market conditions with which the Company must
10 contend, as well as investors’ expectations and requirements for both risks and
11 returns. Further, in light of recent capital market conditions and the
12 Company’s capital investment plans, it is critical that the Company be
13 afforded the opportunity to maintain a financial profile that will enable it to
14 access the capital markets at reasonable rates. As discussed throughout my
15 testimony, an important factor in achieving that profile is the ability to earn a
16 reasonable ROE.

17
18 **IV. CAPITAL MARKET ENVIRONMENT**

19
20 Q. HOW DO ECONOMIC CONDITIONS INFLUENCE THE REQUIRED COST OF
21 CAPITAL AND REQUIRED ROE?

22 A. The required cost of capital, including the ROE, is a function of prevailing
23 and expected financial market conditions. Consistent with the *Hope* and
24 *Bluefield* decisions, the authorized ROE for a public utility should allow the
25 company to attract investor capital at reasonable cost under a variety of
26 economic and financial market conditions. The ability to attract capital on
27 reasonable terms is especially important for utilities such as the Company that

1 plan to invest considerable amounts of capital in investments designed to
2 maintain and enhance system reliability.

3
4 Q. DOES THE POTENTIAL FOR INCREASING INTEREST RATES INCREASE RISK TO
5 UTILITIES?

6 A. Yes, it does. It is well established that utility stock prices decline as interest
7 rates increase. Such lower valuation levels reflect increased costs of attracting
8 the equity capital needed to fund the Company's capital investment program,
9 and, therefore, reflect the need for a commensurately higher ROE. The
10 financial community has consistently recognized that the stock prices of
11 capital-intensive companies (such as the Company) have a negative correlation
12 to interest rates. Value Line, for example, establishes "price targets" based on
13 the ratio of dividends per share to interest rates; as interest rates increase, the
14 price target declines, resulting in an increased dividend yield. Consistent with
15 Value Line's methodology, as shown in Chart 1 (below), there is a strong,
16 positive statistical relationship between the proxy companies' average dividend
17 yield and the 30-year Treasury yield.

18

1

Chart 1: Proxy Group Average Dividend Yield vs. 30-Year Treasury Yield²



2

3 Q. WHAT IS THE SIGNIFICANCE OF THIS RELATIONSHIP TO THE COST OF EQUITY?

4 A. Long-term Treasury rates are currently at low levels by historical standards.

5 As such, it is reasonable to assume that, on balance, long-term rates are more

6 likely to increase than decrease in the intermediate term. In fact, the Blue

7 Chip Financial Forecasts projects the 30-year Treasury bond to yield 5.70

8 percent by 2014,³ while the 30-day average yield on 30-year Treasury securities

9 was approximately 3.83 percent as of October 29, 2010, resulting in a

10 projected increase of approximately 128 basis points. Therefore, rising

11 interest rates are a significant element of market risk at the time of this filing.

² Source: Bloomberg Professional Service.

³ Blue Chip Financial Forecasts, Vol. 29, No. 6, June 1, 2010, at 14.

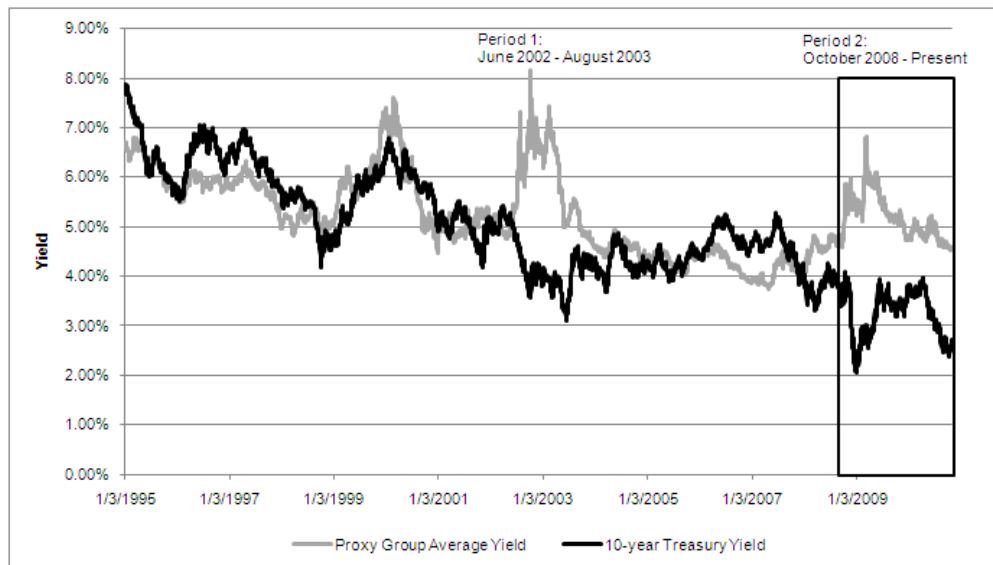
1

2 Q. WHAT ANALYSIS HAVE YOU CONDUCTED TO ASSESS CURRENT CAPITAL
3 MARKET CONDITIONS?

4 A. I examined the relationship between the interest rate on ten-year Treasury
5 notes and the dividend yield of my proxy group over time. That relationship
6 is reflected in Chart 2.

7

Chart 2: Treasury Yield/Dividend Yield Inversion⁴



8

9

10 While dividend yields and Treasury yields have historically been positively
11 correlated, as shown in Chart 2, the 2008 – 2009 financial dislocation created a
12 significant inversion (wherein, the dividend yield exceeded the Treasury yield)
13 of the ten year Treasury yield relative to the proxy group average dividend
14 yield. The most recent prior period during which these yields were
15 significantly inverted was the period from mid-2002 through mid-2003, which
16 likewise was a period of credit and equity valuation contraction. Similar to
17 the current market, one outcome of the 2002-2003 market dislocation was a

1 renewed emphasis on capital market access, and the importance of
2 maintaining a strong financial profile. Such strength and capital market access
3 are equally important in the current market environment.
4

5 Q. HAS THE SIGNIFICANCE OF THIS INVERSION BEEN NOTED?

6 A. Yes. In a 2009 article, the *The Wall Street Journal* noted this same inverted
7 relationship between utility dividend yields and the ten-year Treasury yield,
8 noting that:

9 ...dividend yields have tended to track the yield on 10-year
10 Treasuries closely. Since 1970, the spread of regulated utilities'
11 dividend yields over Treasury yields has averaged 0.24
12 percentage point. Today, with utilities yielding about 5.65%,
13 the spread is 10 times that, having peaked in March at 3.75
14 percentage points. You have to go all the way back to the
15 early 1980s for the last time it reached such heights.

16 ***

17 Regulated utilities' dividend yields decoupled from Treasury
18 yields in December 2007, as the U.S. recession began. After
19 the initial flight to quality cut yields on Treasuries, particularly
20 after Lehman Brothers collapsed in September 2008, the
21 Federal Reserve's policy of buying up government debt has
22 helped keep them low.⁵
23

24 As shown in Chart 2, that inversion of dividend yield relative to the ten-year
25 Treasury has continued unabated since that article was published,
26 demonstrating the extraordinarily low level of Treasury yields discussed
27 previously and the continuing high level of capital market uncertainty that
28 began in 2008.
29

⁴ Source: Bloomberg Professional Service.

⁵ *A Short Circuit in the Stock Market*, *The Wall Street Journal*, Liam Denning, October 23, 2009, at C10.

1 Furthermore, as noted in the June 2010 Federal Reserve Open Market
2 Committee (“FOMC”) Minutes, during the period from April to June 2010,
3 “[t]he spread between the staff’s estimate of the expected real return on
4 equities over the next 10 years and an estimate of the expected real return on a
5 10-year Treasury note—a measure of the equity risk premium—increased
6 from its already elevated level.”⁶

7
8 Q. WHAT DO YOU CONCLUDE FROM YOUR ANALYSIS OF THESE RELATIONSHIPS?

9 A. While there has been a strong relationship between yields of utility company
10 stocks and Treasury yields, the current capital market continues to experience
11 high levels of risk aversion, and uncertainty. The result is an increased, not a
12 decreased, cost of equity.

13
14 **V. USE OF PROXY GROUP COMPANIES**

15
16 Q. PLEASE EXPLAIN WHY YOU HAVE USED A GROUP OF PROXY COMPANIES TO
17 DETERMINE THE COST OF EQUITY FOR THE COMPANY.

18 A. In this proceeding, we are focused on estimating the cost of equity for the
19 Company, a rate-regulated, wholly-owned subsidiary of XEI. Since the ROE
20 is a market-based concept, and given that the Company is not publicly traded,
21 it is necessary to establish a group of companies that are both publicly traded
22 and comparable to the Company in certain fundamental business and financial
23 respects to serve as its “proxy” in the ROE estimation process.

24
25 Even if the Company were a publicly traded entity, it is possible that transitory
26 events could bias its market value in one way or another over a given period

⁶ Federal Open Market Committee, Minutes of the Meeting of June 22-23, 2010, at 6.

1 of time. A significant benefit of using a proxy group, therefore, is that it
2 moderates the effects of unusual events that may be associated with any one
3 company. The proxy companies used in my analyses all possess a set of
4 operating and risk characteristics that are substantially comparable to the
5 Company, and thus provide a reasonable basis to derive and estimate the
6 appropriate ROE for the Company.

7
8 Q. HOW DID YOU SELECT THE COMPANIES INCLUDED IN YOUR PROXY GROUP?

9 A. I began with the companies that Value Line classifies as “Electric Utilities,”
10 which comprise a group of 54 domestic U.S. utilities. I then simultaneously
11 applied the following screening criteria:

- 12 • I excluded companies that do not pay consistent quarterly cash
13 dividends.
- 14 • I excluded companies that have not been covered by at least two
15 generally recognized utility industry equity analysts.
- 16 • All of the companies in my proxy group had senior bond and/or
17 corporate ratings from Standard and Poor’s (“S&P”) of BBB- to AAA.
- 18 • I excluded companies that do not own regulated generation assets.
- 19 • I excluded companies whose regulated revenues and net income
20 comprised less than 60.00 percent of the respective totals for the
21 company.
- 22 • To ensure a focus on companies whose revenues and net income are
23 derived primarily from electric operations, I excluded companies whose
24 regulated electric revenues and net income represented less than 90
25 percent of total regulated revenues and net income.
- 26 • Finally, I eliminated any companies that are currently known to be party
27 to a merger or other transforming transaction.

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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. As shown in Exhibit __ (AEB-1), Schedule 3, the criteria discussed above resulted in a proxy group of the following twelve companies:

Table 1: Screening Results

Company	Ticker
American Electric Power Company, Inc.	AEP
Cleco Corp.	CNL
DPL, Inc	DPL
Great Plains Energy Inc.	GXP
Hawaiian Electric	HE
IDACORP, Inc.	IDA
NextEra Energy, Inc	NEE
Pinnacle West Capital Corp.	PNW
Portland General Electric Company	POR
Progress Energy	PGN
Southern Company	SO
Westar Energy, Inc.	WR

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Q. DO YOU BELIEVE THAT TWELVE COMPANIES CONSTITUTES A SUFFICIENTLY LARGE PROXY GROUP?

A. Yes, I do. The analyses performed are more likely to be representative of the subject utility's cost of equity to the extent that the proxy companies are fundamentally comparable to the subject utility. Because I applied a screening process to arrive at a proxy group that is comparable to the Company, the group, by definition, is not randomly drawn from a larger population.

1 Q. HOW IS THE REQUIRED ROE DETERMINED?

2 A. The required ROE is estimated by using one or more analytical techniques
3 that rely on market-based data to quantify investor expectations regarding
4 required equity returns, adjusted for certain incremental costs and risks.
5 Informed judgment is applied, based on the results of those analyses, to
6 determine where within the range of results the cost of equity for the
7 Company falls. The resulting adjusted cost of equity serves as the
8 recommended ROE for ratemaking purposes. As a general proposition, the
9 key consideration in determining the cost of equity is to ensure that the
10 methodologies employed reasonably reflect investors' view of the financial
11 markets as well as the subject company's common stock.

12

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

14 A. I relied primarily on the results of the DCF model corroborated by the results
15 of the Risk Premium approach. I also considered the Capital Asset Pricing
16 Model ("CAPM"). However, the current market data used for the
17 assumptions of this model are not reflective of the level of risk aversion in the
18 current market. As such, I did not rely on the results of the CAPM in
19 developing my recommendation.

20

21 **A. Constant Growth DCF Model**

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

24 A. Yes. DCF models are widely used in regulatory proceedings and have sound
25 theoretical bases, although neither the DCF model nor any other model can
26 be applied without considerable judgment in the selection of data and the
27 interpretation of results. In its simplest form, the DCF model expresses the

1 cost of equity as the sum of the expected dividend yield and long-term growth
2 rate.

3
4 Q. PLEASE DESCRIBE THE DCF APPROACH.

5 A. The DCF approach is based on the theory that a stock's current price
6 represents the present value of all expected future cash flows. In its most
7 general form, the DCF model is expressed as follows:

$$8 \quad P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \dots + \frac{D_\infty}{(1+k)^\infty} \quad [1]$$

9 Where P_0 represents the current stock price, $D_1 \dots D_\infty$ are all expected future
10 dividends, and k is the discount rate, or required ROE. Equation [1] is a
11 standard present value calculation that can be simplified and rearranged into
12 the following form:

$$13 \quad k = \frac{D(1+g)}{P_0} + g \quad [2]$$

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

17
18 Q. WHAT ASSUMPTIONS ARE REQUIRED FOR THE CONSTANT GROWTH DCF
19 MODEL?

20 A. The Constant Growth DCF model requires the following assumptions: (1) a
21 constant growth rate for earnings and dividends; (2) a stable dividend payout
22 ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater
23 than the expected growth rate. To the extent that any of these assumptions
24 are violated, considered judgment and/or specific adjustments should be
25 applied to the results.

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B. Dividend Yield for the DCF Model

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

A. 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 October 29, 2010.

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

A. It is important to use an average of recent trading days 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. The averaging period should also be reasonably representative of expected capital market conditions over the long term. At the same time, it is important to reflect 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 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, it is reasonable to apply one-half of the expected annual dividend growth for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected dividend yield is, on average, representative of the coming twelve-month period, and does not

1 overstate the aggregated dividends to be paid during that time. As such, the
2 DCF estimates provided in Exhibit __ (AEB-1), Schedule 3 reflect one-half of
3 the expected growth in the dividend yield component of the model.
4

5 **C. Growth Rates for the DCF Model**

6 Q. IS IT IMPORTANT TO SELECT APPROPRIATE MEASURES OF LONG-TERM GROWTH
7 IN APPLYING THE DCF MODEL?

8 A. Yes, it is. The Constant Growth DCF model (*i.e.*, Equation [2]) assumes a
9 single growth estimate in perpetuity. In order to reduce the long-term growth
10 rate to a single measure, one must assume a constant payout ratio, and that
11 earnings per share, dividends per share and book value per share all grow at
12 the same constant rate. Over the long run, however, dividend growth can
13 only be sustained by earnings growth. It, therefore, is important to
14 incorporate a variety of sources of long-term earnings growth into the
15 Constant Growth DCF model.
16

17 **D. Results for Constant Growth DCF Model**

18 Q. PLEASE SUMMARIZE YOUR INPUTS TO THE CONSTANT GROWTH DCF MODEL.

19 A. I applied the DCF model to the proxy group of twelve integrated electric
20 utility companies using the following inputs for the price and dividend terms:

- 21 1. The average daily closing prices for the 30-trading days, 90-trading days,
22 and 180-trading days ended October 29, 2010 for the term P_0 ; and
- 23 2. The annualized dividend per share as of October 29, 2010 for the term
24 D_0 .

25
26 I established the long-term growth estimate for each of the proxy group
27 companies using the following growth estimates:

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

4
5 Q. HOW DID YOU CALCULATE YOUR DCF RESULTS?

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

14
15 Q. WHAT ARE THE RESULTS OF YOUR DCF ANALYSIS?

16 A. As shown in Exhibit __ (AEB-1), Schedule 3, the mean DCF results for my
17 proxy group (before consideration of flotation costs) are 11.09 percent, 11.21
18 percent, and 11.34 percent for the 30-, 90-, and 180-trading day periods,
19 respectively. The mean high DCF result for the 30-, 90-, and 180-day
20 averaging periods are 12.51 percent, 12.63 percent, and 12.76 percent,
21 respectively (before consideration of flotation costs).

22 23 **E. Flotation Cost Recovery**

24 Q. WHAT ARE FLOTATION COSTS?

25 A. Flotation costs are the costs associated with the sale of new issues of common
26 stock. These costs include: underwriter discounts; audit, legal and listing fees;
27 printing costs; and other direct issuance expenses.

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Q. WHY IS IT IMPORTANT TO RECOGNIZE FLOTATION COSTS IN THE ALLOWED RETURN ON EQUITY?

A. 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.

Q. ARE FLOTATION COSTS LIMITED TO EQUITY ISSUANCES PLANNED FOR THE TEST YEAR?

A. No, they are not. Flotation costs are not expenses that flow through the income statement, but instead reduce the proceeds of the issuance, resulting in a net reduction to the common equity portion of the balance sheet. As noted previously, when common stock is issued to the public, the issuing corporation incurs several costs, including: underwriter discounts; audit, legal and listing fees; printing costs; and other direct 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 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.

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

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

11

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

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

21

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

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

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Q. IS THE NEED FOR A FLOTATION COST ADJUSTMENT RECOGNIZED BY THE ACADEMIC AND FINANCIAL COMMUNITIES?

A. Yes, it is. The need to recover equity issuance costs is recognized by the academic and financial communities for the same fundamental reason that investors reasonably expect to recover the costs of debt issuances. This treatment is consistent with the philosophy of a fair rate of return. 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.⁸

Q. HAS XEI RECENTLY ISSUED COMMON EQUITY?

A. Yes. XEI Inc. closed on an equity issuance of approximately \$483 million (21,850,000 shares of common stock) on August 10, 2010. The Company will need to access the equity market in the next several years on a more regular basis than in the past in order to finance its capital investment plan.

⁸ Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-221.

1 Q. HAVE YOU CALCULATED THE EFFECT OF FLOTATION COSTS ON THE ROE?
 2 A. Yes, I have. I modified the DCF calculation to provide a dividend yield that
 3 would reimburse investors for issuance costs. Based on the issuance costs
 4 provided in Exhibit__(AEB-1), Schedule 4, an adjustment of 0.22 percent (*i.e.*,
 5 22 basis points) is reflective of flotation costs for the Company, which is
 6 reflected on Exhibit__(AEB-1), Schedule 3. Table 2, below, presents the
 7 DCF results including flotation costs.

8 **Table 2: DCF Results Including Flotation Costs**

	Low Mean DCF Results	Mean DCF Results	High Mean DCF Results
Constant Growth DCF – 30-day Avg. Stock Price	9.69%	11.31%	12.72%
Constant Growth DCF – 90-day Avg. Stock Price	9.81%	11.43%	12.85%
Constant Growth DCF – 180-day Avg. Stock Price	9.94%	11.56%	12.98%

9
 10 Q. DID YOU UNDERTAKE ANY ADDITIONAL ANALYSES TO SUPPORT YOUR DCF
 11 MODEL RESULTS?
 12 A. Yes. As noted earlier, I used the Bond Yield Plus Risk Premium approach as
 13 a means of assessing the reasonableness of my DCF results. As noted
 14 previously, I considered the use of the CAPM. However since the financial
 15 market dislocation, the underlying assumptions used in the traditional
 16 application of this model are not indicative of market expectations and
 17 therefore the results from the traditional application of the model are not
 18 representative of current market conditions. Therefore, I did not rely on the
 19 CAPM in developing my recommended ROE.
 20

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

3 A. As shown in Equation [3], the CAPM is defined by four components, each of
4 which theoretically must be a forward-looking estimate; however, since the
5 financial market dislocation, each these components have not reflected current
6 market conditions.

7

$$8 \quad K_e = r_f + \beta(r_m - r_f) \quad [3]$$

9 where:

10 k_e = the required market ROE

11 β = Beta of an individual security

12 r_f = the risk free rate of return

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

14

15 The risk free rate, “ r_f ”, in the CAPM formula is represented by the interest rate
16 on long-term U.S. Treasury securities. During the financial dislocation,
17 investors reacted to the extraordinary levels of market volatility discussed
18 earlier by investing in low-risk securities such as Treasury bonds. Therefore,
19 when measured on a historical basis, the first term in the model (*i.e.*, the risk-
20 free rate) is currently lower than it would have been absent the elevated degree
21 of risk aversion.

22

23 The second term of the CAPM, $(r_m - r_f)$, measures the Market Risk Premium
24 (“MRP”). As noted in equation [3], the MRP is calculated as the difference
25 between the expected market return and the risk free rate. As a result of the
26 extraordinary loss in equity values during 2008, the historical MRP decreased
27 from the prior year, even though other current measures of investor

1 sentiments, including market volatility and credit spreads, indicated high levels
2 of risk aversion. That result is counter-intuitive. While the 2009 market rally
3 resulted in a somewhat higher historical MRP, it still remains below its pre-
4 financial crisis level. Consequently, the second term of the CAPM understates
5 the current MRP.

6
7 Finally, the third term in the CAPM, Beta, measures the systematic risk of a
8 particular stock relative to a broader market index, the S&P 500. Beta is
9 estimated for an individual stock by regressing the Company's stock price
10 against a market index. The Beta estimates reported by Value Line and
11 Bloomberg are calculated over historical periods of 60 and 24 months,
12 respectively. The use of such longer-term measurement periods includes data
13 from the recent financial market dislocation as well as the period prior to the
14 market dislocation and results in Beta estimates that are significantly lower
15 than historical and current measures of Beta. As a result, 60 and 24 month
16 historical Beta estimates may not be reasonable measures of current systematic
17 risk.

18
19 Therefore, since the underlying market data used to develop each of the
20 assumptions of the CAPM are not reflective of current market conditions and
21 investors' current level of risk aversion, I did not rely on this model to
22 establish my recommended ROE.

23 24 **F. Bond Yield Plus Risk Premium Analysis**

25 Q. PLEASE DESCRIBE THE BOND YIELD PLUS RISK PREMIUM APPROACH.

26 A. In general terms, this approach is based on the fundamental principal that
27 equity investors bear the residual risk associated with ownership and therefore

1 require a premium over the return they would have earned as a bondholder.
2 That is, since returns to equity holders are more risky than returns to
3 bondholders, equity investors must be compensated to bear that risk. Risk
4 premium approaches, therefore, estimate the cost of equity as the sum of the
5 equity risk premium and the yield on a particular class of bonds. In my
6 analysis, I used actual authorized returns for electric utilities as the historical
7 measure of the cost of equity to determine the risk premium.

8
9 Q. ARE THERE OTHER CONSIDERATIONS THAT SHOULD BE ADDRESSED IN
10 CONDUCTING THIS ANALYSIS?

11 A. In addition, it is important to recognize both academic literature and market
12 evidence indicating that the equity risk premium (as used in this approach) is
13 inversely related to the level of interest rates. That is, as interest rates increase
14 (decrease), the equity risk premium decreases (increases). Consequently, it is
15 important to develop an analysis that: (1) reflects the inverse relationship
16 between interest rates and the equity risk premium; and (2) is based on more
17 recent market conditions. Such an analysis can be developed based on a
18 regression of the risk premium as a function of Treasury yields. If we let
19 authorized integrated electric utility ROEs serve as the measure of required
20 equity returns and define the yield on the long-term Treasury bond as the
21 relevant measure of interest rates, the risk premium simply would be the
22 difference between those two points.⁹

23

⁹ 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 below, 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.

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

2 A. As shown on Chart 3, from 1992 through 2010, there was, in fact, a strong
3 negative relationship between risk premia and interest rates. To estimate that
4 relationship, I conducted a regression analysis using the following equation:
5

6
$$RP = a + b(T) \quad [4]$$

7

8 where:

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

11 a = Intercept term

12 b = Slope term

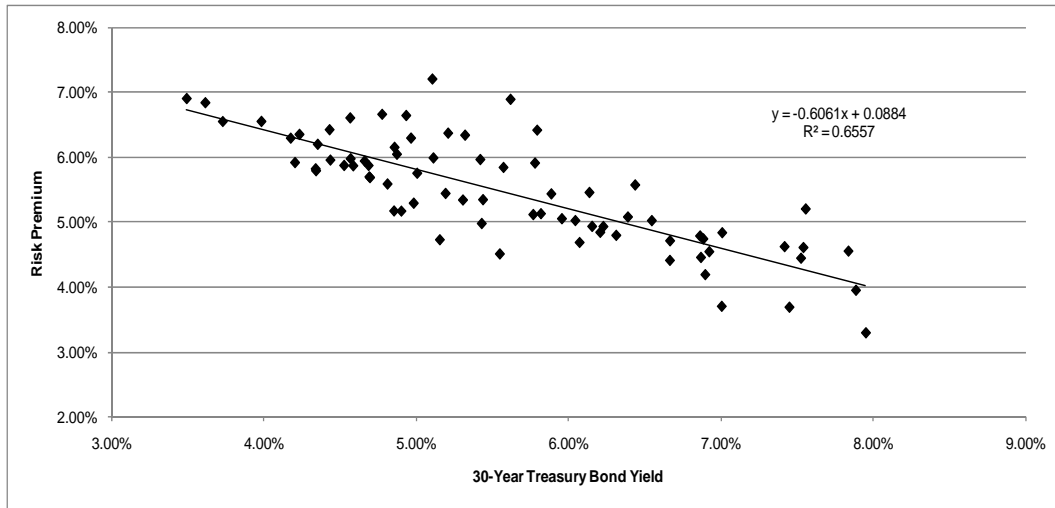
13 T = 30-year Treasury Bond Yield
14

15 Data regarding allowed ROEs were derived from 461 rate cases from 1992
16 through October 29, 2010 as reported by Regulatory Research Associates.
17 This equation's coefficients were statistically significant at the 99% level.¹⁰
18

¹⁰ In order to ensure that the regression coefficients were not biased as a result of serially correlated error terms, the equation presented in Exhibit __ (AEB-1), Schedule 5 was also estimated using the Prais-Winsten corrective routine. That equation continues to produce a negative slope coefficient and a ROE estimate of approximately 10.64% to 11.19%.

1

Chart 3: Risk Premium vs. Interest Rates



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As shown on Exhibit ___(AEB-1), Schedule 5, based on the near-term (2010-2012) projections of the 30-year Treasury bond yield (*i.e.* 4.22 percent), the risk premium would be 6.29 percent, resulting in an estimated ROE of 10.51 percent. Based on longer-term (2012-2021) projections of the 30-year Treasury Bond yield (5.80 percent), the risk premium would be 5.33 percent, resulting in an estimated ROE of 11.13 percent. While these values are lower than my DCF results and recommendation, it is important to note that these values reflect all electric utilities and are not limited to companies that meet the criteria of comparability to the Company. Further, these results do not include the effect of the Company's specific risk factors, as discussed in Section VII of my Direct Testimony.

1 **VII. BUSINESS AND ECONOMIC RISKS**

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

4 A. No, the mean DCF results do not necessarily provide an appropriate estimate
5 of the Company's cost of equity. The relative size of the Company's planned
6 capital investment program and the risks associated with this program should
7 be considered in terms of their overall effect on the Company's business risk
8 when compared with the proxy group.

9
10 Q. PLEASE SUMMARIZE THE COMPANY'S CAPITAL EXPENDITURE PLANS.

11 A. The Company estimates that during the four-year period 2010-2013 it will
12 invest approximately \$4.9 billion,¹¹ averaging over \$1.2 billion per year over
13 that four-year period. These capital expenditures include the Company's
14 investment in the Nobles and Merricourt Wind Projects and the CAPX2020
15 Group 1 transmission project, which previously received an Advanced
16 Determination of Need from this Commission. The Company's total net
17 utility plant as of December 31, 2009 was approximately \$6.4 billion.¹² The
18 \$4.9 billion anticipated capital expenditures are approximately 76.8 percent of
19 the Company's December 31, 2009 net utility plant in service.

20
21 Q. HOW IS THE COMPANY'S RISK PROFILE AFFECTED BY THE SUBSTANTIAL
22 INCREASE IN ITS PLANNED CAPITAL EXPENDITURES?

23 A. As with any utility faced with a substantial capital expenditure plan, the
24 Company's risk profile is adversely affected in two significant and related

¹¹ SEC Form 10-K, Xcel Energy, Inc, for the year ending December 31, 2009, at 74.

¹² FERC Form 1, Northern States Power Company (Minnesota), for the period ending December 31, 2009, at 110.

1 ways: (1) the heightened level of investment increases the risk of under-
2 recovery, or the delayed recovery of the invested capital; and (2) an inadequate
3 authorized ROE, which could put downward pressure on key credit metrics.
4

5 Q. DO CREDIT RATING AGENCIES RECOGNIZE THE RISKS ASSOCIATED WITH
6 INCREASED CAPITAL EXPENDITURES?

7 A. Yes, they do. From a credit perspective, the additional pressure on cash flows
8 associated with high levels of capital expenditures exerts corresponding
9 pressure on credit metrics and, therefore, credit ratings. S&P has noted
10 several long term challenges for utilities' financial health, including: heavy
11 construction programs to address demand growth, declining capacity margins,
12 and aging infrastructure and regulatory responsiveness to mounting requests
13 for rate increases. S&P further noted that:

14 To sustain their current credit quality in the face of these
15 long-lived challenges, utilities need to have established—
16 and be able to maintain—a firm credit foundation. This
17 will require a strong and effective working relationship
18 among management, regulators, and increasingly legislators
19 and governors, in the planning and execution of strategies.
20 A comprehensive vetting and understanding of the risks
21 associated with the regulatory mechanisms under which the
22 utility will recover its investment, which could include a
23 cash return during construction and timely recognition of
24 volatile costs, will be paramount in preserving
25 creditworthiness.¹³
26

27 S&P specifically identified the risks associated with NSP's capital expenditure
28 plan in its July 2010 rating of the Company. In that report, S&P noted that its
29 credit rating reflects in part the full cost recovery of larger construction

¹³ 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.

1 projects. In addition, S&P notes that the current stable outlook could be
2 revised to negative if construction projects are not completed on time and
3 budget or if expected rate recovery is less than expected.¹⁴

4
5 Q. WHAT RISKS DO EQUITY ANALYSTS FORESEE IN RELATION TO CAPITAL
6 EXPENDITURES?

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

10 Credit and liquidity concerns have driven many companies
11 to revisit capital spending plans and reassess operational
12 efficiencies. The primary response has generally been to
13 delay projects, as opposed to outright cancellation. Initially,
14 reductions in capital programs were a function of lower
15 growth, which eliminated the need for growth-related
16 capital spending on items such as line extensions and new
17 substations. However, as difficult economic conditions
18 persist, the cuts have grown more extensive, with deferrals
19 in non-core maintenance spending, reevaluating the cost-
20 effectiveness of running older inefficient power plants, and
21 pursuing company restructurings or mergers.¹⁵

22
23 Q. WILL THE COMPANY NEED CONTINUED ACCESS TO THE CAPITAL MARKETS IN
24 ORDER TO FINANCE ITS CAPITAL EXPENDITURE PLAN?

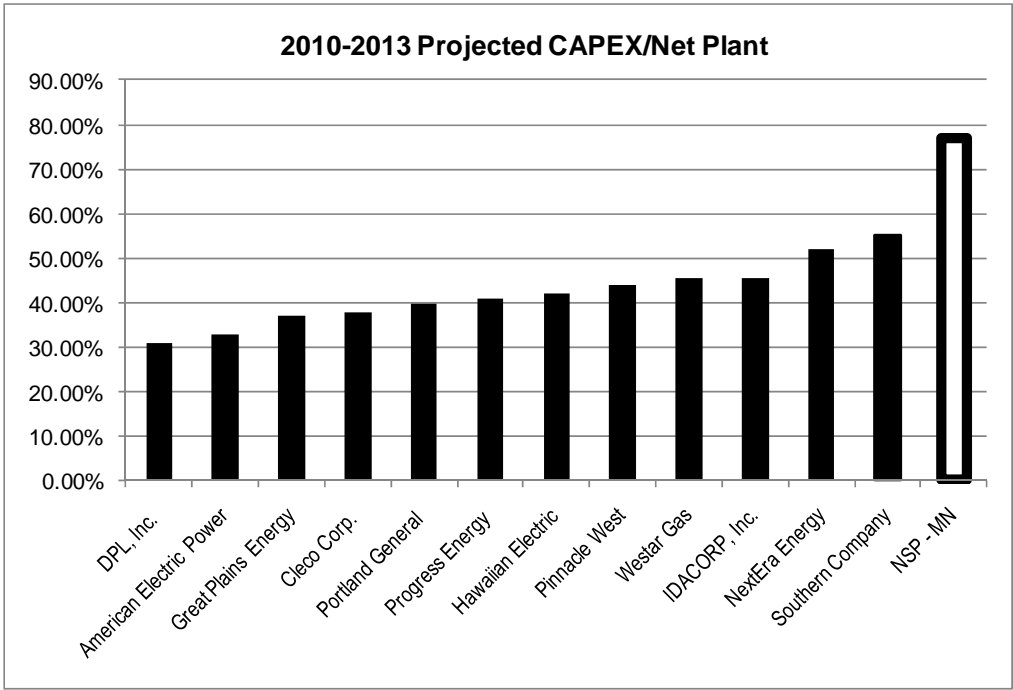
25 A. Yes. Given the magnitude and long-term nature of the anticipated capital
26 expenditures, the Company will require continued access to the capital
27 markets, at reasonable terms, in order to finance its capital expenditure plan.

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

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

1 Q. HOW DOES THE LEVEL OF THE COMPANY'S EXPECTED CAPITAL
 2 EXPENDITURES COMPARE TO THE PROXY GROUP?
 3 A. As shown in Exhibit__(AEB-1), Schedule 6, I calculated the ratio of expected
 4 capital expenditures to net assets for each of the companies in the Proxy
 5 Group. For the projected period from 2010-2013, I performed that
 6 calculation using the Company's projected capital expenditures and its total
 7 net assets as of December 31, 2009. As shown in Schedule 6, the Company's
 8 relative level of capital expenditures is 1.4 to 2.5 times the projected
 9 investments of the proxy group companies. Chart 4 below compares the
 10 projected capital expenditures of the Company and my electric utility proxy
 11 group.

12 **Chart 4: Comparison of Capital Expenditures¹⁶**



13
 14

¹⁶ Sources: Value Line, SEC Form 10-K, Xcel Energy, Inc, for the year ending December 31, 2009, at 74, and FERC Form 1, Northern States Power Company (Minnesota), for the period ending December 31, 2009, at 110.

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

3 A. It is clear that the Company is projecting a substantial capital expenditure
4 program over the next four years that will require continued access to the
5 capital markets. It also is clear that equity investors and credit rating agencies
6 recognize the additional risks associated with substantial capital expenditures.
7 Therefore, the relative size of the Company's capital expenditure plan suggests
8 that an ROE toward the upper end of the range of results for my proxy group
9 would be appropriate. These additional risk factors also confirm that the
10 Company's proposed ROE of 11.25 percent is conservative.

11

12 Q. ARE YOU AWARE THAT THE COMPANY HAS REQUESTED THAT THE
13 COMMISSION APPROVE A STEP-UP IN ITS 2012 REVENUE REQUIREMENT?

14 A. Yes, I am aware of the Company's proposal and have considered this proposal
15 in my recommended ROE. As discussed in greater detail in the testimony of
16 Company witness Ms. Anne E. Heuer's testimony, the Company is proposing
17 to increase its 2012 revenue requirement to recover the costs of specific
18 capital and operations and maintenance costs in lieu of filing a general rate
19 case at that time.

20

21 VIII. CAPITAL STRUCTURE

22

23 Q. WHAT IS THE COMPANY'S PROJECTED CAPITAL STRUCTURE?

24 A. As described in the Direct Testimony of Mr. Felling, the Company's proposed
25 capital structure consists of 52.56 percent common equity, 46.30 percent long-
26 term debt, and 1.14 percent short-term debt.

27

1 Q. PLEASE DISCUSS THE IMPORTANCE OF MAINTAINING A STRONG BALANCE
2 SHEET AND CAPITAL STRUCTURE IN THE CURRENT MARKET ENVIRONMENT.

3 A. As discussed in Section IV, the current financial market is characterized by a
4 continuing contraction of credit availability, and a relatively high level of
5 interest costs. Under such conditions, financing options are more limited and
6 the need to maintain a strong balance sheet as a means of preserving access to
7 capital is more acute than it would be in a more normal market environment.

8

9 Q. PLEASE DISCUSS YOUR ANALYSIS OF THE CAPITAL STRUCTURES OF THE PROXY
10 GROUP COMPANIES.

11 A. My analysis of the actual proxy group capital structures is provided in
12 Exhibit__(AEB-1), Schedule 7. As shown in that Schedule, I calculated the
13 mean of the proportions of common equity and long-term debt over the most
14 recent eight quarters¹⁷ for each of the proxy group companies. The mean of
15 the proxy group actual capital structures is 51.99 percent common equity,
16 45.90 percent long-term debt, and 2.11 percent short-term debt.¹⁸ The proxy
17 group companies' equity ratios range from a low of 46.78 percent to 60.44
18 percent. Based on that review, it is apparent that the Company's proposed
19 capital structure is generally consistent with the capital structures of the proxy
20 group companies.

21

¹⁷ In this analysis, I calculated the average capital structure using the quarterly capital structures reported for the proxy group companies for the period from September 2008 through June 2010.

¹⁸ Excludes preferred equity.

1 Q. WHAT IS YOUR CONCLUSION REGARDING AN APPROPRIATE CAPITAL
2 STRUCTURE FOR NSP?

3 A. Considering the actual capital structures of the proxy group and the
4 Company's extensive capital investment program, I believe that the
5 Company's proposed equity ratio of 52.56 percent is reasonable.

6

7 Q. WILL THE CAPITAL STRUCTURE AND ROE AUTHORIZED IN THIS PROCEEDING
8 AFFECT THE COMPANY'S ABILITY TO COMPLETE ITS CAPITAL EXPENDITURE
9 PLAN?

10 A. Yes, I believe so. The level of earnings authorized by the Commission directly
11 affects the Company's ability to fund capital investment with internally
12 generated funds; and both lenders and equity investors expect a significant
13 portion of on-going capital investments to be financed with internally
14 generated funds. The need to generate funds internally also is important in
15 light of the constrained, volatile, and expensive capital market conditions.

16

17 It also is important to realize that investors weigh a given utility's authorized
18 ROE in the context of the nature of its expected capital investments. Because
19 a utility's investment horizon is very long, investors require the assurance of a
20 sufficiently high return to satisfy the long-run financing requirements of the
21 assets it puts into service. Those assurances, which often are measured by the
22 relationship between internally generated cash flows and debt (or interest
23 expense), depend quite heavily on the capital structure. As a consequence,
24 both the ROE and capital structure are very important to both debt and equity
25 investors. Given the capital market conditions and the Company's significant
26 financing requirements, the authorized ROE and capital structure are
27 extremely important considerations in this proceeding.

IX. SUMMARY AND CONCLUSIONS

Q. WHAT IS YOUR CONCLUSION REGARDING THE ROE AND CAPITAL STRUCTURE FOR NSP?

A. Based on the results of the analyses presented in Table 3 below, I believe that an ROE in the 50 basis point range of 11.30 percent to 11.80 percent represents the range of equity investors’ required rate of return for investment in integrated electric utilities in today’s capital markets. NSP’s requested ROE of 11.25 percent is slightly below the bottom of that range. Considering the Company’s risk profile relative to the proxy group, an ROE at the upper end of my range would be supported. As such, I find the Company’s requested ROE to be conservative.

Finally, I conclude that the Company’s proposed capital structure, which consists of 52.56 percent common equity, 46.30 percent long-term debt and 1.14 percent short-term debt, is reasonable.

Table 3: Summary of Analytical Results

	Mean Low	Mean	Mean High
Constant Growth DCF (including Flotation Costs)			
Constant Growth DCF – 30-Day Average	9.69%	11.31%	12.72%
Constant Growth DCF – 90-Day Average	9.81%	11.43%	12.85%
Constant Growth DCF – 180-Day Average	9.94%	11.56%	12.98 %
Supporting Methodology			
	Low	Mean	High
Risk Premium (Authorized ROE and Treasury Yields)	10.50%	10.82%	11.13%

20

1 Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?


2 A. Yes, it does.

1 STATE OF NORTH DAKOTA
2 BEFORE THE
3 PUBLIC SERVICE COMMISSION
4

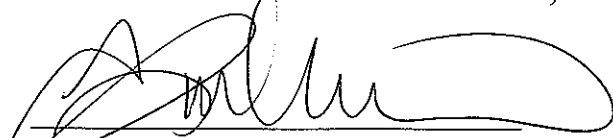
5
6 In the Matter of the Application of Northern)
7 States Power Company, a Minnesota corporation)
8 For Authority to Increase Rates for Electric Service) Case No. PU-10-____
9 in North Dakota)

10
11
12
13 **AFFIDAVIT OF**
14 **Ann E. Bulkley**
15

16
17 I, the undersigned, being duly sworn, depose and say that the foregoing is
18 the Direct Testimony of the undersigned, and that such Direct Testimony and the
19 exhibits or schedules sponsored by me to the best of my knowledge, information
20 and belief, are true, correct, accurate and complete, and I hereby adopt said
21 testimony as if given by me in formal hearing, under oath.
22

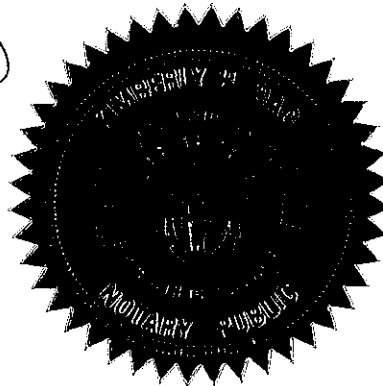
23
24 
25 Ann E. Bulkley
26

27
28
29
30 Subscribed and sworn to before me, this 16th day of December, 2010.
31

32
33 
34 Notary Public
35



36
KIMBERLY H. DAO
Notary Public
Commonwealth of Massachusetts
My Commission Expires
April 16, 2015



Ann E. Bulkley
Assistant Vice President

Ms. Bulkley has over 15 years of experience consulting to the energy industry. Ms Bulkley has a strong foundation in economic principles, finance, regulatory policies and quantitative forecasting. Ms. Bulkley has a range of experience including, asset valuation, merger and acquisition due diligence, property appraisal, and regulatory representation and litigation support. Ms. Bulkley has extensive regulatory experience on both electric and natural gas issues, including cost of capital, market development, asset purchase and sales transactions, regulatory strategy and policy formulation.

REPRESENTATIVE PROJECT EXPERIENCE

Strategic and Financial Advisory Services

Ms. Bulkley has assisted several clients across North America with analytically based strategic planning, due diligence and financial advisory services.

Representative projects include:

- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed, and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.
- Significant experience utilizing numerous valuation methodologies to value generation assets for strategic planning, tax, financing and other purposes. Methodologies include traditional discounted cash flow, Monte Carlo risk analysis, market analysis and replacement cost. Prepared expert reports, testimony and certifications for use in regulatory and state judicial forums.
- Prepared a valuation of numerous generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract. Assisted clients in implementing generation divestiture programs. Acted as a liaison between the bidders and the seller in the divestiture process. Provided documentation, detailed due diligence and marketing support. Participated in site tour development, training and implementation.
- Prepared a valuation of numerous purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, a traditional discounted cash flow valuation

approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and VAR for the selling utility.

- Prepared a valuation of several FirstEnergy generating facilities using the income, cost, and comparable sales approaches as well as risk analysis. Prepared an independent report.
- Prepared a valuation of Northern Indiana Public Service Company's generation, transmission and distribution assets for a recent electric rate proceeding. Valuation approaches used in this project included income, cost and comparable sales approaches.

Regulatory Analysis and Ratemaking

Ms. Bulkley has provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking. Specific services have included: cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies; development of merchant function exit strategies; analysis and program development to address residual energy supply and/or provider of last resort obligations; stranded costs assessment and recovery; performance-based ratemaking analysis and design; and many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation).

Representative projects/clients have included:

- Prepared Cost of Capital and Return on Equity testimony and supporting analysis for Federal and State regulatory proceedings.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Analyzed and evaluated rate application. Attended hearings and conducted investigation of rate application for regulatory staff. Prepared, supported and defended recommendations for revenue requirements and rates for the company. Developed rates for gas utility for transportation program and ancillary services.
- Worked with numerous clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Analyzed the implementation of performance-based ratemaking in the electric industry and in the corporate strategies of private sector organizations. Evaluated the effect of various performance-based ratemaking mechanisms in earnings and corporate strategies for two electric utilities. Analyzed a performance-based ratemaking proposal for the regulatory agency to determine the viability of the program and the impact on ratepayers.
- Acted as an advisor to state regulators with regards to the unbundling of the natural gas industry. Worked with utilities, marketers and state agencies, in a collaborative forum, to clearly identify the underlying cost structure for each customer class and to evaluate the impact that alternative approaches retail choice would have on each customer segment. Worked with the Collaborative to identify the appropriate approach to the retail choice offering and develop the terms and conditions for the program.

Litigation Support and Expert Testimony

Ms. Bulkley has supported company witnesses in various proceedings on variety of topics which included the development of capital structure, cost of capital, fair value rate base, and rate design. In addition, Ms. Bulkley has provided testimony on integrated resource planning and cost of service and rate design issues.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)

Assistant Vice President
Project Manager

Navigant Consulting, Inc. (1995 – 2002)
Project Manager

Cahners Publishing Company (1995)
Economist

EDUCATION

M.A., Economics, Boston University, 1995

B.A., Economics and Finance, Simmons College, 1991

EXPERT TESTIMONY OF ANN E. BULKLEY

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Massachusetts Department of Public Utilities				
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Indiana Utility Regulatory Commission				
Kokomo Gas And Fuel Company	09/10	Kokomo Gas And Fuel Company	Docket No. 43942	Fair Value
Northern Indiana Fuel And Light Company, Inc.	09/10	Northern Indiana Fuel And Light Company, Inc.	Docket No. 43943	Fair Value

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	15,000,000	\$20.860	\$20.200	\$0.100	\$0.005	\$20.095	\$11,475,000	\$312,900,000	\$301,425,000	3.667%
8/10/2010	21,850,000	\$22.100	\$21.500	\$0.065	\$0.027	\$21.408	\$15,119,325	\$482,885,000	\$467,765,675	3.131%
<i>Weighted Average Flotation Costs</i>							\$90,411,926	\$2,044,350,255	\$1,953,938,328	4.423%

The flotation adjustment is derived by dividing the dividend yield by 1-F (where F = flotation costs expressed in percentage terms), or by 0.9558, 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:

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

FLOTATION COST ADJUSTMENT

Flotation Cost Adjustment - Electric Proxy Group

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	
	Stock Price	Annualized Dividend	Dividend Yield	Expected Dividend Yield	Expected Dividend Yield Adjusted for Flotation Costs	Proj EPS Growth (Zacks)	Proj EPS Growth (V.L.)	Proj EPS Growth (First Call)	Average Growth Estimate	DCF k(e)	Flotation Adjusted DCF k(e)	
American Electric Power	AEP	\$36.41	\$1.68	4.61%	4.70%	4.92%	4.00%	3.00%	3.90%	3.63%	8.33%	8.55%
Cleco Corp.	CNL	\$30.28	\$1.00	3.30%	3.41%	3.57%	7.00%	9.50%	3.00%	6.50%	9.91%	10.07%
DPL, Inc.	DPL	\$26.56	\$1.21	4.56%	4.70%	4.92%	NA	7.00%	5.90%	6.45%	11.15%	11.37%
NextEra Energy, Inc.	NEE	\$54.89	\$2.00	3.64%	3.75%	3.93%	6.40%	5.00%	6.83%	6.08%	9.83%	10.00%
Great Plains Energy Inc.	GXP	\$18.90	\$0.83	4.39%	4.62%	4.83%	13.00%	4.50%	13.00%	10.17%	14.78%	15.00%
Hawaiian Electric	HE	\$22.59	\$1.24	5.49%	5.75%	6.02%	9.50%	11.50%	8.03%	9.68%	15.43%	15.70%
IDACORP, Inc.	IDA	\$36.09	\$1.20	3.33%	3.40%	3.56%	4.00%	5.50%	4.00%	4.50%	7.90%	8.06%
Pinnacle West Capital	PNW	\$41.45	\$2.10	5.07%	5.22%	5.46%	6.80%	6.00%	5.50%	6.10%	11.32%	11.56%
Portland General	POR	\$20.52	\$1.04	5.07%	5.22%	5.47%	9.60%	3.00%	5.75%	6.12%	11.34%	11.58%
Progress Energy	PGN	\$44.64	\$2.48	5.56%	5.66%	5.92%	4.00%	3.50%	3.63%	3.71%	9.37%	9.63%
Southern Co.	SO	\$37.68	\$1.82	4.83%	4.95%	5.18%	5.10%	4.50%	5.32%	4.97%	9.92%	10.15%
Westar Energy	WR	\$24.59	\$1.24	5.04%	5.26%	5.50%	8.00%	7.50%	10.00%	8.50%	13.76%	14.00%
MEAN				4.57%	4.72%		7.04%	5.88%	6.24%		11.09%	11.31%
MEAN												11.31%
UNADJUSTED CONSTANT GROWTH DCF MEAN												11.09%
DIFFERENCE (FLOTATION COST ADJUSTMENT)											[12]	0.22%

[1] Source: Bloomberg, 30 day average price

[2] Bloomberg

[3] = [1] / [2] or [Annualized Dividend] / [Price]

[4] = [3] x [1 + .5g] 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])

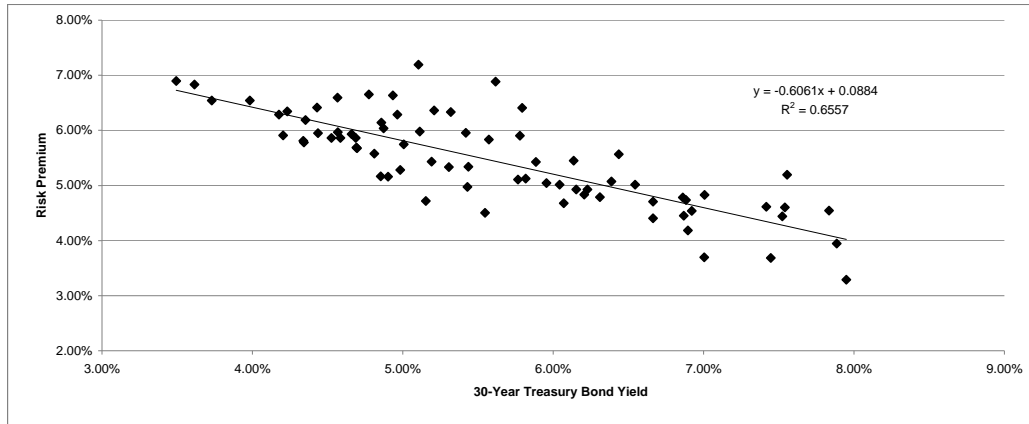
[11] = (Column [5] + Column [9])

[12] Equals Mean Adjusted DCF, Column [11] - Mean Unadjusted DCF, Column [10]

BOND YIELD RISK PREMIUM

Quarter [1b]	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	11.08%	6.15%	4.93%
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	10.78%	5.44%	5.34%
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	10.55%	4.69%	5.86%
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%	5.43%
2006.3	10.06%	4.90%	5.16%
2006.4	10.37%	4.70%	5.68%
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	10.39%	4.53%	5.86%
2008.1	10.15%	4.34%	5.81%
2008.2	10.54%	4.57%	5.97%
2008.3	10.38%	4.44%	5.95%
2008.4	10.39%	3.49%	6.89%
2009.1	10.45%	3.62%	6.83%
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	10.45%	4.59%	5.86%
2010.2	10.11%	4.20%	5.91%
2010.3	10.27%	3.73%	6.54%
2010.4	10.53%	3.98%	6.54%
Mean	11.05%	5.59%	5.45%

BOND YIELD RISK PREMIUM



SUMMARY OUTPUT

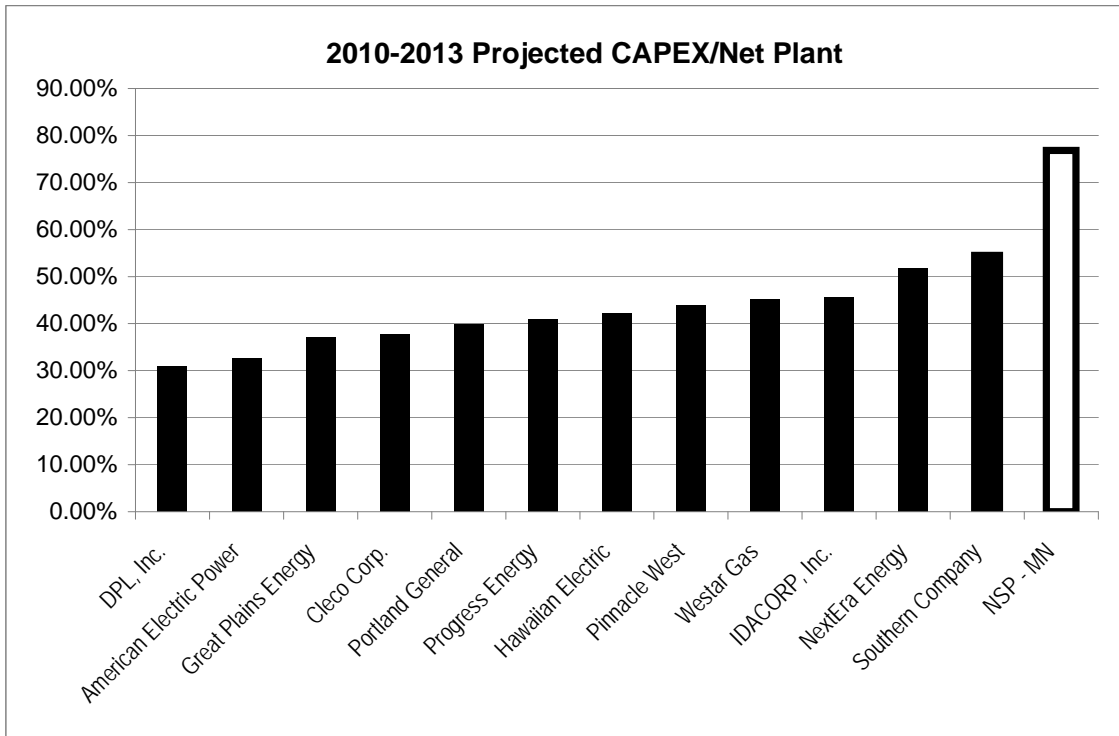
Regression Statistics	
Multiple R	0.809736943
R Square	0.655673916
Adjusted R Square	0.651020861
Standard Error	0.004971705
Observations	76

ANOVA					
	df	SS	MS	F	Significance F
Regression	1	0.003483056	0.003483056	140.9125596	8.36465E-19
Residual	74	0.001829121	2.47179E-05		
Total	75	0.005312177			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	0.08842722	0.002912554	30.36071059	1.62859E-43	0.082623829	0.0942306	0.082623829	0.094230611
X Variable 1	-0.606131597	0.051061324	-11.87065961	8.36465E-19	-0.707873504	-0.5043897	-0.707873504	-0.50438969

30 Year Treasury Yield	30 Year Treasury	Risk Prem [3]	ROE
Blue Chip Consensus Forecast (2010-2011) [5]	4.22%	6.29%	10.50%
Blue Chip Consensus Forecast (2012 - 2021) [6]	5.80%	5.33%	11.13%
MEAN		5.81%	10.82%

- Notes
- [1] Source: Regulatory Research Associates, *Rate Case Statistics*, accessed October 29, 2010.
 - [2] Source: Bloomberg Professional Service. Quarterly T-bond yields are the average of the last trading day of each month in the quarter.
 - [3] Independent variable = Treasury Yield; Dependent Variable = Risk Premium.
 - [4] Source: Bloomberg Professional Service
 - [5] Source: Aspen Publishers, *Blue Chip Financial Forecasts*, Vol. 29, No. 10 October 1, 2010, p. 2
 - [6] Source: Aspen Publishers, *Blue Chip Financial Forecasts*, Vol. 29 No. 6 June 1, 2010 p.14



Projected CAPEX / 2009 Net Plant	
Company	2010-2013^[1]
DPL, Inc.	30.87%
American Electric Power	32.64%
Great Plains Energy	37.14%
Cleco Corp.	37.77%
Portland General	39.77%
Progress Energy	40.98%
Hawaiian Electric	42.13%
Pinnacle West	43.93%
Westar Gas	45.28%
IDACORP, Inc.	45.64%
NextEra Energy	51.80%
Southern Company	55.02%
NSP - MN	76.82%
Proxy Group Average	41.91%

Notes

^[1] NSP-MN Capital expenditures are projected through 2010-2013, however Value Line projects capital expenditures through 2010, 2011, and 2013-2014.

CAPITAL STRUCTURE - ELECTRIC PROXY GROUP

Equity Ratio

Company Name	Ticker	2010 Q2	2010 Q1	2009 Q4	2009 Q3	2009 Q2	2009 Q1	2008 Q4	2008 Q3	Overall Average
American Electric Power	AEP	52.65%	52.60%	48.57%	49.15%	49.04%	47.93%	48.75%	48.49%	49.65%
Cleco Corp.	CNL	50.52%	50.69%	45.45%	47.08%	46.43%	45.54%	45.07%	47.49%	47.28%
DPL, Inc.	DPL	61.42%	61.53%	61.73%	58.46%	57.38%	57.09%	62.56%	63.33%	60.44%
NextEra Energy, Inc.	NEE	55.70%	53.38%	57.62%	56.91%	56.65%	56.59%	57.41%	53.94%	56.03%
Great Plains Energy Inc.	GXP	49.39%	49.46%	49.96%	51.46%	50.76%	44.33%	46.95%	49.30%	48.95%
Hawaiian Electric	HE	55.10%	54.99%	55.26%	53.15%	54.29%	56.00%	55.69%	52.92%	54.67%
IDACORP, Inc.	IDA	48.20%	47.56%	47.45%	48.15%	46.32%	44.90%	46.36%	45.30%	46.78%
Pinnacle West Capital	PNW	51.49%	48.39%	50.37%	50.74%	46.75%	47.17%	49.64%	52.58%	49.64%
Portland General	POR	46.26%	46.47%	46.94%	49.37%	49.17%	51.68%	47.42%	50.17%	48.44%
Progress Energy	PGN	54.16%	53.05%	54.07%	53.01%	51.58%	49.99%	48.96%	50.04%	51.86%
Southern Co.	SO	52.21%	52.11%	51.42%	52.05%	50.58%	50.95%	52.02%	53.28%	51.83%
Westar Energy	WR	56.96%	56.93%	57.00%	57.68%	56.69%	59.74%	60.23%	61.52%	58.34%
Proxy Group Average										51.99%

		Equity Ratio								
Company Name	Ticker	2010 Q2	2010 Q1	2009 Q4	2009 Q3	2009 Q2	2009 Q1	2008 Q4	2008 Q3	
AEP Texas Central Company	AEP	44.03%	44.13%	44.03%	43.91%	46.38%	44.26%	43.96%	42.70%	
AEP Texas North Company	AEP	45.28%	45.92%	45.76%	46.81%	46.69%	46.90%	46.90%	47.47%	
Appalachian Power Company	AEP	43.68%	45.21%	44.51%	44.98%	44.74%	41.04%	43.00%	43.52%	
Columbus Southern Power Company	AEP	47.05%	46.48%	46.95%	46.18%	46.81%	46.39%	46.40%	47.26%	
Indiana Michigan Power Company	AEP	46.41%	46.56%	45.97%	45.86%	45.42%	43.20%	51.18%	51.09%	
Kentucky Power Company	AEP	43.59%	44.27%	44.04%	44.00%	43.94%	48.92%	48.74%	47.70%	
Kingsport Power Company	AEP	100.00%	100.00%	51.61%	55.30%	54.84%	55.05%	55.59%	55.66%	
Ohio Power Company	AEP	52.46%	49.54%	50.07%	50.27%	53.45%	48.16%	47.41%	48.97%	
Public Service Company of Oklahoma	AEP	45.56%	45.49%	45.77%	48.71%	47.61%	45.02%	45.99%	45.69%	
Southwestern Electric Power Company	AEP	47.89%	47.48%	51.79%	51.60%	48.26%	47.39%	46.83%	42.67%	
Wheeling Power Co	AEP	63.16%	63.54%	63.72%	62.98%	61.25%	60.92%	60.29%	60.62%	
Cleco Power LLC	CNL	50.52%	50.69%	45.45%	47.08%	46.43%	45.54%	45.07%	47.49%	
Dayton Power and Light Company	DPL	61.42%	61.53%	61.73%	58.46%	57.38%	57.09%	62.56%	63.33%	
Hawaii Electric Light Company, Inc.	HE	55.10%	54.99%	55.26%	53.15%	54.29%	56.00%	55.69%	52.92%	
Kansas City Power & Light Company	GXP	48.43%	49.26%	49.48%	51.40%	50.23%	45.35%	47.92%	50.55%	
KCP&L Greater Missouri Operations Company	GXP	50.35%	49.66%	50.45%	51.52%	51.29%	43.32%	45.98%	48.04%	
Idaho Power Co.	IDA	48.20%	47.56%	47.45%	48.15%	46.32%	44.90%	46.36%	45.30%	
Florida Power & Light Company	NEE	55.70%	53.38%	57.62%	56.91%	56.65%	56.59%	57.41%	53.94%	
Arizona Public Service Company	PNW	51.49%	48.39%	50.37%	50.74%	46.75%	47.17%	49.64%	52.58%	
Portland General Electric Company	POR	46.26%	46.47%	46.94%	49.37%	49.17%	51.68%	47.42%	50.17%	
Carolina Power & Light Company	PGN	57.20%	56.93%	56.19%	55.69%	54.55%	53.96%	54.93%	55.37%	
Florida Power Corporation	PGN	51.11%	49.16%	51.96%	50.33%	48.61%	46.03%	42.99%	44.72%	
Alabama Power Company	SO	49.26%	49.25%	48.92%	48.89%	46.71%	46.69%	48.51%	49.01%	
Georgia Power Company	SO	51.45%	51.78%	50.61%	52.40%	50.44%	49.01%	49.40%	48.81%	
Gulf Power Company	SO	49.72%	48.96%	47.69%	48.32%	47.26%	50.31%	47.98%	49.30%	
Mississippi Power Company	SO	58.41%	58.44%	58.45%	58.58%	57.91%	57.78%	62.18%	65.98%	
Kansas Gas and Electric Company	WR	56.49%	56.24%	57.15%	57.23%	56.43%	65.33%	65.35%	65.25%	
Westar Energy (KPL)	WR	57.42%	57.61%	56.85%	58.13%	56.96%	54.15%	55.10%	57.78%	

CAPITAL STRUCTURE - ELECTRIC PROXY GROUP

Long Term Debt Ratio

Company Name	Ticker	2010 Q2	2010 Q1	2009 Q4	2009 Q3	2009 Q2	2009 Q1	2008 Q4	2008 Q3	Overall Average
American Electric Power	AEP	47.35%	47.40%	51.43%	50.85%	50.96%	52.07%	51.25%	51.51%	50.35%
Cleco Corp.	CNL	49.48%	49.31%	54.55%	52.92%	53.57%	52.05%	54.93%	52.51%	52.42%
DPL, Inc.	DPL	38.58%	38.47%	38.27%	36.76%	36.79%	36.69%	37.44%	32.89%	36.99%
NextEra Energy, Inc.	NEE	38.81%	38.92%	39.70%	40.09%	40.75%	42.74%	39.56%	37.87%	39.80%
Great Plains Energy Inc.	GXP	41.81%	42.54%	43.15%	45.75%	46.16%	47.25%	43.67%	46.47%	44.60%
Hawaiian Electric	HE	44.31%	44.43%	44.74%	46.38%	41.15%	42.62%	42.37%	40.73%	43.34%
IDACORP, Inc.	IDA	51.80%	52.44%	52.55%	51.85%	52.27%	51.24%	49.24%	49.40%	51.35%
Pinnacle West Capital	PNW	48.51%	48.81%	49.63%	49.26%	50.27%	49.37%	42.61%	43.35%	47.73%
Portland General	POR	53.74%	53.53%	53.06%	50.63%	50.83%	48.32%	45.74%	48.41%	50.53%
Progress Energy	PGN	45.84%	46.95%	45.93%	46.70%	48.42%	49.19%	48.03%	49.96%	47.63%
Southern Co.	SO	47.66%	47.02%	47.61%	47.49%	48.65%	48.19%	45.82%	43.65%	47.01%
Westar Energy	WR	40.06%	40.45%	39.96%	40.19%	42.51%	37.12%	37.59%	34.70%	39.07%
Proxy Group Average										45.90%

		Long Term Debt Ratio								
Company Name	Ticker	2010 Q2	2010 Q1	2009 Q4	2009 Q3	2009 Q2	2009 Q1	2008 Q4	2008 Q3	
AEP Texas Central Company	AEP	55.97%	55.87%	55.97%	56.09%	53.62%	55.74%	56.04%	57.30%	
AEP Texas North Company	AEP	54.72%	54.08%	54.24%	53.19%	53.31%	53.10%	53.10%	52.53%	
Appalachian Power Company	AEP	56.32%	54.79%	55.49%	55.02%	55.26%	58.96%	57.00%	56.48%	
Columbus Southern Power Company	AEP	52.95%	53.52%	53.05%	53.82%	53.19%	53.61%	53.60%	52.74%	
Indiana Michigan Power Company	AEP	53.59%	53.44%	54.03%	54.14%	54.58%	56.80%	48.82%	48.91%	
Kentucky Power Company	AEP	56.41%	55.73%	55.96%	56.00%	56.06%	51.08%	51.26%	52.30%	
Kingsport Power Company	AEP	0.00%	0.00%	48.39%	44.70%	45.16%	44.95%	44.41%	44.34%	
Ohio Power Company	AEP	47.54%	50.46%	49.93%	49.73%	46.55%	51.84%	52.59%	51.03%	
Public Service Company of Oklahoma	AEP	54.44%	54.51%	54.23%	51.29%	52.39%	54.98%	54.01%	54.31%	
Southwestern Electric Power Company	AEP	52.11%	52.52%	48.21%	48.40%	51.74%	52.61%	53.17%	57.33%	
Wheeling Power Co	AEP	36.84%	36.46%	36.28%	37.02%	38.75%	39.08%	39.71%	39.38%	
Cleco Power LLC	CNL	49.48%	49.31%	54.55%	52.92%	53.57%	52.05%	54.93%	52.51%	
Dayton Power and Light Company	DPL	38.58%	38.47%	38.27%	36.76%	36.79%	36.69%	37.44%	32.89%	
Hawaii Electric Light Company, Inc.	HE	44.31%	44.43%	44.74%	46.38%	41.15%	42.62%	42.37%	40.73%	
Kansas City Power & Light Company	GXP	44.19%	45.52%	45.73%	47.58%	47.63%	48.90%	40.81%	41.73%	
KCP&L Greater Missouri Operations Company	GXP	39.42%	39.55%	40.57%	43.91%	44.68%	45.59%	46.52%	51.21%	
Idaho Power Co.	IDA	51.80%	52.44%	52.55%	51.85%	52.27%	51.24%	49.24%	49.40%	
Florida Power & Light Company	NEE	38.81%	38.92%	39.70%	40.09%	40.75%	42.74%	39.56%	37.87%	
Arizona Public Service Company	PNW	48.51%	48.81%	49.63%	49.26%	50.27%	49.37%	42.61%	43.35%	
Portland General Electric Company	POR	53.74%	53.53%	53.06%	50.63%	50.83%	48.32%	45.74%	48.41%	
Carolina Power & Light Company	PGN	42.80%	43.07%	43.81%	44.31%	45.45%	46.04%	43.69%	44.63%	
Florida Power Corporation	PGN	48.89%	50.84%	48.04%	49.09%	51.39%	52.34%	52.37%	55.28%	
Alabama Power Company	SO	50.26%	50.75%	51.08%	51.11%	53.29%	53.31%	51.27%	50.14%	
Georgia Power Company	SO	48.53%	48.22%	49.39%	47.60%	49.55%	50.32%	49.91%	45.21%	
Gulf Power Company	SO	50.28%	47.55%	48.41%	49.96%	49.80%	46.90%	44.29%	45.24%	
Mississippi Power Company	SO	41.59%	41.56%	41.55%	41.30%	41.97%	42.22%	37.82%	34.02%	
Kansas Gas and Electric Company	WR	43.51%	43.76%	42.85%	42.77%	43.57%	34.67%	34.65%	34.75%	
Westar Energy (KPL)	WR	36.62%	37.14%	37.07%	37.62%	41.44%	39.56%	40.54%	34.65%	

CAPITAL STRUCTURE - ELECTRIC PROXY GROUP

Short Term Debt Ratio

Company Name	Ticker	2010 Q2	2010 Q1	2009 Q4	2009 Q3	2009 Q2	2009 Q1	2008 Q4	2008 Q3	Overall Average
American Electric Power	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cleco Corp.	CNL	0.00%	0.00%	0.00%	0.00%	0.00%	2.41%	0.00%	0.00%	0.30%
DPL, Inc.	DPL	0.00%	0.00%	0.00%	4.78%	5.83%	6.23%	0.00%	3.78%	2.58%
NextEra Energy, Inc.	NEE	5.48%	7.70%	2.68%	3.00%	2.60%	0.67%	3.03%	8.19%	4.17%
Great Plains Energy Inc.	GXP	8.80%	8.00%	6.89%	2.79%	3.08%	8.42%	9.38%	4.23%	6.45%
Hawaiian Electric	HE	0.59%	0.58%	0.00%	0.47%	4.56%	1.38%	1.95%	6.35%	1.98%
IDACORP, Inc.	IDA	0.00%	0.00%	0.00%	0.00%	1.41%	3.86%	4.40%	5.30%	1.87%
Pinnacle West Capital	PNW	0.00%	2.80%	0.00%	0.00%	2.98%	3.46%	7.75%	4.08%	2.63%
Portland General	POR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.84%	1.42%	1.03%
Progress Energy	PGN	0.00%	0.00%	0.00%	0.29%	0.00%	0.81%	3.01%	0.00%	0.51%
Southern Co.	SO	0.13%	0.87%	0.98%	0.46%	0.77%	0.87%	2.16%	3.07%	1.16%
Westar Energy	WR	2.98%	2.62%	3.04%	2.12%	0.80%	3.14%	2.18%	3.78%	2.58%
Proxy Group Average										2.11%

		Short Term Debt Ratio							
Company Name	Ticker	2009 Q1	2008 Q4	2008 Q3					
AEP Texas Central Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
AEP Texas North Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Appalachian Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Columbus Southern Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Indiana Michigan Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kentucky Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kingsport Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ohio Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Public Service Company of Oklahoma	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Southwestern Electric Power Company	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Wheeling Power Co	AEP	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cleco Power LLC	CNL	0.00%	0.00%	0.00%	0.00%	0.00%	2.41%	0.00%	0.00%
Dayton Power and Light Company	DPL	0.00%	0.00%	0.00%	4.78%	5.83%	6.23%	0.00%	3.78%
Hawaii Electric Light Company, Inc.	HE	0.59%	0.58%	0.00%	0.47%	4.56%	1.38%	1.95%	6.35%
Kansas City Power & Light Company	GXP	7.37%	5.22%	4.79%	1.02%	2.14%	5.74%	11.27%	7.71%
KCP&L Greater Missouri Operations Company	GXP	10.23%	10.79%	8.99%	4.57%	4.02%	11.09%	7.49%	0.75%
Idaho Power Co.	IDA	0.00%	0.00%	0.00%	0.00%	1.41%	3.86%	4.40%	5.30%
Florida Power & Light Company	NEE	5.48%	7.70%	2.68%	3.00%	2.60%	0.67%	3.03%	8.19%
Arizona Public Service Company	PNW	0.00%	2.80%	0.00%	0.00%	2.98%	3.46%	7.75%	4.08%
Portland General Electric Company	POR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.84%	1.42%
Carolina Power & Light Company	PGN	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.38%	0.00%
Florida Power Corporation	PGN	0.00%	0.00%	0.00%	0.59%	0.00%	1.63%	4.64%	0.00%
Alabama Power Company	SO	0.49%	0.00%	0.00%	0.00%	0.00%	0.00%	0.22%	0.84%
Georgia Power Company	SO	0.02%	0.00%	0.00%	0.00%	0.01%	0.67%	0.70%	5.98%
Gulf Power Company	SO	0.00%	3.50%	3.91%	1.71%	2.94%	2.79%	7.73%	5.46%
Mississippi Power Company	SO	0.00%	0.00%	0.00%	0.12%	0.12%	0.00%	0.00%	0.00%
Kansas Gas and Electric Company	WR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Westar Energy (KPL)	WR	5.96%	5.25%	6.08%	4.25%	1.60%	6.29%	4.36%	7.57%