Case No. PU-12-813
Exhibit NSP-38

Northern States Power Company
Corrections/Changes to Testimony of NSP Witnesses

Laura McCarten

- Exhibit 6 McCarten-Rebuttal
  - Change reference from "Mr. Mugrace" to "Dr. Pavlovic":
    - Page 18, line 23;
    - Page 19, line 26;
    - Page 20, lines 6 and 16;
    - Page 21, lines 7, 12, 15, and 16.

Ann Bulkley

- Exhibit 15 Bulkley-Rebuttal
  - Change reference in Footnote 47 on page 39 from "*Ibid*, at 6." to "American Academy of Actuaries, "Understanding the Assumptions used to Evaluate Social Security's Financial Condition," September 2009, at 6."
  - Change reference on page 62, line 21 from "Schedule 9" to "Schedule 6".
  - Change reference on page 64, line 21 from "(0.71 percent)" to "(0.31 percent)".

Steve Wishart

- Exhibit 17 Wishart-Rebuttal
  - Change reference from "Mr. Mugrace" to "Dr. Pavlovic":
    - Page 2, lines 4, 14, and 17;
    - Page 3, lines 10, 18, and 24;
    - Page 5, lines 1, 4, and 6;
    - Page 6, lines 4 and 6;
    - Page 7, line 11;
    - Page 9, lines 20 and 21;
    - Page 10, line 4;
    - Page 11, lines 18, 20 and 26;
    - Page 12, line 26;
    - Page 13, lines 1 and 13;
    - Page 14, line 24;
    - Page 15, lines 14 and 18;
    - Page 16, lines 23 and 25;
    - Page 18, lines 6, 9, and 18.

Rebuttal Testimony and Schedules
Laura McCarten

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in North Dakota

Case No. PU-12-813
Exhibit___(LM-2)

Policy

August 12, 2013

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Laura McCarten. I am Regional Vice President for Northern States Power Company – Minnesota (NSPM or Company).

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed Direct Testimony providing an overview of our electric rate case filing, including the key drivers of our request.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I summarize our response to the Direct Testimony filed by Advocacy Staff of the North Dakota Public Service Commission and Staff Consultants, and identify the Company witnesses sponsoring Rebuttal Testimony.

Q. WHAT KEY ISSUES WERE RAISED IN RESPONSE TO THE COMPANY'S DIRECT TESTIMONY?

A. Our review of testimony submitted by Advocacy Staff and Staff Consultants indicates that there are several areas of general agreement, including the system investments that drive the need for this case and our proposed class cost of service and class allocation. The key areas of disagreement are:

- Application of appropriate ratemaking principles, including:
  - The appropriate jurisdictional demand allocator;
  - Use of a historical three-year average for determining 2013 operations and maintenance (O&M) expenses;
  - Reliance on other jurisdictional determinations on single issues;
- Determination on issues outside of the test year;

- The Company's management of its investments and expenditures; and
- Return on equity (ROE).

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S RESPONSE TO THESE ISSUES.

A. We appreciate the careful review and consideration of our case. While the areas of disagreement may be relatively few, they are significant in terms of both importance and magnitude. In particular, we are concerned by Staff Consultant Dr. Karl R. Pavlovic's recommended change to our long-standing method of allocating the majority of production and transmission costs using the 12-month coincident peak demand allocation method (12 CP). His suggestion of using a 1 CP deviates from widely-accepted ratemaking principles and 20 years of past Commission precedent, and significantly undermines the Company's ability to recover its costs of service and earn a reasonable rate of return.

We believe Staff's primary issues can be addressed by discussing the following four topics:

- Potential rate mitigation measures;
- Appropriate application of ratemaking principles;
- Management of differences in state energy policy; and
- Management of system investments and costs.

In summary, we believe the Commission's decisions in this proceeding should be guided by long-standing ratemaking principles and past precedent. We acknowledge the concerns with our rate increase request, but believe that resolution of these concerns should uphold the regulatory compact and

preserve our ability to provide the kind of service our customers depend on and expect. We have indicated areas in our Rebuttal Testimony where we agree to Staff's recommendations or propose an alternative that is based on sound principles.

Q. PLEASE DESCRIBE HOW YOUR TESTIMONY IS ORGANIZED.

A. First I provide an overview of our request, as modified by Rebuttal Testimony. I then discuss the key areas of disagreement and the Company's recommendations. Finally, I introduce the Company's Rebuttal witnesses and outline their responsibilities in the proceeding.

II. SUMMARY OF REQUEST AND POTENTIAL RATE MITIGATION

Q. PLEASE SUMMARIZE THE COMPANY'S INITIAL REQUEST IN THIS PROCEEDING.

A. We seek the rate relief needed to support the ongoing costs of providing reliable, high-quality service to our customers. To accomplish this, on December 18, 2012 we requested authority to increase our electric rates by $16.9 million, or 9.25 percent. We based this request on a forecasted 2013 Test Year, using a 10.6 percent ROE and a 52.56 percent equity ratio. Under our proposal, a residential customer using 850 kWh per month would see a monthly bill increase of about $7 per month or nine percent.

Q. HAVE YOU MODIFIED YOUR REQUEST SINCE THE FILING OF YOUR CASE?

A. Yes. Our Rebuttal Testimony incorporates various corrections and updates to our Application, each offered with the intent of providing the Commission the most current and accurate information. We now seek Commission approval for a $14.9 million increase, based on corrected and updated financial

information and a 10.25 percent return on equity. The Rebuttal Testimony of Company witness Ms. Anne E. Heuer provides detail on our proposed corrections and updates and modified request.

Q. HAS THE REQUESTED RETURN ON EQUITY BEEN MODIFIED?

A. Yes. As explained in the Rebuttal Testimony of Company witness Ms. Ann E. Bulkley, our updated analysis supports an ROE range of 10.00 percent to 10.50 percent. Within that range, the Company requests an ROE of 10.25 percent based on market conditions and the expectation of and risk associated with rising interest rates. A 10.25 percent ROE is within the range of ROEs approved by other state commissions and sends a signal to investors that the Commission supports utility investment in North Dakota.

Q. HAS THE COMPANY CONSIDERED ADVOCACY STAFF'S CONCERN ABOUT THE IMPACT OF ITS RATE REQUEST ON ITS NORTH DAKOTA CUSTOMERS?

A. Yes. This Commission has recognized the importance of finding the proper balance between ensuring utilities like the Company have the resources needed to ensure continued safe, reliable and economic electric service and just and reasonable rates for our customers. We share this goal.

As I discussed in my Direct Testimony, the Company is in the midst of a significant investment cycle. We find it encouraging that Staff Consultants have generally agreed with the prudence of our investments and reasonableness of the costs driving our rate increase. However, we recognize Advocacy Staff's concern with the cost of our continued system investments and the corresponding impact on customers. We are willing to work with the Commission and Staff to find appropriate opportunities to help mitigate this

impact while still allowing the Company to recover its cost of service and earn a reasonable rate of return.

Q. PLEASE PROVIDE AN EXAMPLE OF A POTENTIAL OPPORTUNITY TO LESSEN THE RATE IMPACT OF THE COMPANY'S REQUEST.

A. One option we could explore is a "smoothing" mechanism to address our pension costs. In my Direct Testimony, I noted that the Company is experiencing higher pension costs in 2013 as a result of amortizing market losses in our pension fund incurred during the 2008 economic downturn, which we call the "2008 market loss." I also noted that the Company is open to considering additional smoothing mechanisms that would reduce the 2013 impact of these pension costs while still allowing the Company to recover this cost of service over time.

A smoothing mechanism would essentially extend the amortization period for 2008 market loss and/or cap the expense per year and defer the amount above the cap. The end result is an ability to mitigate the total impact of this cost in the current test year by spreading it out over a number of years.

Q. HAS THE COMPANY IDENTIFIED OTHER OPPORTUNITIES TO ADDRESS CONCERNS WITH ITS RATE REQUEST?

A. Yes. Advocacy Staff has expressed some concern with the rate impacts of our investment cycle. One way to mitigate the rate impacts is to provide predictability to our customers of the rates they pay for electric service.

Our rigorous planning processes, which I describe further below, allow us to predict with some certainty our major future capital investments that can drive

future rate requests. Our currently-forecasted future capital investments are largely (but not totally) driven by transmission and nuclear projects, some of which the Commission has already found to be prudent. When such capital investments are generally known and measurable, the "capital step" is an available ratemaking tool that can alleviate the need for future general rate request proceedings.

The capital step tool identifies known and measurable capital projects and provides for a "step" increase in rates each year for a specified amount of years beyond the current test year. The step process would include Commission review and evaluation of these projects, without additional general rate request proceedings. By addressing these future costs, our customers would have greater certainty about their electric rates in the years covered by a step. The Company requested and the Commission approved a capital step in our last rate case to account for the 2012 capital costs of our nuclear program.

We believe that an appropriately crafted capital step or steps can help with the predictability of our electric rates and mitigate the Company's need to make future general rate requests. The Company is interested in working with the Commission and Staff to identify an appropriate step mechanism to achieve this goal.

III. UPHOLDING RATEMAKING PRINCIPLES

Q. WHAT IS THE OVERALL OBJECTIVE OF THE RATEMAKING PROCESS FOR REGULATED UTILITIES?

A. A regulated utility has both the right and obligation to serve all customers that live or do business in its established service territory. In order to reliably serve customers, the utility must invest in and maintain its infrastructure and operate its business to deliver on this obligation. The overall purpose of the ratemaking process is to set rates that allow the utility to recover the reasonable costs it incurs to satisfy that obligation, including the opportunity to earn a return that is sufficient to attract the capital needed to support continued investment. This is often referred to as the "regulatory compact." Decades of regulatory proceedings and rulings have established extensive precedent, principles, and standards that promote a fair, constructive, and stable regulatory environment.

Q. HOW DO CUSTOMERS BENEFIT FROM A CONSTRUCTIVE AND STABLE REGULATORY ENVIRONMENT?

A. We share with our North Dakota customers the goal of having reliable, safe, and economical energy available 24 hours a day, 365 days a year. Meeting this goal requires significant ongoing investment that far exceeds what the Company can finance on its own. As a result, we must turn to the capital markets to raise the funds necessary to make improvements to our system. The cost at which we can raise capital depends in large part on investors' perceived risk of investing with us and the expected return, which is a function of the regulatory environment. With a constructive and stable regulatory environment that allows us to keep our balance sheet strong and consistently meet investor expectations, we have been able to achieve record-low borrowing costs that lower the overall cost of service to our customers and will benefit customers for decades to come. Thus, customers have an important interest in keeping the Company financially healthy.

Q. HAVE STAFF CONSULTANTS MADE RECOMMENDATIONS IN THIS PROCEEDING THAT WOULD CHALLENGE THE STABILITY OF THE REGULATORY COMPACT?

A. Yes. The Staff Consultants have proposed methodological changes that are inconsistent with long-standing ratemaking principles in North Dakota. We believe it is important to maintain a principled approach to ratemaking that preserves the stability of the regulatory compact, and ultimately supports continued safe and reliable electric service to our customers in North Dakota. As I discussed above, we are interested in addressing the Staff's stated concerns with the magnitude and frequency of the Company's proposed rate increases; however, we believe that we can resolve these issues while upholding sound ratemaking principles.

Q. PLEASE PROVIDE EXAMPLES OF RECOMMENDATIONS THAT MAY DEVIATE FROM LONG-STANDING RATEMAKING PRINCIPLES IN NORTH DAKOTA.

A. The most significant deviation is the Staff Consultants' recommendation that the Company change its demand allocator from the 12 CP methodology to the one (annual) coincident peak (1 CP) methodology. Other examples include: using historic data from 2010 to 2012 to set selected future 2013 test-year costs; reliance on the determination of regulatory commissions in other states for certain, single issues; and the recommendation to disallow costs outside of the test year for which the Company has not yet sought recovery.

A. Determination of Demand Allocator

Q. WHAT IS THE COMPANY'S METHOD AND DR. PAVLOVIC'S RECOMMENDATION FOR ALLOCATING THE MAJORITY OF PRODUCTION AND TRANSMISSION COSTS TO NORTH DAKOTA CUSTOMERS?

A. The Company currently utilizes a 12 CP demand-based allocation. Dr. Pavlovic is recommending that the Company now shift to a 1 CP methodology.

Q. DOES THE COMPANY AGREE WITH DR. PAVLOVIC'S RECOMMENDATION?

A. No. We do not believe there is any need or justification for the Commission to modify the long-standing demand allocation methodology. The Company has used the 12 CP demand allocation methodology in all of our jurisdictions for almost 20 years, as it reasonably reflects the costs caused by each jurisdiction, is used by the Midcontinent Independent System Operator (MISO) and Federal Energy Regulatory Commission (FERC), and promotes more stable jurisdictional cost responsibility over time. The Staff Consultants have not identified any changes to the NSP System that warrant a change in our allocation methodology and are proposing a more volatile allocation methodology. Further, their recommendation does not comport with the Commission's precedent on this issue. Company witness Mr. Scott B. Brockett further explains our position and recommendation.

B. Use of Future Test Year

Q. WHAT IS THE RECOMMENDATION OF THE STAFF CONSULTANTS WITH RESPECT TO USING HISTORIC DATA TO DETERMINE CERTAIN TEST-YEAR AMOUNTS?

A. Although the Staff Consultants generally support the prudence of the costs that are driving our rate request, they selectively apply a three-year historical average methodology to determine some of our revenue and expenses in our test year.

Q. DOES THE COMPANY AGREE WITH THIS RECOMMENDATION?

A. No. Utilizing a three-year historic average fails to match 12 months of expenses with 12 months of revenue and also fails to accurately reflect the revenues and costs the Company will have during the period rates are in effect. Our future test-year methodology is consistent with North Dakota statutes and established practice of the Company and the Commission, and it properly reflects changes in our operations from past years. Utilizing this historic methodology could result in larger future revenue deficiencies, which would cause the Company to seek more, not fewer, rate increases. We believe using this methodology is contrary to stated concerns with the Company's frequency of rate requests. Company witness Ms. Heuer further discusses our concerns with this methodology.

C. Reliance on Other Commission Orders for Single Issues

Q. DID A STAFF CONSULTANT RELY ON ANOTHER JURISDICTION'S COMMISSION DECISION TO SUPPORT THIS RECOMMENDATION?

A. YES. Staff Consultant, Mr. Dante Mugrace, recommends that all incentive compensation be disallowed in part because the Wisconsin Public Service Commission decided not to allow incentive compensation in rates.

Q. WHAT IS THE COMPANY'S RESPONSE TO THIS RECOMMENDATION?

A. We do not believe it is appropriate to disallow this cost based on ratemaking practices in one state. The Wisconsin Commission decision is inconsistent with all of the other commissions in jurisdictions we serve. Mr. Mugrace also isolated this one issue without considering the other outcomes of the Wisconsin Commission decision.

Though Mr. Mugrace looked to our Wisconsin proceeding for guidance related to incentive compensation, his recommendation does not reflect the totality of the outcome of our Wisconsin rate case. In its decision, the Wisconsin Commission approved approximately 90 percent of the Company's rate request, a 10.4 percent ROE, and allowed the use of a 12 CP demand allocator. A complete copy of the order is included as Exhibit___(LM-2), Schedule 1.

Fundamental to the purpose of ratemaking is the establishment of an overall revenue requirement that considers individual issues as part of the larger whole. Selective application of one commission's policy decision on one issue deviates from the application of principled ratemaking methodologies in keeping with the regulatory compact.

Q. DID MR. MUGRACE RAISE OTHER CONCERNS RELATED TO INCENTIVE COMPENSATION?

A. Yes. Mr. Mugrace stated that the Company's application contained insufficient documentation to support its incentive compensation request.

Q. WHAT IS THE COMPANY'S RESPONSE TO THIS CONCERN?

A. The level of documentation we provided in our application is consistent with our prior rate filings in North Dakota. Through the discovery process, we were not made aware of the broader concern about lack of support for our incentive compensation costs.

However, to supplement the record, we provide Rebuttal Testimony by Company witness Ms. Sharon L. Koenig that provides additional discussion of

our incentive compensation request. As Ms. Koenig explains, our overall compensation package impacts our ability to attract and retain the talent necessary to operate our business. Having a market-competitive compensation package is a fundamental requirement for attracting and retaining a skilled workforce.

D. Consideration of Issues Outside the Test Year

Q. PLEASE DESCRIBE RECOMMENDATIONS REGARDING COSTS THAT THE COMPANY HAS NOT YET SOUGHT TO RECOVER.

A. Advocacy Staff is recommending the Commission:

- Exclude the costs of the Odell Project from the Fuel Cost Rider (FCR);
- Exclude the costs of the Pleasant Valley Wind Project from rate base;
- Deny cost recovery of all solar projects that may be undertaken to comply with Minnesota's new solar mandate; and
- Reassess our proposal in Case No. PU-13-194 where we request an advanced determination of prudence (ADP) for the construction of new gas combustion turbines in Minnesota and North Dakota.

Q. WHAT IS THE COMPANY'S RESPONSE TO THESE RECOMMENDATIONS?

A. We believe these recommendations are premature, because the Company has not yet sought recovery of these costs in a rate application. Analyses of these resource additions should be made on a complete record, so that the Commission may assess all of the facts and make a reasoned and informed decision.

Q. WILL THE COMPANY SEEK COMMISSION REVIEW OF THE COSTS OF THESE PROJECTS?

A. Yes. The Company has filed timely applications for an advance determination of prudence for the Courtenay, Odell, and Pleasant Valley Projects (Case Nos. PU-13-706, PU-13-707, PU-13-708), as well as for our natural gas turbine proposal (Case No. PU-13-194). In those Cases, the Company is requesting the Commission determine that our intent to procure these resources is prudent. A full and complete record on these issues is necessary, and the Company believes that the current ADP proceedings are the appropriate forum for developing the record. The Company intends to seek recovery of these costs based on the outcomes of those proceedings.

As I discuss further below, if and when the Company seeks to acquire additional solar resources, we will ensure that there is a process in place for Commission review and input on those resource acquisitions. Thus, we recommend the Commission take no action on these issues in this rate case.

E. Review of Transmission Cost Rider

Q. PLEASE DESCRIBE THE STAFF CONSULTANT DR. PAVLOVIC RECOMMENDATION WITH RESPECT TO THE COMPANY'S PROPOSED TRANSMISSION COST RIDER (TCR).

A. Dr. Pavlovic recommends that the Commission not approve our proposed TCR, stating our proposal is incomplete. He recommends that the Company re-file its proposal when we have identified the initial set of transmission projects we intend to incorporate into the TCR.

Q. HOW DO YOU RESPOND TO THIS RECOMMENDATION?

A. We disagree with Dr. Pavlovic's recommendation because it is inconsistent with North Dakota statutes and contrary to Advocacy Staff's stated intent that

the Company minimize its rate filings. A TCR mechanism, applied based on a Commission approved tariff, provides a sensible and organized approach. With an approved TCR mechanism in place, when qualifying transmission projects are to be placed in service, the focus can be on the merits of the project and not the details of the recovery mechanism. Further, the TCR is permitted by law, and the Commission has approved similar riders for other utilities in North Dakota.

Q. WHY IS DR. PAVLOVIC'S RECOMMENDATION INCONSISTENT WITH NORTH DAKOTA STATUTE?

A. I am not a lawyer, but I have been advised that North Dakota Century Code Section 49-05-04.3 contemplates a two-step process in which the utility first files for its TCR Tariff and then, when it seeks to make a rate adjustment under the approved TCR, the information Dr. Pavlovic identifies as missing would be provided. I am further advised that the while the statute does not prohibit a combined filing, as recommended by Dr. Pavlovic, it does not require one either.

Q. HOW COULD APPROVAL OF THE TCR HELP MINIMIZE FUTURE GENERAL RATE REQUESTS?

A. In the next several years, the Company will be placing into service several transmission investments, including the CapX2020 Group 1 Projects. By utilizing the TCR mechanism, we can recover the costs of these types of investments without a rate case. Our proposed TCR mechanism and North Dakota law provide the Commission with oversight of any transmission projects prior to our inclusion of these projects into the TCR to ensure such costs are prudent. Consequently, the TCR facilitates efficient review and cost

recovery of approved transmission investments outside the context of a general rate request.

F. Economic Development Expenses and Charitable Contributions

Q. PLEASE DESCRIBE MR. MUGRACE'S RECOMMENDATIONS ON THE COMPANY'S ECONOMIC DEVELOPMENT EXPENSES AND CHARITABLE CONTRIBUTIONS.

A. Mr. Mugrace has recommended complete disallowance of all economic development expenses and charitable contributions. We have requested recovery of 50 percent of eligible economic development and charitable contribution expenses.

Q. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No, I do not. As discussed in our response to Data Request No. NDPSC-2-015, (included as Exhibit___(LM-2), Schedule 2), we included 50 percent of our charitable contributions and economic development expenses in our rate request, consistent with our previous requests in North Dakota. We believe this is appropriate, because the contributions provide important support to the communities and organizations in the areas we serve. Given the long-term nature of our relationship to the communities in our service territory, we believe we have a responsibility and expectation to help support the stability and economic vitality of these communities. Charitable contributions and economic development activities help us deliver on that responsibility. We propose only 50 percent recovery to provide added assurance that the charitable and economic development contributions are made in a responsible and reasoned manner.

IV. MANAGING STATE ENERGY POLICY DIFFERENCES

Q. PLEASE SUMMARIZE THE CONCERNS RAISED THAT RELATE TO COSTS RESULTING FROM RENEWABLE INVESTMENTS AND EXPENSES.

A. We acknowledge the concerns that the Commission and Staff have raised about North Dakota customers sharing costs that are not perceived to be economic for North Dakota customers. These concerns have generally related to the costs of resource acquisitions the Company has undertaken to, in part, meet the higher renewable energy requirements of our Minnesota jurisdiction.

Q. HOW HAS THE COMPANY RESPONDED TO THESE CONCERNS?

A. We are making significant efforts to ensure we are responsive to these concerns. These efforts are mainly focused on meeting our commitments to provide timely information so that the Commission is made aware of our plans in advance and to provide for Commission input into our resource decisions.

These commitments arise primarily from the Settlement Agreement in Case No. PU-07-776. The Settlement was based on a cooperative approach to providing all of our customers the benefits of an integrated system while acknowledging the different energy priorities of the states we serve. As the Commission has voiced additional concerns or expectations, such as those in Case No. PU-12-59, we have been diligently working to ensure that they are addressed.

A. Compliance with Commitments to the Commission

Q. PLEASE DESCRIBE THE COMPANY'S COMMITMENTS TO KEEP THE COMMISSION INFORMED.

A. Consistent with our commitments, we continue to file our Resource Plans for the integrated NSP System with the Commission and provide an alternative system-wide analysis that strictly meets both federal and North Dakota environmental and renewable requirements for the same time period. We also provide a forward-looking five-year plan identifying our intended generation and transmission investments or purchase agreements in our annual Ten Year Plan filings, which also include an anticipated schedule of future ADP applications. We have also agreed to meet with the Commission and Staff as necessary to conduct updates on resource planning efforts and decisions and discuss any plans or updates filed in that year.

Q. PLEASE DESCRIBE THE COMPANY'S COMMITMENTS TO PROVIDE THE COMMISSION OPPORTUNITIES TO PROVIDE TIMELY INPUT INTO ITS RESOURCE DECISIONS.

A. In addition to the Commission's ability to provide comments to our informational filings, and our commitment to meet with the Commission and Staff on our resource acquisitions or rehabilitations, we agreed in the Settlement to file an application for an ADP for any resource addition or rehabilitation where the generating facility is at least 50 MW or the transmission facility is at least 50 miles long. More recently, we made an additional commitment in Case No. PU-12-59 to make such ADP filings within two weeks of making a similar filing in Minnesota. Also in Case No. PU-12-59, the Commission indicated its expectation that our contractual

commitments for resource additions should be contingent on Commission approval.

Q. HOW HAS THE COMPANY MET THESE COMMITMENTS?

A. Since the Commission approved the Settlement in Case No. PU-07-776, we have filed Applications for ADPs for projects including the Nobles Wind Farm, Merricourt Wind Farm, CapX2020 transmission projects, significant projects at our Prairie Island nuclear generating facility, Prairie Rose Wind Farm, our proposal for three gas combustion turbines, and our proposed 600 MW of wind additions.

Following the Commission's direction in Case No. PU-12-59, our ADP Applications for our combustion turbine proposal and our wind additions have been made less than two weeks after similar filings with the Minnesota Public Utilities Commission. As I discuss in my testimony in the ADP proceeding for our 600 MW wind proposal, our contracts for those resources are contingent on this Commission's approval.

B. Recovery of Power Purchases

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS MADE WITH RESPECT TO THE IMPACT OF RESOURCE RECOVERY ON THESE INTERJURISDICTIONAL ISSUES?

A. While not a part of our rate request in this proceeding, Staff Consultant ~~Mr. Mugrace~~ Dr. Pavlovic has recommended disallowance of several renewable energy purchased power agreements (PPAs) and all costs of the Prairie Rose Project incurred until the end of this case. Advocacy Staff also recommended that all costs related to meeting the new solar mandate established in Minnesota be preemptively disallowed. Additionally, Advocacy Staff recommends that we

issue a refund to North Dakota customers to reflect the Minnesota Commission's disallowance of certain costs associated with the St. Paul Cogeneration biomass facility.

Q. DOES THE COMPANY AGREE WITH THESE RECOMMENDATIONS?

A. No, with the exception of the refund for disallowed St. Paul Cogeneration costs. We are aware of the Commission's concerns and have been seeking to address them through the processes I previously described. Therefore, we do not believe it is necessary for the Commission to take further action on these items at this time.

Additionally, we believe these recommendations are inconsistent with a cooperative approach to ensuring that the Commission's concerns can be met. The Settlement Agreement in Case No. PU-07-776 recognized the need to address the Commission's concerns while also allowing the Company to recover its cost of service and earn a reasonable return. We are concerned that these recommendations do not reflect this approach.

We do agree to calculate a refund for North Dakota customers related to disallowed St. Paul Cogeneration PPA costs. This is described by Company witness Mr. Steven W. Wishart in his Rebuttal Testimony.

1. Purchased Power Costs

Q. PLEASE ELABORATE ON THE COMPANY'S CONCERNS WITH THE RESPECT TO RECOMMENDATIONS ON PURCHASED POWER COSTS.

A. ~~Mr. Mugrace's~~ Dr. Pavlovic recommendation to disallow recovery through the FCR of the costs of energy of 17 biomass, solar, and wind PPAs will impact our ability to

reliably plan future resource additions for our integrated system. Further, the recommendation is incomplete.

Q. WHY WILL THESE PURCHASED POWER RECOMMENDATIONS IMPACT THE COMPANY'S PLANNING?

A. Our recovery of the PPAs identified by ~~Mr. Mugrace~~ Dr. Pavlovic is consistent with the Commission's rules and our Commission-approved FCR. Many of these PPAs have been recovered through the FCR for several years. Because of this, the Company has relied on the availability of these resources and our ability to recover their costs through Commission-approved mechanisms. Abrupt disallowance of cost recovery of these resources, will impact our resource procurement decisions in a way that could leave us vulnerable to volatile market pricing. Mr. Wishart discusses these impacts in his Rebuttal Testimony.

Most concerning is that ~~Mr. Mugrace's~~ Dr. Pavlovic's recommendation essentially results in our North Dakota customers receiving energy for free. While he frames this as our North Dakota customers obtaining savings, the savings are in fact the result of our customers receiving energy they do not pay for. Mr. Wishart provides further information with respect to the concept of free energy.

Q. WHAT IS THE COMPANY'S RECOMMENDATION ON THE ISSUE OF RECOVERY OF CERTAIN PURCHASED POWER COSTS?

A. These costs are not part of the revenue requirements in this rate case, because recovery of these costs is through the FCR. If the Commission is interested in further review, we suggest that the Commission open a separate docket to review how costs recoverable via the FCR are to be reviewed in the future.

Such a docket may result in changes to the FCR Rider tariff or the establishment of a new process for reviewing purchased power agreements. Addressing these issues in a separate docket would allow the Commission to decline to take action at this time.

Should the Commission choose to take action in this proceeding, we believe the Company should recover the costs of the PPAs identified by ~~Mr. Mugrace~~ for the reasons explained in the Rebuttal Testimony of Mr. Wishart.

Dr. Pavlovic

2. Prairie Rose Wind

Q. PLEASE ELABORATE ON THE COMPANY'S CONCERNS WITH RESPECT TO ~~MR. MUGRACE'S~~ RECOMMENDATION ON PRAIRIE ROSE WIND.

DR. PAVLOVIC'S

A. The recommendation that the costs incurred for the Prairie Rose Wind project not be recovered prior to the termination of this case does allow us to recover fully the costs of a generation resource that ~~Mr. Mugrace~~ admits is prudent. The Company recommends that since ~~Mr. Mugrace~~ concluded this project is acceptably priced and reasonable, the Company should be able to recover fully all costs of the project.

Dr. Pavlovic

Dr. Pavlovic

3. Minnesota Solar Mandate

Q. WHAT DOES THE COMPANY PROPOSE IN RESPONSE TO ADVOCACY STAFF'S POSITION ON MINNESOTA SOLAR MANDATE COSTS?

A. As I mentioned, we believe that Advocacy Staff's proposal is premature since the Company has not sought to recover any of these costs in this case. However, we recognize that the new solar mandate recently implemented by the Minnesota legislature is part of the Commission's general concerns

regarding renewable mandates. Therefore, we believe it is best to proactively address the impact of the solar mandate on our North Dakota customers.

As part of the development of the solar mandate legislation in Minnesota, we intended to seek a provision that would ensure the costs to comply with the mandate were borne only by Minnesota rate payers. Due to the procedure that was used to pass the bill in the final days of the session, however, we did not have the opportunity to propose that provision. We will continue to work to achieve this goal through future legislation or regulatory applications and commit to the Commission that we will make our best efforts to seek appropriate opportunities to ensure recovery of the costs of complying with the mandate solely from our Minnesota customers. We commit to keeping the Commission's Staff apprised of our efforts and our strategic decisions to achieve this goal.

V. MANAGING SYSTEM INVESTMENTS AND COSTS

A. System Investments

Q. WHAT ISSUES DID ADVOCACY STAFF RAISE RELATED TO THE COMPANY'S SYSTEM INVESTMENTS AND COST MANAGEMENT PRACTICES?

A. Advocacy Staff expressed concern about the overall level, timing, and planning of the Company's system investments and the Company's renewable energy acquisitions in particular. Advocacy Staff questioned whether the Company is investing in a well-organized and thoughtful way that considers the impacts on ratepayers. Additionally, Advocacy Staff is concerned that the Company is making opportunity purchases that are "not needed" and adding costs for our customers, stating that getting a good price on an investment does not justify

its purchase if it is not needed to meet incremental loads. Advocacy Staff is also concerned about the impacts of wind generation on our existing generation fleet.

Q. WHAT IS THE COMPANY'S RESPONSE TO ADVOCACY STAFF'S CONCERN ABOUT THE LEVEL AND TIMING OF INVESTMENT IN THE SYSTEM?

A. The investments we are making are part of an extensive and ongoing resource planning process that encompasses both short- and long-term needs assessments. Such planning ensures that our customers continue to have energy that is reliable, economical and sustainable, and that we comply with regulatory requirements. The Company, like many other utilities, is currently in a cycle of significant system investment, as we replace and refresh infrastructure that was originally built to handle the rapid post-war growth during the 1950's to 1970's. As discussed in my Direct Testimony, a significant driver of this case is our investment to keep our nuclear plants operating safely and reliably for an additional 20 years. This investment cannot be delayed or deferred, because the investments are required as part of our operating license renewals.

These investments will position us well for the future and will serve and benefit customers over the long run. Additionally, because we are currently able to take advantage of favorable financing, we can ensure these investments have as low a customer impact as possible.

As discussed in our response to Data Request No. NDPSC-6-016 (included as Exhibit___(LM-2), Schedule 3), capital projects are identified through a rigorous planning process that results in short- and long-term investment

plans. We develop our investment plans to ensure projects are completed prior to adverse reliability impacts or compliance issues.

In addition to prioritizing projects for future years, we also closely monitor our budget and any changing circumstances throughout the year, reprioritizing projects when appropriate.

Q. CAN YOU PROVIDE EXAMPLES OF HOW THE COMPANY HAS ELIMINATED OR DEFERRED INVESTMENTS?

A. We continually monitor our plans and adjust them accordingly to new circumstances and opportunities to ensure that we have the right plan to meet customer needs. Our proposals to reevaluate the Black Dog combined cycle project and Prairie Island uprate projects in light of changed circumstances are examples of our efforts to keep our plans aligned with our true needs and avoid costs where possible. Additionally, the phased approaches to refurbish and repower our King, High Bridge, and Riverside generating plants helped to mitigate the impacts on rates. And our participation with ten other utilities to build the Group I CapX2020 transmission lines over several years will enable us to smooth the rate impacts of those projects over a number of years.

Additionally, we have undertaken a number of efficiency and productivity initiatives to help offset rising costs, such as adding new productivity metrics, emphasizing preventative maintenance, and capturing supply chain efficiencies.

Q. DOES ADVOCACY STAFF OFFER RECOMMENDATIONS RELATED TO THE COMPANY'S INVESTMENTS AND SPENDING?

A. Yes. Advocacy Staff recommends the Commission consider:

- Requiring the Company to prepare and submit forecasted budgets demonstrating projects that the Company can delay to help minimize future increases; and
- Capping future rate increases so that the Company has an incentive not to spend.

Q. DOES THE COMPANY AGREE WITH THESE RECOMMENDATIONS?

A. While we appreciate the intentions behind Staff's suggestions, we do not believe additional reporting requirements would be beneficial. As previously discussed, the Company has a rigorous process for identifying, evaluating, and prioritizing capital projects, which provides assurance that the right projects are done at the right time to maintain safety and reliability. We are already submitting information about these projects to the Commission in various ways (*i.e.*, Resource Plans, ADPs, Ten Year Plans, etc.), making additional project forecast information unnecessary. Additionally, because the Company identifies several hundred projects each year, it would be burdensome for both the Company and Commission.

If designed well, prescribed rate caps through a multi-year approach to rate setting, such as the capital step I discuss above, could be an effective way to manage the impacts of a utility's investment program on rates. The Company operated successfully under a formula rate structure while under the "PLUS" performance-based rate plan during the 2001-2005 period. However, it is important that any solution consider current investment needs and trends. It

may be counter-productive to merely set a firm cap on future rate increases, as the Company's requests are based on the costs needed to provide quality service.

B. Opportunity Purchases

Q. WHAT IS THE COMPANY'S RESPONSE TO ADVOCACY STAFF'S CONCERN THAT THE COMPANY IS MAKING OPPORTUNITY PURCHASES?

A. We plan our system to meet the needs of all of the customers we serve, and we are continually seeking opportunities in the marketplace to acquire low-cost energy resources. The renewable energy contracts we have signed will save customers money soon after they go into service because they will displace higher cost fuels, such as natural gas, that would have been otherwise purchased to generate the same energy. Additionally, by making purchases at an attractive price, we will be displacing more expensive generation, which allows us to meet our customers' energy needs at a lower cost. We believe taking advantage of cost-effective pricing when it is available is in the long-term best interest of our customers.

C. Other Issues

Q. IS THE COMPANY STUDYING THE POTENTIAL IMPACTS OF WIND GENERATION ON ITS SYSTEM?

A. Yes. We will be preparing such a study as part of our next resource plan, which we will provide to the Commission.

Q. PLEASE RESPOND TO THE CONCERNS RAISED REGARDING THE USE OF OUTSIDE CONSULTANTS AND ATTORNEYS IN THIS CASE.

A. We balance our internal and external resources to ensure appropriate coverage of all regulatory and legal matters. A rate case is one example where we balance internal and external resources to address large fluctuations in work requirements as a case proceeds, and the need to rely on specialized expertise that we do not maintain in-house. This balancing requires the use of outside counsel and consultants for some of the work.

Our internal attorneys and staff work on rate cases, as well as other regulatory filings, including applications for advanced determinations of prudence, service territory matters, and service changes in all of our jurisdictions. We continually review whether it is appropriate to hire additional staff or to rely on outside resources to fill the gaps when needed. Because there can be large fluctuations in workload and individual expertise required in any given matter, such as a general rate case, we have found it makes sense to maintain a baseload resource of staff and supplement with outside resources for large-volume, specialized projects when they occur. Using external resources to supplement ensures that we are not over-staffed for times of lesser work load.

VI. PRESENTATION OF REBUTTAL WITNESSES

Q. PLEASE INTRODUCE THE COMPANY'S REBUTTAL WITNESSES?

A. In addition to my Policy Rebuttal Testimony, the Company sponsors the following witnesses:

- *Anne E. Heuer*, who responds to recommended financial adjustments and sponsors the Company's revision to the overall revenue requirement for the rate case.

- *Ann E. Bulkley,* of Concentric Energy Advisors, who responds to recommendations regarding the appropriate return on equity and capital structure.
- *Timothy J. O'Connor*, who responds to recommended adjustments for our operations and maintenance expenses at Monticello, nuclear retention program and outage amortization.
- *Sharon L. Koenig,* who sponsors testimony on our incentive compensation request.
- *Lisa H. Perkett,* who sponsors testimony on depreciation and remaining lives for all plant and plant-related items, and on nuclear decommissioning costs.
- *Scott B. Brockett,* who provides testimony on the Company's demand allocator methodology.
- *Steven W. Wishart,* who provides testimony on recovery of power purchase agreements in the Fuel Cost Rider.
- *Steven V. Huso*, who responds to recommendations related to rate design.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. We appreciate that there are several areas of general agreement. However, the few areas where there is disagreement are significant in terms of both importance and magnitude. In particular, Staff Consultant's recommended change to our long-standing demand allocation methodology would undermine the Company's ability to recover its prudent costs of service. We believe resolution of the outstanding issues should be based on sound and

established ratemaking principles that are designed to promote just and reasonable rates.

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST TO THE COMMISSION.

A. We respectfully request that the Commission approve our proposed increase of $14.9 million, based on a 2013 test year and a 10.25 percent return on equity.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota Corporation For Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-12-813

AFFIDAVIT OF
Laura McCarten

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

Laura McCarten

Subscribed and sworn to before me, this 7 day of August, 2013.

Notary Public
My Commission Expires: 1-31-2015

CYNTHIA D. HARRINGTON
NOTARY PUBLIC
MINNESOTA
My Commission Expires Jan. 31, 2015

DATE MAILED
Dec 27, 2012

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates — 4220-UR-118

FINAL DECISION

This is the Final Decision concerning the application of Northern States Power Company-Wisconsin (NSPW), doing business as Xcel Energy, for authority to increase Wisconsin retail electric and natural gas rates in 2013.

Final overall rate changes are authorized consisting of a $35,532,000 annual rate increase for Wisconsin retail electric operations, a 6.09 percent increase; and a $2,717,000 annual rate increase for Wisconsin retail natural gas operations, a 2.53 percent increase, for the test year ending December 31, 2013, based on a 10.40 percent return on common equity.

Introduction

On June 1, 2012, NSPW filed for authority to increase its Wisconsin retail electric and natural gas rates on January 1, 2013. NSPW requested an overall increase in annual Wisconsin retail electric revenues of $39.1 million, an increase of 6.7 percent over present revenues; or, in the alternative, $41.7 million, an increase of 7.2 percent over present revenues, depending on the Commission's treatment of cleanup costs for the manufactured gas plant (MGP) site in Ashland, Wisconsin. NSPW also requested an overall increase in annual Wisconsin retail natural gas revenues of $5.3 million, an increase of 4.9 percent; or, in the alternative, $2.7 million, an increase of 2.5 percent over present revenues, depending on the Commission's treatment of MGP clean-up costs. NSPW's proposed natural gas increase request was limited solely to recovery of MGP cleanup costs.

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On July 31, 2012, a prehearing conference was held to determine the issues to be addressed in this docket and to establish a schedule for the hearing. A hearing was held on November 7, 2012, in Madison, to receive technical information and public comments into the record.

The Commission considered this matter at its open meeting on December 14, 2012. The parties, for purposes of review under Wis. Stat. §§ 227.47 and 227.53, are listed in Appendix A. Others who appeared are listed in the Commission's files.

Findings of Fact

1. Presently authorized rates for NSPW's Wisconsin retail electric utility operations will produce operating revenues of $583,411,000 for the test year ending December 31, 2013, which results in an adjusted net operating income of $46,300,000 and an annual revenue deficiency of $35,532,000. Presently authorized electric rates of NSPW are insufficient.

2. For the Wisconsin retail electric utility operations, the estimated rate of return on average net investment rate base of $788,602,000 at current rates for the test year is 5.87 percent, which is inadequate.

3. A reasonable increase in operating revenue for the test year to produce an 8.57 percent return on NSPW's average net investment rate base for Wisconsin retail electric operations is $35,532,000.

4. NSPW's filed electric operating income statement and net investment rate base for the test year, as adjusted for Commission decisions, are reasonable.

5. Presently authorized rates for NSPW's Wisconsin retail natural gas utility operations will produce operating revenues of $107,597,000 for the test year ending December 31, 2013.

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6. It is reasonable to limit the scope of the natural gas rate increase request to the sole issue of MGP clean-up costs.

7. A 2013 total NSP system test year fuel cost of $1,299.17 million is reasonable.

8. A 2013 total NSP system test year fuel rules monitoring level of fuel costs of $1,130.58 million, or $0.02555 per kilowatt-hour (kWh), as shown in Appendix D, is reasonable.

9. It is reasonable to reflect the signed contract for Green Whey Dairy in fuel costs.

10. It is reasonable to require Commission staff, utilities, and interested intervenors to work together early in 2013 to resolve the issue of the treatment of System Support Resources (SSR) costs. It is reasonable to require Commission staff to prepare and send to the Commission a briefing memorandum outlining the positions of the parties and the alternatives the Commission has to address this issue.

11. It is reasonable to update fuel costs to reflect market prices for electricity, natural gas and heating oil as of November 15, 2012.

12. It is reasonable to allow NSPW to use the final monitored fuel costs as determined by the Commission in this docket for NSPW's fuel cost plan for 2013.

13. It is reasonable to monitor all monitored fuel costs using an annual bandwidth of plus or minus 2 percent.

14. It is reasonable to incorporate actual payroll increases given in 2012 for all employees, a 1.7 percent payroll merit increase in 2013 for non-union employees and a 2.5 percent payroll merit increase in 2013 for union employees under contract in the development of test-year payroll expense and related taxes.

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15. It is not reasonable to include the payroll and related costs associated with the annual incentive plan costs in revenue requirements.

16. It is reasonable to include all uncontested Commission staff adjustments to NSPW's filed electric revenue requirements.

17. It is reasonable that the amortization period of the MGP clean-up costs for Ashland be amortized over a ten-year period, that estimates of the 2013 costs for clean-up at the terrestrial site, but not the bay area, be included in the 2013 test-year amortization calculation and resulting revenue requirement, and that the revenue requirement include 3 percent interest on the unamortized balance of the clean-up costs.

18. It is reasonable to continue to assess MGP clean-up costs to gas ratepayers only.

19. NSPW's proposed voluntary energy efficiency programs are reasonable.

20. It is not reasonable to include labor dollars for Account Managers or Community Service Managers/Supervisors in the conservation escrow budget. Funding should be included in non-escrow operation and maintenance (O&M).

21. It is reasonable to include dollars in the conservation escrow budget for the call center staff that are Energy Experts.

22. It is not appropriate to provide conservation escrow treatment for the Farm Rewiring Program. Funding should be included in non-escrow O&M.

23. It is not reasonable to provide conservation escrow treatment for the low-income assistance dollars contributed to the 2005 Wisconsin Act 141 (Act 141) statewide low-income programs. Funding should be included in non-escrow O&M.

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24. The reasonable level of expensed conservation costs recoverable in rates for the 2013 test year is $8,662,412 for electric operations and $3,014,932 for natural gas operations. The level for electric operations consists of the conservation budget of $8,191,041 plus an escrow adjustment of $470,626 to reflect the estimated overspent balance as of January 1, 2013, of $941,252, amortized over two years. The level for natural gas operations remains at $3,014,932, the same as that authorized in rate case docket 4220-UR-117.

25. A long-term range of 50 percent to 55 percent for NSPW's common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

26. An appropriate target level for the test-year average common equity measured on a financial basis is 52.5 percent.

27. It is reasonable to explore further the target level for common equity in NSPW's next rate case.

28. A reasonable estimate of the debt-equivalent of NSPW's off-balance sheet obligations to be imputed into the financial capital structure for the test year is $4,614,306.

29. A reasonable financial capital structure for the test year consists of 52.50 percent equity, 43.96 percent long-term debt, 3.11 percent short-term debt, and 0.43 percent debt equivalence for off-balance sheet obligations.

30. It is reasonable to require NSPW to submit a ten-year financial forecast in its next rate proceeding.

31. It is reasonable to require NSPW to submit in its next rate proceeding, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent.

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32. A reasonable regulatory capital structure for the test year consists of 52.37 percent equity, 44.49 percent long-term debt, and 3.14 percent short-term debt.

33. It is reasonable that NSPW's dividend restriction be based on the financial capital structure in this proceeding.

34. A reasonable interest rate for short-term borrowing through commercial paper is 0.53 percent for the test year.

35. A reasonable cost of the long-term debt issuance in 2012 is the actual yield to maturity of 3.746 percent.

36. A reasonable average embedded cost for long-term debt is 5.71 percent for the test year.

37. The rate of return on utility common stock equity of 10.40 percent established in NSPW's last rate case, docket 4220-UR-117, remains in place as it was not an issue addressed in this proceeding.

38. A reasonable weighted average composite cost of capital is 8.01 percent.

39. The electric revenue allocation and electric rates shown in Appendix B are reasonable.

40. The structure of the NSPW's voluntary green pricing program, marketed under the Windsource trademark, is reasonable.

41. It is reasonable to require NSPW to modify materials used to market the Windsource program in Wisconsin to accurately reflect what the program offers to participating customers, given the constraints of the Interchange Agreement, within 60 days of the effective date of this Final Decision.

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42. It is reasonable for NSPW to continue to provide only a kilowatt (kW) block-based participation option for the Windsource program.

43. It is reasonable for the final form tariffs authorized in this proceeding to include an update to the Pg-1 tariff so as to preserve the grandfathering treatment for pre-January 1, 2012, vintage customers until a future base rate case proceeding.

44. It is reasonable to allocate the MGP allowance to the natural gas service rate classes on a net investment rate base methodology.

45. It is reasonable to authorize rates for natural gas service for NSPW as shown in Appendix C.

Conclusions of Law

The Commission has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, and 196.395 and Wis. Admin. Code chs. PSC 113, 116, 134, and 137 to enter a Final Decision authorizing NSPW to place in effect the rates and rules for electric and natural gas utility service set forth in Appendices B and C, and the fuel cost treatment set forth in Appendix D, subject to the conditions specified in this Final Decision. The rates and rules for electric and natural gas utility service in Appendices B and C are reasonable and appropriate as a matter of law.

Opinion

Applicant and its Business

NSPW is a public utility, as defined in Wis. Stat. § 196.01(5), operating as an electric and natural gas utility in Wisconsin. NSPW is engaged in providing electric service to approximately 251,000 retail customers in northwestern Wisconsin and the western tip of the Upper Peninsula of

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Michigan. In addition, NSPW provides natural gas service to approximately 107,000 customers in Wisconsin and Michigan. NSPW is a wholly-owned subsidiary of Xcel Energy Inc. (Xcel Energy).

Revenue Requirement

NSPW, intervenors, and Commission staff presented testimony and exhibits at the hearing concerning estimates of NSPW's 2013 electric and natural gas utility operations. NSPW filed its natural gas case showing an estimated deficiency of $7.0 million, of which $5.3 million was associated with MGP cleanup costs. The company indicated it would limit its natural gas increase request to $5.3 million for MGP cleanup costs and forego the remaining $1.7 million. No parties objected to the proposal to limit the natural gas request to this single issue. Commission staff reviewed the gas utility forecasted test-year operations to determine that a rate decrease would not be needed, exclusive of NSPW's requested recovery of MGP clean-up costs. Commission staff's review resulted in no proposed adjustments to natural gas sales revenues or rate base and a reduction to operating expenses of $425,000 on a total company basis exclusive of any adjustment to MGP clean-up cost expenses. This adjustment grossed up for income taxes equates to a reduction to the natural gas deficiency of about $710,000, which is still less than the $1.7 million of which the company indicated it will forego requesting recovery. The Commission therefore finds it is reasonable to limit the scope of the natural gas rate increase request to the sole issue of MGP clean-up costs. Significant issues pertaining to electric operations and MGP clean-up costs are presented below.

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Electric Fuel Costs

A reasonable test-year level of monitored fuel costs is $1,130.58 million, which reflects the cost of fuel as defined by Wis. Admin. Code § PSC 116.02. The test-year monitored fuel costs divided by the test-year estimate of native energy requirements of 44,244,951 megawatt-hours (MWh) results in an average net monitored fuel cost per MWh of $25.55. Appendix D shows the monthly fuel costs to be used for monitoring purposes. The total fuel costs are based on indices for electric, natural gas, and heating oil prices as of November 15, 2012. It is reasonable to monitor NSP system's fuel costs using a plus or minus 2 percent bandwidth, as provided in Wis. Admin. Code § PSC 116.06(3).

System Support Resources

NSPW requested that the Commission determine, in this proceeding, how SSR charges from the Midwest Independent Transmission System Operator, Inc. (MISO), will be treated in subsequent rate proceedings. MISO may assess SSR charges to NSPW if MISO requires another market participant to run a facility to support the transmission system even if the market participant desires to retire that facility. NSPW requested a determination that SSR charges be treated as a monitored fuel cost. SSR charges have never been assessed by MISO, but are expected to be assessed in the future. The Commission finds that there is not a sufficient basis, at this time, to determine how SSR charges are to be treated.

The Commission finds it reasonable to require Commission staff, investor-owned utilities and interested intervenors to work together after January 1, 2013, to address the SSR issue and for Commission staff to prepare a briefing memorandum outlining the parties' positions and alternatives for the Commission to consider.

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2013 Fuel Cost Plan

NSPW requested that the Commission-authorized monitored fuel costs for 2013 be designated as the NSPW 2013 Fuel Cost Plan for purposes of Wis. Admin. Code § PSC 116.06(3). The Commission finds it reasonable to allow NSPW to use the Commission-authorized monitored fuel costs for NSPW's 2013 Fuel Cost Plan.

Annual Merit Pay Factors

NSPW's filed payroll forecast for the test-year included annual merit wage increases in 2012 of 2.0 percent for non-bargaining non-exempt employees, no increase for non-bargaining exempt employees, and 2.75 percent for all bargaining employees. NSPW's filing included wage increases in 2013 of 2.5 percent for all non-bargaining employees and 3.25 percent for all bargaining employees. Commission staff's forecasted payroll incorporated the 2012 actual wage increases as filed by NSPW and included 2013 wage increases of 3.25 percent for bargaining employees under contract and 1.7 percent for the non-bargaining employees based on inflation. The use of 1.7 percent for the non-bargaining employees resulted in a staff adjustment reducing test-year payroll O&M expense by $104,000.

The Commission finds that Commission staff's use of 2012 actual wage increases of 2.0 percent for non-bargaining non-exempt employees, no increase for non-bargaining exempt employees, 2.75 percent for all bargaining employees as well as forecasted 2013 wage increases of 3.25 percent for bargaining employees under contract and 1.7 percent for the non-bargaining employees based on inflation is reasonable in the development of test year payroll expense and related taxes. Incorporating these factors appropriately reflects the current economic conditions in Wisconsin.

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Annual Incentive Plan Compensation

Xcel Energy must meet certain financial and operational goals in order for the current Annual Incentive Plan (AIP) to pay out incentive awards for the year to its non-bargaining employees. Incentive payments are in addition to annual base wage increases. According to the overall company performance component, which establishes the company's ability to pay, certain targeted earnings per share goals must be achieved by the company before the program will pay any awards. In addition, the final funding percentage will be determined by the Chief Executive Officer.

Commission staff reduced NSPW's 2013 payroll O&M expense for electric operations by $2,136,000 to eliminate the costs associated with the AIP. Elimination of costs associated with the incentive pay plan is consistent with the decisions made in the last round of rate cases for other large investor-owned utilities in which the costs associated with incentive pay plans were not included in revenue requirements.

NSPW maintains that the Commission should allow recovery of all or at least a portion of its AIP costs because it is important to compensate employees at a level that is comparable to the relevant market in order to ensure safe and reliable service at a reasonable cost. Because 97 percent of the goals relate to operational excellence, NSPW believes that 97 percent of the AIP costs should be recoverable.

In previous rate cases in which incentive adjustments have been contested, the Commission has excluded incentive plans from revenue requirement when such plans are based primarily on financial results (*e.g.*, prevailing stock price, earnings per share, or achieving a specified net income or return on investments, etc.). The Commission has determined that such

plans most directly benefit the utility shareholders, and therefore the costs of the plans should not be borne by ratepayers. While the company has modified some of the elements of the AIP, it has not eliminated the financial performance of the company as one of the payout metrics. Specifically, earnings per share targets must be met before AIP funds can be paid, making it a system of compensation that occurs if and only if the company meets financial benchmarks.

In addition, while the operational goals of the AIP may benefit ratepayers, they also are intertwined in benefiting shareholders, making it difficult to separate which group benefits more.

Consistent with the other large-investor-owned utilities in Wisconsin, in which the costs associated with incentive pay plans are not included in revenue requirements, because of the continued tie to financial performance, the Commission finds it appropriate to exclude these AIP costs from revenue requirement.

U.S. Department of Energy Settlement Proceeds

In the last rate case proceeding in docket 4220-UR-117, the Commission authorized a one-time credit on customer bills for the first payment received in a settlement that was reached with the U.S. Department of Energy (DOE) relating to the partial breach of its contract to take spent nuclear fuel from Northern States Power Company-Minnesota's (NSPM) Monticello and Prairie Island nuclear generating plants. The settlement provides a mechanism for the NSP companies to recover nuclear spent fuel storage damages from January 1, 2009, through December 31, 2013. In 2012, the company received the second and third payments and expects to receive two additional payments at the end of 2013 and 2014, respectively. In this rate proceeding, NSPW proposed that the second and third payments received in 2012, including interest from the separate interest bearing account in which the funds are held, be returned to

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ratepayers by offsetting the 2013 electric revenue deficiency. The company proposed to allocate the settlement payments to the jurisdictions and customer classes in the same manner as the first payment, as approved by the Commission in docket 4220-UR-117. The proceeds from the second and third payments net of outside legal costs incurred in pursuit of the settlement included as a reduction to the 2013 electric revenue deficiency is $5,358,101 on a Wisconsin retail jurisdictional basis, and is for damages through December 31, 2011.

The Commission finds it reasonable to include the second and third payments from the DOE settlement net of outside legal costs incurred in pursuit of the settlement in the final electric revenue requirement approved in this proceeding. It is appropriate for the company to track, in a regulatory asset or liability account, the actual payments received, plus interest, less any unrecovered outside legal fees, and add or subtract the difference from the credit assumed in this case in future cases. It is appropriate for interest accrual on the sum of the second and third payments of $5,358,101 to terminate with the beginning of the 2013 test year.

Ashland Manufactured Gas Plant Site Cleanup

NSPW requested that the Commission include costs related to the clean-up of a former MGP site in Ashland in the 2013 test year. The company proposed that 2013 rates include estimates of expenses for the terrestrial and bay area clean-up. NSPW also requested that the Commission make an exception from its policy on the rate recovery of MGP clean-up costs. Specifically, NSPW requested that the amortization period be stretched from four or six years to ten years, that recovery begin immediately for expected costs rather than deferred to a later year, and that the company's imbedded cost of debt for the unamortized clean-up expenses be included in rates. NSPW also proposed an alternative that involved allocating the revenue requirement

impact to both electric and gas utilities instead of the current practice of allocating MGP costs to just the gas utility. Other intervenors proposed variations on NSPW's proposal.

The Commission must balance many concerns when it addresses rate recovery of MGP clean-up costs. In this case, the magnitude of the clean-up cost relative to the size of the customer base is significant. Applying the current policy to this particular site may cause financial harm to the company and cause significant rate shock to the utility's ratepayers. The Commission finds that making a limited exception to its policy on rate recovery of MGP clean-up costs is reasonable in this case. NSPW's request, as proposed, however, does not appropriately balance the concerns of the ratepayers against the financial health of the company.

It is reasonable that the net clean-up costs of the MGP clean-up for this site be amortized over a ten-year period, that estimates of the 2013 costs for clean-up at the terrestrial site, but not the bay area, be included in the 2013 test-year revenue requirement, and that the rates include 3 percent interest on the average balance of the unamortized clean-up costs. Lengthening the amortization period will help to mitigate the rate shock of large rate increases for this clean-up, while allowing immediate recovery of estimated expenses; and allowing the utility to recover some of the carrying costs of the clean-up will mitigate potential financial harm to NSPW.

Based upon the record in this proceeding, the Commission finds that it is not reasonable to deviate from the Commission's past practice of allocating MGP clean-up costs to just the gas utility. However, the Commission recognizes that neither the gas nor the electric utilities are the cause of this historic MGP liability. Accordingly, the Commission finds that is reasonable to review the practice of allocating the Ashland MGP clean-up costs as gas utility costs in the next rate proceeding to examine more fully whether such costs could or should be allocated to the

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electric utility, if appropriate, and to determine whether these clean-up costs should be included in the Interchange Agreement.

Energy Efficiency and Conservation Activities

The Commission's *Order*, dated August 30, 2011 (PSC REF#: 152745), conditionally approved NSPW's 2012 and 2013 voluntary utility energy efficiency programs. One of the requirements of the Order was to continue to work with the Commission and Focus on Energy staff to ensure NSPW offerings remain consistent with Focus on Energy offerings. The Commission determines that to date, the conditions of the *Order* have been met. NSPW's voluntary energy efficiency programs are reasonable, and it is appropriate to include their funding in the conservation escrow budget.

Conservation Budget and Escrow Adjustment

NSPW proposed a 2013 conservation escrow budget of $12,188,374, with $9,355,073 allocated to electric operations and $2,833,301 allocated to natural gas operations. Commission staff's analysis of conservation expenses included forecasting the over-spent balance in the conservation escrow at the beginning of the test year, reviewing the proposed test-year conservation expenditures, and reviewing the company's forecasted amortization expense associated with previously escrowed demand-side management expenditures. The reasonable levels of expensed conservation costs included in revenue requirement for the 2013 test year are $8,662,412 for electric operations and $3,014,932 for gas operations. The level for electric operations consists of a conservation budget of $8,191,786, plus an escrow adjustment of $470,626 to reflect the estimated overspent balance as of January 1, 2013, of $941,252, amortized over two years. Since the current natural gas rate case proceeding is limited to the

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single issue of MGP costs, the level of natural gas related expensed conservation costs included in revenue requirement for the 2013 test year remains at $3,014,932, the same as that authorized in rate case docket 4220-UR-117. Any adjustments to the conservation escrow balance for the natural gas operations will be addressed in a future rate proceeding.

Several adjustments were made to NSPW's proposed conservation escrow budget. In docket 5-BU-105 (PSC REF#: 168310), the Commission provided a definition of customer service conservation activities and services for which conservation escrow treatment is appropriate. Based on this definition, the Commission determines it appropriate to remove $114,000, $84,000 from electric operations and $29,640 from natural gas operations, for Account Managers. These NSPW employees devote less than 51 percent of their time to energy efficiency. Likewise, $156,912 is removed from the conservation escrow budget, $116,115 from electric operations and $40,797 from natural gas operations, for Community Service Managers/Supervisors because less than 51 percent of their time is devoted to energy efficiency. The Commission also finds that NSPW's Farm Rewiring Program does not meet the definition of customer service conservation because the primary purpose of this program is to assist customers in obtaining safe and reliable farm wiring and reduce levels of stray voltage, not energy efficiency. To reflect this, $752,129 is removed from the electric conservation escrow budget. Finally, low-income assistance dollars are removed from the conservation escrow, $210,683 from electric operations and $74,032 from natural gas operations. NSPW is required to contribute these low-income assistance dollars to Act 141 programs that provide both weatherization and bill payment assistance to low income customers. Because the program provides for bill payment assistance in addition to weatherization, and because the contribution

level remains the same every year, its funding is not appropriate for conservation escrow treatment.

NSPW originally indicated that it has about 400 call center staff that devote about 6 percent of their time to energy efficiency. In response to a Commission staff data request, NSPW clarified that in 2011 it developed an Energy Experts team. This Energy Experts team consists of call center staff that is specially trained to provide residential customers detailed energy efficiency information. NSPW indicates that these Energy Experts devote 100 percent of their time to energy efficiency issues. The Commission finds is reasonable to allow conservation escrow treatment for the Energy Expert staff.

Summary of Income Statement

In addition to the specific items discussed in this Final Decision, all other uncontested Commission staff adjustments to NSPW's filed electric operating income statement are appropriate. Accordingly, the estimated Wisconsin retail electric utility operating income statement at present rates for the 2013 test year, which is considered reasonable for the purpose of determining the electric revenue requirement in this proceeding, is as follows:

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	Retail Electric (000's)
Operating Revenues	
Sales	$583,411
Other Operating Revenues	1,928
Total Operating Revenues	$585,339
Operating Expenses	
Production Expense	$367,614
Transmission Expenses	(8,819)
Distribution Expenses	21,683
Customer Accounts Expenses	8,913
Customer Service & Sales Expenses	11,888
Administrative & General Expenses	36,481
Total Operation & Maintenance Expenses	$437,760
Depreciation Expense	63,503
Amortization Expense	(125)
Taxes Other Than Income Taxes	21,856
State Income Taxes	1,600
Federal Income Taxes	4,742
Deferred Income Taxes – Net	10,379
Investment Tax Credits Restored	(637)
Total Operating Expenses	$539,078
Chippewa Flambeau Improvement Company Income	39
Net Operating Income	$ 46,300

Average Net Investment Rate Base

Allowance for Funds Used During Construction

NSPW requested to accrue excess Allowances for Funds Used During Construction (AFUDC) on all Construction Work in Progress (CWIP), which is consistent with the accrual methodology used by the other Wisconsin utilities.

Consistent with the calculation of AFUDC for other Wisconsin utilities, it is appropriate to permit NSPW to accrue AFUDC on all CWIP at the weighted average cost of capital instead of at the Federal Energy Regulatory Commission (FERC) AFUDC rate. This rate treatment allows NSPW to recover the full carrying costs from retail customers and is appropriate as long

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as the accrual of excess AFUDC above the FERC-calculated AFUDC does not flow though the Interchange Agreement, either from or to NSPW.

Summary of Average Net Investment Rate Bases

The estimated Wisconsin retail electric utility average net investment rate base for the 2013 test year, which is considered reasonable for the purpose of determining the electric revenue requirement in this proceeding, is as follows:

	Retail Electric (000's)
Utility Plant in Service	$1,911,536
Less: Accumulated Reserve for Depreciation	895,913
Net Utility Plant	$1,015,623
Add: Fuel Inventory	9,701
Materials and Supplies	4,256
Investments in Associated Companies	537
Less: Accumulated Deferred Income Taxes	228,067
Customer Advances – net of tax	13,448
Average Net Investment Rate Base	$788,602

***Pro Forma* Rate of Return**

The adjusted net operating income at present rates for purposes of this proceeding for the test year ending December 31, 2013, results in a rate of return on average net investment rate base of 5.87 percent for Wisconsin retail electric utility operations.

Financial Capital Structure and Dividend Restriction

A reasonable long-term range for NSPW's common equity ratio, on a financial basis, is 50 to 55 percent common equity. The exact level of the common equity ratio within that range should not be static, but rather should dynamically reflect the circumstances facing NSPW at a given time. An appropriate target level for the test-year average common equity measured on a

financial basis is 52.50 percent. This target level shall be further examined in NSPW's next rate proceeding.

In calculating capital structures, on a financial basis, this Commission has imputed debt associated with obligations not reported on balance sheets. Detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent is necessary for the Commission to make an independent judgment regarding NSPW's financial capital structure. This information is most readily available from NSPW and must be provided as part of its next rate case application. The information shall include, at a minimum, the following information:

1. the minimum annual lease and purchased power agreement obligations;
2. the method of calculation, along with the calculated amount of the debt equivalent; and
3. supporting documentation, including all reports, correspondence, and any other justification that clearly established Standard & Poor's (S&P) and other major credit rating agencies' determination of the off-balance sheet debt equivalent to the extent available, and publicly available documentations when S&P and other major credit rating agencies' documentation is not available.

For the test year, the Commission finds that it is reasonable to impute $4,614,306 of debt equivalent associated with NSPW's off-balance sheet obligations. Incorporating the above off-balance sheet debt equivalents and other Commission determinations, NSPW's financial capital structure for the test year will consist of 52.50 percent equity, 43.96 percent long-term debt, 3.11 percent short-term debt, and 0.43 percent debt equivalence for off-balance sheet obligations.

Assessing the reasonableness of NSPW's capital structure depends upon three important principles. First, capital structure decisions must be based on NSPW's needs, not on the needs of the non-utility operations of the holding company. Second, the capital structure should provide

adequate flexibility to NSPW and to the Commission to allow proper utility investment now and in the future. Third, the dividend policy of NSPW should be similar to typical electric utility dividend practices as long as NSPW is below the estimated test-year common equity ratio.

In previous dockets, the Commission recognized the need to protect ratepayers and to ensure that utility needs are placed before non-utility needs in capital structure and dividend policy choices. Consequently, NSPW may not pay dividends, including pass-through of subsidiary dividends, in excess of the $31,189,664 forecasted in this case, if its actual average common equity ratio, on a financial basis, is or will fall below the test-year authorized level of 52.50 percent.

Ten-Year Financial Forecast

NSPW's ten-year financial forecast is useful to the Commission and shall be submitted in future rate cases. The ten-year forecast can be combined with other business risk information to assess capital structure needs and rate of return requirements.

Regulatory Capital Structure and Cost of Capital

As in the previous rate case docket, Commission staff deducted from the utility's equity the non-utility investments or other equity adjustments on which ratepayers should not pay an equity return for ratemaking purposes. Consequently, a reasonable utility rate making capital structure for the purpose of establishing just and reasonable rates for the test year consist of 52.37 percent equity, 44.49 percent long-term debt, and 3.14 percent short-term debt.

Short-Term Debt

NSPW's test-year capital structure contains approximately $33,144,000 of short-term debt. The interest rate associated with the short-term indebtedness is the commercial paper rate.

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A reasonable estimate of the average cost of short-term commercial paper for NSPW for the test year is 0.53 percent. This forecast is based on the average of test year commercial paper rate estimates provided by the *Blue Chip Financial Forecasts* newsletter, adjusted by 33 basis points to reflect the spread between A-1/P-1 and A-2/P-2 rated commercial paper yields. This is a reasonable and objective method of determining short-term debt costs.

Long-Term Debt

NSPW's test-year long-term debt included an issuance of 30-year debt aggregating $100,000,000 principal amount forecasted for issuance in 2012. On October 10, 2012, NSPW issued the debt with a coupon rate of 3.7 percent and a yield to maturity of 3.746 percent. A reasonable interest rate for the debt is 3.746 percent. The resulting embedded cost of long-term debt is 5.71 percent for the test year.

Return on Common Equity

The Commission previously determined, in docket 4220-UR-117, a 10.40 percent return on utility common equity for NSPW to be reasonable. As rate of return on common equity was not an issue addressed in this proceeding, the Commission determines that this return on equity shall remain in place until addressed in a subsequent rate case proceeding. Using a 10.40 percent return on equity, NSPW's average utility capitalization ratios, annual cost rates, and the composite cost of capital rate considered reasonable and just for setting rates for the test year are as follows:

	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$552,337	52.37%	10.40%	5.45%
Long-Term Debt	469,183	44.49%	5.71%	2.54%
Short-Term Debt	33,144	3.14%	0.53%	0.02%
Total Utility Capital	$1,054,664	100.00%		8.01%

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The weighted cost of capital of 8.01 percent is reasonable for NSPW for the test year. It generates an economic cost of capital of 11.66 percent and a pre-tax interest coverage ratio of 4.56 times on the regulatory capital structure.

Rate of Return on Rate Base

The 8.01 percent composite cost of capital must be translated into a rate of return that can then be applied to the average net investment rate base and used to compute the overall return requirement in dollars. The estimate of NSPW's average net investment rate base plus CWIP for the test year is 93.49 percent of capital applicable primarily to utility operations plus deferred investment tax credit. This estimate reflects all appropriate Commission adjustments, and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to the average net investment rate base. Accordingly, the rate of return on average Wisconsin retail electric utility net investment rate base, which is reasonable for the purpose of determining just and reasonable rates in this proceeding, is as follows:

	Retail Electric
Cost of Capital	8.01%
Average Percent of Utility Net Investment Rate Base Plus CWIP to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	93.49%
Percent Return Requirement Applicable to Net Investment Rate Base	8.57%

Revenue Requirement

On the basis of the findings in this Final Decision, a $35,532,000 increase in Wisconsin retail electric utility revenues is reasonable for the purpose of determining reasonable and just rates in this proceeding and is computed as follows:

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	Retail Electric (000's)
Pro Forma Return on Average Net Investment Rate Base at Present Rates	5.87%
Required Return on Average net Investment Rate Base	8.57%
Earnings Deficiency as a Percent of Average Net Investment Rate Base	2.70%
Average Net Investment Rate Base (000's)	$788,602
Amount of Earnings Deficiency on Average Net Investment Rate Base (000's)	$21,283
Revenue Deficiency to Provide for Earnings Deficiency Plus Federal and State Income Taxes (000's)	$35,532

Electric Cost-of-Service

Both NSPW and Commission staff submitted the results of several cost-of-service studies. The two major electric cost-of-service issues contested in this proceeding are the allocation of production capacity costs and the allocation of distribution system costs. The allocation of these costs significantly affects the cost responsibility for providing electric service.

The Commission routinely considers electric cost-of-service studies as a guide along with other factors in its decisions regarding the allocation of revenue responsibility. In this proceeding, the Commission determines that it is reasonable to continue its past practice of relying on the results of more than one cost-of-service study, as well as other factors for determining an appropriate allocation of the revenue responsibility.

Electric Revenue Allocation

Allocating the increase in NSPW's revenue requirement for the provision of electric service was also a significant contested issue in this proceeding. Both NSPW and Commission

staff submitted a comprehensive allocation of the proposed electric revenue increase. NSPW proposed a very narrow range of increases within 0.2 percent of its overall 6.7 percent electric increase for all of the major customer classes. Commission staff's alternative was similar, but included a slightly wider range of increase within 0.5 percent of its overall 5.65 percent electric increase, except the medium commercial and industrial classes get approximately 0.9 percent below the overall average.

The Commission routinely considers factors other than cost-of-service studies such as bill impacts, existing relationships between rate classes, and the overall magnitude of the revenue change, in its decisions regarding the allocation of revenue responsibility. The results of the cost studies introduced in this case support various revenue allocations. The Commission determines that a reasonable allocation of the electric revenue increase is a 7.2 percent increase for the residential classes, a 5.8 percent increase for the medium commercial and industrial classes, a 5.0 percent increase for the large commercial and industrial classes and a 6.8 percent increase for the lighting and miscellaneous classes, as adjusted for the final revenue requirement.

Commissioner Callisto dissents.

Electric Rate Design

NSPW initially proposed a rate design that included increases in energy charges, demand charges and lighting charges, for the various customer classes. NSPW initially proposed similar percentage increases for both the energy and demand charges. That proposal also increases the voltage discounts for the transmission level customers and increases high load factor credits. Commission staff's alternative rate design included similar percentage increases for both the energy charges and demand charges, but included lower increases in the high load factor credit and no increase for the voltage discounts.

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Wisconsin Industrial Energy Group (WIEG) argued that the rate design for the Cg-9, Cp-1 and the RTP-1 classes should include greater than average increases for the demand charges and less than average increases for the energy charges. WIEG also supported NSPW's proposal to increase the voltage discounts for the transmission level customers and increase high load factor credits. NSPW responded by introducing a compromise proposal that included demand charge increases half way between WIEG's proposal and the Commission staff's proposal and energy charge increases that are lower than the average increase percentage for these classes. This proposal also included the increases to the transmission voltage discounts and increases to the high load factor credits that were part of NSPW's initial proposal. The Commission determines that NSPW's compromise proposal for changing the demand and energy charges affecting all of the commercial and industrial customers, and its proposal to increase the transmission voltage discounts and high load factor energy charge credits affecting the large commercial and industrial customers, are reasonable.

Commissioner Callisto dissents on the authorization of the higher transmission voltage discounts.

The Commission also finds NSPW's electric rate design and the changes in energy and lighting charges for the residential, small commercial, lighting and miscellaneous classes, adjusted for the final revenue requirement, are reasonable. The authorized electric rates are shown in Appendix B.

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Act 141 in Electric Rates

Act 141 contains a limitation on how much the "large energy customers"[1] can pay in rates for these Act 141 costs. Act 141 requires the large energy customer "capped rates" increase each year by the lesser of the prior year Consumer Price Index (CPI) or the utility's change in revenue from the prior year. Both NSPW and Commission staff agree that the increase in the "capped rates" should be 3.2 percent for 2013, which reflects inflation based on the prior year CPI. Both NSPW and Commission staff proposed rate factors representing the Act 141 costs in electric rates for the non-large energy customers that are essentially the same except for differences between NSPW's and Commission staff's electric sales forecast and a calculation error in the inflation rate NSPW initial used.

The correct reflection of the capped Act 141 costs in the RTP-1 rates was a rate issue that was controversial, but the record was somewhat unclear. NSPW filed a rate and revenue analysis in Ex.-NSPW-Dahl-2 that did not show an explicit amount for the capped Act 141 costs in the RTP-1 rates. Under this approach, it is assumed that the Act 141 costs are in the based rates for the RTP-1 class. Commission staff filed a rate and revenue analysis in Ex.-PSC-Albrecht-2r that included an explicit amount for Act 141 costs that the RTP-1 rate class is required to pay under Wisconsin Statutes. This was a change from how it was handled in NSPW's last rate case. WIEG argued that NSPW's approach was correct. Determining the correct approach on this issue is difficult based upon the record in this case. This issue should be fully vetted in NSPW's next rate case. It is reasonable to maintain the status quo and accept

[1] A "large energy customer" is defined as a customer whose facility consumes at least 1,000 kilowatts of electricity per month or at least 10,000 decatherms of natural gas per month, and who is billed at least $60,000 in a month for electric and gas services. All of the utility billing accounts of a company are considered to determine if the company qualifies as a large energy customer. A company that qualifies will have all of its accounts treated as a large energy customer for billing purposes, despite the accounts being served under different tariffs.

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NSPW's approach of not showing any explicit capped Act 141 costs in the rate and revenue analysis for the RTP-1 class.

Windsource Program

Order Point 33 of the *Final Decision* in docket 4220-UR-117, stated that "a full analysis shall be required in NSPW's next rate case on the issue of the company's Windsource voluntary green pricing program." During that proceeding, the Commission expressed concerns regarding the structure and pricing of the Windsource program due to the way in which renewable energy is treated under the Interchange Agreement.

Typically, when utility customers elect to participate in green energy pricing programs, the utility purchases more renewable energy than it is otherwise required to purchase. However, because the Interchange Agreement already requires NSPW to purchase more renewable energy than is required to comply with Wisconsin's renewable portfolio standard, a customer's participation in the Windsource program does not lead to a greater amount of renewable energy on the NSPW system than would have existed otherwise. NSPW retires Renewable Energy Credits not used for compliance with Wisconsin's renewable portfolio standard in order to satisfy renewable energy purchases through Windsource.

The Commission finds the overall structure of NSPW's Windsource program to be reasonable. While NSPW does not purchase additional renewable energy as a direct result of a person signing up for Windsource, the program still offers value to customers seeking ways in which to "green" their energy consumption. However, due to the potential for customer confusion, NSPW shall modify materials used to market the Windsource program in Wisconsin

to accurately reflect what the program offers to participating customers, given the constraints of the Interchange Agreement, within 60 days of the effective date of this Final Decision.

Commission staff also proposed that NSPW modify Windsource to allow customers the option of buying a percentage of their energy from the program. NSPW believes that this change to the program would be cost prohibitive. Given the information available in the record, the Commission finds it reasonable for NSPW to continue to provide only a kW block-based participation option for the Windsource program. However, NSPW shall provide in its next base rate case, additional information regarding the billing system costs the company claims would be associated with providing a percentage-based participation option for the Windsource program.

Net Metering

NSPW did not propose any changes to its Pg-1 net metering tariff. Based on the understanding that the company wished to leave the Pg-1 net energy billing tariff as is, and continue grandfathering pre-January 1, 2012, vintage customers until a future proceeding, Commission staff proposed that final form tariffs authorized in this proceeding should include an update to the Pg-1 tariff so as to preserve the grandfathering treatment for pre-January 1, 2012, vintage customers until a future base rate case proceeding. The Commission finds Commission staff's proposed treatment of the Pg-1 tariff to be reasonable.

Electric Tariff Changes

NSPW proposed changes to its electric Distribution Extension Allowances that are shown in Ex.-NSPW-Marx-1, Schedule 6. There were no objections to these changes. The distribution extension allowances are part of NSPW's electric rule and regulation tariffs. The Commission

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finds it reasonable to approve these proposed changes to NSPW's electric rule and regulation tariffs.

NATURAL GAS COST-OF-SERVICE STUDIES AND RATES

Natural Gas Cost-of-Service Studies

The natural gas rate increase will provide for the allowed incremental MGP costs of $2,717,362. This singular cost allowance did not necessitate a cost-of-service analysis of NSPW's overall costs of providing natural gas service. For purposes of this proceeding, the costs allocation and rate recovery was limited to MGP costs. Several cost allocation methodologies were identified and considered appropriate; however, the Commission determines that final rates for natural gas service shall be based on the net investment rate base cost allocation methodology.

Revenue Recovery Adequacy of Service Class Rates

Overall, the rates authorized for NSPW in Appendix C of this Final Decision will provide for the incremental cost recovery of the allowed MGP costs of $2,717,362. This represents an increase of 6.42 percent in margin rates and an increase of 2.53 percent in total natural gas sales revenues. Margin rates exclude natural gas costs.

Authorized rates as set forth in Appendix C include a rate "adjustment" over present rates that were determined on a volumetric unit basis given estimated 2013 test-year sales and the MGP cost allocations as discussed above. Summaries of the rate impacts on a service rate class are shown in Appendix C.

As shown in Appendix C, the authorized natural gas rates result in a range of increases in the charges to the various service rate classes. The percentage rate decrease to any individual

customer will not necessarily equal the overall percentage decrease to the associated service rate class, but will depend on the specific usage level of the customer.

Appendix C also shows some typical natural gas bills for residential service, comparing existing rates with new rates, including the cost of natural gas.

Order

1. This Final Decision takes effect one day after the date of mailing.

2. The authorized rate increases and tariff provisions that restrict the terms of service may take effect January 1, 2013, provided that the utility files these rates and tariff provisions with the Commission and places them in all of the utility's offices and pay stations by that date. If these rate increases and tariff provisions are not filed with the Commission and placed in all offices and pay stations by that date, they take effect on the date they are filed with the Commission and placed in all offices and pay stations.

3. NSPW may revise its existing rates and tariff provisions for electric and natural gas utility service, substituting the rate increases and tariff provisions that restrict the terms of service, as shown in Appendices B and C. These changes shall be in effect until the Commission issues an order establishing new rates and tariff provisions.

4. The electric fuel costs in Appendix D shall be used for monitoring of the NSP system's 2013 fuel costs, pursuant to Wis. Admin. Code § PSC 116.06(3).

5. NSPW shall not include labor dollars in the conservation escrow budget for Account Managers or Community Service Managers/Supervisors.

6. The Farm Rewiring Program shall not receive escrow treatment.

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7. Low-income assistance dollars required by Act 141 to be contributed to statewide low-income programs shall not receive escrow treatment.

8. NSPW shall record annual conservation accrual amounts of $8,662,412 for electric operations and $3,014,932 for natural gas operations. The level for electric operations consists of the conservation budget of $8,191,041 plus an escrow adjustment of $470,626 to reflect the estimated overspent balance as of January 1, 2013, of $941,252, amortized over two years. The level for natural gas operations remains at $3,014,932, the same as that authorized in rate case docket 4220-UR-117.

9. NSPW shall maintain 50 to 55 percent common equity on a financial basis in its capital structure.

10. The appropriate target level for NSPW's common equity shall be further explored in the company's next rate case.

11. NSPW shall submit a ten-year financial forecast in its next rate case.

12. NSPW shall submit, in its next rate case application, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at a minimum: (1) the minimum annual lease and purchase power agreement obligations; (2) the method of calculation, along with the calculated amount of the debt equivalent; and (3) supporting documentation, including all reports, correspondence and any other justification that clearly established S&P's and other major credit rating agencies' determination of the off-balance sheet debt equivalent, to the extent available, and publicly available documentation when S&P and other major credit rating agencies' documentation is not available.

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13. NSPW shall not pay dividends, including pass-through of subsidiary dividends, in excess of $31,189,664, if its actual average common equity ratio, on a financial basis, is or will fall below the test year authorized level of 52.50 percent.

14. NSPW shall modify materials used to market the Windsource program in Wisconsin so as to accurately reflect what the program offers to participating customers, given the constraints of the Interchange Agreement, within 60 days of the effective date of this Final Decision.

15. In its next base rate case, NSPW shall provide additional information regarding the billing system costs the company claims would be associated with providing a percentage-based participation option for the Windsource program.

16. Jurisdiction is retained.

Dissent and Concurrence

Commissioner Callisto dissents in part, concurs, and writes separately (attached).

Dated at Madison, Wisconsin, this 27th day of December, 2012.

By the Commission:

Sandra J. Paske
Secretary to the Commission

SJP:CCS:cmk:DL:00611941

See attached Notice of Rights

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PUBLIC SERVICE COMMISSION OF WISCONSIN
610 North Whitney Way
P.O. Box 7854
Madison, Wisconsin 53707-7854

NOTICE OF RIGHTS FOR REHEARING OR JUDICIAL REVIEW, THE TIMES ALLOWED FOR EACH, AND THE IDENTIFICATION OF THE PARTY TO BE NAMED AS RESPONDENT

The following notice is served on you as part of the Commission's written decision. This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

PETITION FOR REHEARING

If this decision is an order following a contested case proceeding as defined in Wis. Stat. § 227.01(3), a person aggrieved by the decision has a right to petition the Commission for rehearing within 20 days of mailing of this decision, as provided in Wis. Stat. § 227.49. The mailing date is shown on the first page. If there is no date on the first page, the date of mailing is shown immediately above the signature line. The petition for rehearing must be filed with the Public Service Commission of Wisconsin and served on the parties. An appeal of this decision may also be taken directly to circuit court through the filing of a petition for judicial review. It is not necessary to first petition for rehearing.

PETITION FOR JUDICIAL REVIEW

A person aggrieved by this decision has a right to petition for judicial review as provided in Wis. Stat. § 227.53. In a contested case, the petition must be filed in circuit court and served upon the Public Service Commission of Wisconsin within 30 days of mailing of this decision if there has been no petition for rehearing. If a timely petition for rehearing has been filed, the petition for judicial review must be filed within 30 days of mailing of the order finally disposing of the petition for rehearing, or within 30 days after the final disposition of the petition for rehearing by operation of law pursuant to Wis. Stat. § 227.49(5), whichever is sooner. If an *untimely* petition for rehearing is filed, the 30-day period to petition for judicial review commences the date the Commission mailed its original decision.[2] The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

If this decision is an order denying rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not permitted.

Revised: December 17, 2008

[2] *See State v. Currier*, 2006 WI App 12, 288 Wis. 2d 693, 709 N.W.2d 520.

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APPENDIX A
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SERVICE LIST

In order to comply with Wis. Stat. § 227.47, the following parties who appeared before the agency are considered parties for purposes of review under Wis. Stat. § 227.53.

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(Not a party, but must be served)
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NORTHERN STATES POWER COMPANY (WISCONSIN)

SUMMARY OF ELECTRIC REVENUE
FOR TEST YEAR 2013

INDIVIDUAL RATE CLASSES	PRESENT REVENUES	AUTHORIZED REVENUES	DOLLAR INCREASE	PERCENT INCREASE
Rg-1 (Residential)	$ 200,189,419	$ 214,305,579	$ 14,116,160	7.05%
Rg-2 (Residential - Optional Time-of-Day)	11,070,696	11,862,113	791,417	7.15%
Fg-1 (Farm Service)	9,624,585	10,341,693	717,108	7.45%
Cg-6 (Optional Off-Peak Service -- Res.)	85,932	91,589	5,657	6.58%
S-1 (Automatic Protective Lighting -- Res.)	438,673	468,403	29,730	6.78%
Cg-1 (Small General - Optional Time-of-Day)	454,208	487,166	32,958	7.26%
Cg-2 (Small General Non-TOD)	42,534,695	45,608,668	3,073,973	7.23%
S-1 (Automatic Protective Lighting -- Com.)	580,166	619,537	39,371	6.79%
Ms-6 (Underground Area Lighting - Private)	31,576	33,725	2,149	6.81%
Cg-5 (General Service TOD)	84,367,437	89,258,322	4,890,885	5.80%
Cg-6 (Optional Off-Peak Service -- C&I)	225,034	240,552	15,518	6.90%
Cp-2 (Peak Controlled Non-TOD)	3,127,321	3,312,569	185,249	5.92%
Cg-9 (Large General TOD)	157,496,035	165,563,370	8,067,335	5.12%
DS-1 (Military Fac. Distrib. Service)	629,430	643,234	13,804	2.19%
Cp-1 (Peak Controlled Service)	54,126,007	56,777,630	2,651,622	4.90%
RTP-1 (Real-Time Pricing)	12,718,600	13,237,016	518,416	4.08%
Ms-2 (Company Owned Street Lighting)	3,309,285	3,534,299	225,014	6.80%
Ms-3 (Cust. Owned Incand./Fluor. Lighting)	6,971	7,445	474	6.80%
Ms-4 (Customer Owned Lighting)	468,570	500,767	32,197	6.87%
Ms-6 (Underground Area Lighting - Public)	345,477	368,983	23,506	6.80%
Ms-7 (Metered - Customer Owned Lighting)	125,613	133,940	8,327	6.63%
Mp-1 (Municipal Water Pumping)	1,096,849	1,179,235	82,386	7.51%
Mz-3 (Fire Siren Service)	4,878	4,878	0	0.00%
VRE (Voluntary Renewable Energy - Windsource)	184,950	184,950	0	0.00%
Pg-2 (Parallel Generation Service)	0	0	0	0.00%
TOTAL ELECTRIC RETAIL SALES	583,242,407	618,765,663	35,523,256	6.09%
Interdepartmental Sales	168,592	177,816	9,224	5.47%
TOTAL ELECTRIC	**$ 583,410,999**	**$ 618,943,479**	**$ 35,532,480**	**6.09%**

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
RESIDENTIAL SERVICE, Rg-1			
Customer Charge (per Month):	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Water Heating Meter Chg. (per Month per Meter)		$2.00	$2.00
Load Management Credit (per Month):			
Water Heating		$2.00	$2.00
Air Conditioning (Summer Only)		$6.00	$6.00
Energy Charge (per kWh)	Summer	11.3780 ¢	12.2600 ¢
	Non-Summer	10.2920 ¢	11.0900 ¢
RESIDENTIAL TOD SERVICE, Rg-2			
Customer Charge (per Month):	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Energy Charge (per kWh):	On-Peak (Summer)	21.2320 ¢	22.8420 ¢
	On-Peak (Non-Summer)	19.6070 ¢	21.0940 ¢
	Off-Peak (Summer)	5.4210 ¢	5.8390 ¢
	Off-Peak (Non-Summer)	5.4210 ¢	5.8390 ¢
FARM SERVICE, Fg-1			
Customer Charge (per Month):	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Load Management Credit (per Month):			
Water Heating		$2.00	$2.00
Air Conditioning (Summer Only)		$6.00	$6.00
Energy Charge (per kWh)	Summer	11.3780 ¢	12.2600 ¢
	Non-Summer	10.2920 ¢	11.0900 ¢
SMALL GENERAL SERVICE, Cg-2			
Customer Charge (per Month):	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Un-metered Cust. Charge (per Month):	Single-Phase	$4.50	$4.50
	Three-Phase	$6.50	$6.50
Water Heating Meter Chg. (per Month per Meter)		$2.00	$2.00
Energy Charge (per kWh)	Summer	11.3780 ¢	12.2600 ¢
	Non-Summer	10.2920 ¢	11.0900 ¢
Act 141 $ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0630 ¢	0.0650 ¢
SMALL GENERAL TOD SERVICE, Cg-1			
Customer Charge (per Month)	Single-Phase	$8.00	$8.00
	Three-Phase	$10.00	$10.00
Energy Charge (per kWh):	On-Peak (Summer)	21.2320 ¢	22.8420 ¢
		19.6070 ¢	21.0940 ¢
	Off-Peak (Summer)	5.4210 ¢	5.8390 ¢
		5.4210 ¢	5.8390 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
GENERAL SERVICE, Cg-5			
Customer Charge (per Month):		$30.00	$30.00
Demand Charges (per kW):	Secondary (Summer)	$11.25	$11.95
	Secondary (Non-Summer)	$9.25	$9.95
	Primary (Summer)	$10.70	$11.36
	Primary (Non-Summer)	$8.74	$9.40
Energy Charge (per kWh)	Summer	6.0050 ¢	6.3275 ¢
	Non-Summer	5.4640 ¢	5.7577 ¢
Act 141 $ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0480 ¢	0.0480 ¢
Primary Volt. Energy Discount (per kWh)		2.00%	2.00%
Primary Volt. Demand Discount (per kW)	Summer	$0.55	$0.59
[Discounts Reflected Above]	Non-Summer	$0.51	$0.55
Energy Charge Credit (per kWh in excess of 400 hours x Billed kW)		0.8000 ¢	0.9000 ¢
PEAK CONTROLLED SERVICE, Cp-2			
Customer Charge (per Month):		$40.00	$40.00
Demand Charges (per kW):			
Firm Demand:	Secondary (Summer)	$11.25	$11.95
	Secondary (Non-Summer)	$9.25	$9.95
	Primary (Summer)	$10.70	$11.36
	Primary (Non-Summer)	$8.74	$9.40
Controlled Demand:	Secondary (Summer)	$6.54	$7.05
	Secondary (Non-Summer)	$6.54	$7.05
	Primary (Summer)	$6.08	$6.56
	Primary (Non-Summer)	$6.08	$6.56
Energy Charge (per kWh)	Summer	6.0050 ¢	6.3275 ¢
	Non-Summer	5.4640 ¢	5.7577 ¢
Act 141 $ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0230 ¢	0.0230 ¢
Primary Volt. Energy Discount (per kWh)		2.00%	2.00%
Primary Volt. Demand Discount (per kW)	Summer	$0.55	$0.59
[Discounts Reflected Above]	Non-Summer	$0.51	$0.55
Energy Charge Credit (per kWh in excess of 400 hours x Billed kW)		0.900 ¢	0.900 ¢
OPTIONAL OFF-PEAK SERVICE, Cg-6			
Customer Charge (per Month):	Single-Phase	$4.00	$4.00
	Three-Phase	$10.00	$10.00
Energy Charge (per kWh)	Secondary (Summer)	4.9780 ¢	5.3720 ¢
	Secondary (Non-Summer)	4.9780 ¢	5.3720 ¢
	Primary (Summer)	4.8784 ¢	5.2650 ¢
	Primary (Non-Summer)	4.8784 ¢	5.2650 ¢
Non-Authorized Use Charge (per kWh)		21.9150 ¢	22.4020 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
LARGE GENERAL TOD SERVICE, Cg-9			
Customer Charge (per Month):	Mandatory	$155.00	$155.00
	Optional	$55.00	$55.00
On-Peak Demand Charges (per kW):	Secondary (Summer)	$9.75	$10.45
	Secondary (Non-Summer)	$7.75	$8.45
	Primary (Summer)	$9.56	$10.24
	Primary (Non-Summer)	$7.60	$8.28
	Trans. Transformed (Sum.)	$9.12	$9.72
	Tr. Transform. (Non-Sum.)	$7.25	$7.86
	Transmission (Summer)	$9.07	$9.67
	Transmission (Non-Sum.)	$7.21	$7.82
Customer Demand Charges (per kW):	Secondary	$1.30	$1.39
	Primary	$0.97	$1.04
	Trans. Transformed	$0.55	$0.59
	Transmission	$0.00	$0.00
Energy Charge (per kWh):	On-Peak (Summer)	7.6960 ¢	8.0210 ¢
	On-Peak (Non-Summer)	6.9420 ¢	7.2350 ¢
	Off-Peak (Summer)	4.5380 ¢	4.7300 ¢
	Off-Peak (Non-Summer)	4.5380 ¢	4.7300 ¢
Act 141 $ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0370 ¢	0.0370 ¢
Voltage Discounts - Energy:	Primary	2.00%	2.00%
	Trans. Transformed	6.50%	7.00%
	Transmission	7.00%	7.50%
Voltage Discounts = [**Reflected in Demand Charges Above**]:			
On-Peak (per kW):	Primary (Summer)	$0.19	$0.21
	Primary (Non-Summer)	$0.15	$0.17
	Trans. Transformed (Sum.)	$0.63	$0.73
	Tr. Transform. (Non-Sum.)	$0.50	$0.59
	Transmission (Summer)	$0.68	$0.78
	Transmission (Non-Sum.)	$0.54	$0.63
Customer (per kW):	Primary	$0.33	$0.35
	Trans. Transformed	$0.75	$0.80
	Transmission	$1.30	$1.39
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.8000 ¢	0.9000 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
PEAK CONTROLLED TOD SERVICE, Cp-1			
Customer Charge (per Month):	Demands >200 kW	$175.00	$175.00
	Demands ≤ 200 kW	$75.00	$75.00
On-Peak Demand Charges (per kW):	Secondary (Summer)	$9.75	$10.45
	Secondary (Non-Summer)	$7.75	$8.45
	Primary (Summer)	$9.56	$10.24
	Primary (Non-Summer)	$7.60	$8.28
	Trans. Transformed (Sum.)	$9.12	$9.72
	Tr. Transform. (Non-Sum.)	$7.25	$7.86
	Transmission (Summer)	$9.07	$9.67
	Transmission (Non-Sum.)	$7.21	$7.82
Customer Demand Charges (per kW):	Secondary	$1.30	$1.39
	Primary	$0.97	$1.04
	Trans. Transformed	$0.55	$0.59
	Transmission	$0.00	$0.00
Controlled Demand Charges (per kW):	Secondary (Summer)	$5.04	$5.55
	Secondary (Non-Summer)	$5.04	$5.55
	Primary (Summer)	$4.94	$5.44
	Primary (Non-Summer)	$4.94	$5.44
	Trans. Transformed (Sum.)	$4.72	$5.16
	Tr. Transform. (Non-Sum.)	$4.72	$5.16
	Transmission (Summer)	$4.71	$5.14
	Transmission (Non-Sum.)	$4.70	$5.14
Energy Charge (per kWh):	On-Peak (Summer)	7.6960 ¢	8.0210 ¢
	On-Peak (Non-Summer)	6.9420 ¢	7.2350 ¢
	Off-Peak (Summer)	4.5380 ¢	4.7300 ¢
	Off-Peak (Non-Summer)	4.5380 ¢	4.7300 ¢
Act 141 $ in Base Rates		0.1210 ¢	0.1280 ¢
Approx. Act 141 $ in Lg.Cust. Rates		0.0310 ¢	0.0310 ¢
Voltage Discounts - Energy:	Primary	2.00%	2.00%
	Trans. Transformed	6.50%	7.00%
	Transmission	7.00%	7.50%
Voltage Discounts [**Reflected in Demand Charges Above**]:			
On-Peak (per kW):	Primary (Summer)	$0.19	$0.21
	Primary (Non-Summer)	$0.15	$0.17
	Trans. Transformed (Sum.)	$0.63	$0.73
	Tr. Transform. (Non-Sum.)	$0.50	$0.59
	Transmission (Summer)	$0.68	$0.78
	Transmission (Non-Sum.)	$0.54	$0.63
Customer (per kW):	Primary	$0.33	$0.35
	Trans. Transformed	$0.75	$0.80
	Transmission	$1.30	$1.39
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.800 ¢	0.900 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
MILITARY FACILITY DISTRIBUTION SERVICE, DS-1			
Distribution Service Charge (per kW)		$4.56	$4.66
EXPERIMENTAL REAL TIME PRICING, RTP-1			
Customer Charge (per Month)		$300.00	$300.00
Contract Demand Charges (per kW):	Secondary	$9.09	$9.12
	Primary	$8.91	$8.93
	Trans. Transformed	$8.50	$8.48
	Transmission	$8.45	$8.44
Distribution Demand Charges (per kW):	Secondary	$1.30	$1.39
	Primary	$0.97	$1.04
	Trans. Transformed	$0.55	$0.59
	Transmission	$0.00	$0.00
Energy Charges (per kWh):		Authorized Hourly Energy Prices included in the table below	
Energy Voltage Discounts (per kWh):	Primary	0.100 ¢	0.100 ¢
	Trans. Transformed	0.331 ¢	0.376 ¢
	Transmission	0.356 ¢	0.403 ¢
Limited Energy Surcharge (per kWh)		10.9500 ¢	11.6500 ¢
Energy Charge Credit (Applies up to 400 hours & Limited to 50% of kWh)		0.7000 ¢	0.9000 ¢

Energy Chgs. $ per kWh	Day Types 1	2	3	4	5	6	7	8
12 am - 6 am	0.05502	0.04995	0.04744	0.04288	0.04047	0.03605	0.03571	0.03395
6 am - 9 am	0.09550	0.07812	0.06412	0.06501	0.06210	0.04680	0.04636	0.03934
9 am - 12 pm	0.24700	0.17101	0.10770	0.08563	0.07065	0.06046	0.04961	0.04285
12 pm - 6 pm	0.41163	0.27233	0.15836	0.09828	0.07065	0.06046	0.04961	0.04285
6 pm - 9 pm	0.29765	0.22167	0.13303	0.08741	0.07065	0.06046	0.04961	0.04285
9 pm - 12 pm	0.09297	0.07526	0.06755	0.06007	0.04971	0.04448	0.04072	0.03821

AUTOMATIC PROTECTIVE LIGHTING, S-1		
Monthly Charges (per Unit):		
175 Watt MV Lamps (Closed)	$8.51	$9.09
250 Watt MV Lamps (Closed)	$11.33	$12.10
400 Watt MV Lamps (Closed)	$15.24	$16.28
70 Watt HPS Lamps	$6.08	$6.49
100 Watt HPS Lamps	$7.40	$7.90
150 Watt HPS Lamps	$8.93	$9.54
250 Watt HPS Lamps	$12.11	$12.93
400 Watt HPS Lamps	$17.31	$18.49

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS	PRESENT RATES	AUTHORIZED RATES
COMPANY OWNED STREET LIGHTING, Ms-2		
Monthly Charges (per Lamp):		
Overhead:		
175 Watt MV Lamps (Closed)	$12.43	$13.28
250 Watt MV Lamps (Closed)	$14.16	$15.12
400 Watt MV Lamps (Closed)	$17.51	$18.70
70 Watt HPS Lamps	$10.21	$10.90
100 Watt HPS Lamps	$11.13	$11.89
150 Watt HPS Lamps	$12.40	$13.24
250 Watt HPS Lamps	$15.42	$16.47
400 Watt HPS Lamps	$20.05	$21.41
Underground:		
175 Watt MV Lamps (Closed)	$18.21	$19.45
250 Watt MV Lamps (Closed)	$19.82	$21.17
70 Watt HPS Lamps	$15.28	$16.32
100 Watt HPS Lamps	$16.21	$17.31
150 Watt HPS Lamps	$17.48	$18.67
250 Watt HPS Lamps	$20.74	$22.15
400 Watt HPS Lamps	$25.12	$26.83
Decorative Underground:		
100 Watt HPS Lamps	$34.65	$34.65
150 Watt HPS Lamps	$36.21	$36.21
250 Watt HPS Lamps	$39.36	$39.36
400 Watt HPS Lamps	$43.94	$43.94
Maintenance Option:		
100 Watt HPS Lamps	$8.28	$8.84
150 Watt HPS Lamps	$9.88	$10.55
250 Watt HPS Lamps	$13.02	$13.91
400 Watt HPS Lamps	$17.60	$18.80

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS	PRESENT RATES	AUTHORIZED RATES
CUSTOMER OWNED STREET LIGHTING, Ms-4		
Monthly Charges (per Lamp):		
Group I - Energy and Maintenance:		
175 Watt MV Lamps (Closed)	$6.91	$7.38
250 Watt MV Lamps (Closed)	$8.49	$9.07
400 Watt MV Lamps (Closed)	$12.05	$12.87
700 Watt MV Lamps (Closed)	$19.06	$20.36
50 Watt HPS Lamps	$4.19	$4.47
70 Watt HPS Lamps	$4.66	$4.98
100 Watt HPS Lamps	$5.56	$5.94
150 Watt HPS Lamps	$6.60	$7.05
250 Watt HPS Lamps	$9.66	$10.32
400 Watt HPS Lamps	$13.24	$14.14
Group I - Energy and Maintenance (No Paint):		
175 Watt MV Lamps (Closed)	$6.66	$7.13
250 Watt MV Lamps (Closed)	$8.24	$8.82
400 Watt MV Lamps (Closed)	$11.80	$12.62
700 Watt MV Lamps (Closed)	$18.81	$20.11
50 Watt HPS Lamps	$3.94	$4.22
70 Watt HPS Lamps	$4.41	$4.73
100 Watt HPS Lamps	$5.31	$5.69
150 Watt HPS Lamps	$6.35	$6.80
250 Watt HPS Lamps	$9.41	$10.07
400 Watt HPS Lamps	$12.99	$13.89
Group II - Energy Only:		
100 Watt MV Lamps (Closed)	$2.69	$2.87
175 Watt MV Lamps (Closed)	$4.30	$4.59
400 Watt MV Lamps (Closed)	$9.48	$10.12
700 Watt MV Lamps (Closed)	$16.18	$17.28
35 Watt HPS Lamps	$0.90	$0.96
50 Watt HPS Lamps	$1.30	$1.39
70 Watt HPS Lamps	$1.72	$1.84
100 Watt HPS Lamps	$2.59	$2.77
150 Watt HPS Lamps	$3.99	$4.26
200 Watt HPS Lamps	$5.07	$5.41
250 Watt HPS Lamps	$6.16	$6.58
400 Watt HPS Lamps	$9.70	$10.36
1000 Watt HPS Lamps	$21.98	$23.47

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
COMPANY OWNED STREET LIGHTING, Ms-4.2 (Closed)			
Ornamental:			
250 Watt MV Lamps		$15.84	$16.92
400 Watt MV Lamps		$18.87	$20.15
150 Watt HPS Lamps		$15.74	$16.81
250 Watt HPS Lamps		$18.65	$19.92
UNDERGROUND AREA LIGHTING, Ms-6			
Monthly Charges (per Lamp):			
175 Watt MV Lamps (Closed)		$16.01	$17.10
100 Watt HPS Lamps		$14.26	$15.23
150 Watt HPS Lamps		$16.26	$17.37
METERED CUSTOMER OWNED STREET LIGHTING, Ms-7			
Customer Charge (per Month)		$7.25	$7.25
Energy Charge (per kWh)		5.8780 ¢	6.2890 ¢
COMPANY OWNED STREET LIGHTING, Ms-3 (Closed)			
Monthly Charges (per Lamp):			
2,500 Lumen - Incand. (AN)		$7.92	$8.46
4,000 Lumen - Incand. (AN)		$9.66	$10.32
6,000 Lumen - Incand. (AN)		$11.65	$12.44
10,000 Lumen - Incand. (AN)		$15.53	$16.59
F72H0 - Fluorescent (4AN)		$15.77	$16.84
F72H0 - Fluor. (2AN+2MN)		$13.88	$14.82
MUNICIPAL WATER PUMPING, Mp-1			
Customer Charge (per Month)		$10.00	$10.00
Minimum Charge: Cust. Chg. + All hp > 5 (per hp)		$0.80	$0.80
Energy Charge (per kWh)	Summer	11.3780 ¢	12.2600 ¢
	Non-Summer	10.2920 ¢	11.0900 ¢
Primary Voltage Energy Discount (per kWh)		2.00%	2.00%
FIRE SIREN SERVICE, Mz-3			
Minimum Charge (per Month)		$2.00	$2.00
Rate per hp of Connected Capacity		38.30 ¢	38.30 ¢
WINDSOURCE, VRE (Green Pricing Tariff)			
Energy Charge Adder		1.37 ¢	1.37 ¢

NORTHERN STATES POWER COMPANY (WISCONSIN)

ELECTRIC RATES

RATE CLASSES & RATE DESCRIPTIONS		PRESENT RATES	AUTHORIZED RATES
PARALLEL GENERATION, Pg-2A			
Customer Charge (per Month):			
For Generator Rating: 21-100 kW:	Delivering < 200 amps	$6.40	$6.40
	Delivering > 200 amps	$8.60	$8.60
For Generator Rating: > 100 kW		13.80	$13.80
NSPW 's Energy payments are based on LMP prices and are adjusted by Delivery Voltage to reflect losses.			Rates are automatically adjusted in November for the TY 2013
Historic Day Ahead LMP payments (per kWh):			
On-Peak		0.03640	
On-Peak		0.02309	
HYDRO ENERGY PURCHASE, Pg-2.2 (Closed)			
Customer Charge (per Month):			
For Generator Rating: 21-100 kW:	Delivering < 200 amps	$6.40	$6.40
	Delivering > 200 amps	$8.60	$8.60
For Generator Rating: > 100 kW		13.80	$13.80
Capacity Rate (Primary) paid per kWh:			
20-Year Option:			
Service beginning in 1992		4.220 ¢	4.220 ¢
Average Energy Rate (Primary):			
For Service in 1996 & After Until Changed by PSC Order		3.000 ¢	3.200 ¢
ELECTRIC SERVICE EXTENSION ALLOWANCES			
Residential & Farm Service:			
(for Rg-1, Rg-2, Fg-1)		$452.00	$499.00
General Service -- Non-Demand:			
(for Cg-1, Cg-2, Mp-1, Mz-3)		$490.00	$532.00
General Service -- Demand:			
(for Cg-5 and Cp-2) per kW:		$67.00	$79.00
Large General Service -- Demand:			
(for Cg-9 and Cp-1)			
Secondary (per kW):		$59.00	$53.00
Primary (per kW):		$50.00	$45.00
Street and Area Lighting:			
(for Ms-2, Ms-4, Ms-6)		$82.00	$108.00

APPENDIX C
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Northern States Power Company

Gas Revenue Summary

Service Rate Classes	Volumes	Current Margin & Admin Revenues	+ Cost of Gas Revenues	= Rebundled Service Class Revenues	+ Proposed Distribution Rev Change/Class	= Total Bundled Rev. by Dist. Class	Percent Change Rebundled w/COG	Percent Change Rebundled w/o COG
Residential								
Residential (Rg-1)	61,622,593	$ 26,154,965	$ 29,265,354	$ 55,420,319	$ 1,731,595	$ 57,151,914	3.12%	6.62%
Subtotal	61,622,593	$ 26,154,965	$ 29,265,354	$ 55,420,319	$ 1,731,595	$ 57,151,914	3.12%	6.62%
Commercial & Industrial, Cg-1 (0 to 29,999)								
Commercial - Firm (Cg1-SSS-F)	50,407,832	$ 11,264,064	$ 23,576,958	$ 34,841,022	$ 650,261	$ 35,491,283	1.87%	5.77%
Commercial - Contract (Cg1-SSS-CD)	3,558,475	$ 621,533	$ 1,980,765	$ 2,602,298	$ 45,904	$ 2,648,202	1.76%	7.39%
Commercial - Interdepart. (Cg1-SSS-F)	153,802	$ 29,177	$ 73,442	$ 102,619	$ 1,984	$ 104,603	1.93%	6.80%
Commercial - Transport (Cg-1-CSS)	522,920	$ 75,935		$ 75,935	$ 6,746	$ 82,680	8.88%	8.88%
Subtotal Cg-1	54,643,029	$ 11,990,708	$ 25,631,166	$ 37,621,873	$ 704,895	$ 38,326,768	1.87%	5.88%
Commercial & Industrial, Cg-2 (30,000 to 199,999)								
Commercial - Interruptible (Cg-2-SSS-CD)	11,805,217	$ 237,904		$ 237,904	$ 22,430	$ 260,334	9.43%	9.43%
Commercial - Interruptible (Cg-2-SSS-I)	9,216,682	$ 1,381,434	$ 3,515,780	$ 4,897,214	$ 71,890	$ 4,969,104	1.47%	5.20%
Commercial - Transport (Cg-2-CSS)	571,315	$ 58,017		$ 58,017	$ 4,456	$ 62,474	7.68%	7.68%
Subtotal Cg-2	21,593,214	$ 1,677,355	$ 3,515,780	$ 5,193,135	$ 98,776	$ 5,291,912	1.90%	5.89%
Commercial & Industrial, Cg-3 (200,000 to 499,999)								
Commercial - Interruptible (Cg-3-SSS-I)	2,784,555	$ 271,389	$ 1,051,448	$ 1,322,837	$ 10,303	$ 1,333,140	0.78%	3.80%
Commercial - Transport (Cg-3-CSS)	1,918,203	$ 122,917		$ 122,917	$ 7,097	$ 130,014	5.77%	5.77%
Subtotal Cg-3	4,702,758	$ 394,306	$ 1,051,448	$ 1,445,754	$ 17,400	$ 1,463,154	1.20%	4.41%
Commercial & Industrial, Cg-4 (500,000 to 1,999,999)								
Commercial - Interruptible (Cg-4-SSS-I)	10,398,729	$ 761,555	$ 3,926,560	$ 4,688,115	$ 38,475	$ 4,726,590	0.82%	5.05%
Commercial - Transport (Cg-4-CSS-I)	6,050,718	$ 283,947		$ 283,947	$ 22,388	$ 306,335	7.88%	7.88%
Commercial - Contract (Contract)	1,415,600	$ 14,016		$ 14,016	$ 5,662	$ 19,678	40.40%	40.40%
Subtotal Cg-4	17,865,047	$ 1,059,518	$ 3,926,560	$ 4,986,078	$ 66,525	$ 5,052,603	1.33%	6.28%
Commercial & Industrial, Cg-5 (2,000,000 to 5,999,999)								
Commercial - Interruptible (Cg-5-SSS-I)	3,823,508	$ 238,341	$ 1,443,757	$ 1,682,098	$ 15,294	$ 1,697,392	0.91%	6.42%
Commercial - Inter-InterD (Cg-5-CSS-I)	1,051,300	$ 90,576	$ 406,669	$ 497,245	$ 4,205	$ 501,450	0.85%	4.64%
Commercial - Transport (Cg-5-CSS-I)	13,554,927	$ 534,426		$ 534,426	$ 54,220	$ 588,645	10.15%	10.15%
Subtotal Cg-5	18,429,735	$ 863,342	$ 1,850,426	$ 2,713,768	$ 73,719	$ 2,787,487	2.72%	8.54%
Commercial & Industrial, Cg-6 (6,000,000+)								
Commercial - Transport (Cg-6-CSS-I)	6,387,405	$ 202,560		$ 202,560	$ 25,550	$ 228,110	12.61%	12.61%
Subtotal Cg-6	6,387,405	$ 202,560	$ -	$ 202,560	$ 25,550	$ 228,110	12.61%	12.61%
Total Gas Sales Revenues		**$ 42,342,754**	**$ 65,240,733**	**$ 107,583,487**	**$ 2,718,460**	**$ 110,301,948**	**2.53%**	**6.42%**
Plus:								
Other Gas Revenue				$ 452,907		$ 452,907	0.00%	0.00%
Total Gas Operating Revenue				**$ 108,036,394**		**$ 110,754,855**	**2.52%**	**6.35%**

Northern States Power Company

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Residential		
Monthly Customer Charge - (Rg-1)	$ 10.25	$ 10.25
Volumetric Charges:		
Distribution Service Charge - (Rg-1)	$ 0.2077	$ 0.2358
Peak Day Backup Charge (SSS-F)	$ 0.0020	$ 0.0020
Gas Acquisition Charge (SSS-F)	$ 0.0336	$ 0.0336
Commercial (Cg-1, Annual Usage < 30,000 therms)		
Monthly Customer Charge	$ 20.00	$ 20.00
Additional Meter Charge	$ 4.00	$ 4.00
Volumetric Charges:		
Distribution Service Charge	$ 0.1420	$ 0.1549
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-CD)	$ 0.0321	$ 0.0321
Commercial (Cg-2, Annual Usage 30,000 - 199,999 therms)		
Monthly Customer Charge	$ 100.00	$ 100.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge - (Cg-2-SSS-CD)	$ 0.0984	$ 0.1062
Distribution Service Charge - (Cg-2-SSS-I)	$ 0.0984	$ 0.1062
Peak Day Backup Charge (SSS-F)	$ 0.0047	$ 0.0047
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256

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Northern States Power Company

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Commercial (Cg-3, Annual Usage 200,000 - 499,999 therms)		
Monthly Customer Charge	$ 300.00	$ 300.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge	$ 0.0653	$ 0.0690
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256
Commercial (Cg-4, Annual Usage 500,000 - 1,999,999 therms)		
Monthly Customer Charge	$ 350.00	$ 350.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge	$ 0.0549	$ 0.0586
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256
Commercial (Cg-5, Annual Usage 2,000,000 - 5,999,999 therms)		
Monthly Customer Charge	$ 550.00	$ 550.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge	$ 0.0480	$ 0.0520
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256

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Northern States Power Company

Present and Authorized Gas Rates

	Present Rates	Authorized Rates
Commercial (Cg-6, Annual Usage 6,000,000+ therms)		
Monthly Customer Charge	$ 625.00	$ 625.00
Transportation Administrative Charge	$ 50.00	$ 50.00
Volumetric Charges:		
Distribution Service Charge	$ 0.0443	$ 0.0483
Peak Day Backup Charge (SSS-F)	$ -	$ -
Gas Acquisition Charge (SSS-F, SSS-I, SSS-CD)	$ 0.0256	$ 0.0256
Base Average Cost of Gas Rates:		
Commodity ("Comm") rate	$ 0.5904	$ 0.3686
Peak Day Demand ("D1") rate	$ 0.0975	$ 0.1144
Annual Demand ("D2") rate	$ 0.0100	$ 0.0090
Balancing ("Bal") rate	$ 0.0039	$ -
Act 141 Volumetric Distribution Rates 1/		
Residential	$ 0.0113	$ 0.0113
Commercial (Cg-1, Annual Usage < 30,000 therms)	$ 0.0152	$ 0.0152
Commercial (Cg-2, Annual Usage 30,000 - 199,999 therms)	$ 0.0152	$ 0.0152
Commercial (Cg-3, Annual Usage 200,000 - 499,999 therms)	$ 0.0152	$ 0.0152
Commercial (Cg-4, Annual Usage 500,000 - 1,999,999 therms)	$ 0.0152	$ 0.0152
Commercial (Cg-5, Annual Usage 2,000,000 - 5,999,999 therm	$ 0.0152	$ 0.0152
Commercial (Cg-6, Annual Usage 6,000,000+ therms)	$ 0.0152	$ 0.0152

1/ Act 141 volumetric distribution rates are included in the above volumetric Distribution Service Charges.

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Northern States Power Company

Monthly Residential Bill Comparison

Gas Costs	Summer	Winter
Firm Sales Service	0.3776	0.4920

Monthly Use Therms		Current Customer Charge	Current Distribut'n Charges	Total Monthly Cost	Gas Costs	Total Costs	Authorized Customer Charges	Authorized Distribut'n Charges	Total Monthly Cost	Gas Costs	Total Costs	Monthly Bill Increase (Decrease)	Monthly Percent Increase (Decrease)
Rg-1: Residential Firm Sales Service During Summer Months													
5		$ 10.25	$ 1.22	$ 11.47	$ 1.89	$ 13.35	$ 10.25	$ 1.36	$ 11.61	$ 1.89	$ 13.50	$ 0.14	1.05%
10		$ 10.25	$ 2.43	$ 12.68	$ 3.78	$ 16.46	$ 10.25	$ 2.71	$ 12.96	$ 3.78	$ 16.74	$ 0.28	1.71%
18	avg.	$ 10.25	$ 4.38	$ 14.63	$ 6.80	$ 21.43	$ 10.25	$ 4.89	$ 15.14	$ 6.80	$ 21.93	$ 0.51	2.36%
25		$ 10.25	$ 6.08	$ 16.33	$ 9.44	$ 25.77	$ 10.25	$ 6.79	$ 17.04	$ 9.44	$ 26.48	$ 0.70	2.73%
50		$ 10.25	$ 12.17	$ 22.42	$ 18.88	$ 41.30	$ 10.25	$ 13.57	$ 23.82	$ 18.88	$ 42.70	$ 1.41	3.40%
75		$ 10.25	$ 18.25	$ 28.50	$ 28.32	$ 56.82	$ 10.25	$ 20.36	$ 30.61	$ 28.32	$ 58.93	$ 2.11	3.71%
95		$ 10.25	$ 23.11	$ 33.36	$ 35.87	$ 69.24	$ 10.25	$ 25.78	$ 36.03	$ 35.87	$ 71.91	$ 2.67	3.86%
125		$ 10.25	$ 30.41	$ 40.66	$ 47.20	$ 87.86	$ 10.25	$ 33.93	$ 44.18	$ 47.20	$ 91.38	$ 3.51	4.00%
150		$ 10.25	$ 36.50	$ 46.75	$ 56.64	$ 103.39	$ 10.25	$ 40.71	$ 50.96	$ 56.64	$ 107.60	$ 4.22	4.08%
200		$ 10.25	$ 48.66	$ 58.91	$ 75.52	$ 134.43	$ 10.25	$ 54.28	$ 64.53	$ 75.52	$ 140.05	$ 5.62	4.18%
300		$ 10.25	$ 72.99	$ 83.24	$ 113.28	$ 196.52	$ 10.25	$ 81.42	$ 91.67	$ 113.28	$ 204.95	$ 8.43	4.29%
Rg-1: Residential Firm Sales Service During Winter Months													
5		$ 10.25	$ 1.22	$ 11.47	$ 2.46	$ 13.93	$ 10.25	$ 1.36	$ 11.61	$ 2.46	$ 14.07	$ 0.14	1.01%
10		$ 10.25	$ 2.43	$ 12.68	$ 4.92	$ 17.60	$ 10.25	$ 2.71	$ 12.96	$ 4.92	$ 17.88	$ 0.28	1.60%
18		$ 10.25	$ 4.38	$ 14.63	$ 8.86	$ 23.49	$ 10.25	$ 4.89	$ 15.14	$ 8.86	$ 23.99	$ 0.51	2.15%
25		$ 10.25	$ 6.08	$ 16.33	$ 12.30	$ 28.63	$ 10.25	$ 6.79	$ 17.04	$ 12.30	$ 29.34	$ 0.70	2.45%
50		$ 10.25	$ 12.17	$ 22.42	$ 24.60	$ 47.02	$ 10.25	$ 13.57	$ 23.82	$ 24.60	$ 48.42	$ 1.41	2.99%
75		$ 10.25	$ 18.25	$ 28.50	$ 36.90	$ 65.40	$ 10.25	$ 20.36	$ 30.61	$ 36.90	$ 67.51	$ 2.11	3.22%
95		$ 10.25	$ 23.11	$ 33.36	$ 46.74	$ 80.10	$ 10.25	$ 25.78	$ 36.03	$ 46.74	$ 82.77	$ 2.67	3.33%
125	avg.	$ 10.25	$ 30.41	$ 40.66	$ 61.50	$ 102.16	$ 10.25	$ 33.93	$ 44.18	$ 61.50	$ 105.68	$ 3.51	3.44%
150		$ 10.25	$ 36.50	$ 46.75	$ 73.80	$ 120.55	$ 10.25	$ 40.71	$ 50.96	$ 73.80	$ 124.76	$ 4.22	3.50%
200		$ 10.25	$ 48.66	$ 58.91	$ 98.40	$ 157.31	$ 10.25	$ 54.28	$ 64.53	$ 98.40	$ 162.93	$ 5.62	3.57%
300		$ 10.25	$ 72.99	$ 83.24	$ 147.60	$ 230.84	$ 10.25	$ 81.42	$ 91.67	$ 147.60	$ 239.27	$ 8.43	3.65%
Avg. Annual Residential Billing													
678		$ 123.00	$ 164.96	$ 287.96	$ 321.22	$ 609.18	$ 123.00	$ 184.01	$ 307.01	$ 321.22	$ 628.23	$ 19.05	3.13%

DL: 00633617

APPENDIX D
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Northern States Power Company-Wisconsin
Docket 4220-UR-118
Monitored Fuel Costs for 2013

	Total Fuel Rules Cost	System Requirements	Monthly $/kWh	Cumulative $/kWh
January	$ 99,502,442	3,908,277,000	$ 0.02546	$ 0.02546
February	86,010,289	3,464,646,000	$ 0.02483	$ 0.02516
March	91,692,462	3,605,956,000	$ 0.02543	$ 0.02525
April	87,900,287	3,294,527,000	$ 0.02668	$ 0.02558
May	92,710,473	3,471,330,000	$ 0.02671	$ 0.02580
June	94,736,702	3,849,584,000	$ 0.02461	$ 0.02559
July	108,281,873	4,280,612,000	$ 0.02530	$ 0.02554
August	106,092,692	4,128,944,000	$ 0.02569	$ 0.02556
September	90,802,480	3,555,480,000	$ 0.02554	$ 0.02556
October	88,557,671	3,455,883,000	$ 0.02563	$ 0.02556
November	90,075,118	3,419,131,000	$ 0.02634	$ 0.02563
December	94,217,160	3,810,581,000	$ 0.02473	$ 0.02555
Total	$ 1,130,579,649	44,244,951,000	$ 0.02555	

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates — 4220-UR-118

DISSENT AND CONCURRENCE OF COMMISSIONER ERIC CALLISTO

While I generally concur in the Final Decision, I write separately to explain my dissenting position on two issues.

I also write separately here in concurrence, as I did in the recent rate decisions for Superior Water, Light and Power Company, Madison Gas and Electric Company, and We Energies, to highlight a recurring inequity associated with how Wisconsin law treats certain large energy customer contributions to Focus on Energy, the state's utility-funded energy efficiency and renewable resource program.[1]

Revenue Allocation

The electric rate increase in this case is substantial—just a bit over 6 percent.[2] The allocations proposed by both Northern States Power Company-Wisconsin (NSPW) and Commission staff recognized the magnitude of this increase and were similar, though Commission staff had a wider range from the average. Commission staff had a range of 0.45 percent above the average to 0.95 percent below the average, while NSPW had a range of

[1] *See Final Decisions* in dockets 5820-UR-113 (Commissioner Callisto, concurring), 3270-UR-118 (Commissioner Callisto, concurring and dissenting in part), and 5-UR-106 (Commissioner Callisto, concurring and dissenting in part).

[2] For those electric customers who also take gas from NSPW, they will also experience an increase in their gas rates, approximately 2.53 percent.

0.30 percent above the average to 0.20 percent below the average.[3] The Wisconsin Industrial Energy Group and the Citizens Utility Board argued for lesser increases to their constituencies.

I proposed an increase that was based upon an approximate 0.25 percent spread from the average, with the residential class receiving the highest increase (6.30 percent) and large commercial and industrial (C&I) class receiving the smallest (5.8 percent). In acknowledgement of the collaborative process the Commission has on these issues, I indicated receptivity to a wider range, and explicitly agreed to Commissioner Nowak's alternate proposal, which had the residential class at 6.4 percent and the large C&I class at the same increase I proposed, 5.8 percent.

By the time the majority reached consensus, it agreed to a 7.2 percent increase for the residential class and only a 5.0 percent increase for the large C&I class.[4] In an effort to reach a 3-0 vote on this important issue, and to mitigate this large increase over the average to the residential class, I indicated my willingness to cap the residential class at 7.0 percent. This was not acceptable to my colleagues.

Thus the swing from Commissioner Nowak's original proposal, a proposal to which I agreed, is approximately $1.8 million more to the residential and small C&I classes, all largely to the benefit of the large C&I classes. This is contrary to the reasonable allocations proposed by Commission staff and NSPW, and is too skewed to the benefit of a small number and type of customers.

[3] NSPW's allocation assumed an overall increase of 6.7 percent, its filed request, while Commission staff's allocation assumed an increase of 5.65 percent, the result of their audit. The ultimate increase, after late adjustments, is 6.09 percent.

[4] Commission staff has rerun its models in an effort to reach the majority's desired conclusion. The final allocations lead to a 7.07 percent increase to residential customers, and an unanticipated (at least as reflected by our discussion of record) 7.23 percent increase for small C&I customers. Large C&I is at 5.0 percent. *See* Appendix B.

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Discounts for C&I Customers

The majority agreed to both the high load factor energy charge credit and voltage discount changes proposed by NSPW. I believe the high load factor change that the Commission agreed to in this case, which provides approximately $679,000 of benefit to high load factor customers, is appropriate and appropriately incremental. While a reasonable argument is made to change the transmission voltage discounts, it benefits only eight customers, many of whom are also benefitting from the high load factor change. These two changes, together, amount to more than $900,000, and collectively go too far.

2005 Wisconsin Act 141 Large Energy Customer Contributions

Energy efficiency programs in Wisconsin are governed by 2005 Wisconsin Act 141 (Act 141). Among other things, Act 141 requires the state's utilities to collectively establish and fund a statewide energy efficiency program (Focus on Energy), establishes priorities for the expenditure of those funds, and creates a system of joint oversight, involving the state's utilities, the Commission, and the third party contractor that administers the program. *See generally* Wis. Stat. § 196.374.

Focus on Energy is funded through ratepayer dollars, at an amount equal to 1.2 percent of utility revenues. Wis. Stat. §§ 196.374(3)(b)2. and (5)a. However, each individual ratepayer's contribution to Focus on Energy is not equal to 1.2 percent of their utility bills. While the Commission has determined that the rate classes should generally pay an amount equal to the amount of Focus on Energy incentives distributed to their class, a limited number of large customers pay much less. That disparity and the subsidy that it necessitates is the result of a section of Act 141 which specifically directs that certain "Large Energy

Customers"[5] (LECs) pay into Focus on Energy the amount they paid towards similar programs in 2005, rather than the amount determined by the Commission. Wis. Stat. § 196.374(5)(b)1. and 2005 Wisconsin Act 141, § 102(8)(c). There are currently 869 LECs in Wisconsin, and specifically 50 LECs in the service territory of NSPW.

Most LECs pay less into Focus on Energy than they otherwise would in the absence of the statutory exemption. Some LECs pay no money into Focus on Energy because they were paying no money to similar programs in 2005. Regardless of how much they pay into the program, all LECs remain eligible to receive the benefits of Focus on Energy, at an undiminished level.

In the NSPW rate case we approve today, LECs are paying about $1.4 million less than they would if all customers were required to pay proportionally equal amounts.[6] The amount last year was about the same.[7] Accounting for the state's six largest utilities, in 2010, the most recent year for which full data is available, LECs paid $16.2 million less than they would have if the statutory exemption didn't exist.[8] Because the utilities are required to fund the program at 1.2 percent of revenues, that missing LEC money must come from somewhere else, and indeed it does. Those costs are allocated to other non-residential customers. In this case, all of NSPW's commercial, industrial, and lighting customers that do not meet the LEC threshold are

[5] A "large energy customer" is a customer that has a demand of at least 1,000 kilowatts of electricity per month or of at least 10,000 decatherms of natural gas per month and, in a month, is billed at least $60,000 for electric service, natural gas service, or both. Wis. Stat. § 196.374(1)(em).
[6] This includes both gas and electric large energy customers of the utility.
[7] On average, the NSPW LECs enjoy a 63 percent discount on the electric rate they pay for Act 141 programs when compared against proportionally equal amounts. The rate for all of the non-residential customers to pay for Act 141 programs would have been approximately $0.00091/kilowatt-hour (kWh), if not for this legislation. Under the approved rates for 2013, LECs will pay $0.00034/kWh for Act 141 program contributions, while non-LECs will pay $0.00128/kWh. Under present rates, the disparity is $0.00040/kWh vs. $0.00121/kWh.
[8] *See* Wisconsin Legislative Audit Bureau Report 11-13, Evaluation of the Focus on Energy Program, pp. 21–22 (December 2011).

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required to pick up these extra amounts, and essentially subsidize the rate break enjoyed by 50 LECs.

And while, generally, under-collection from LECs is the result of the Act 141 exemption, some LECs in Wisconsin have actually paid more than their proportional share of utility revenues because of the operation of the exemption.[9] Either way, the result is inequitable.

Furthermore, the LEC exemption creates perverse incentives that may not be readily apparent. If a LEC is close to the cutoff line for retaining this designation (*i.e.*, its monthly energy use and/or bill amounts are dropping close to the statutory thresholds), it may not choose to pursue energy efficiency because the energy savings may have a value less than the likely "full" Focus on Energy payment it would be required to make as a non-LEC. Conversely, those customers falling just short of the LEC threshold may have an incentive to use more energy—even when they don't need it—if they believe getting the LEC designation (and the resulting lower Focus on Energy payment) will be more valuable than the energy costs incurred to get to the threshold. It cannot be that Act 141 was intended to create economic incentives for inefficient and wasteful energy usage, which is precisely what the LEC exemption promotes.

Freezing the LEC contributions to Focus on Energy at 2005 levels was meant to be temporary.[10] Act 141 required the Commission, by no later than the end of 2008, to provide the Legislature with a recommendation for equitable cost recovery from all rate classes. Wis. Stat. § 196.374(5)(bm)1. While the Commission did submit a proposal recommending a 3-year

[9] *See id.* at p. 22, Table 7 (illustrating how Wisconsin Power & Light Company's LECs pay $616,000 more that they would without Act 141's exemption).
[10] *See id.* at p. 20 ("Legislative documents describe [the Act 141 LEC exemption] as a 'first step' . . . .).

phase-in to proportionally equal funding for LECs, no legislative action was undertaken.[11] As a result, most LECs continue to enjoy proportionally lower contributions to Focus on Energy than other customers in their own rate classes, and in other non-residential customer classes.[12] And those rate breaks for the LECs continue to be subsidized by other commercial and industrial customers.

Not every inequity created by the statutes warrants the Commission's attention. However, where the Legislature empowered the Commission to make a recommendation to resolve an acknowledged disparity in the initial statutory scheme, where that recommendation was not acted on, and where the inequity persists, it is reasonable to make a run at it again. I encourage the Legislature to resolve this issue in the next legislative session.

[11] The Commission's 2008 recommendation can be found at PSC REF#: 106987.
[12] LEC contributions to Focus on Energy are subject to annual adjustments equal to the lesser of the percentage increase in the host utility's operating revenues in the preceding year or the increase in the consumer price index. Wis. Stat. § 196.374(5)(bm)2.

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy

Case No.:	PU-12-813		
Response To:	North Dakota Public Service Commission	Data Request No.	NDPSC-2-015
Requestor:	Michael Diller and Sara Cardwell		
Date Received:	March 8, 2013		

Question:

Heuer Question:

A. For the Charitable Donations information provided in Heuer's Exhibit (AEH-1), Schedule 16 and workpapers, Section VIII Adjustments, Tab A13, pages A13-3 and 4, please provide complete information regarding the recipients of the Electric Corporate Contributions, Focus Area Grants, and Matching Gifts Program. What are the organizations and amounts received by each?

B. Please explain the Management Reductions amount and what it means.

C. Does the Company include Xcel Energy Foundation administrative costs in its proposed test-year revenue requirement in ND? If so, what is the amount?

D. According to page 67 of Heuer's testimony, ND ratepayers are being asked to cover 50% of the costs of corporate charitable contributions that benefit the state of ND in the test year. Please explain why and how each of the following benefits ND customers. Note that in some cases there is a list of organizations that follow the heading "Made up of Following Organizations". And for Big Brothers Big Sisters, are these locations in the state of ND?

Charitable Contributions	
Organization	Amount
National Conference on LGBT Equality	$ 15.00
University of Minnesota	$ 735.00
Made up of Following Organizations	$ 116.00
Diversity & Inclusion Events	$ 185.00
Made up of Following Organizations	$ 788.00
Made up of Following Organizations	$ 462.00
Made up of Following Organizations	$ 237.00
Journal Communications	?
Made up of Following Organizations	$ 9,709.00
Big Brothers Big Sisters	$ 316.00
Made up of Following Organizations	$ 3,459.00
Women's Innovation Network	$ 46.00
	$ 16,068.00

E. If the Company records charitable contributions below the line, why does the Company believe that customers should pay even 50% of these contributions?

Response:

A. Please see Attachment A to this response, Pages 1 and 2, which identifies each grant by Focus Area, City served, Applicant Name, the brief purpose as provided by the applicant, the communities served by the projects and the dollar amount of the 2012 grant.

We have also supplied our 2012 Employee Giving/Company Match data. Please see Attachment A, Page 3. The information is identified by Program, Program Segment, Organization Name, City, number of hours volunteered, employee/retiree contribution and the amount of the Company Match (of which we would be seeking 50% recovery).

B. The Foundation itself is a 501(c)3 and does not operate from a corpus. It receives its funding from Xcel Energy Inc. In the fall of 2012, the Company reviewed 2013 budgets to identify, if any, reductions that could be made to operating expenses across the Xcel Energy Operating Companies. Based on management discussion, it was determined that the Foundation could reduce its 2013 budget by $400,000 without reducing support to our communities by dipping into a small operating reserve for the $400,000.

C. Yes, the Company included $21,904 in Xcel Energy Foundation administration costs in the 2013 test-year revenue requirements for North Dakota. This

amount includes $21,096 in administrative and general costs and $808 in payroll taxes. This is the North Dakota electric jurisdiction portion of the Foundation costs, which are allocated across all four Xcel Energy Operating Companies and eight retail jurisdictions.

D. Charitable contributions demonstrate the Company's commitment to be a good "corporate citizen" and support the communities and organizations in the areas served. These charitable contributions in turn provide assistance to customers that reside in those service areas.

The organizations provided in Part A of the inquiry are a subset of organizations that may receive a charitable contribution from the Company via a business area operating budget. The entire list was provided in the Revenue Analysis Workpapers Volume, Tab VIII. Adjustments, Tab A13. Donations, pages A13-5 through A13-7 of the rate case application.

When operating budgets are developed, it is not always known which specific organizations will solicit contributions from the Company. Historical recipients were listed under the heading "Made up of Following Organizations" to illustrate the types of organizations that may receive contributions during the test year. Each organization that receives a charitable contribution from the Company must be an IRS designated 501(c)3 or governmental entity for charitable purposes, be non-discriminatory and non-profit, and provide services related to education, fine arts and culture, mentoring, or cruelty prevention.

For example, the Big Brothers Big Sisters organization, located in Fargo, matches at-risk youth in the Fargo-Moorhead community with adult volunteers who spend consistent time building a friendship with a child.

E. The Company records all charitable contributions below the line, and then includes 50% of the contributions amount in its rate case recovery request through an adjustment, as summarized in the Revenue Analysis Workpapers Volume, Tab VIII. Adjustments, Tab A13, Donations, page 13-3. The Company believes it is appropriate to include in rates 50% of the charitable contributions made in the communities in which we provide utility service area, because such contributions are a reasonable, recognized cost of doing business in the states we serve. We believe the communities we serve expect their local businesses to be good corporate citizens, support local charitable organizations and be involved in the community.

A regulated utility is unlike other businesses in that it has a defined service territory and is literally connected to each community it serves – virtually every household, every business. Our contributions through the Foundation are not a

promotional effort, nor are they about increasing sales or building brand recognition. Rather, they are about long-term commitments to our customers and communities, because we want these communities to be stable, economically healthy places to live and work.

As an example, when communities are in crisis – whether caused by economic conditions or a natural disaster (such as the Minot flood) – our Foundation allows us to provide support in the form of disaster relief donations to our communities.

Also, demonstrated care for our communities increases job satisfaction among employees; this can have a broad impact on our ability to deliver safe, quality service to our customers. We match employee contributions to organizations such as The American Red Cross and United Way to help create even more support for our communities. Many of our employees who give and volunteer during our United Way campaign report that the Company match provides an incentive to give or to give more.

Allowing 50% recovery of charitable contributions encourages utilities to act as responsible corporate citizens in their support of the communities in which they serve. Limiting the amount of charitable contribution recovery to 50% also ensures that utilities make contributions in a responsible and reasoned manner. The limit reflects a reasonable sharing of the responsibility that both shareholders and ratepayers have for the well-being of the communities they live in.

Witness:	Anne E. Heuer
Preparer:	Julie A. Rushton / Mary Pope
Title:	Representative, Sponsorship Data / Senior Rate Analyst
Department:	Contributions / Revenue Requirements North
Telephone:	651-458-4443 / 612-330-6574
Date:	April 10, 2013

Northern States Power Company
Electric Utility - State of North Dakota
Year End 2012 Focus Area Grants

Case No. PU-12-813
NDPSC Data Request 2-015
Attachment A - Page 1 of 3

Focus Area	City	Applicant Name	Brief Purpose	Project Area	Total
Arts and Culture	Fargo	City of Fargo Park District	The Fargo Park District would like to request $4000 in funding to continue to expand free and low cost programming for the residents of Fargo-Moorhead. The grant would focus on providing quality arts experiences throughout the community. The outreach would focus on low income neighborhoods and underserved populations. The program reached over 2800 participants, up from the previous year of 2100.	Southeast Cass County; Western Clay County	$4,000
		Plains Art Museum	To increase and enhance our capacity to provide affordable programs for area low income youth and families in conjunction with the opening of the museum's Katherine Kilbourne Burgum Center for Creativity. We are requesting $5000 for a NO WAITING LIST Kid Quest and a one time $3000 grant to provide families in need class/workshop scholarships until an ongoing scholarship fund can be established.	Fargo-Moorhead-West Fargo metro area, including surrounding communities.	$8,000
		Red River Human Services Foundation	To increase and enhance our capacity to provide affordable programs for area low income youth and families in conjunction with the opening of the museum's Katherine Kilbourne Burgum Center for Creativity. We are requesting $5000 for a NO WAITING LIST Kid Quest and a one time $3000 grant to provide families in need class/workshop scholarships until an ongoing scholarship fund can be established.	Fargo, ND and surrounding areas; Moorhead, MN and surrounding areas; Wahpeton, ND	$1,000
	Fargo Total				**$13,000**
	Grand Forks	ArtWise	To increase and enhance our capacity to provide affordable programs for area low income youth and families in conjunction with the opening of the museum's Katherine Kilbourne Burgum Center for Creativity. We are requesting $5000 for a NO WAITING LIST Kid Quest and a one time $3000 grant to provide families in need class/workshop scholarships until an ongoing scholarship fund can be established.	Grand Forks, Thompson, Manvel, North Dakota	$500
		Fire Hall Theatre	3200 local elementary students will receive16 hours of art instruction through the ArtWise artist in the classroom program. They will showcase their visual artwork in a free and open to the public venue in March 2013. The 3 day Art Show will be a festival of children's activities, art demonstrations and community performances. 350 volunteers help prepare and run this amazing event for children.	Greater Grand Forks, ND	$1,000
		North Dakota Museum of Art	Family Day is a free, fun, and casual event where families enjoy art activities, educational games, and more. Each Family Day, children and adults of all ages create and learn through projects inspired by the current exhibition on display in the Museum galleries. This successful event offers families the chance to spend time together and also learn about the Museum and it's exhibitions.	Grand Forks County, ND and Polk County, MN	$1,500
	Grand Forks Total				**$3,000**
	Minot	Lillian and Coleman Taube Museum of Art	To provide 4,000 elementary children in the Minot Public Schools with a unique hands on art experience, due to lack of an art elementary program. The students will learn proper art techniques and vocabulary. Provide teachers with follow up activities that connect the project with North Dakota Standards. Students will learn about the artist role in our society from masters, contemporary, to local.	Ward County, McHenry County, Mountrail County, Renville County, McLean County	$2,300
		Minot Area Council of the Arts Inc.	The Minot Area Council of the Arts requests funds for the expansion and development of the Arts in the Parks free outdoor summer concert series. Each of the season concerts features a performance and a visual arts display and demonstration. Funding will be used to promote the season and to further develop audience favorites – "At the Hop", and the Sousa Concert.	Minot, Ward County communities within a 75 mile radius of Minot	$2,300
		Norsk Høstfest Association	Funding maintains and enhances the educational outreach programs of Norsk Høstfest known as Høstfest in the Schools and Scandinavian Youth Camp, both designed to reach children who otherwise might not be exposed to lessons of the heritage prevalent in this region. Programs are offered free of charge to thousands of area youth. Students participate in both the festival and hands on activities.	Cities of Minot, Surrey, Burlington, Glenburn, Nedrose and South Prairie School Districts, Ward and Renville Counties; State of North Dakota	$5,200
	Minot Total				**$9,800**
	Moorhead	FutureBuilders in support of Trollwood Performing Arts Sc	Bluestem Center for the Arts in support of Trollwood Performing Arts School requests $10,000 to support at-risk youth through the Students At Risk program. STAR uses the arts as a tool to support youth facing extraordinary challenges in their lives including economic hardship, physical, social and/or emotional disabilities, cultural disparity, low academic standing, and substance abuse.	Cass County, ND; Clay County, MN.	$5,000
	Moorhead Total				**$5,000**
Arts and Culture Total					**$30,800**
Economic Sustainability	Fargo	Cultural Diversity Resources, Inc	Cultural Diversity Resources will assist 250-300 low income and minority individuals to obtain the necessary education and skills to achieve economic sustainability. The Education and Development Center was established to provide job readiness (i.e. resume creation, job searches, online applications and job placements), computer and financial literacy in Cass County, ND and Clay County, MN.	Cass County, North Dakota and Clay County, Minnesota	$2,380
		SouthEastern North Dakota Community Action Agency	This grant will provide energy conservation information, education, and materials to low-income households served by Xcel Energy in the Agency's six county service area.	Cass, Ransom, Richland, Sargent, Steele, and Trail Counties of North Dakota.	$13,200
	Fargo Total				**$15,580**
	Grand Forks	Community Violence Intervention Center, Inc.	Our program assists low-income individuals impacted by domestic violence in Grand Forks and Nelson counties to become economically self-sufficient, providing: (1) transitional housing and support for at least four single-parent families, (2) assistance in securing accessible housing for 170 individuals, and (3) employment and educational counseling for 70 individuals.	Grand Forks County; Nelson County	$5,000
		Red River Valley Community Action	Funding provided through this grant will assist 150+ low income households to make daily living more affordable by reducing the impact of energy costs. Our continuing priority is to provide energy conservation education and materials including shrink and seal window kits, energy conservation kits and set back thermostats and have funds available to assist clients who have energy related emergencies.	Cities of Grand Forks, Larimore, Emerado, Reynolds and Thompson, ND.	$12,000
	Grand Forks Total				**$17,000**
	Jamestown	Energy Share of North Dakota	To assist elderly, low-income, unemployed and under employed households who are in crisis to meet their utility obligation and prevent shut-offs. Energy Share of North Dakota served 1400 clients in 2011.	The entire state of North Dakota is served by this program.	$20,000
	Jamestown Total				**$20,000**
Focus Area	**City**	**Applicant Name**	**Brief Purpose**	**Project Area**	**Total**
Economic Sustainability	Minot	Young Women's Christian Association, Minot, ND	To assist up to 75 women with skills to obtain a job. This includes dressing skills, interview skills, financial skills, housekeeping skills and anything else that would assist them in obtaining a job and permanent housing.	Minot	$7,500
	Minot Total				**$7,500**
Economic Sustainability Total					**$60,080**

Northern States Power Company
Electric Utility - State of North Dakota
Year End 2012 Focus Area Grants

Case No. PU-12-813
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Focus Area	City	Applicant Name	Brief Purpose	Project Area	Total
Education	Bismarck	Bismarck State College Foundation	To assist 5 students with scholarship funds to complete their studies in Power Plant Technology, Process Plant Technology or Electrical Transmission Systems Technology and to provide a competent, diverse, and stable workforce for the energy industry through directly applicable education. Scholarships will enable deserving and qualified students to prepare for careers in the energy industry.	The Online Energy Technology Programs are available nationwide and serve placebound students.	$2,000
	Bismarck Total				**$2,000**
	Fargo	Fargo Public Schools Development Foundation	To provide grants to classroom teachers, so they can introduce creative techniques to excite students to learn science, math, and technology.	City of Fargo, ND	$1,000
		Junior Achievement of the Upper Midwest- North Dakota	Junior Achievement teaches 5,300 Fargo-Moorhead area students in K-5th grade about personal financial responsibility in an ever-changing market. From the basic concepts of needs and wants to the more complex ideas of credit, philanthropy and budgeting, JA programs expose children to a world beyond their neighborhoods and inspire opportunity in every young mind.	Fargo-Moorhead area	$3,000
		North Dakota State University Development Foundation	This grant request is for funds to support scholarships for NDSU engineering students.	North Dakota and Minnesota	$17,000
		Northern Lights Council, Boy Scouts of America	The purpose of the grant is to provide scholarship assistance for families who are unable to pay the full cost of the Scouting program.	The Northern Lights Council, Boy Scouts of America serves the greater Fargo-Moorhead area and requests $1,500 for scholarships in this area. We also serve the greater Minot area and request $500 to help provide scholarship funding in the Minot area. In addition, we serve the entire State of North Dakota, 18 counties in NW Minnesota and 2 counties each in South Dakota and Montana.	$2,000
		Prairie Public Broadcasting	To provide underwriting support for educational public television programming for children and adults, focusing on science and math. Prairie Public delivers these unparalleled educational programsùSid the Science Kid, Cyberchase, NOVA, and Natureùto over 600,000 households of every socio-economic status, along with outreach services to schools and dynamic web-based educational resources.	North Dakota: Berthold, Bismarck, Buffalo, Burlington, Buxton, Casselton, Cummings, Des Lacs, Emerado, Fargo, Grand Forks, Grand Forks A.F.B., Hankinson, Hatton, Horace, Larimore, Lone Tree, Mapleton, Mayville, Minot, Oriska, Portland, Reynolds, Thompson,	$3,520
	Fargo Total				**$26,520**
		Grand Forks Public Schools Junior Achievement Program	Junior Achievement (JA) teaches basic economics, workforce readiness, entrepreneurship & financial literacy. All teachers in 18 elementary schools of the Grand Forks Consortium may request JA for their students. Kits contain materials for 5 lessons, including interdisciplinary activities, covering areas in science, language arts, math, career & character education, as well as social studies.	Grand Forks, Grand Forks Air Force Base, Emerado, Manvel, Larimore, Buxton, Reynolds, Northwood, Thompson - ND	$3,000
		University of North Dakota Foundation	Funding will support the University of North Dakota and provide scholarships to students in the areas of math, science, technology, and the environment.	Grand Forks, East Grand Forks, Thompson, Buxton, Reynolds, Hatton, Mayville, Portland, and Emerado.	$15,000
	Grand Forks Total				**$18,000**
	Minot	Junior Achievement, Inc., Minot	Junior Achievement is designed to teach young people about the importance of the free enterprise system. Those in Minot public and private schools in grades K through 6 are taught about saving money, staying away from credit card debt and how a community works, among many other topics.	Minot, ND	$2,000
		Minot State University Development Foundation	To assist 10 or more students by providing scholarship awards.	The world	$4,000
	Minot Total				**$6,000**
	Moorhead	Concordia College	To provide scholarship funding for Concordia College students pursuing degrees in Science and Mathematics. Concordia enrolls 2746 undergraduate students, including 1,845 from Minnesota and 447 from North Dakota.	Minnesota, North Dakota, South Dakota, Wisconsin and Colorado.	$2,500
		Minnesota State University Moorhead Alumni Foundation,	To provide scholarships to students majoring in 1) Operations Management, a 2+2 degree program accepting technically oriented AAS degrees as the first 2 yrs of study; 2) Industrial Education with Industrial Management or Industrial Distribution emphasis. These two degrees are offered by the College of Business and Industry and are accredited by the National Association of Industrial Technology.	Scholarship support will assist in recruiting and retaining students from across the nation. Minnesota and North Dakota employers receive the most benefit from an educated and talented workforce.	$5,000
	Moorhead Total				**$7,500**
Education Total					**$60,020**
Environment	Fargo	Audubon	This project will identify/prioritize Important Bird Areas in support of statewide wind energy siting and mitigation; involve Xcel/partners in on-the-ground habitat restoration in the Grand Forks County Prairie IBA; and connect underserved youth in our DakotaLark Youth Leadership Program with mentors at Xcel through a Conservation Action Project restoring Tallgrass urban prairie in Fargo-Moorhead.	Fargo, Grand Forks, and West Fargo, with potential inclusion of Casselton, Horace, Moorhead (MN), Thompson, and Reile's Acres. (IBAs - statewide).	$1,200
	Fargo Total				**$1,200**
	Grand Forks	City of Grand Forks	The City of Grand Forks has partnered with Xcel Energy through the Xcel Energy Foundation in projects and activities that enhance the environment as well as engaging and educating the community. Grand Forks would like to continue its partnership with Xcel Energy by developing a "Natural Playground" in an appropriate location in the City.	Grand Forks, ND; Moorhead, MN	$10,000
	Grand Forks Total				**$10,000**
Environment Total					**$11,200**
Grand Total					**$162,100**

Northern States Power Company
Electric Utility -State of North Dakota
Year End 2012 Focus Area Grants

Case No. PU-12-813
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Program	Program Segment	Organization Name	City	Sum of Gift Hours	Sum of Emp/Retiree Contribution	Sum of Company Gift or Matched Amount	Sum of Total Gifts
Matching Gift	Higher Education	Minot State University Development Foundation	Minot		$ 300.00	$ 300.00	$ 600.00
		North Dakota State University Development Foundation	Fargo		$ 6,170.00	$ 6,070.00	$ 12,240.00
		University of North Dakota Foundation	Grand Forks		$ 5,255.83	$ 5,255.83	$ 10,511.66
	Higher Education Total				**$ 11,725.83**	**$ 11,625.83**	**$ 23,351.66**
	Non-Profit	Altru Health Foundation	Grand Forks		$ 2,100.00	$ 2,100.00	$ 4,200.00
		American Heart Association, Lake Park Minnesota	Jamestown		$ 50.00	$ 50.00	$ 100.00
		Boy Scouts of America Council	Fargo		$ 1,450.00	$ 1,450.00	$ 2,900.00
		Dakota Boys and Girls Ranch Foundation	Minot		$ 1,000.00	$ 750.00	$ 1,750.00
		Empire Arts Center	Grand Forks		$ 160.00	$ 160.00	$ 320.00
		Friends of Chimbote	West Fargo		$ 500.00	$ 150.00	$ 650.00
		Great Plains Food Bank	Fargo		$ 300.00	$ 300.00	$ 600.00
		North Dakota Association for the	Grand Forks		$ 950.00	$ 950.00	$ 1,900.00
		Prairie Public Broadcasting Inc	Fargo		$ 50.00	$ 50.00	$ 100.00
		Salvation Army	Fargo		$ 100.00	$ 100.00	$ 200.00
		YMCA of Cass and Clay Counties	Fargo		$ 750.00	$ 750.00	$ 1,500.00
		Zone 2A Relief Fund	Minot		$ 1,000.00	$ 750.00	$ 1,750.00
	Non-Profit Total				**$ 8,410.00**	**$ 7,560.00**	**$ 15,970.00**
Matching Gift Total					**$ 20,135.83**	**$ 19,185.83**	**$ 39,321.66**
Volunteering	Dollars for Doing	Make-A-Wish Foundation of North Dakota	Fargo	100		$ 1,000.00	$ 1,000.00
	Dollars for Doing Total			**100**		**$ 1,000.00**	**$ 1,000.00**
	Team Volunteer	I Help Inc.	Minot	3		$ 500.00	$ 500.00
		Lutheran Social Service of North Dakota	Fargo	34		$ 500.00	$ 500.00
		Minot Indoor Rodeo, Inc.	Minot	8		$ 500.00	$ 500.00
		ND Associaition for the Disabled	Grand Forks	39		$ 1,000.00	$ 1,000.00
		ND Special Olympics Inc.	Grand Forks	30		$ 500.00	$ 500.00
		North Dakota State Fair Foundation	Minot	59		$ 500.00	$ 500.00
		Sanford Health Foundation North	Fargo	12		$ 500.00	$ 500.00
	Team Volunteer Total			**185**		**$ 4,000.00**	**$ 4,000.00**
Volunteering Total				**285**	**Attachment A**	**$ 5,000.00**	**$ 5,000.00**
United Way	United Way	Missouri Slope Areawide United Way	Bismarck		$ 65.00	$ 65.00	$ 130.00
		Souris Valley United Way	Minot		$ 7,887.92	$ 6,996.92	$ 14,884.84
		United Way of Barnes County	Valley City		$ 20.00	$ 10.00	$ 30.00
		United Way of Cass-Clay	Fargo		$ 17,856.20	$ 17,337.70	$ 35,193.90
		United Way of Grand Forks, East Grand Forks and Area	Grand Forks		$ 7,369.32	$ 6,051.82	$ 13,421.14
		United Way of Richland-Wilkin	Wahpeton		$ 1,136.04	$ 1,136.04	$ 2,272.08
	United Way Total				**$ 34,334.48**	**$ 31,597.48**	**$ 65,931.96**
United Way Total					**$ 34,334.48**	**$ 31,597.48**	**$ 65,931.96**
Grand Total				**285**	**$ 54,470.31**	**$ 55,783.31**	**$ 110,253.62**

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy
Case No.: PU-12-813
Response To: North Dakota Public Service Commission Data Request No. NDPSC-6-016
Requestor: Snavely King Majoros & Associates
Date Received: April 2, 2013

Question:

Please refer to page 1, lines 22-26 of the Direct Testimony of Stephen R. Foss. Please (1) describe and explain in detail NSPM's system planning and capital budgeting processes for its Distribution, Transmission, and Energy Supply business units, (2) provide documentation of NSPM's planning and budgeting procedures and guidelines, and (3) provide a map or maps of NSPM's system showing the location of distribution and transmission planning load centers.

Response:

Please refer to Company witness Anne Heuer's Direct testimony pages 5 through 10 for discussion related to the Company's O&M and capital budget development process. In addition, Corporate Budget Instructions for budgeting operating and maintenance (O&M) and capital expenses for Xcel Energy are provided as Attachment A in the Company's response to information request NDPSC-1-019.

(1) Describe and explain in detail NSPM's system planning and capital budgeting processes for its Distribution, Transmission, and Energy Supply business units,

Distribution:

Distribution Operations has a well-defined process for identifying, ranking and budgeting electric line and distribution substation projects. The key steps necessary to ensure the preparation of a comprehensive capital budget are summarized as follows. Engineering and operations personnel identify potential problems or risks on the system and solutions. "Risks" are potential detrimental impacts or threats to safety, the quality/reliability of our service, environmental quality, our ability to meet our legal obligations, or our financial standing. These identified risks drive the need for

initiatives to address the risks. These initiatives, in turn, often require capital expenditures. In the capital budgeting process, potential "solutions" or "mitigations" are essentially "projects;" *i.e.*, work to be performed that will mitigate a certain risk, or set of risks. These projects are the focus of the capital budget process. Projects are screened and evaluated against each other based on their costs, how effectively they address certain risks, and how critical the risks are. The evaluation or scoring of risks, mitigations and solutions is only an intermediate step. The ultimate goal is to determine which projects will be funded and at what levels.

Each risk and mitigation is reviewed for accuracy, completeness and reasonableness. As each risk and solution is considered, it is scored based on certain criteria, likelihood of occurring, and the consequences of not addressing it. All potential mitigations are ranked or prioritized. After the ranking is completed, business leadership reviews the list, the level of risk associated with the various projects, as well as capital levels based on financial criteria. Projects chosen to be funded are assigned a capital project number based on the type of work. These capital projects are classified as either "specific" or "routine." Capital project numbers for large pools of small projects (e.g., underground extensions, overhead services, etc.) are automatically tied to closing patterns based on the attributes of the work. For larger individual projects, in-service dates are assigned. Project managers then forecast expenditures based on the particulars of a project and its projected in-service date. All capital projects that are included are reviewed and approved, both at the business area level and at the corporate level.

Transmission:

The Capital budget for Transmission begins with the Planning Group identifying new projects to be added for consideration to the new five year budget. The projects are entered into the Tamcasting system along with the description, need and benefits of the project. At minimum, a scoping level estimate is required to be done for the proposed budget and the project must have gone through the first level of constructability meetings to justify the need for the project. All projects in the current approved budget are "refreshed" by the engineering and planning groups who provide the best available data for the project for this budget cycle. All data is compiled and reviewed in detail by project by Project Management and Portfolio Delivery to further vet the need, amount and the timing of the proposed projects. Existing projects that have changed significantly in scope or forecast may require further scrutiny during a "challenge session" to take a deeper look at the details of the project and its associated forecast. A second layer of management review is done at the Vice President of Transmission level before the budget is submitted for corporate review and approval. Projects meeting the criteria for Investment Review Committee or Board approval are presented as part of the budget process.

Energy Supply:

There are multiple factors driving Energy Supply capital requirements. The most significant factors include safety, generation load growth, environmental regulations, and unit operational condition.

Each year, projects submitted by the plants are evaluated and ranked according to their financial and operational merits, such as impact on safety, availability and environmental compliance. Each capital project is reviewed and prioritized using multiple criteria, including safety, financial merit (such as Present Value of Revenue Requirements) and operational factors (such as impact on Unplanned Outage Rate, equipment condition, environmental compliance and/or regulation). Projects that are evaluated include those that may be completed in a single year as well as those that will require multiple years to execute and complete.

A ranked list of projects is evaluated against the available capital budget for the next year, as well as the planned unit outage schedule for the next several years and known regulatory factors, such as new environmental regulations. This process allows the Company to develop a capital plan that covers a five-year period, thus allowing the Company to utilize the five-year capital expenditures and estimated in-service dates in the capital budget process. As this list of projects is finalized in each jurisdiction (NSPM, NSPW, PsCo and SPS), it is reviewed and approved by Plant Directors, General Managers, Vice Presidents and Xcel Energy's Financial Council.

Capital budgets are established at least 12-18 months prior to their execution. Part of the project development process includes the identification of key schedule dates and budgetary milestones. Once a capital project has been approved for execution, it is assigned to a Project Manager ("PM"). The PM is responsible for working with the plant to review and more fully develop the schedule and monthly cash flow requirements for the assigned project. The PM will typically contact vendors and contractors to firm up cost and schedule data and begin engineering and purchasing activities. As the PM works through the project details, they develop detailed cash flows and schedules for the project. Those schedules and cash flows are entered into corporate accounting. Monthly review activities include verifying that planned activities have been undertaken as scheduled. If cost or schedule variances arise, they are discussed at the monthly project meetings along with corrective actions. As the project is completed and placed in-service, the PM follows close-out activities to update plant drawings and procedures.

(2) Provide documentation of NSPM's planning and budgeting procedures and guidelines,

Please see Attachment A to the Company's response to information request NDPSC-1-019. The budget instructions include the schedule and describe the guiding principles used to establish the corporate O&M and capital budgets.

(3) Please see Attachment A for a map of NSPM load centers.

Witness:	Stephen Foss
Preparer:	Greg Robinson/Mark Wehlage
Title:	Manager/Manager
Department:	Financial Planning & Analysis/Transmission Planning
Telephone:	612-215-4631/612-330-7631
Date:	May 3, 2013

XCEL ENERGY INC.

NSP LOAD AREAS

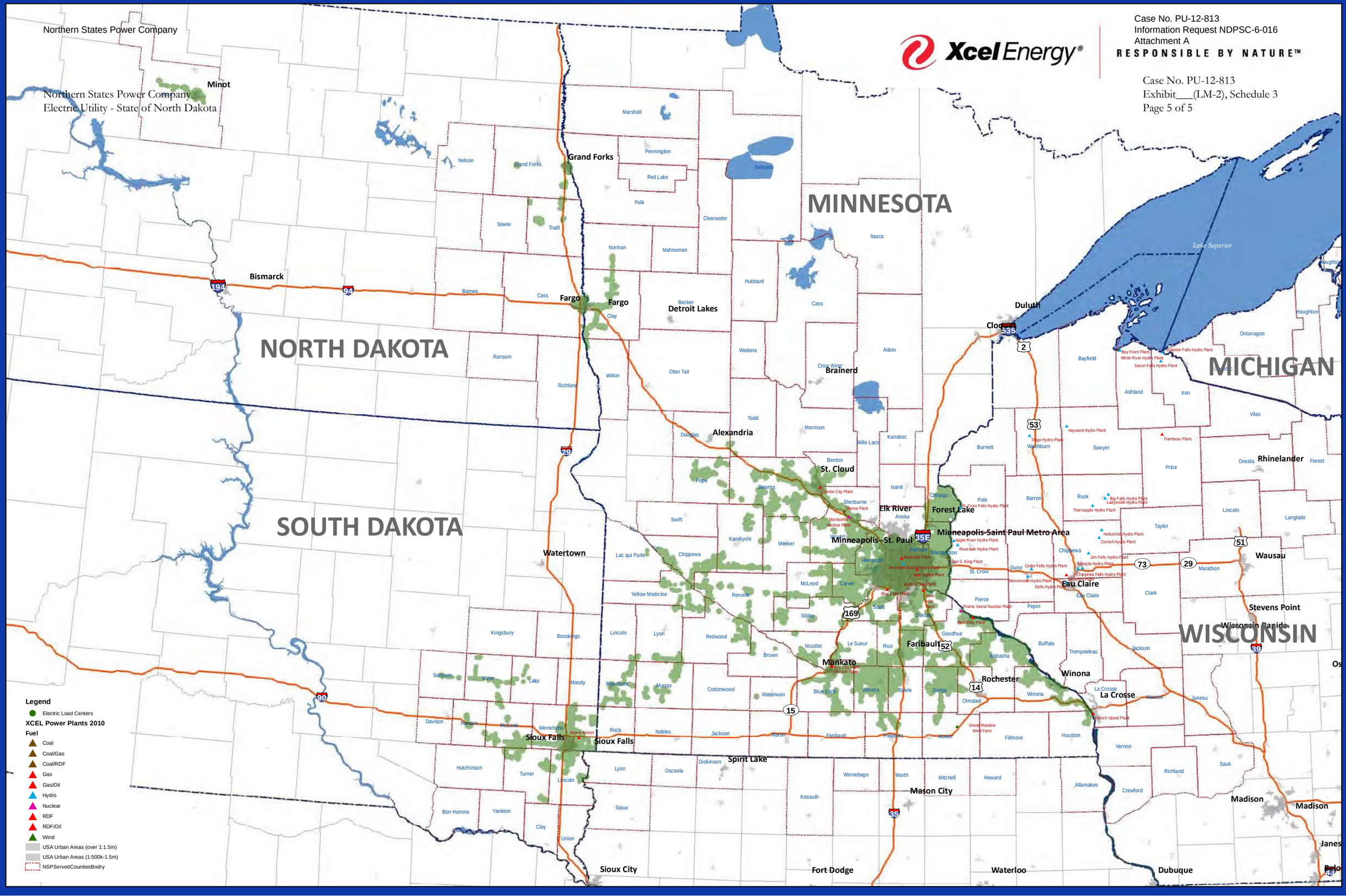
Northern States Power Company

Northern States Power Company
Electric Utility - State of North Dakota

Case No. PU-12-813
Information Request NDPSC-6-016
Attachment A

Xcel Energy®
RESPONSIBLE BY NATURE™

Case No. PU-12-813
Exhibit___(LM-2), Schedule 3
Page 5 of 5



Rebuttal Testimony and Schedules
Ann E. Bulkley

Before the North Dakota Public Service Commission
State of North Dakota

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

Case No. PU-12-813
Exhibit___(AEB-2)

Return on Equity

August 12, 2013

Table of Contents

Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND EMPLOYER.

A. My name is Ann E. Bulkley. I am employed by Concentric Energy Advisors (Concentric) as a Vice President.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS REBUTTAL TESTIMONY?

A. I am submitting this Rebuttal Testimony on behalf of Northern States Power Company, a Minnesota corporation operating in North Dakota (NSPM or the Company). NSPM is a wholly-owned subsidiary of Xcel Energy Inc. (XEI).

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the Direct Testimony of Mr. Charles W. King regarding the appropriate return on equity (ROE) and capital structure for NSPM to be determined by the North Dakota Public Service Commission (the Commission) in this proceeding.

Q. HAVE YOU PREPARED ANY EXHIBITS TO SUPPORT YOUR ANALYSIS AND RECOMMENDATIONS?

A. Yes. My updated analysis and recommendations are supported by the data presented in Exhibit__ (AEB-2), Schedules 1 through 15, which have been prepared by me or under my direction.

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

A. The remainder of my Rebuttal Testimony is organized as follows:

- In Section II, I provide a summary and overview of my Rebuttal Testimony.
- In Section III, I discuss the important factors to be considered in establishing the ROE, including a review of current capital market conditions and their implications for the ROE in this proceeding.
- In Section IV, I provide updated analyses and recommendations regarding the Company's ROE.
- In Section V, I respond to Mr. King's analyses and recommendations.
- In Section VI, I discuss my conclusions and recommendations on the Company's capital structure and cost of short term debt.
- Finally, in Section VII, I summarize my conclusions and recommendations.

II. SUMMARY AND OVERVIEW

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE APPROPRIATE ROE FOR NSPM.

A. Selecting the appropriate ROE is not simply a matter of performing the calculations of the traditional ROE models, but rather a matter of judgment, as the Commission has recognized in prior cases. While the analytical results of ROE estimation models provide a starting point, it is necessary to consider other factors in determining the appropriate ROE, including the applicable standards, market conditions, and investor expectations. Based on those factors, I believe that a reasonable range for the return on equity for NSPM is between 10.00 percent and 10.50 percent. Within that range, a

10.25 percent ROE is somewhat conservative in my view, but is within the range of results produced my updated analyses.

Applicable standards. The applicable standards for selecting an ROE include: (i) consistency with returns available from other businesses having comparable risks; (ii) adequacy of the ROE to support the utility's financial integrity and access to capital at reasonable rates; (iii) and the overall reasonableness of the end results, as opposed to the theory or model applied. [1] As discussed further later in my Rebuttal Testimony, the selection of the appropriate ROE is the result of sound judgment, not the result of a mathematical calculation.

Market conditions. Estimating the Cost of Equity is a forward-looking exercise, which means that it is reasonable to consider not only current market conditions but prospective market conditions. Recent market conditions and Federal Reserve monetary policy have resulted in unsustainably low interest rates. As a result, it is important to take into account the likelihood that borrowing costs will increase rather significantly in the near to intermediate term during which the ROE set in this case might be in effect. The likelihood of increasing interest rates represents a significant risk for dividend paying stocks, such as electric and gas utilities, as interest rates on government and corporate bonds increase and become more competitive with dividend yields. That risk should be considered in selecting the ROE in this case. Furthermore, the ROE should not be set at a

[1] *Bluefield Waterworks and 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).*

level so low that a financial incentive for quickly re-filing a rate case would result.

There are some differences in market conditions since the Company's last rate proceeding; some indicating higher risk, and others indicating lower risk. On balance, market conditions today are generally similar to those in February 2012 and do not support a significant reduction in the Company's authorized ROE, much less the 140 basis point reduction recommended by Mr. King.

Investor expectations. It is important to consider investor return expectations. As I explain later in my Rebuttal Testimony, the Commission has recognized that the collective judgment of investors is the most critical test of whether an ROE is adequate.

Authorized returns in other regulatory jurisdictions provide a readily observable benchmark for returns available from investments in other utilities. It is clear that investors are interested in authorized ROEs. For example, in a recent report on regulated and diversified utilities, Morgan Stanley commented on Xcel Energy's allowed ROEs as follows:

> Unlike many of its larger peers, XEL's allowed ROEs, in the mid-to-low 10% range, have only modest risk. These ROE levels are consistent with the US average, and recent decisions have pointed toward them remaining this way, but we continue to watch them in a handful of pending rate cases this year.[2]

[2] Morgan Stanley Research North America, "Regulated and Diversified Utilities/IPPs, Refreshing Estimates and Price Targets; Outlook Unchanged," July 8, 2013, at 8.

While Mr. King believes that authorized ROEs are too high in general and urges the Commission to take a very different approach than other state commissions. Utility investors have many alternatives, and utilities such as NSPM must compete for their investment dollars. Utility investors compare the returns that can be obtained at a given level of risk and have no incentive to make investments in states with low authorized returns when higher returns are available elsewhere for comparable risk. If the Commission follows Mr. King's advice, utility investors will recognize that the authorized return for NSP in North Dakota will be at the very bottom of authorized ROEs for integrated electric utilities.

As I demonstrate later in my Rebuttal Testimony, the average authorized return for integrated electric utilities for the period from January 2012 through July 2013 was 10.04 percent, which is 104 basis points above Mr. King's recommended ROE. Further, 50 of the 51 cases decided in that period have awarded authorized ROEs exceeding the level recommended by Mr. King.

Recent experience shows that investors will downgrade their assessments of state jurisdictions as a place for utility investments as a result of extreme outlier ROE awards. For example, in 2012, after the South Dakota Public Utilities Commission authorized a 9.25 percent ROE for NSP, Regulatory Research Associates ("RRA") downgraded the South Dakota regulatory jurisdiction from "Average/2" to "Average/3". RRA indicates that these rankings are "assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by the jurisdiction's utilities. The evaluation reflects our assessment of the probable

level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative, and court actions".[3] RRA's specific commentary reflects concerns about low authorized ROEs. RRA states that "[W]e view the South Dakota regulatory environment as somewhat restrictive from an investor viewpoint. Recent decisions rendered by the PUC have contained equity returns that have been below industry averages."[4]

Investor ratings of utility commissions are important to ratepayers because a downgrade of a jurisdiction's regulatory rating is significant to investors who are concerned with a utility's business risk. For a utility, the regulatory environment is an important part of a company's overall business risk. A decrease in a jurisdiction's regulatory rating means an increase in business risk for the regulated companies operating in that jurisdiction. That increased risk could lead to an increase in the cost of capital and cost of providing service. It is reasonable to expect that an increase in the cost of capital will have more long-run implications when a utility is in the midst of a significant capital investment plan because the costs of borrowing will remain in place for a long time.

Investors continue to regard North Dakota as a constructive regulatory environment, in part because the North Dakota Commission has historically responded to changing market conditions with moderate adjustments to the allowed ROE. For example, in 2007 NSPM's authorized ROE was 10.75 percent. In the Company's most recent case, in 2012, the Commission

[3] SNL Financial, South Dakota Public Utilities Commission profile, Accessed August 5, 2013.
[4] *Ibid*.

authorized a 10.40 percent ROE, which was a 35 basis point reduction. Over that period, interest rates declined 209 basis points.

While there may be some controversy regarding certain of the investments being made by the Company, it is clear that NSPM is making very substantial investments in its nuclear and fossil generation and to refresh and upgrade the infrastructure needed to provide safe and reliable service. Investors are very sensitive to the question of whether there is regulatory support for utility investment, and the long run cost of capital can be adversely affected if investors perceive a reduction of such support.

Results of ROE estimation models. A ROE range of 10.00 percent to 10.50 percent and an ROE of 10.25 percent are reasonable and appropriate considering current market conditions, the expectation of and risk associated with rising interest rates, and my updated analysis as shown in Table 1.

Table 1
Updated Analytical Results[5]

Constant Growth DCF - Including Flotation Costs				
	Mean (Low Growth)	Mean	Mean (High Growth)	
30-Day Average Price	8.47%	9.73%	11.34%	
90-Day Average Price	8.32%	9.58%	11.19%	
180-Day Average Price	8.49%	9.75%	11.36%	
Multi-Stage DCF - Including Flotation Costs				
	Mean (Low Growth)	Mean	Mean (High Growth)	
30-Day Average Price	9.64%	9.98%	10.52%	
90-Day Average Price	9.50%	9.83%	10.35%	
180-Day Average Price	9.67%	10.02%	10.55%	
Capital Asset Pricing Model				
	Current Risk-Free Rate (3.46%)	**2013-2014 Projected Risk Free Rate (3.73%)**	**2015-2019 Projected Risk Free Rate (5.20%)**	**Mean**
Bloomberg Beta	10.56%	10.64%	11.04%	10.74%
Value Line Beta	10.41%	10.49%	10.91%	10.60%
Bond Yield Plus Risk Premium				
Risk Premium	10.17%	10.28%	10.87%	10.44%

Q. WHAT FACTORS SUPPORT A 10.25 PERCENT ROE IN THIS CASE?

A. A 10.25 percent ROE:

- Is supported by my updated analyses which is summarized above;
- Is consistent with the ROEs awarded by other state jurisdictions, which is significant to investors and a useful benchmark of comparability to other similar investments;

[5] *See* Exhibit ___ (AEB-2), Schedules 1-5.

- Will support the Company's ability to attract capital to finance investments at reasonable rates, which will provide long term benefits to ratepayers by limiting the long term cost of capital;
- Will be consistent with the Commission's past practice of preserving stability by making gradual adjustments to ROEs, which will maintain investor confidence and also contribute to long run costs of capital; and
- Balances shareholder and ratepayer interests.

Q. PLEASE PROVIDE AN OVERVIEW OF MR. KING'S ROE RECOMMENDATION IN THIS PROCEEDING.

A. Mr. King recommends an ROE for NSPM of 9.00 percent, including seven basis points for flotation costs, based on the results of his analyses. Mr. King does not offer a range of results for his proxy group. He does, however, present the results of five different analyses that he conducted to estimate the Cost of Equity for NSPM. Those results range from 7.97 percent (the median for his sustainable growth DCF analysis) to 10.02 percent (the average of recent ROE awards in other jurisdictions). Mr. King then assigns a weight to each of his results in order to calculate an overall ROE for the proxy group which he recommends for the Company.

Q. HOW DOES MR. KING'S ROE RECOMMENDATION COMPARE TO RECENT AVERAGE AUTHORIZED ROES?

A. The average authorized ROE for vertically-integrated electric utilities from January 2012–July 2013 was 10.04 percent.[6] The Company is a vertically integrated utility. In the development of our respective proxy groups, both

[6] Source: SNL Financial. *See* Exhibit ___ (AEB-2), Schedule 13.

Mr. King and I agree that a risk comparable proxy group for NSPM includes only companies that own generation.[7] As a result, the authorized return analysis for NSPM should also focus on vertically integrated utilities.

Q. DO THE DECISIONS OF OTHER REGULATORY COMMISSIONS PROVIDE A USEFUL BENCHMARK FOR COMPARABILITY TO OTHER INVESTMENTS?

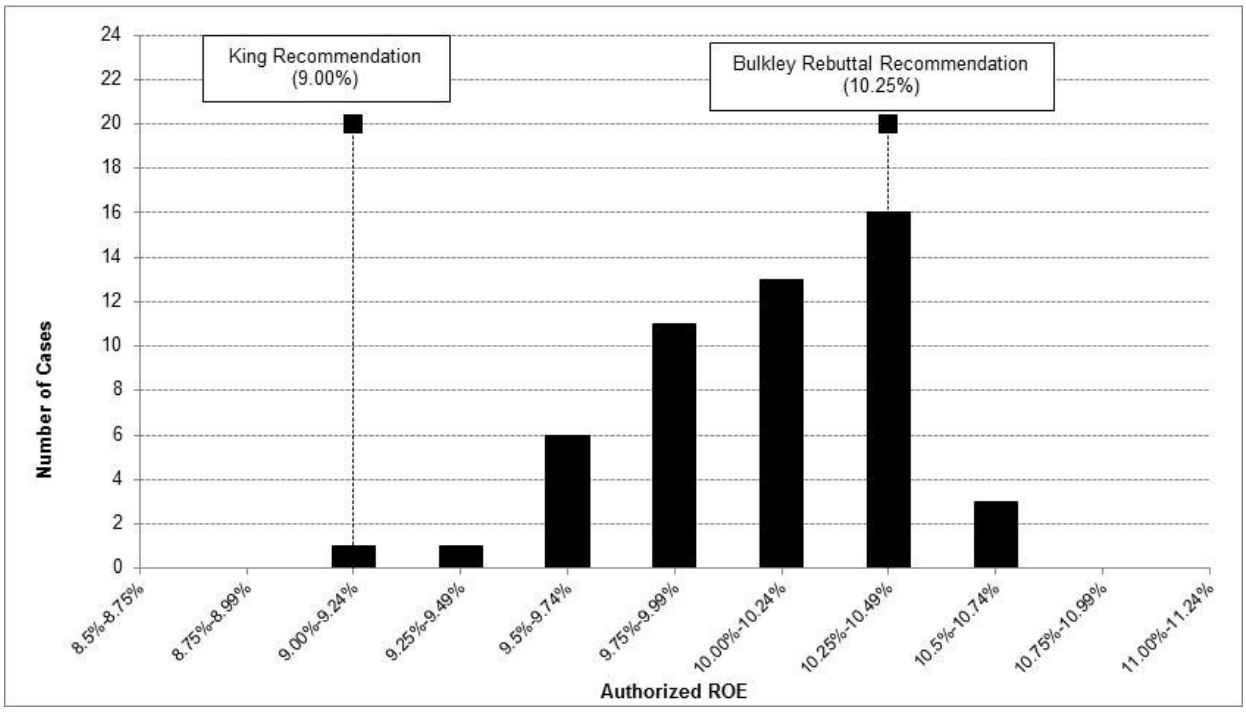
A. Yes. It is a fundamental regulatory principle that authorized ROEs must be comparable to other investments of commensurate risk. The regulatory decisions of other Commissions provide a basic test of reasonableness and a benchmark that investors consider in assessing the authorized ROE against the returns available from other regulated utilities with comparable risk.

As shown on the Chart 1 below, 50 out of 51 cases during this time period have been above Mr. King's recommended return.[8] This evidence supports my view that Mr. King's ROE recommendation would not allow NSPM to compete for equity capital with other comparable risk electric utility companies. Authorized ROEs are a widely available and readily understood benchmark that investors use to compare utility investment alternatives. If the Commission were to accept Mr. King's ROE recommendation of 9.00 percent, both large and small utility investors would recognize that NSP's ROE in North Dakota was below almost all other states and would have strong incentives to make investments in other states with more attractive return potential.

[7] Direct Testimony of Charles W. King at 15.

[8] The only integrated electric utility that was authorized a 9.00 percent ROE was Maui Electric Company. This decision arose from a Commission modification to a proposed settlement.

Chart 1
Authorized ROEs for Integrated Electric Utilities[9]
January 2012 through July 2013
Average ROE: 10.04%



Q. DO YOU AGREE WITH MR. KING'S OPINIONS REGARDING DECISIONS BY OTHER STATE COMMISSIONS?

A. No, I do not. Mr. King claims that ROEs authorized by state commissions "have been artificially higher than necessary" and that "eliminating the glass floor of ten percent would provide a boost to the economy."[10] Mr. King's position dismisses the collective decisions of many utility regulators across the country and ignores the inverse relationship between interest rates and the equity risk premium. In addition, Mr. King's recommendation also

[9] While the analysis of authorized ROEs presented in Mr. King's Direct Testimony was not limited to integrated electric utilities, Mr. King and I agree that it is important to include only those companies that are integrated electric utilities in the proxy group. *See* Direct Testimony of Charles W. King at 15.

[10] Direct Testimony of Charles W. King, at 10.

suggests that investors would be willing to accept a return from the Company's North Dakota operations that is more than 100 basis points less than the average authorized ROE for other integrated electric utilities in other states. There is no support for this position. Further, as I will discuss later in my Rebuttal Testimony, adoption of Mr. King's ROE recommendation could be detrimental for North Dakota rate payers over the longer term.

Q. DOES AN EXTREMELY LOW AUTHORIZED ROE PROVIDE FINANCIAL INCENTIVES TO A UTLITY TO FILE ANOTHER RATE CASE?

A. Yes. Investors expect utility management to take appropriate actions to obtain a reasonable return. Accordingly, an extremely low authorized ROE could provide a strong incentive to promptly reapply for a rate increase and a reasonable return. The incentive to re-file is made stronger by the Company's history of low actual earnings in North Dakota, as shown on Exhibit ___(AEB-2), Schedule 15, which is based on the Company's annual reports to the Commission.

III. FACTORS TO BE CONSIDERED IN ESTABLISHING THE ROE

Q. WHAT FACTORS SHOULD BE CONSIDERED IN EVALUATING THE RESULTS OF ROE MODELS AND ESTABLISHING THE AUTHORIZED ROE?

A. The primary factors that should be considered are: (i) the importance of investors' *actual* return requirements and the critical role of judgment in selecting the ROE, as compared to mathematical results of models; (ii) the importance of providing a return that is comparable to returns of other

electric utilities with commensurate risk that are available to investors; (iii) the need for a return that supports a utility's ability to attract needed capital at reasonable terms, which affects the long run cost of capital and cost of service; (iv) the importance of a Commission maintaining relative long term stability of returns rather than reacting to short-term factors; and (v) the effect of current and expected capital market conditions.

Q. HAS THE COMMISSION RECOGNIZED THE IMPORTANCE OF INVESTOR RETURN REQUIREMENTS AND THE USE OF JUDGMENT IN SETTING THE ROE?

A. Yes. The Commission has recognized that selecting the ROE is not a mathematical exercise and that investors' perspective is the most important test in selecting the ROE, stating:

> There is no one percentage that can be termed "fair" nor is there any mathematical formula available to solve the problem. There can be many variations of opinion depending largely on the weight to be given to the different elements considered in deriving a return… Such an approach [the cost of capital approach used by the witnesses] is helpful as a guide but is by no means a precise measure of the return that should be earned. In the final analysis, the collective judgment of the investors is the most important and crucial test of whether a return is adequate. The rate of return is not something that can be fixed with mathematical precision nor do the rates fixed assure that a given return will result.[11]

The Commission has affirmed the importance of judgment, stating:

> [A] fair rate of return is a figure reached through the exercise of judgment rather than a figure resulting from a simple arithmetic computation.[12]

[11] 47 PUR 3d, North Dakota Public Service Commission, Re: Montana-Dakota Utilities Company, Case No. 6224, December 14, 1962, at 61. Emphasis added.

[12] 47 PUR 3d, North Dakota Public Service Commission, Re: Otter Tail Power Company, Case No. 6344, July 29, 1963, at 310.

Q. PLEASE EXPLAIN THE REQUIREMENT THAT THE ROE BE SUFFICIENT TO ENABLE A UTILITY TO RAISE CAPITAL ON REASONABLE TERMS.

A. The ROE needs to be sufficient to allow the Company to attract capital at reasonable rates. This requirement will have a long term effect on the utility's cost of capital and the corresponding cost of service for ratepayers. A decision to reduce a utility's authorized ROE below the level available from other comparable utilities may provide short term rate reductions at the expense of long term cost increases. The Commission has also recognized the importance of this principle in a previous decision, stating: "The return to equity owners should be commensurate with the return on investments on other enterprises having corresponding risks and also sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital."[13] If the Company cannot attract capital, there are negative consequences for ratepayers. While they may be controversy regarding certain of the investments being made by the Company, it is clear that NSPM is in a very substantial construction phase and that the costs of capital incurred for this construction will affect the cost of service for many years. An authorized ROE of 9.00 percent, as proposed by Mr. King, is not sufficient based on current market conditions and the returns on alternative investments of comparable risk.

[13] *Ibid*, at 60.

Q. PLEASE EXPLAIN THE IMPORTANCE OF MAINTAINING RELATIVE STABILITY IN SETTING ROEs.

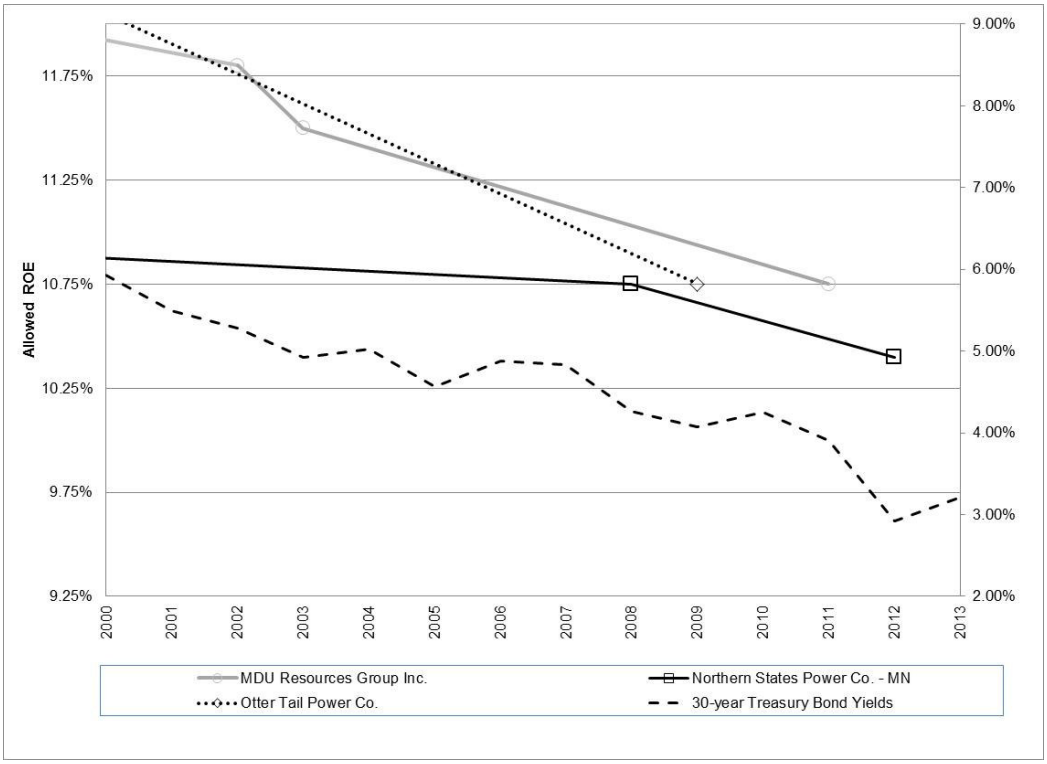
A. It is important to consider how investors would perceive an authorized ROE of 9.00 percent for NSPM in North Dakota. According to Regulatory Research Associates, "The North Dakota regulatory climate continues to be somewhat constructive from an investor viewpoint. Equity return authorizations are typically in line with, or slightly above, nationwide averages at the time established by the PSC."[14] An authorized ROE of 9.00 percent would not be perceived by investors as a supportive regulatory climate. In turn, such perceptions could make it difficult for NSPM to attract capital.

Q. HOW HAS THE COMMISSION HISTORICALLY ESTABLISHED THE ALLOWED ROE?

A. The Commission has historically adjusted the allowed ROE in a measured, gradual manner in response to changing market conditions, which has helped to persuade equity investors that utilities in North Dakota can expect to receive compensatory returns, and that any adjustments will be gradual. As shown on Chart 2 below, the authorized ROE for the three major electric utilities in North Dakota has fallen gradually since 2000 as interest rates have declined. However, the change in ROE has been much more gradual than Mr. King's proposal to reduce the Company's ROE by 140 basis points (from 10.40 percent to 9.00 percent) over an eighteen-month period.

[14] SNL Financial, North Dakota Commission Profile, accessed July 29, 2013.

CHART 2
AUTHORIZED ROEs FOR ELECTRIC UTILITIES IN
NORTH DAKOTA - 1990-PRESENT



Adoption of Mr. King's ROE recommendation of 9.00 percent could cause investors to question the stability and certainty of the regulatory climate in North Dakota, and ultimately could lead to higher capital costs (both debt and equity) for ratepayers. For this reason, it would be reasonable for the Commission to continue to pursue a policy of gradualism with respect to ROE awards, especially when, as discussed in the next section, interest rates are projected to rise over the next few years.

Q. PLEASE SUMMARIZE MR. KING'S POSITION ON CAPITAL MARKET CONDITIONS AND THE IMPLICATION FOR THE COST OF EQUITY.

A. Mr. King provides an overview of current economic and capital market conditions. In particular, Mr. King observes that interest rates on

government and corporate bonds are near historic lows,[15] although he does acknowledge that yields have been "inching up" on government bonds and utility bonds in the last several weeks due to uncertainty over when the Fed will reverse the policy of quantitative easing.[16] According to Mr. King, "the principal implication is that the desirability of utility stocks relative to other forms of investment has increased with the decline in interest rates."[17]

Q. DO YOU AGREE WITH MR. KING'S ASSESSMENT?

A. No, I do not. While Mr. King is correct that interest rates on government bonds have been near historically low levels, I disagree with his conclusion that low interest rates imply a correspondingly low Cost of Equity for electric utilities such as NSPM. Further, Mr. King focuses on the *current* level of interest rates rather than the markets' *expectation* that interest rates on both government and corporate bonds are projected to increase substantially over the next five years. Since the process of estimating the Cost of Equity is a forward-looking exercise, it is not appropriate to base that estimate entirely on the current level of interest rates and economic conditions, especially when those interest rates are expected to be significantly higher in the next several years.

Mr. King is correct that interest rates have been steadily declining for the past three decades. However, that period of declining interest rates cannot continue forever. In fact, many economists are predicting that markets are at or near a turning point, and that interest rates will increase by several

[15] Direct Testimony of Charles W. King, at 3-5.
[16] Direct Testimony of Charles W. King, at 30.
[17] *Ibid*, at 8.

percentage points from current levels as the Federal Reserve begins to consider tapering the extraordinary monetary stimulus and as the domestic economy continues to recover from the last recession.[18] This change in Federal Reserve policy would represent a significant risk for dividend paying stocks such as electric and gas utilities, as interest rates on government and corporate bonds become more competitive with dividend yields.

Q. IS THERE EVIDENCE THAT LONG-TERM INTREST RATES ARE EXPECTED TO INCREASE?

A. Yes. The 30-day average yield on the 30-year U.S. Treasury bond as of July 12, 2013 was 3.46 percent. By contrast, the Blue Chip Financial Forecast consensus estimate projects that the average yield on the 30-year U.S. Treasury bond will increase to 5.20 percent for the period from 2015 through 2019.[19] Thus, the consensus estimate from leading economists is an increase of 174 basis points in U.S. Treasury bond yields over the next several years.

Investment advisors and financial industry regulators have recently warned investors about the risks associated with rising interest rates. For example, the Financial Industry Regulatory Association recently issued the following statement:

> Currently, interest rates are hovering near historic lows. Many economists believe that interest rates are not likely to get much lower and will eventually rise. If that is true, then outstanding bonds, particularly those with low interest rates and high duration may experience significant price drops as interest rates

[18] Wall Street Journal, "Fed's Lockhart Says Reduction in Bond Buys Could Come in September", August 6, 2013. Wall Street Journal, "IMF Urges More Clarity from Fed", July 26, 2013.

[19] Blue Chip Financial Forecasts, Vol. 32, No. 6, June 1, 2013, at 14.

> rise along the way. If you have money in a bond fund that hold primarily long-term bonds, expect the value of that fund to decline, perhaps significantly, when interest rates rise.[20]

Q. HAS THE FEDERAL OPEN MARKET COMMITTEE PROVIDED ANY GUIDANCE ON FORWARD LOOKING INTEREST RATES?

A. Yes. In May 2013, the Federal Open Market Committee (FOMC) report summarized member views on monetary policy. Certain members expressed views that continuing to communicate the intention to keep the Federal Funds rate at an extremely low level could result in macroeconomic and financial imbalances, suggesting that the FOMC might start to taper its purchases of long-term Treasury bonds. Mr. Bernanke, the Chairman of the Board of Governors of the Federal Reserve System noted that "a long period of low interest rates has costs and risks" including "the possibility that very low interest rates, if maintained too long, could undermine financial stability." Furthermore, Mr. Bernanke noted that the FOMC "actively seeks economic conditions consistent with sustainably higher interest rates."[21]

Q. HOW DID FINANCIAL MARKETS REACT TO THE FOMC MAY 2013 POLICY STATEMENT?

A. The financial market response was quite dramatic, especially in government and corporate bond markets and among dividend paying stocks such as electric utilities. Chart 3 below compares the yield on the 30-year Treasury to the performance of the S&P 500 index and the S&P Utility index in 2013.

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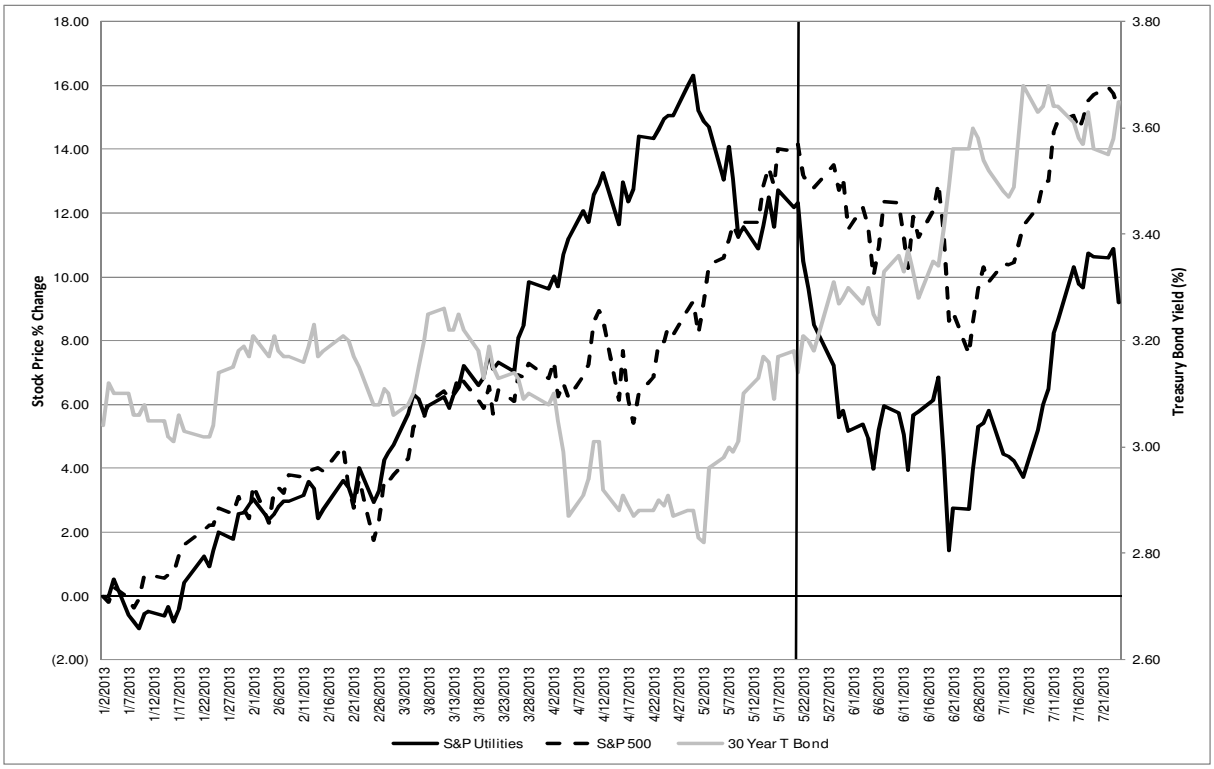
[20] Financial Industry Regulatory Association, "Duration – What an Interest Rate Hike Could Do to Your Bond Portfolio," February 14, 2013.

[21] Statement by Ben S. Bernanke, Chairman Board of Governors of the Federal Reserve System before the Joint Economic Committee of the U.S. Congress, May 22, 2013. Federal Open Market Committee Meeting Minutes, May 2013.

Chart 3
Comparison of Returns for S&P 500 and S&P Utilities Index to 30-Year Treasury Yields



As shown on the chart, the S&P utility index was quite strong until May 2013, when the FOMC policy statement was released. Since that time, interest rates on 30-year Treasury Bonds have increased from approximately 2.80 percent in late April to slightly above 3.60 percent in late July, while the S&P utility index decreased from a 16.30 percent gain for the year through April 30, 2013 to a 1.41 percent gain for the year by June 20, 2013. Since that date, the S&P 500 has recovered to its previous level of late April, but the S&P utility index remains well below the April peak. This demonstrates the effect that rising interest rates have on utility stocks relative to the broader market.

Q. WHAT EFFECT DO RISING INTEREST RATES HAVE ON THE COST OF EQUITY?

A. The potential for rising interest rates would indicate that the calculated Cost of Equity for the proxy companies using current market data is likely to be conservative. Consequently, rising interest rates would support selection of a return toward the upper end of a reasonable range of equity cost rate estimates.

Q. HOW DO CURRENT CAPITAL MARKET CONDITIONS COMPARE TO THOSE AT THE TIME OF NSPM'S LAST RATE CASE DECISION?

A. Market conditions today are not significantly different than they were in February 2012, when the Commission approved NSPM's current ROE of 10.40 percent;

- Credit spreads have narrowed approximately 12-20 basis points since the date of that decision.
- The spread between the dividend yield for the proxy group and the 10-year Treasury bond yield has also narrowed, especially in the past two months, but continues to be very volatile.
- Interest rates are projected to increase, which has a negative effect on the utility's ability to attract capital.
- As shown in Table 2, (below), short-term projected interest rates are higher today than in February 2012.
  - 2013-2014 average projected Treasury yield in February 2012 was 3.41 percent as compared with the current average projection of 3.79 percent, an increase of 38 basis points.

– Five-year projected Treasury yields in December 2011, as reported by Blue Chip Financial Forecast, were 5.10 percent for the 2013-2017 period, as compared to the long-term projection of 5.20 percent for the 2015-2019 period reported by Blue Chip in June 2013.

Comparing current market data to the market conditions in February 2012, when the ROE was last authorized for NSPM, current market data does not support a 140 basis point reduction in NSPM's authorized ROE, as recommended by Mr. King.

Table 2
Comparison of market conditions February 2012 and July 2013[22]

	July 2013	February 2012	Difference (7/13-2/12)
Moody's Baa-rated Utility Bond and Moody's A-rated Utility Bond Credit Spreads[23]	0.51%	0.70%	-0.19%
30-year Treasury Yields (18-month projection)[24]	3.79%	3.41%	0.38%
30-year Treasury Yields (5-year projection)[25]	5.20%	5.10%	0.10%

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF HIGHER INTEREST RATES FOR ELECTRIC UTILITIES SUCH AS NSPM?

A. My primary conclusion is that the potential for higher interest rates is a significant risk factor for electric utilities over the next few years. If the allowed ROE is set at a level that reflects the unusually low interest rate environment of the past two years, and interest rates increase to more historically normal levels, then electric utilities such as NSPM will not have a

22 90-day average.
23 Bloomberg.
24 Blue Chip Financial Forecasts
25 Blue Chip Financial Forecasts

reasonable opportunity to actually earn their authorized ROE, and they will need to file more frequent rate cases in order to recover their prudently-incurred allowable costs in a timely fashion. For that reason, I recommend an authorized ROE for NSPM that takes into consideration the likelihood that borrowing costs will increase in the near to intermediate term during which rates might be in effect. This is not the appropriate time to be reducing NSPM's allowed ROE below 10.00 percent, as investors are becoming increasingly concerned with the implications of higher interest rates.

IV. UPDATED ANALYSES

Q. HAVE YOU UPDATED YOUR DCF ANALYSES?

A. Yes. I have updated the Constant Growth and Multi-Stage DCF analyses based on data through July 12, 2013. In the Constant Growth DCF analysis and the first stage of the Multi-Stage DCF analysis, I have continued to use earnings growth estimates from Zacks, First Call, and Value Line as the relevant measure of growth and to present results for the most recent 30, 90 and 180-trading days. The updated mean results of my DCF analysis, including flotation costs of 24 basis points, are shown on Exhibit __ (AEB-2), Schedules 1-3 and in Table 3 (below).

Table 3
Updated DCF Results

	Mean (Low Growth)	Mean	Mean (High Growth)
Constant Growth DCF			
30-Day Average	8.47%	9.73%	11.34%
90-Day Average	8.32%	9.58%	11.19%
180-Day Average	8.49%	9.75%	11.36%
Multi-Stage DCF			
	Mean (Low Growth)	**Mean**	**Mean (High Growth)**
30-Day Average	9.64%	9.98%	10.52%
90-Day Average	9.50%	9.83%	10.35%
180-Day Average	9.67%	10.02%	10.55%

Q. HAVE YOU PERFORMED AN UPDATED CAPM ANALYSIS?

A. Yes, I have also updated the CAPM analysis to reflect market data as of July 12, 2013. The updated results are shown in Table 4 (below) (*see* also Exhibit __ (AEB-2), Schedule 4.0.

Table 4
Updated CAPM Results

	Current 30-Year Treasury (3.46%)	2013-2014 Projected 30-Year Treasury (3.73%)	2015-2019 Projected 30-Year Treasury (5.20%)	Mean Result
Bloomberg Beta	10.56%	10.64%	11.04%	10.74%
Value Line Beta	10.41%	10.49%	10.91%	10.60%

Q. HAVE YOU UPDATED THE BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. Yes. The updated Bond Yield Plus Risk Premium analysis includes authorized ROEs as reported by RRA through July 12, 2013 for electric

utilities. As shown in Exhibit__ (AEB-2), Schedule 5, my updated risk premium results range from 10.17 percent to 10.87 percent, with a mean result of 10.44 percent.

Q. WHAT IS YOUR ROE RECOMMENDATION BASED ON THIS UPDATED ANALYSIS?

A. My updated ROE recommendation is 10.25 percent. This ROE recommendation is well within the range of DCF results and reflects several factors, including:

- A 10.25 percent ROE better reflects the similarities of market conditions between now and the time of the Company's last rate case, in which the Company received a 10.40 percent ROE.
- A 10.25 percent ROE is within the range of the ROE decisions of other state commissions and will support the financial integrity of NSPM and enable the Company to attract capital at reasonable rates.
- A 10.25 percent ROE will facilitate rate stability and could avoid providing strong financial incentives for the Company to quickly re-file a request to increase rates.

V. RESPONSE TO MR. KING'S ANALYTICAL METHODOLOGY

Q. PLEASE SUMMARIZE MR. KING'S ANALYSES AND RECOMMENDATION.

A. Mr. King recommends an ROE for NSPM of 9.00 percent based on his proxy group of 16 electric utilities which he considers risk comparable to NSPM. Mr. King does not offer a range of results based on his various analyses. Rather, Mr. King offers a single point recommendation based on

his weighting of the results of five ROE estimates, including: (1) the Constant Growth DCF model, (2) the Three-Stage DCF model, (3) the Sustainable Growth DCF model, (4) the Capital Asset Pricing Model, and (5) recent ROE awards in other jurisdictions. Mr. King indicates that, in his view, the Constant Growth DCF model using earnings growth rates provides the most reliable ROE estimate,[26] and he offers numerous reasons why the other models are not as reliable for purposes of estimating the Cost of Equity for NSPM.[27] Despite his concerns about many of the estimation models, Mr. King arrives at his ROE recommendation by assigning specific weight to the results of each of the five ROE estimation approaches that are developed in his testimony.

Q. PLEASE SUMMARIZE YOUR PRIMARY CONCERNS WITH MR. KING'S ANALYSES.

A. In several instances, Mr. King's testimony and analyses contain significant internal inconsistencies and are different than the position he has taken in other recent cases. In addition, I disagree with certain of the methodologies that Mr. King relies on in developing his ROE recommendation. The following summarize those areas of disagreement.

- I do not believe that it is appropriate to assign any weight to Mr. King's "Three-Stage" DCF model.
  - Mr. King's Three-Stage DCF does not actually consider growth in three separate stages and does not consider the time value of money, as is typical of this form of the DCF model where growth rates differ over periods of years. By averaging the three "stages" of growth and adding that to the dividend yield, Mr. King's Three-

[26] Direct Testimony of Charles W. King, at 19.
[27] Direct Testimony of Charles W. King, at 23 and 27.

Stage DCF model is simply another form of the Constant Growth DCF model.

- Similar to the Multi-Stage DCF model, I do not believe that the results of Mr. King's Sustainable Growth DCF model should be afforded any weight in the final ROE recommendation for three reasons.
  - First, Mr. King's sustainable growth model relies on a fundamental assumption that low retention ratios are associated with low future earnings growth rates. Academic studies performed in 2003 demonstrate the opposite is true; that is, future earnings growth is associated with high dividend payout ratios.
  - Second, while Mr. King's sustainable growth DCF model relies on data from Value Line, the results of that model are 182 basis points lower than the Value Line average projected ROE for Mr. King's proxy group.
  - Third, in his Direct Testimony, Mr. King enumerates several concerns with the sustainable growth model. In fact, in a recent case before the New York Public Service Commission, a jurisdiction that primarily relies on the sustainable growth model, Mr. King did not include this model in his analysis.
- Mr. King's analyses are inconsistent with his criticisms of the analyses contained in my Direct Testimony.
  - Mr. King's sustainable growth DCF analysis uses projected figures from Value Line for the 2016-18 period, even though he criticizes my CAPM analysis for using forecasted interest rates over that same time period.

- Mr. King dismisses my Bond Yield plus Risk Premium analysis as circular, but he gave weight to a very similar analysis in a Maryland case involving Baltimore Gas and Electric in testimony filed in October 2012.
- In his analysis of recent returns in other jurisdictions, Mr. King includes transmission and distribution companies, even though he excludes those same companies when he is selecting his proxy group for NSPM.

• Finally, Mr. King's flotation cost adjustment does not recognize that flotation costs are a permanent adjustment to the equity capital of the company and therefore need to be considered permanently.

Q. HOW HAVE YOU ADDRESSED THOSE INCONSISTENCIES?

A. I recommend that Mr. King's "Multi-Stage" DCF and sustainable growth DCF results be given no weight in the determination of the ROE in this case. As shown on Table 8 (below), (*see also* Exhibit___(AEB-2), Schedule 6) I have applied Mr. King's relative weights to the remaining models and included the results of the Bond Yield plus Risk Premium analysis, which produces an ROE estimate of 9.97 percent.

A. Proxy Group Selection

Q. PLEASE DESCRIBE THE SCREENING CRITERIA THAT MR. KING USED TO SELECT HIS PROXY GROUP.

A. Mr. King used four screening criteria to develop his proxy group: (1) the percentage of revenues derived from electric utility operations; (2) the percentage of revenues from non-regulated operations; (3) S&P credit ratings within two notches of NSP's current rating of A-; and (4) utilities that

are vertically integrated (*i.e.,* they own generation assets).[28] Based on these screens, Mr. King selects a group of 16 electric utilities which he asserts are comparable in business and financial risk to NSPM.[29]

Q. IS IT IMPORTANT TO SELECT A PROXY GROUP THAT IS SIMILAR IN OVERALL FINANCIAL AND BUSINESS RISK TO THE SUBJECT COMPANY?

A. Yes. Selecting a proxy group that is comparable to the subject company is essential to meeting the criteria of comparability of earnings, as the United States Court of Appeals for the District of Columbia (the "Court of Appeals") has explained:

> That proxy group arrangements must be risk-appropriate is the common theme in each argument. The principle is well-established. *See Hope Natural Gas Co.*, 320 U.S. at 603 ("[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."); … The principle captures what proxy groups do, namely, provide market-determined stock and dividend figures from public companies comparable to a target company for which those figures are unavailable.[30]

Q. HOW DOES YOUR PROXY GROUP DIFFER FROM MR. KING'S?

A. As shown in Table 5 (below), eleven of the 17 companies in Mr. King's proxy group are included in my proxy group. The reason each company in Mr. King's proxy group was excluded from my proxy group is provided in the far right column.

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28 Direct Testimony of Charles W. King, at 14-15.

29 On Exhibit CWK-2, Schedule 1, Mr. King excludes American Electric Power from his proxy group because he indicates the company does not pass his credit rating screen. However, AEP has an S&P rating of BBB, not B as reported by Mr. King. Therefore, AEP passes Mr. King's screen and should be included in his proxy group. Further, on that same exhibit, Mr. King indicates that TECO Energy is included in his proxy group. However, TECO does not pass his revenue screen. It does not appear that Mr. King included TECO in his analysis on the subsequent exhibits.

30 *Petal Gas Storage v. FERC*, 496 F.3d 695, 699 (D.C. Cir. 2007).

TABLE 5
COMPARISON OF BULKLEY AND KING PROXY GROUPS

	Ticker	Bulkley Proxy Group	King Proxy Group	Reason Excluded from Bulkley Proxy Group[31]
ALLETE	ALE	□	□	
Alliant Energy Corp.	LNT		□	(1)
American Electric Power	AEP	□	□	
Cleco Corp.	CNL	□	□	
Duke Energy	DUK		□	(2)
El Paso Electric	EE		□	(3)
Empire District Electric	EDE	□	□	
First Energy Corp.	FE	□		
Great Plains Energy	GXP	□	□	
Hawaiian Electric	HE	□		
IDACORP	IDA	□	□	
Northwestern Corp.	NWE		□	(1)
Otter Tail Power	OTTR	□		
PG&E Corp.	PCG		□	(1)
Pinnacle West Capital	PNW	□	□	
Portland General	POR	□	□	
Southern Company	SO	□	□	
Westar Energy	WR	□	□	
Wisconsin Energy	WEC	□	□	
Xcel Energy Corp.	XEL		□	(4)

Q. DO YOU AGREE WITH MR. KING'S SCREEN BASED ON THE PERECENTAGE OF REVENUE FROM ELECTRIC UTILITY OPERATIONS?

A. No, I do not. While I agree with Mr. King that it is important to select companies that are primarily engaged in electric utility operations, I disagree with his screen based on the percentage of revenues from electric utility

[31] Reasons: (1) – Percent operating income derived from regulated electric operations; (2) – involved in merger or significant transaction; (3) – history of consistent quarterly cash dividends; (4) – parent company of NSPM.

operations. As Mr. King recognizes in his testimony, utility investors are interested in *income* from dividends. Dividends are a function of *earnings, not revenues*. As such, it is more appropriate to screen potential proxy companies based on operating income rather than revenue because operating income is more closely related to earnings, which are then used to support dividend payments. For that reason, I have selected my proxy group based on the percentage of operating income that each company derived from regulated electric operations over the past three years.

Q. WHAT IS YOUR RESPONSE TO MR. KING'S CONCERN WITH THE INCLUSION OF OTTER TAIL CORPORATION IN YOUR PROXY GROUP?

A. Mr. King excludes Otter Tail Corporation from his proxy group because it does not pass his screening criteria for percent of revenue derived from electric operations and credit rating.[32] Mr. King cites Otter Tail as an example of why his revenue screen is more appropriate than my operating income screen.[33] I disagree with Mr. King with respect to the inclusion of Otter Tail Corp. in the proxy group for NSPM for several reasons. According to the most recent Value Line report for Otter Tail, which Mr. King also relies on:

> The company has made several important divestitures in recent years, which has allowed it to reduce its risk profile and increase focus on the Electric business. This line ought to benefit from a substantial increase in its regulated rate base and should deliver more predictable growth. Otter Tail plans to

[32] Mr. King excludes companies that are not within two bond ratings of the A- rating that S&P has assigned to NSP. My screening criteria exclude companies that do not have an investment grade rating by S&P or Moody's.

[33] Direct Testimony of Charles W. King, at 31-32.

> invest in generation and transmission projects for this business that should boost earnings and returns on capital.[34]

This is consistent with Otter Tail's recent investor presentation in which the company indicated that its focus is on expanding the regulated electric utility business. Otter Tail projects compound annual growth in electric utility rate base of 10.5 percent from 2013-2017[35] and targets approximately 75 percent of earnings from electric utility operations.[36] Based on this information, it is clear that Otter Tail's future earnings growth will be driven by electric utility operations. As such, I have continued to include Otter Tail in my proxy group for NSPM.

Q. WHAT IS YOUR CONCLUSION WITH RESPECT TO THE APPROPRIATE PROXY GROUP FOR NSPM IN THIS PROCEEDING?

A. For the reasons explained in my Rebuttal Testimony, my proxy group of thirteen electric utilities is risk comparable to NSPM and therefore I have made no adjustments to my proxy group based on Mr. King's suggestions.

B. Calculation of Dividend Yield in Constant Growth DCF Model

Q. PLEASE EXPLAIN MR. KING'S CALCULATION OF THE DIVIDEND YIELD AND HOW THAT COMPARES TO THE METHOD USED IN YOUR TESTIMONY.

A. Mr. King calculates the dividend yield based on projected dividends from Value Line for each company in his proxy group for the last two quarters of 2013 and the first two quarters of 2014. By comparison, my approach adjusts the most recent annual dividend for future expected growth. Since

[34] Value Line, Otter Tail Corporation, June 21, 2013.
[35] Otter Tail Corporation, Presentation to Edison Electric Institute Course on Strategy, May 2013, Slide 7.
[36] *Ibid*, Slide 3.

dividends are changed at different times throughout the year, the calculation is made by multiplying the most recent annual dividend by 0.5X the growth rate for each company in my proxy group.

Q. WHY DO YOU DISAGREE WITH MR. KING'S APPROACH?

A. The Constant Growth DCF model assumes that earnings, dividends, and book value per share all grow at the same constant rate and that the dividend payout ratio remains constant. Mr. King's dividend yield calculation violates these assumptions by including dividend payments that are the same in the future period as in the current period even though earnings are expected to increase. Holding the dividend payments constant effectively assumes, contrary to the fundamental assumptions of the Constant Growth DCF model, that the dividend payout ratio will change.

Q. PLEASE DISCUSS MR. KING'S EXAMPLE OF THE EMPIRE DISTRICT ELECTRIC DIVIDEND GROWTH ASSUMPTIONS.

A. As support for his approach, Mr. King cites the Empire District Electric ("EDE") dividend assumption. Value Line projects the EDE dividend as $1.00 in both 2013 and 2014. Mr. King notes that EDE had not made any changes to its dividend payment for several periods prior to its dividend cut in 2011. Therefore, Mr. King concludes that it is not reasonable to assume an increasing dividend.

Q. DO YOU AGREE WITH THIS CONCLUSION?

A. No, I do not. In addition to being inconsistent with the DCF model, the underlying facts do not support his conclusion. EDE suspended its dividend payment for two quarters in 2011 after the tornado in Joplin,

Missouri, stating that it would resume the dividend in 2012 at a lower rate. EDE did, in fact, reinstate the dividend at the lower $1.00 level in 2012. Under my approach, EDE's dividend payment is expected to grow by 4.0 percent from $1.00 to $1.04 per share. This seems reasonable considering that the previous dividend had been $1.28 per share and that the reinstated lower dividend related to an explainable event. As such, I do not share Mr. King's opinion that the EDE dividend history supports his position.

Q. DO YOU HAVE OTHER SPECIFIC CONCERNS WITH MR. KING'S CALCULATION OF THE DIVIDEND YIELD FOR HIS PROXY COMPANIES?

A. Yes, I do. Mr. King's dividend yield calculation for Pinnacle West Capital ("PNW") is incorrect because the dividend used by Mr. King is not a regular annual dividend for PNW. The PNW dividend for 2013 as reported by Value Line was $1.66 per share.[37] However, as Value Line explains, this amount includes only three dividend payments because PNW moved the January 2013 dividend payment to December 2012 in an effort to avoid possible higher tax rates on dividends.[38] The actual quarterly dividend for PNW in the third quarter of 2013 is $0.55 per share, which Value Line projects will increase to $0.57 in the fourth quarter of 2013 and the first two quarters of 2014. Therefore, the dividend yield for PNW using Mr. King's method would be 3.88 percent rather than the 3.41 percent that he has calculated. As shown in Exhibit___ (AEB-2), Schedule 7, correcting the dividend yield calculation for PNW increases the average of Mr. King's Constant Growth DCF results from 9.11 percent to 9.21 percent.

[37] Value Line, Pinnacle West Capital Corporation, May 3, 2013.
[38] *Ibid*.

C. Application of Multi-Stage DCF model

Q. PLEASE DISCUSS THE RESULTS OF MR. KING'S MULTI-STAGE (OR THREE-STAGE) DCF MODEL.

A. Mr. King's Multi-Stage DCF analysis produces an ROE estimate of 8.43 percent.[39] Mr. King does not present his Multi-Stage DCF results for each individual company in his proxy group, so it is not possible to determine from his exhibit if any of the individual company results should be excluded as being below the 7.23 percent floor that he establishes for his Constant Growth DCF results.

Q. PLEASE SUMMARIZE THE MULTI-STAGE MODEL AND MR. KING'S APPLICATION OF THAT MODEL.

A. The Multi-Stage DCF is designed to allow for different growth rate assumptions in the near term, intermediate term and long term. As discussed in my Direct Testimony, the Multi-Stage DCF model utilizes different growth rates in different time periods, and discounts those growth rates back to the net present value at the current period.[40] Discounting the growth rates recognizes the time value of money of different growth rates during different time periods. Mr. King states that he relies on Value Line dividend growth rates in the first stage (years 1-5), average earnings per share growth rates in the second stage (years 6-10), and GDP growth rate projections from the Congressional Budget Office and Social Security Administration in the third stage (year 11 and beyond).[41]

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39 *See* Exhibit CWK-2, Schedule 3.
40 Direct Testimony of Ann E. Bulkley, at 18-19.
41 Direct Testimony of Charles W. King, at 20.

Although Mr. King's testimony suggests that he has utilized different growth rates in different time periods (or stages),[42] this does not appear to be the case. As shown on Exhibit CWK-2, Schedule 3, Mr. King derives his growth rate by simply averaging the growth rates for his three "stages". That is, the growth rate in Mr. King's Multi-Stage DCF model is a simple average of (1) dividend growth rates from Value Line, (2) the average of analyst earnings growth rates and long-term GDP growth rates, and (3) long-term GDP growth rates. Mr. King then adds the dividend yield to the average growth rate to arrive at his Multi-Stage DCF result. By applying a simple average of the three growth rates discussed above, Mr. King's Three-Stage DCF model fails to reflect the time value of money, which is inconsistent with the theory that the return that is estimated using the Multi-Stage DCF model reflects changes in rates of growth over time. Mr. King's Three-Stage DCF model is actually a Constant Growth DCF model that uses the average of three different sources of growth rates rather than relying on one estimate of growth. As such, Mr. King's model is not properly characterized as a Multi-Stage or Three-Stage DCF model and should be given no weight in the selection of the ROE.

By contrast, my Multi-Stage DCF model utilizes different growth rates in the three different stages, including long-term GDP growth in the third stage (which covers years 11-200 in my multi-stage model), as explained in my Direct Testimony.[43]

[42] Direct Testimony of Charles W. King, at 20.
[43] Direct Testimony of Ann E. Bulkley, at 18-19.

Q. DO YOU DISAGREE WITH OTHER ASPECTS OF MR. KING'S MULTI-STAGE DCF ANALYSIS?

A. Yes, I disagree with four other aspects of his analysis. First, as discussed previously in my Rebuttal Testimony, Mr. King's dividend yield calculation for PNW is incorrect because the dividend used by Mr. King is not a regular annual dividend for PNW. Correcting that calculation increases the average dividend yield for Mr. King's proxy group to 3.85 percent.

My second area of disagreement is with the Value Line dividend growth rate that Mr. King relies on in the first stage of his analysis. Throughout his testimony, Mr. King correctly states that earnings growth rates are the most important indicator of growth for investors.[44] His Constant Growth DCF model relies exclusively on earnings growth rates from Value Line, First Call, and Zacks. Thus, it is not clear why Mr. King chose to use dividend growth rates from Value Line in the first stage of his Multi-Stage DCF model. By contrast, I have used earnings growth rates in the first stage of my Multi-Stage DCF model. As discussed in my Direct Testimony, earnings are the fundamental determinant of a company's ability to pay dividends. Furthermore, academic research has shown that stock prices are more closely tied to earnings growth than to dividend or book value growth.[45]

My third area of disagreement with Mr. King's application of the Multi-Stage DCF model is that he uses earnings growth rates in the second stage. While I agree that earnings are a reliable indicator of investors' growth expectations, I note that analyst earnings growth rates typically project five

[44] Direct Testimony of Charles W. King, at 17.
[45] Direct Testimony of Ann E. Bulkley, at 17-18.

years of growth from the date of the estimate. Therefore, it is not appropriate to use five-year projected earnings growth rates in the second stage of the Multi-Stage DCF, which projects growth in years six through ten. In my Multi-Stage DCF model, the second stage allows for a transition from the short-term growth rate to the long-term growth rate.

My final area of disagreement with Mr. King's Multi-Stage DCF analysis relates to the reasonableness of his long-term growth rate of 4.43 percent, which is based on projected nominal GDP growth rates from the Congressional Budget Office ("CBO") and the Social Security Administration ("SSA"). Specifically, I disagree with the timing of the growth rates in the Multi-Stage DCF model, I question the appropriateness of the sources for estimating long-term GDP growth and finally, I disagree with the overall reasonableness of the resulting 4.43 percent estimate of long-term growth.

Q. IS IT APPROPRIATE TO RELY ON THE CBO'S PROJECTION OF THE LONG-TERM GROWTH RATE AS MR. KING HAS APPLIED IT?

A. No. Mr. King states that his DCF model has three stages and that the long-term growth rate would apply to the last stage of the model, beyond 10 or 15 years".[46] The CBO projection that Mr. King relies on is for the period from [2019-2023], which does not correspond to the time period for which Mr. King states that he is applying that growth rate (*i.e.,* years 11 and beyond). In using that growth rate in the final stage of his model, even though the CBO's intent was to project growth over a more near term defined period, Mr. King

[46] Direct Testimony of Charles W. King at 20.

is assuming that the long-term nominal GDP growth rate will be almost 200 basis points lower than it has been on average in the U.S. since 1929. Mr. King offers no support for that assumption. By comparison, my GDP growth rate of 5.40 percent acknowledges that future inflation is projected to be approximately 2.10 percent (which is somewhat lower than the historical inflation rate), while relying on the actual historical growth rate in real GDP of 3.22 percent from 1929-2012.

Q. WHY DO YOU DISAGREE WITH THE USE OF THE PROJECTED GDP GROWTH RATE PUBLISHED BY THE SSA?

A. Mr. King relies on the SSA projection of real GDP growth of 2.10 percent. Two of my primary concerns with the SSA growth rate are shared by the American Academy of Actuaries (AAA), (1) what the SSA is predicting in its growth rate, and (2) the sensitivity of the growth rate to the inputs. First, in their analysis of the SSA growth rates, the AAA states that the SSA is not forecasting growth in GDP, but rather is estimating growth in the labor force and productivity. The AAA states that the SSA trustees "do not directly make an assumption regarding growth of gross domestic product."[47] Rather, "the trustees arrive at their estimate of GDP growth indirectly by estimating growth in the labor force and growth in productivity."[48] Second, AAA notes that the SSA projected long-term GDP growth rate is very sensitive to slight changes in the underlying assumptions that are used to estimate the GDP growth rate.

* 47 ~~*Ibid*, at 6.~~ American Academy of Actuaries, "Understanding the Assumptions used to Evaluate Social Security's Financial Condition," September 2009, at 6.

48 *Ibid.*

Q. ARE THERE OTHER REASONS WHY THE SSA GROWTH RATE SHOULD NOT BE USED TO ESTIMATE LONG-TERM GDP GROWTH?

A. Yes. The purpose of the SSA trustees' report is to evaluate the long-term viability of the social security program. As a result, the SSA has an incentive to underestimate long term growth.

The AAA report concludes that "there have always been some observers who questioned whether the Social Security trustees' assumptions are the best basis for evaluating the financial condition of Social Security and the impact of various reform proposals. Certainly, other assumptions may also be reasonable, and even small changes in assumptions can, over a 75 year period, lead to large changes in the projections. Any projection over a 75-year period is subject to a high degree of uncertainty."[49]

For all of these reasons, my view is that the SSA estimate of long-term GDP growth is likely understated, and is based on underlying assumptions which are very sensitive to economic and demographic trends which cannot be predicted with any degree of certainty over a long time period. Therefore, I continue to believe that the use of historical real GDP growth, adjusted for projected inflation, is more appropriate.

Q. IS THERE FURTHER EVIDENCE THAT MR. KING'S GDP GROWTH RATE IS AT ODDS WITH THE EQUITY RETURNS THAT INVESTORS REQUIRE?

A. Yes. Bank of America Merrill Lynch publishes a monthly report titled "Quantitative Profiles" that presents the implied and required returns for the

[49] *Ibid*, at 8.

S&P 500 and the various industry sectors (*e.g.,* utilities) on a monthly basis. As shown on the table below, the implied and required returns for the utilities sector for the months of February 2013 through April 2013 ranged from 9.50 percent to 9.70 percent. Subtracting the average yield on utility bonds over that same period produces an implied growth rate of between 5.50 percent and 5.60 percent.

Table 6
Implied Growth Rates for Utilities Sector[50]

	Utilities Implied Return	Utilities Yield	Implied Growth
February 2013	9.7%	4.2%	5.5%
March 2013	9.6%	4.1%	5.5%
April 2013	9.5%	3.9%	5.6%

Q. HAS THERE BEEN A TENDENCY TO UNDER-ESTIMATE GDP GROWTH RATES IN THE DECADE AFTER SEVERE ECONOMIC EVENTS?

A. Yes. The financial crisis and recession that began in 2007 were qualitatively different from most other U.S. economic downturns, which were followed by a rapid return to pre-recession overall output growth levels. In that regard, the current U.S. economic growth situation is similar to that following the two most severe economic events in U.S. history (*i.e.*, the 1929 stock market crash and the 1973 oil shock). Economists who have examined the repercussions of those two historical crises (and similar severe

[50] Source: Bank of America Merrill Lynch, Quantitative Profiles, February 2013, March 2013, April 2013.

financial crises in other countries) have found that GDP growth rates tended to be lower during the decade following such events.

Q. HAVE YOUR PERFORMED AN ANALYSIS OF GDP GROWTH AFTER A SEVERE FINANCIAL CRISIS?

A. Yes. I compared the average real GDP growth in the first ten years immediately following the two historical economic crises most comparable to the recent financial crisis (*i.e.*, the 1929 stock market crash and the 1973 oil shock) to the average real GDP growth in the next two decades following each crisis (*i.e.*, eleven to 30 years after the events). I did the same for each of the 20th-century U.S. recessions for which sufficient data are available. My findings are presented in the table below.

Table 7
Real GDP Growth Rates Following U.S. Economic Downturns[51]

Event	Compound Average Real GDP Growth Rate		
	Decade Following Crisis	Next Two Decades	Difference (Basis Points)
Major Economic Crises			
1929 Stock Market Crash	2.06%	4.72%	266
1973 Oil Shock	2.55%	3.39%	83
Other Recessions			
1937	6.68%	4.15%	-253
1945	3.77%	3.59%	-18
1948	3.79%	3.95%	16
1953	3.60%	3.23%	-37
1957	4.84%	3.13%	-170
1960	4.41%	3.28%	-112
1969	3.57%	3.01%	-56
1980	3.32%	2.45%	-88
1981	3.52%	2.62%	-90

Table 7 shows that real GDP growth in the first ten years following the 1929 stock market crash and the 1973 oil shock was substantially lower than real GDP growth in the next two decades following each event. In contrast, eight out of the nine other 20th-century U.S. economic downturns analyzed showed the opposite pattern.

Q. WHAT DO YOU CONCLUDE REGARDING GDP GROWTH?

A. In light of the academic research cited above and the findings presented in Table 7, it is reasonable to conclude that current projections of real GDP

[51] Real GDP data are from the U.S. Bureau of Economic Analysis. The years in which each recession started are from the National Bureau of Economic Research ("NBER"), "US Business Cycle Expansions and Contractions," available at http://www.nber.org/cycles.html. Note that this table excludes the three most recent recessions, which started in 1990, 2001, and 2007 owing to a lack of sufficient data for GDP growth in the following years to calculate comparable long-term GDP growth rates.

growth are under-stated. The most reasonable means to forecast long-term GDP growth is to assume a return to long-term historical rates of real GDP growth and to estimate long-term nominal GDP growth based largely on market-based, long-term inflation estimates.

Q. HAVE YOU RE-CREATED MR. KING'S MULTI-STAGE DCF ANALYSIS FOR THE INDIVIDUAL COMPANIES IN HIS COMPARABLE GROUP?

A. Yes. Exhibit___ (AEB-2), Schedule 8 applies Mr. King's "Multi-Stage" DCF methodology for each of the companies in his proxy group. In reviewing the results of his Constant Growth DCF analysis, Mr. King established a floor of 7.23 percent, excluding observations below that return as being unreasonably low relative to the yield on corporate bonds. As shown on Exhibit___ (AEB-2), Schedule 8, applying that lower boundary to the results of Mr. King's "Multi-Stage" DCF analysis, El Paso Energy (at 6.82 percent) should have been excluded from the results of Mr. King's Multi-Stage DCF analysis, which would increase the results of his analysis to 8.55 percent.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS ON MR. KING'S "MULTI-STAGE" DCF MODEL.

A. My primary conclusion is that Mr. King's "Multi-Stage" DCF model has a number of serious flaws and should not be considered in selecting an ROE in this proceeding. Specifically, his model does not apply different growth rates for different time periods. Rather, it applies an average growth rate in perpetuity. Further, the dividend yield is incorrect and the growth rates used by Mr. King in the different stages of his analysis are not reasonable, and tend to understate the Cost of Equity for electric utilities such as NSPM.

Based on the methodological issues I have identified with Mr. King's Multi-Stage DCF analysis, I believe it is appropriate not to afford the results of this analysis any weight in the determination of the appropriate ROE for NSPM.

Q. DOES YOUR MULTI-STAGE DCF MODEL AVOID THESE ERRORS?

A. Yes. The short-term and long-term growth rates in my Multi-Stage DCF analysis are based on reasonable estimates of earnings growth in the short-term and nominal GDP growth in the long-term. Research has shown that real GDP growth tends to be slower in the decade following a severe economic recession, so it is more appropriate to rely on historical real GDP growth and projected inflation rates to derive the projected nominal GDP growth rate, as I have done in developing my terminal growth rate.

D. Sustainable Growth DCF Model

Q. PLEASE SUMMARIZE MR. KING'S SUSTAINABLE GROWTH DCF ANALYSIS.

A. Mr. King develops what are described as "sustainable" growth rates for each of his proxy group companies based on projected Value Line data for the period from 2016-2018. Specifically, Mr. King calculates the sustainable growth rate by multiplying the retention ratios and returns on book value (known as b x r) and adding the product of the growth in shares outstanding and the market/book ratio (known as s x v). Based on Mr. King's analysis, the sustainable growth rate for his proxy group companies is 4.17 percent. Excluding the results below 7.23 percent (Mr. King's low threshold), the results of his sustainable growth DCF model are 8.19 percent (mean) and 7.97 percent (median).

Q. PLEASE SUMMARIZE YOUR PRIMARY CONCERNS WITH MR. KING'S SUSTAINABLE GROWTH DCF MODEL.

A. I have three primary concerns with Mr. King's sustainable growth model. First, Mr. King's sustainable growth model relies on a fundamental assumption that low retention ratios are associated with low future earnings growth rates. Academic studies performed in 2003 demonstrate the opposite is true; that is, future earnings growth is associated with high dividend payout ratios. Second, while Mr. King's sustainable growth DCF model relies on data from Value Line, the results of his model are 182 basis points lower than the Value Line average projected ROE for Mr. King's proxy group, which shows that his results are inconsistent with his sources. Third, in his Direct Testimony, Mr. King enumerates several concerns with the sustainable growth model. In fact, in a recent case before the New York Public Service Commission, a jurisdiction that primarily relies on the sustainable growth model, Mr. King did not include this model in his analysis.

Q. PLEASE SUMMARIZE THE RELATIONSHIP BETWEEN PAYOUT RATIOS AND GROWTH RATES.

A. The underlying premise of Mr. King's calculation of sustainable growth is that future earnings will increase as the retention ratio (*i.e.,* the portion of earnings not paid out in dividends) increases. There are, however, several reasons why that may not be the case. Management decisions to conserve cash for capital investments, to manage the dividend payout for the purpose of minimizing future dividend reductions, or to signal future earnings prospects can and do influence the dividend payout (and therefore earnings

retention) in the near-term. Consequently, it is appropriate to determine whether the data used to calculate the sustainable growth rate support the assumption that higher earnings retention ratios necessarily are associated with higher future earnings growth rates.

Q. DOES RESEARCH SUPPORT MR. KING'S VIEW ON THE RELATIONSHIP BETWEEN EARNINGS GROWTH RATES AND EARNINGS RETENTION RATIOS?

A. No, it does not. Contrary to Mr. King's assertion that "its conceptual foundation is unassailable,"[52] two articles appeared in Financial Analysts Journal in 2006, which addressed the theory that high dividend payouts (*i.e.,* low retention ratios) are associated with low future earnings growth.[53] Both of those articles cite a 2003 study[54] which found that, over the course of 130 years of data, future earnings growth is associated *with high, rather than low dividend payout* ratios.[55] In summary, the findings of those articles demonstrate that there is a *negative,* not a *positive* relationship between earnings retention ratios and future earnings growth rates. As such, I believe that Mr. King's reliance on the sustainable growth rate DCF model is not appropriate.

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52 Direct Testimony of Charles W. King, at 35.

53 Ping Zhou, William Ruland, *Dividend Payout and Future Earnings Growth*, Financial Analysts Journal, Vol. 62, No. 3, 2006. *See* also Owain ap Gwilym, James Seaton, Karina Suddason, Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns*, Financial Analysts Journal, Vol. 62, No. 1, 2006.

54 Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, 2003.

55 Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

Q. DO YOU HAVE OTHER CONCERNS ABOUT MR. KING'S USE OF THE VALUE LINE DATA IN THE SUSTAINABLE GROWTH DCF MODEL?

A. Yes. Mr. King relies on Value Line projected data for the period from 2016-2018 to calculate his sustainable growth rate. While I generally agree with the use of projected data in the DCF model, Mr. King criticizes my use of forecasted interest rates for years beyond 2014 and describes such projections as "intrinsically speculative".[56] His use of projected data from this time period seems inconsistent with his criticism of my analysis. In order to assess whether the time period affects the results of Mr. King's analysis, I recreated Mr. King's sustainable growth rate DCF model substituting Value Line's 2013 data for the projected 2016-2018 data and have included that in my presentation of the modified results of Mr. King's approach. (*see* Exhibit___ (AEB-2), Schedule 9)

Q. IS THERE OTHER EVIDENCE THAT SUGGESTS MR. KING'S SUSTAINABLE GROWTH DCF ANALYSIS DOES NOT PRODUCE REASONABLE RESULTS?

A. Yes. Mr. King states that the average projected ROE for the companies in my proxy group, as reported by Value Line, is 9.68 percent. That projection is 149 basis points higher than the mean results of Mr. King's sustainable growth rate analysis and 68 basis points higher than his ROE recommendation of 9.00 percent.

[56] Direct Testimony of Charles W. King, at 34.

Q. HAVE YOU CONDUCTED A SIMILAR ANLAYSIS FOR MR. KING'S PROXY GROUP?

A. Yes, I have. I relied on the Value Line projected return on shareholder equity for the period from 2016 through 2018 for Mr. King's proxy group of 16 companies. As shown in Exhibit___ (AEB-2), Schedule 10, the average projected return on shareholder equity for Mr. King's proxy group is 9.81 percent. Therefore, while Mr. King relies on Value Line as the source of the sustainable growth rate used in this form of the DCF model, the average Value Line projected ROE for his proxy group is 173 basis points higher[57] than the average result of his Sustainable Growth DCF model.

Q. IS MR. KING'S USE OF THE SUSTAINABLE GROWTH MODEL CONSISTENT WITH HIS TESTIMONY AND APPROACH IN A PRIOR CASE?

A. No, it isn't. Mr. King enumerates a number of concerns with the Sustainable Growth Model in his Direct Testimony, including: (1) whether book value determines earnings growth; (2) the effect of unregulated activities on earnings and book value; (3) the use of book value growth to estimate earnings growth; (4) the inherent circularity of the sustainable growth calculation; and (5) reliance on Value Line as the sole source for information in performing the calculation.[58]

In spite of those concerns, Mr. King assigns 18.75 percent weight to the results of his sustainable growth DCF analysis in this case. Further, in another recent proceeding in New York, Mr. King did not rely on the sustainable growth rate in his DCF analysis, even though that jurisdiction has

[57] See Exhibit CWK-2, Schedule 9.

[58] Direct Testimony of Charles W. King at 23.

historically placed significant emphasis on a sustainable growth DCF model.[59]

Q. WHAT IS YOUR CONCLUSION REGARDING THE RELEVANCE OF THE SUSTAINABLE GROWTH DCF MODEL?

A. My principal conclusion is that Mr. King's sustainable growth DCF model does not produce a reliable estimate of the Cost of Equity for NSPM at this time. Based on the shortcomings of the model, I recommend that the results of Mr. King's sustainable growth DCF model should not be given any weight in determining the ROE for NSPM in this proceeding.

E. Flotation Costs

Q. DOES MR. KING ADD FLOTATION COSTS TO HIS COST OF EQUITY ESTIMATE FOR NSPM?

A. Yes. Mr. King acknowledges that flotation costs are a legitimate cost of issuing equity that must be recovered either as an expense or as an adder to the ROE.[60] Mr. King calculates a flotation cost adjustment of seven basis points based on amortizing the flotation costs of Xcel Energy over the past ten years and dividing that amount by the total book value of Xcel Energy's common equity as calculated using Value Line data.

[59] State of New York Public Service Commission Case Nos. 13-E-0030, 13-G-0031, and 13-S-0032, Direct Testimony of Charles W. King, May, 31, 2013, pp. 23-24, 26-27

[60] Direct Testimony of Charles W. King, at 29.

Q. DO YOU AGREE WITH MR. KING THAT YOUR FLOTATION COST ADJUSTMENT OVER-RECOVERS FLOTATION COSTS FOR NSPM?

A. No, I do not. I disagree with his assertion that my method for calculating flotation costs results in over-recovery of those costs.

Q. OVER WHAT PERIODS OF TIME ARE ISSUANCE AND FLOTATION COSTS RECOGNIZED?

A. The approach that Mr. King has relied on (*i.e.,* amortizing the flotation costs over a period of time) is a generally accepted treatment for the recovery of flotation costs associated with debt issuances. However, there is a difference between equity issuances and debt issuances that affects the flotation costs associated with the costs of debt and equity.

The issuance costs associated with long-term debt reflect the incurrence of issuance costs that can be assigned a definite life or period of applicability. Those costs are amortized over the life of the debt issuance, either to maturity or upon retirement of the debt.

The flotation costs associated with equity issuance, however, do not have a definite period of applicability, but rather have a permanent life. These costs permanently reduce the equity in the capital structure and therefore it is appropriate to recover flotation costs incurred in the sale of equity over the life of the equity capital, which is permanent.

Q. WHY IS IT NOT APPROPRIATE TO AMORTIZE FLOTATION COSTS OVER A FINITE PERIOD OF TIME AS SUGGESTED BY MR. KING.

A. While amortization of flotation costs is theoretically a simple way to recover the costs of issuance, it is not an appropriate recovery of the flotation costs associated with equity issuances because the flotation cost is a permanent reduction to the equity capital of the company. That capital remains in common equity providing benefits to ratepayers over an indefinite period of time.

Since the actual book equity of a stock issuance is calculated as the market value less the flotation costs, the book equity of that issuance is always less than the market value of the stock. Therefore, investors can only earn their Cost of Equity in any year if the company is allowed to earn a return on the common equity that is higher than the required return. This is because the total common equity base has been permanently reduced by the amount of the flotation cost. As noted in New Regulatory Finance:

> Unlike the case of bonds, common stock has no finite life so that flotation costs cannot be amortized and therefore must be recovered by way of an upward adjustment to the allowed return on equity.[61]

Further, a permanent adjustment is needed:

> The following illustration … shows that: (1) even if no further stock issues are contemplated, the flotation cost adjustment is still permanently required to keep shareholders whole … .[62]

[61] Morin, Roger, New Regulatory Finance, Public Utilities Report, Inc. (2006), p. 327.
[62] *Ibid.* at 329.

Q. HOW DID YOU DERIVE THE FLOTATION COST PERCENTAGE USED IN YOUR CALCULATION OF THE FLOTATION COST ADJUSTMENT?

A. In order to establish a representative percentage of flotation costs, as discussed in my Direct Testimony, I calculated the flotation cost percentage of 5.281 percent based on the average flotation cost percentage of all stock issuances for Xcel Energy and NSP from 1949 to the present. This data is used to determine the percentage for the flotation cost adjustment. As shown in Exhibit___ (AEB-2), Schedule 2, applying that flotation cost percentage to the current dividend yield for my proxy companies results in a flotation cost adjustment of 24 basis points.

Q. DOES YOUR APPROACH TO THE FLOTATION COST ADJUSTMENT HAVE WIDE SUPPORT?

A. Yes. New Regulatory Finance identifies the "conventional approach' to the flotation cost adjustment as follows;

> For flotation costs of 5%, dividing the expected dividend by 0.95 will produce the adjusted cost of equity capital.[63]

Further, "[I]ts use in regulatory proceedings by cost of capital witnesses is widespread" and it is discussed in several college level corporate finance textbooks such as Brigham and Ehrhardt (2005).[64]

[63] Morin, Roger, New Regulatory Finance, Public Utilities Report, Inc. (2006), p. 329.
[64] *Ibid.*

Q. HOW DOES THAT PERCENTAGE COMPARE TO THE MEAN FLOATION COST PERCENTAGE FOR THE LAST THREE EQUITY ISSUANCES RELIED ON BY MR. KING?

A. As shown on Exhibit___ (AEB-2), Schedule 2, the last three equity issuances for Xcel Energy were in 2002, 2008, and 2010. The mean flotation cost percentage associated with those three issuances is 5.266 percent, which is generally consistent with the flotation cost percentage over all equity issuances of NSP and Xcel Energy that I used (5.281percent) and results in the same flotation cost adjustment since these costs are used only to determine a rate to be applied to the dividend yield.

F. Application of the Capital Asset Pricing Model

Q. PLEASE SUMMARIZE MR. KING'S CAPM ANALYSIS AND RESULTS.

A. Mr. King's CAPM analysis produces an ROE estimate for NSPM of 9.04 percent, based on a risk-free rate of 3.43 percent, a Beta coefficient of 0.67, and a Market Risk Premium of 8.43 percent.[65] Mr. King criticizes the CAPM due to concerns about the subjectivity of the inputs and assumptions. In particular, he expresses concern with whether Beta captures all the non-diversifiable risk associated with an investment,[66] and with the difficulty of estimating the equity risk premium on a forward-looking basis.[67] In spite of these reservations, Mr. King assigns the CAPM results 12.50 percent weighting in his calculation of the ROE for NSPM.

[65] Exhibit CWK-2, Schedule 6.
[66] Direct Testimony of Charles W. King, at 25.
[67] Direct Testimony of Charles W. King, at 26.

Q. DO YOU AGREE WITH THE RISK-FREE RATE MR. KING USES IN HIS CAPM ANALYSIS?

A. Not entirely. Mr. King uses the average yield on the 30-year Treasury security for the week from June 19 to June 25, 2013 of 3.43 percent as the risk-free rate in his CAPM analysis. While I have used a 30-day average current yield on the 30-year Treasury, I also have considered the projected yield on the 30-year Treasury bond for the 2013-2014 time period, as well as the projected yield for 2017-2019. Mr. King agrees that the CAPM requires forward-looking inputs for the equity risk premium, and yet he criticizes my use of projected Treasury yields as "intrinsically speculative". As discussed in Section IV of my Rebuttal Testimony, this point is especially important under current market conditions, where investors are very concerned about the potential for rising interest rates and the implications for stock prices, especially for those stocks such as electric utilities that generate a signification portion of their total return through dividends.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE MARKET RISK PREMIUM MR. KING USES IN HIS CAPM ANALYSIS?

A. Yes. Mr. King develops his Market Risk Premium (MRP) based on an average of the historical and projected returns for the equity markets. In his analysis, the historical MRP is calculated by subtracting the Treasury bond yield from the historical market return provided by Morningstar for the period from 1929-2010. The projected return MRP is derived using Value Line's projected dividend yield and stock price appreciation for the next three to five years less the Treasury yield. Mr. King ultimately arrives at an MRP of 8.43 percent. While this estimate is within the range of equity risk premiums that I have employed in my CAPM analysis, I do not agree with

Mr. King's use of historical data to estimate the MRP, especially when current interest rate levels are much lower than those that prevailed during most of the historical period from 1929-2010. In addition, it is not clear why Mr. King did not include historical market returns through 2012 rather than 2010.

Q. WHAT IS YOUR CONCLUSION REGARDING MR. KING'S CAPM ANALYSIS?

A. My conclusion is that Mr. King's CAPM analysis understates the Cost of Equity for NSPM because he fails to take into consideration the likelihood of higher interest rates and the effect that would have on the CAPM results. Given the current market conditions and investors' uncertainty regarding the Federal Reserve's interest rate policy, I believe it is appropriate to include both current and projected Treasury yields in the CAPM analysis. By doing so, my CAPM analysis reflects investors' return requirements under both current and projected interest rate environments.

Q. HOW WOULD MR. KING'S CAPM RESULTS BE AFFECTED BY THE USE OF PROJECTED TREASURY YIELDS?

A. As shown in Exhibit___ (AEB-2), Schedule 11, the five-year projected Treasury Yield is 5.20 percent. Relying on that yield, holding the remainder of Mr. King's assumptions constant, the results of the CAPM would be 9.63 percent.

G. Recent Returns in Other Jurisdictions

Q. PLEASE SUMMARIZE MR. KING'S ANALYSIS OF RECENT RETURNS IN OTHER JURISDICTIONS.

A. Mr. King provides an analysis of returns for electric utilities in other jurisdictions based on information provided by NSPM in response to a data request. Mr. King observes that the average return on equity for electric utilities that were included in his analysis is 10.02 percent.[68] Although Mr. King expresses concern with the circular logic of using returns in other jurisdictions to set the return for NSPM, he assigns this result 12.50 percent weight in his calculation of NSPM's Cost of Equity.

Q. PLEASE COMMENT ON MR. KING'S ANALYSIS OF AUTHORIZED RETURNS IN OTHER JURISDICTIONS.

A. While Mr. King screens his DCF proxy group to eliminate transmission and distribution ("T&D") companies, Mr. King's analysis of authorized returns in other jurisdictions includes returns for T&D companies. As explained earlier in my Rebuttal Testimony, the Company is an integrated electric utility, and investors have indicated that integrated utilities have different risk profiles than T&D companies. Accordingly, T&D companies should not be included in the analysis of returns from other jurisdictions.

[68] Exhibit CWK-2, Schedule 7.

Q. HAVE YOU CONDUCTED AN ANALYSIS OF AUTHORIZED ROEs THAT IS CONSISTENT WITH MR. KING'S PROXY GROUP SCREENING CRITERIA?

A. Yes. I began with the authorized ROEs reported in Mr. King's Exhibit 2, Schedule 7. I reviewed each company to determine whether or not the operating company owned regulated generation. That analysis identified five companies that do not own generation in the operating company for which the ROE was being established: Ameren Illinois; Commonwealth Edison Company; Baltimore Gas and Electric Company; Niagara Mohawk Power Company; and Narragansett Electric Company. Excluding the authorized ROEs for those companies, the average return for the integrated electric companies in Mr. King's analysis is 10.21 percent.

Q. WHAT IS YOUR RESPONSE TO MR. KING'S POSITION THAT THESE DATA ARE NOT RELEVANT DUE TO CONCERNS ABOUT CIRCULAR LOGIC?

A. Mr. King acknowledges the importance of the comparable investment standard on page 13 of his Direct Testimony. If utilities are to compete for equity capital, they must offer investors a reasonable opportunity to earn returns that are commensurate with those returns available from other utilities of similar risk.

Since we are focused on the actual judgments of investors, it is reasonable to rely on the same information that is readily available to investors. For that reason, I disagree with Mr. King that these data are not relevant. Investors carefully review the allowed ROEs and consider them as benchmarks against which the allowed return for NSPM in this case will be evaluated.

Q. DO YOU HAVE ANY OTHER COMMENTS WITH RESPECT TO MR. KING'S ANALYSIS OF ALLOWED RETURNS IN OTHER JURISDICTIONS?

A. Yes. Mr. King's ROE recommendation of 9.00 percent is more than 120 basis points lower than the average of the ROEs that have been granted to integrated electric utilities in other jurisdictions. However, Mr. King does not offer any evidence to explain why NSPM's business risk is so much lower than the proxy group that investors would require 120 basis points less than the average ROE for other vertically-integrated electric utilities.

Q. HAVE YOU REVIEWED THE AUTHORIZED ROES FOR THE COMPANIES IN MR. KING'S PROXY GROUP?

A. Yes, I have. As shown on Exhibit___ (AEB-2), Schedule 12, the average of the most recent authorized ROE for the operating companies in Mr. King's proxy group is 10.21 percent, or 121 basis points higher than his ROE recommendation of 9.00 percent. This demonstrates that the companies that Mr. King considers to be risk comparable to NSPM have been awarded returns in the jurisdictions where they operate that are substantially higher than the ROE that Mr. King has recommended for NSPM in this proceeding.

Q. WHAT IS YOUR CONCLUSION WITH RESPECT TO THE USEFULNESS OF AUTHORIZED ROES IN OTHER JURISDICTIONS?

A. While the Commission is certainly not bound by return awards in other jurisdictions, my view is that investors rely on this information as a relevant benchmark. Although I have not used these returns to establish my ROE recommendation, I have evaluated the reasonableness of my results and recommendation against these ROEs. My revised ROE recommendation of

10.25 percent is consistent with the prevailing level of authorized returns for vertically-integrated electric utilities in recent years.

H. Relevance of Bond Yield Plus Risk Premium Analysis

Q. DID MR. KING UTILIZE A BOND YIELD PLUS RISK PREMIUM ANALYSIS TO ESTIMATE THE COST OF EQUITY FOR NSPM?

A. No, he did not. Mr. King argues that the Bond Yield plus Risk Premium analysis is based on circular logic. That is, the analysis requires knowledge of the required return to stocks in order to estimate the required return to stocks.[69] Mr. King also criticizes my use of forward-looking Treasury yields in the regression equation to estimate the Cost of Equity for NSPM.[70]

Q. HAS MR. KING PREVIOUSLY GIVEN WEIGHT TO A BOND YIELD PLUS RISK PREMIUM ANALYSIS IN OTHER JURISDICTIONS?

A. Yes. In Maryland, for example, Mr. King recently gave weight to a Risk Premium analysis based on the relationship between public utility bond yields and the equity returns awarded to electric utilities by regulatory agencies.[71] Mr. King offered the same criticism of that methodology as he offers for the Bond Yield plus Risk Premium analysis in my Direct Testimony, expressing concerns about relying on returns in other jurisdictions as surrogates for the required ROE. In that case, however, Mr. King gave equal weight to the results of the sustainable growth DCF model and the risk premium approach in Maryland; 15.79 percent.[72]

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69 Direct Testimony of Charles W. King, at 34.

70 Direct Testimony of Charles W. King, at 35.

71 Direct Testimony of Charles W. King, Baltimore Gas and Electric Company, October 12, 2012, at 17-18.

72 Direct Testimony of Charles W. King, Baltimore Gas and Electric Company, Case No. 9299, Exhibit

Q. WHAT IS YOUR RESPONSE TO MR. KING'S CRITICISM OF YOUR APPLICATION OF THE BOND YIELD PLUS RISK PREMIUM MODEL?

A. With regard to Mr. King's first concern, one purpose of my Bond Yield plus Risk Premium analysis is to demonstrate the inverse relationship between interest rates and the equity risk premium. In other words, as interest rates decline, the equity risk premium rises. As Mr. King points out, my risk premium analysis shows that a return on equity of 10.00 percent is reasonable given the current level of interest rates and the historical risk premium.[73] With respect to his concern about the use of forecasted Treasury yields, as discussed previously, Mr. King has also relied on forecasted data from Value Line for the 2016-18 time period to develop his sustainable growth DCF model. As such, Mr. King's second concern is not consistent with his own analyses.

Q. WHAT IS YOUR CONCLUSION REGARDING THE APPROPRIATENESS OF USING A BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. As discussed in my Direct Testimony, I used the Bond Yield Plus Risk Premium analysis as a means of corroborating the reasonableness of my DCF results.[74] While I do not rely on this analysis as my primary method for estimating the authorized ROE for NSPM, it does provide the Commission with a relevant benchmark that investors consider when they evaluate the authorized ROE for NSPM relative to that available from other comparable risk electric utilities. For that reason, I have continued to present this

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CWK-2, Schedule 7. October 12, 2012.

[73] Direct Testimony of Charles W. King, at 35.

[74] Direct Testimony of Ann E. Bulkley, at 25-26.

analysis in my updated results, and I believe that Mr. King's concerns with this method are misplaced.

I. Effect of Proposed Adjustments to Mr. King's Analyses

Q. PLEASE SUMMARIZE THE ADJUSTMENTS THAT SHOULD BE MADE TO MR. KING'S ANALYSES.

A. There are several reasonable adjustments that should be made to Mr. King's Constant Growth DCF, CAPM, and Authorized Returns analyses that affect the overall results of those models. In addition, for the reasons discussed previously, I believe that Mr. King's "Multi-Stage" DCF results should not be afforded any weight. Similarly, based on Mr. King's own concerns about the Sustainable Growth DCF model and academic support for the use of earnings growth, I would not afford any weight to the results of Mr. King's Sustainable Growth DCF model. Finally, consistent with Mr. King's approach in Maryland Case No. 9299, I have applied the same weight to the Risk Premium model that I have relied on in my Rebuttal Testimony.

Q. HOW DO YOUR PROPOSED ADJUSTMENTS TO MR. KING'S ANALYSES AFFECT HIS OVERALL RECOMMENDED ROE?

A. The results of those adjustments are presented in Exhibit___ (AEB-2), Schedule ~~9~~ 6 and are summarized in Table 8 (below). As shown in Table 8, these modifications to Mr. King's analysis result in an ROE of 9.73 percent, before adjustment for flotation costs, which is 88 basis points higher than the 8.85 percent result presented in Mr. King's Direct Testimony. The adjusted ROE, including flotation costs, would be 9.97 percent.

Table 8
Modified King Results[75]

Methodology	Exhibit ___(AEB-2),	Indication	Weighting	Weighting Indication	Composite Indication
Constant Growth DCF					
Mean	Schedule 7	9.22%			
Median	Schedule 7	9.21%			
Average	Schedule 7	9.22%	5	46.08%	
3-Step DCF	Schedule 8	8.55%	0		
Sustainable Growth DCF					
Mean	Schedule 9	8.58%			
Median	Schedule 9	8.59%			
Average	Schedule 9	8.58%	0		
CAPM	Schedule 11	9.63%	2	19.26%	
Risk Premium	Schedule 5	10.44%	3	31.32%	
Recent ROE Awards	Schedule 13	10.04%	2	20.08%	
Total			12	116.75%	9.73%
Flotation Cost	Schedule 2				.24%
Adjusted Total					9.97%

VI. CAPITAL STRUCTURE AND COST OF SHORT TERM DEBT

Q. PLEASE SUMMARIZE THE CAPITAL STRUCTURE PROPOSED BY MR. KING.

A. Mr. King proposes to rely on the Company's capital structure as of March 31, 2013 as the ratemaking capital structure in this case. At that time, the Company's capital structure consisted of 45.24 percent long-term debt, 1.33 percent short-term debt, and 53.42 percent common equity. [76]

[75] *See* Exhibit _(AEB-2), Schedule 6.
[76] Direct Testimony of Charles W. King at 12.

Q. IS THE CAPITAL STRUCTURE PROPOSED BY MR. KING CONSISTENT WITH THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. The two structures are generally comparable. The Company proposed a capital structure consisting of 44.96 percent long-term debt, 2.48 percent short-term debt, and 52.56 percent common equity, based on budgeted amounts. The Company does not object to the proposed adjustments to the capital structure.

Q. DOES THE SHORT-TERM DEBT RATE PROPOSED BY MR. KING RECOVER ALL OF THE COMPANY'S SHORT-TERM DEBT COSTS?

A. No, it does not. As discussed in his Direct Testimony, Mr. King estimates the short-term debt balances for the 24 months from April 2011 through March 2013.[77] The Company calculates the cost of short-term debt based on two components: (1) interest expense, and (2) financing fees. Mr. King's estimated cost of short-term debt does not consider the monthly financing fees on the Company's short-term credit agreement.

Q. HOW WAS THE COST OF SHORT-TERM DEBT ESTIMATED BY THE COMPANY?

A. The 0.75 percent cost of short-term debt includes the interest expense cost (0.44 percent) and the monthly financing fees (~~0.71~~ 0.31 percent) associated with having a credit facility to provide back-up liquidity for the Company. The calculation is shown on Exhibit. (AEB-2), Schedule 14. The 0.44 percent interest expense is based on the July 2012 Global Insight forecast for the London Interbank Offer Rate ("LIBOR"). The financing fee of 0.31 percent

[77] Direct Testimony of Charles W. King at 12.

reflects the fixed annual commitment fees for our "Amended and Restated Credit Agreement." The financing fee should be included because it is part of the cost of the Company's short term debt.

Q. WHAT WOULD THE SHORT TERM DEBT COMPONENT OF THE CAPITAL STRUCTURE BE IF THE COMMISSION ADOPTED MR. KING'S RECOMMENDATION TO USE AN AVERAGE SHORT TERM INTEREST RATE?

A. If the Commission concludes that a historic average interest rate should be used, Mr. King's 0.36 percent rate (Exhibit CWK-1, Schedule 2) would be substituted for the Company's 0.44 percent interest expense, reducing the short-term rate by 8 basis points from 0.75 percent to 0.67 percent.

VII. SUMMARY AND RECOMMENDATION

Q. PLEASE SUMMARIZE YOUR ANALYTICAL RESULTS AND CONCLUSIONS.

A. Based on the results of my updated analyses as shown on Table 9, I have revised my recommended ROE range to between 10.00 percent and 10.50 percent. The low end of the range is supported by the results of the Multi-Stage DCF model, while the upper boundary is supported by the results of the Capital Asset Pricing Model and the mean high results of the Constant Growth DCF analysis. As discussed earlier in my Testimony, the requested ROE has been reduced from 10.60 percent to 10.25 percent. While this request is somewhat conservative in my view, it does fall within the range of my results and provides the Company with a reasonable return under current market conditions.

Table 9
Summary of Analytical Results

Constant Growth DCF - Including Flotation Costs				
	Mean (Low Growth)	Mean	Mean (High Growth)	
30-Day Average Price	8.47%	9.73%	11.34%	
90-Day Average Price	8.32%	9.58%	11.19%	
180-Day Average Price	8.49%	9.75%	11.36%	
Multi-Stage DCF - Including Flotation Costs				
	Mean (Low Growth)	Mean	Mean (High Growth)	
30-Day Average Price	9.64%	9.98%	10.52%	
90-Day Average Price	9.50%	9.83%	10.35%	
180-Day Average Price	9.67%	10.02%	10.55%	
Capital Asset Pricing Model				
	Current Risk-Free Rate (3.46%)	**2013-2014 Projected Risk Free Rate (3.73%)**	**2015-2019 Projected Risk Free Rate (5.20%)**	**Mean**
Bloomberg Beta	10.56%	10.64%	11.04%	10.74%
Value Line Beta	10.41%	10.49%	10.91%	10.60%
Bond Yield Plus Risk Premium				
Risk Premium	10.17%	10.28%	10.87%	10.44%

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota Corporation For Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-12-813

AFFIDAVIT OF
Ann E. Bulkley

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

Ann E. Bulkley

Subscribed and sworn to before me, this 9th day of August 2013.

Notary Public

JOANNE P. BICKFORD
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS
MY COMMISSION EXPIRES
OCTOBER 15, 2015

30 DAY CONSTANT GROWTH DCF

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line EPS Growth	[6] First Call EPS Growth	[7] Zacks EPS Growth	[8] Average Growth Rate	[9] Low DCF ROE	[10] Mean DCF ROE	[11] High DCF ROE
ALLETE, Inc.	ALE	$1.90	$49.06	3.87%	4.00%	7.00%	6.00%	6.50%	6.50%	9.99%	10.50%	11.01%
American Electric Power Company, Inc.	AEP	$1.96	$45.10	4.35%	4.43%	4.50%	3.82%	3.56%	3.96%	7.98%	8.39%	8.94%
Cleco Corporation	CNL	$1.45	$45.75	3.17%	3.28%	5.50%	8.00%	8.00%	7.17%	8.76%	10.45%	11.30%
Empire District Electric Company	EDE	$1.00	$22.15	4.51%	4.60%	5.00%	3.00%	3.00%	3.67%	7.58%	8.26%	9.63%
FirstEnergy Corporation	FE	$2.20	$37.56	5.86%	5.92%	3.50%	2.63%	0.60%	2.24%	6.48%	8.17%	9.46%
Great Plains Energy Inc.	GXP	$0.87	$22.71	3.83%	3.95%	6.50%	6.26%	6.19%	6.32%	10.14%	10.27%	10.45%
Hawaiian Electric Industries, Inc.	HE	$1.24	$25.09	4.94%	5.04%	5.50%	2.40%	3.70%	3.87%	7.40%	8.90%	10.58%
IDACORP, Inc.	IDA	$1.52	$48.15	3.16%	3.21%	2.00%	4.00%	4.00%	3.33%	5.19%	6.54%	7.22%
Otter Tail Corporation	OTTR	$1.19	$28.25	4.21%	4.45%	21.50%	6.00%	6.00%	11.17%	10.34%	15.61%	26.16%
Pinnacle West Capital Corporation	PNW	$2.18	$55.72	3.91%	4.01%	5.00%	5.45%	4.45%	4.97%	8.45%	8.98%	9.47%
Portland General Electric Company	POR	$1.10	$30.59	3.60%	3.69%	3.50%	5.34%	6.53%	5.12%	7.16%	8.81%	10.24%
Southern Company	SO	$2.03	$43.98	4.62%	4.72%	4.50%	4.67%	4.61%	4.59%	9.22%	9.32%	9.39%
Westar Energy, Inc.	WR	$1.36	$31.50	4.32%	4.42%	6.00%	3.90%	4.31%	4.74%	8.30%	9.16%	10.45%
		PROXY GROUP MEAN		4.18%	4.29%	6.15%	4.73%	4.73%	5.20%	8.23%	9.49%	11.10%
									Flotation Cost	0.24%	0.24%	0.24%
										8.47%	9.73%	11.34%

Notes

[1] Source: Bloomberg
[2] Source: Bloomberg. Based on indicated number of days historical average as of July 12, 2013.
[3] Equals Col. [1]/Col. [2]
[4] Equals Col. [3] x (1 + 0.5 x Col. [8])
[5] Source: Value Line
[6] Source: First Call
[7] Source: Zacks
[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

Company		[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line EPS Growth	[6] First Call EPS Growth	[7] Zacks EPS Growth	[8] Average Growth Rate	[9] Low DCF ROE	[10] Mean DCF ROE	[11] High DCF ROE
ALLETE, Inc.	ALE	$1.90	$49.34	3.85%	3.98%	7.00%	6.00%	6.50%	6.50%	9.97%	10.48%	10.99%
American Electric Power Company, Inc.	AEP	$1.96	$47.65	4.11%	4.19%	4.50%	3.82%	3.56%	3.96%	7.75%	8.15%	8.71%
Cleco Corporation	CNL	$1.45	$46.46	3.12%	3.23%	5.50%	8.00%	8.00%	7.17%	8.71%	10.40%	11.25%
Empire District Electric Company	EDE	$1.00	$22.30	4.48%	4.57%	5.00%	3.00%	3.00%	3.67%	7.55%	8.23%	9.60%
FirstEnergy Corporation	FE	$2.20	$41.38	5.32%	5.38%	3.50%	2.63%	0.60%	2.24%	5.93%	7.62%	8.91%
Great Plains Energy Inc.	GXP	$0.87	$23.14	3.76%	3.88%	6.50%	6.26%	6.19%	6.32%	10.07%	10.20%	10.38%
Hawaiian Electric Industries, Inc.	HE	$1.24	$26.66	4.65%	4.74%	5.50%	2.40%	3.70%	3.87%	7.11%	8.61%	10.28%
IDACORP, Inc.	IDA	$1.52	$48.10	3.16%	3.21%	2.00%	4.00%	4.00%	3.33%	5.19%	6.55%	7.22%
Otter Tail Corporation	OTTR	$1.19	$29.65	4.01%	4.24%	21.50%	6.00%	6.00%	11.17%	10.13%	15.40%	25.94%
Pinnacle West Capital Corporation	PNW	$2.18	$57.67	3.78%	3.87%	5.00%	5.45%	4.45%	4.97%	8.31%	8.84%	9.33%
Portland General Electric Company	POR	$1.10	$30.86	3.56%	3.66%	3.50%	5.34%	6.53%	5.12%	7.13%	8.78%	10.21%
Southern Company	SO	$2.03	$45.72	4.44%	4.54%	4.50%	4.67%	4.61%	4.59%	9.04%	9.14%	9.21%
Westar Energy, Inc.	WR	$1.36	$32.62	4.17%	4.27%	6.00%	3.90%	4.31%	4.74%	8.15%	9.01%	10.29%
		PROXY GROUP MEAN		4.03%	4.14%	6.15%	4.73%	4.73%	5.20%	8.08%	9.34%	10.95%
									Flotation Cost	0.24%	0.24%	0.24%
										8.32%	9.58%	11.19%

Notes

[1] Source: Bloomberg
[2] Source: Bloomberg. Based on indicated number of days historical average as of July 12, 2013.
[3] Equals Col. [1]/Col. [2]
[4] Equals Col. [3] x (1 + 0.5 x Col. [8])
[5] Source: Value Line
[6] Source: First Call
[7] Source: Zacks
[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] Value Line EPS Growth	[6] First Call EPS Growth	[7] Zacks EPS Growth	[8] Average Growth Rate	[9] Low DCF ROE	[10] Mean DCF ROE	[11] High DCF ROE
ALLETE, Inc.	ALE	$1.90	$45.99	4.13%	4.27%	7.00%	6.00%	6.50%	6.50%	10.26%	10.77%	11.28%
American Electric Power Company, Inc.	AEP	$1.96	$45.68	4.29%	4.38%	4.50%	3.82%	3.56%	3.96%	7.93%	8.34%	8.89%
Cleco Corporation	CNL	$1.45	$44.02	3.29%	3.41%	5.50%	8.00%	8.00%	7.17%	8.88%	10.58%	11.43%
Empire District Electric Company	EDE	$1.00	$21.57	4.64%	4.72%	5.00%	3.00%	3.00%	3.67%	7.71%	8.39%	9.75%
FirstEnergy Corporation	FE	$2.20	$41.36	5.32%	5.38%	3.50%	2.63%	0.60%	2.24%	5.93%	7.62%	8.91%
Great Plains Energy Inc.	GXP	$0.87	$22.08	3.94%	4.06%	6.50%	6.26%	6.19%	6.32%	10.25%	10.38%	10.57%
Hawaiian Electric Industries, Inc.	HE	$1.24	$26.25	4.72%	4.82%	5.50%	2.40%	3.70%	3.87%	7.18%	8.68%	10.35%
IDACORP, Inc.	IDA	$1.52	$46.17	3.29%	3.35%	2.00%	4.00%	4.00%	3.33%	5.33%	6.68%	7.36%
Otter Tail Corporation	OTTR	$1.19	$27.63	4.31%	4.55%	21.50%	6.00%	6.00%	11.17%	10.44%	15.71%	26.27%
Pinnacle West Capital Corporation	PNW	$2.18	$55.00	3.96%	4.06%	5.00%	5.45%	4.45%	4.97%	8.50%	9.03%	9.52%
Portland General Electric Company	POR	$1.10	$29.24	3.76%	3.86%	3.50%	5.34%	6.53%	5.12%	7.33%	8.98%	10.42%
Southern Company	SO	$2.03	$44.77	4.53%	4.64%	4.50%	4.67%	4.61%	4.59%	9.14%	9.23%	9.31%
Westar Energy, Inc.	WR	$1.36	$31.01	4.39%	4.49%	6.00%	3.90%	4.31%	4.74%	8.37%	9.23%	10.52%
		PROXY GROUP MEAN		4.20%	4.31%	6.15%	4.73%	4.73%	5.20%	8.25%	9.51%	11.12%
									Flotation Cost	0.24%	0.24%	0.24%
										8.49%	9.75%	11.36%

Notes

[1] Source: Bloomberg
[2] Source: Bloomberg. Based on indicated number of days historical average as of July 12, 2013.
[3] Equals Col. [1]/Col. [2]
[4] Equals Col. [3] x (1 + 0.5 x Col. [8])
[5] Source: Value Line
[6] Source: First Call
[7] Source: Zacks
[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%

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

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:

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]	[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	Value Line EPS Growth	First Call EPS Growth	Zacks EPS Growth	Average Growth Estimate	DCF k(e)	Flotation Adjusted DCF k(e)
ALLETE, Inc.	ALE	$49.06	$1.90	3.87%	4.00%	4.22%	7.00%	6.00%	6.50%	6.50%	10.50%	10.72%
American Electric Power Company, Inc.	AEP	$45.10	$1.96	4.35%	4.43%	4.68%	4.50%	3.82%	3.56%	3.96%	8.39%	8.64%
Cleco Corporation	CNL	$45.75	$1.45	3.17%	3.28%	3.47%	5.50%	8.00%	8.00%	7.17%	10.45%	10.63%
Empire District Electric Company	EDE	$22.15	$1.00	4.51%	4.60%	4.85%	5.00%	3.00%	3.00%	3.67%	8.26%	8.52%
FirstEnergy Corporation	FE	$37.56	$2.20	5.86%	5.92%	6.25%	3.50%	2.63%	0.60%	2.24%	8.17%	8.50%
Great Plains Energy Inc.	GXP	$22.71	$0.87	3.83%	3.95%	4.17%	6.50%	6.26%	6.19%	6.32%	10.27%	10.49%
Hawaiian Electric Industries, Inc.	HE	$25.09	$1.24	4.94%	5.04%	5.32%	5.50%	2.40%	3.70%	3.87%	8.90%	9.18%
IDACORP, Inc.	IDA	$48.15	$1.52	3.16%	3.21%	3.39%	2.00%	4.00%	4.00%	3.33%	6.54%	6.72%
Otter Tail Corporation	OTTR	$28.25	$1.19	4.21%	4.45%	4.69%	21.50%	6.00%	6.00%	11.17%	15.61%	15.86%
Pinnacle West Capital Corporation	PNW	$55.72	$2.18	3.91%	4.01%	4.23%	5.00%	5.45%	4.45%	4.97%	8.98%	9.20%
Portland General Electric Company	POR	$30.59	$1.10	3.60%	3.69%	3.89%	3.50%	5.34%	6.53%	5.12%	8.81%	9.02%
Southern Company	SO	$43.98	$2.03	4.62%	4.72%	4.98%	4.50%	4.67%	4.61%	4.59%	9.32%	9.58%
Westar Energy, Inc.	WR	$31.50	$1.36	4.32%	4.42%	4.67%	6.00%	3.90%	4.31%	4.74%	9.16%	9.40%
		PROXY GROUP MEAN		4.18%	4.29%	4.53%	6.15%	4.73%	4.73%	5.20%	9.49%	9.73%

MEAN		9.73%
UNADJUSTED CONSTANT GROWTH DCF MEAN		9.49%
DIFFERENCE (FLOTATION COST ADJUSTMENT)	[12]	0.24%

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

30-DAY MULTI-STAGE DCF -- MEAN GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[4]	[4]	[4]	[4]	[5]	[6]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.06	$1.90	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	9.77%
American Electric Power Company, Inc.	AEP	$45.10	$1.96	3.96%	4.20%	4.44%	4.68%	4.92%	5.16%	5.40%	9.58%
Cleco Corporation	CNL	$45.75	$1.45	7.17%	6.87%	6.58%	6.28%	5.99%	5.69%	5.40%	9.13%
Empire District Electric Company	EDE	$22.15	$1.00	3.67%	3.96%	4.24%	4.53%	4.82%	5.11%	5.40%	9.67%
FirstEnergy Corporation	FE	$37.56	$2.20	2.24%	2.77%	3.30%	3.82%	4.35%	4.87%	5.40%	10.49%
Great Plains Energy Inc.	GXP	$22.71	$0.87	6.32%	6.16%	6.01%	5.86%	5.71%	5.55%	5.40%	9.67%
Hawaiian Electric Industries, Inc.	HE	$25.09	$1.24	3.87%	4.12%	4.38%	4.63%	4.89%	5.14%	5.40%	10.14%
IDACORP, Inc.	IDA	$48.15	$1.52	3.33%	3.68%	4.02%	4.37%	4.71%	5.06%	5.40%	8.29%
Otter Tail Corporation	OTTR	$28.25	$1.19	11.17%	10.21%	9.24%	8.28%	7.32%	6.36%	5.40%	11.62%
Pinnacle West Capital Corporation	PNW	$55.72	$2.18	4.97%	5.04%	5.11%	5.18%	5.26%	5.33%	5.40%	9.41%
Portland General Electric Company	POR	$30.59	$1.10	5.12%	5.17%	5.22%	5.26%	5.31%	5.35%	5.40%	9.12%
Southern Company	SO	$43.98	$2.03	4.59%	4.73%	4.86%	5.00%	5.13%	5.27%	5.40%	10.03%
Westar Energy, Inc.	WR	$31.50	$1.36	4.74%	4.85%	4.96%	5.07%	5.18%	5.29%	5.40%	9.77%
MEAN											9.75%
FLOTATION COST											0.24%
											9.98%

Notes

[1] Source: Bloomberg. Based on indicated number of days historical average.
[2] Source: Bloomberg.
[3] Average of EPS Growth Rates from Value Line, Zacks, and First Call
[4] Interpolating Growth Rates: Col. [3] - ((Col. [3] - Col. [5])/ 6) * (Year - 5))
[5] Long-term GDP Growth Rate
[6] Calculated ROE

90-DAY MULTI-STAGE DCF -- MEAN GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[4]	[4]	[4]	[4]	[5]	[6]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.34	$1.90	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	9.74%
American Electric Power Company, Inc.	AEP	$47.65	$1.96	3.96%	4.20%	4.44%	4.68%	4.92%	5.16%	5.40%	9.36%
Cleco Corporation	CNL	$46.46	$1.45	7.17%	6.87%	6.58%	6.28%	5.99%	5.69%	5.40%	9.07%
Empire District Electric Company	EDE	$22.30	$1.00	3.67%	3.96%	4.24%	4.53%	4.82%	5.11%	5.40%	9.64%
FirstEnergy Corporation	FE	$41.38	$2.20	2.24%	2.77%	3.30%	3.82%	4.35%	4.87%	5.40%	10.01%
Great Plains Energy Inc.	GXP	$23.14	$0.87	6.32%	6.16%	6.01%	5.86%	5.71%	5.55%	5.40%	9.59%
Hawaiian Electric Industries, Inc.	HE	$26.66	$1.24	3.87%	4.12%	4.38%	4.63%	4.89%	5.14%	5.40%	9.86%
IDACORP, Inc.	IDA	$48.10	$1.52	3.33%	3.68%	4.02%	4.37%	4.71%	5.06%	5.40%	8.30%
Otter Tail Corporation	OTTR	$29.65	$1.19	11.17%	10.21%	9.24%	8.28%	7.32%	6.36%	5.40%	11.34%
Pinnacle West Capital Corporation	PNW	$57.67	$2.18	4.97%	5.04%	5.11%	5.18%	5.26%	5.33%	5.40%	9.27%
Portland General Electric Company	POR	$30.86	$1.10	5.12%	5.17%	5.22%	5.26%	5.31%	5.35%	5.40%	9.09%
Southern Company	SO	$45.72	$2.03	4.59%	4.73%	4.86%	5.00%	5.13%	5.27%	5.40%	9.85%
Westar Energy, Inc.	WR	$32.62	$1.36	4.74%	4.85%	4.96%	5.07%	5.18%	5.29%	5.40%	9.61%
MEAN											9.60%
FLOTATION COST											0.24%
											9.83%

Notes

[1] Source: Bloomberg. Based on indicated number of days historical average.
[2] Source: Bloomberg.
[3] Average of EPS Growth Rates from Value Line, Zacks, and First Call
[4] Interpolating Growth Rates: Col. [3] - ((Col. [3] - Col. [5])/ 6) * (Year - 5))
[5] Long-term GDP Growth Rate
[6] Calculated ROE

180-DAY MULTI-STAGE DCF -- MEAN GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[4]	[4]	[4]	[4]	[5]	[6]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$45.99	$1.90	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	10.06%
American Electric Power Company, Inc.	AEP	$45.68	$1.96	3.96%	4.20%	4.44%	4.68%	4.92%	5.16%	5.40%	9.53%
Cleco Corporation	CNL	$44.02	$1.45	7.17%	6.87%	6.58%	6.28%	5.99%	5.69%	5.40%	9.28%
Empire District Electric Company	EDE	$21.57	$1.00	3.67%	3.96%	4.24%	4.53%	4.82%	5.11%	5.40%	9.79%
FirstEnergy Corporation	FE	$41.36	$2.20	2.24%	2.77%	3.30%	3.82%	4.35%	4.87%	5.40%	10.01%
Great Plains Energy Inc.	GXP	$22.08	$0.87	6.32%	6.16%	6.01%	5.86%	5.71%	5.55%	5.40%	9.79%
Hawaiian Electric Industries, Inc.	HE	$26.25	$1.24	3.87%	4.12%	4.38%	4.63%	4.89%	5.14%	5.40%	9.93%
IDACORP, Inc.	IDA	$46.17	$1.52	3.33%	3.68%	4.02%	4.37%	4.71%	5.06%	5.40%	8.42%
Otter Tail Corporation	OTTR	$27.63	$1.19	11.17%	10.21%	9.24%	8.28%	7.32%	6.36%	5.40%	11.76%
Pinnacle West Capital Corporation	PNW	$55.00	$2.18	4.97%	5.04%	5.11%	5.18%	5.26%	5.33%	5.40%	9.46%
Portland General Electric Company	POR	$29.24	$1.10	5.12%	5.17%	5.22%	5.26%	5.31%	5.35%	5.40%	9.29%
Southern Company	SO	$44.77	$2.03	4.59%	4.73%	4.86%	5.00%	5.13%	5.27%	5.40%	9.94%
Westar Energy, Inc.	WR	$31.01	$1.36	4.74%	4.85%	4.96%	5.07%	5.18%	5.29%	5.40%	9.84%
MEAN											9.78%
FLOTATION COST											0.24%
											10.02%

Notes

[1] Source: Bloomberg. Based on indicated number of days historical average.
[2] Source: Bloomberg.
[3] Average of EPS Growth Rates from Value Line, Zacks, and First Call
[4] Interpolating Growth Rates: Col. [3] - ((Col. [3] - Col. [5])/ 6) * (Year - 5))
[5] Long-term GDP Growth Rate
[6] Calculated ROE

30-DAY MULTI-STAGE DCF -- LOW GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[4]	[4]	[4]	[4]	[5]	[6]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.06	$1.90	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.64%
American Electric Power Company, Inc.	AEP	$45.10	$1.96	3.56%	3.87%	4.17%	4.48%	4.79%	5.09%	5.40%	9.48%
Cleco Corporation	CNL	$45.75	$1.45	5.50%	5.48%	5.47%	5.45%	5.43%	5.42%	5.40%	8.76%
Empire District Electric Company	EDE	$22.15	$1.00	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	9.49%
FirstEnergy Corporation	FE	$37.56	$2.20	0.60%	1.40%	2.20%	3.00%	3.80%	4.60%	5.40%	9.98%
Great Plains Energy Inc.	GXP	$22.71	$0.87	6.19%	6.06%	5.93%	5.80%	5.66%	5.53%	5.40%	9.64%
Hawaiian Electric Industries, Inc.	HE	$25.09	$1.24	2.40%	2.90%	3.40%	3.90%	4.40%	4.90%	5.40%	9.72%
IDACORP, Inc.	IDA	$48.15	$1.52	2.00%	2.57%	3.13%	3.70%	4.27%	4.83%	5.40%	8.04%
Otter Tail Corporation	OTTR	$28.25	$1.19	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.01%
Pinnacle West Capital Corporation	PNW	$55.72	$2.18	4.45%	4.61%	4.77%	4.93%	5.08%	5.24%	5.40%	9.28%
Portland General Electric Company	POR	$30.59	$1.10	3.50%	3.82%	4.13%	4.45%	4.77%	5.08%	5.40%	8.75%
Southern Company	SO	$43.98	$2.03	4.50%	4.65%	4.80%	4.95%	5.10%	5.25%	5.40%	10.00%
Westar Energy, Inc.	WR	$31.50	$1.36	3.90%	4.15%	4.40%	4.65%	4.90%	5.15%	5.40%	9.54%
MEAN											9.41%
FLOTATION COST											0.24%
											9.65%

Notes

[1] Source: Bloomberg. Based on indicated number of days historical average.
[2] Source: Bloomberg.
[3] Minimum of EPS Growth Rates from Value Line, Zacks, and First Call
[4] Interpolating Growth Rates: Col. [3] - ((Col. [3] - Col. [5])/ 6) * (Year - 5))
[5] Long-term GDP Growth Rate
[6] Calculated ROE

90-DAY MULTI-STAGE DCF -- LOW GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[4]	[4]	[4]	[4]	[5]	[6]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.34	$1.90	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.61%
American Electric Power Company, Inc.	AEP	$47.65	$1.96	3.56%	3.87%	4.17%	4.48%	4.79%	5.09%	5.40%	9.26%
Cleco Corporation	CNL	$46.46	$1.45	5.50%	5.48%	5.47%	5.45%	5.43%	5.42%	5.40%	8.70%
Empire District Electric Company	EDE	$22.30	$1.00	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	9.46%
FirstEnergy Corporation	FE	$41.38	$2.20	0.60%	1.40%	2.20%	3.00%	3.80%	4.60%	5.40%	9.54%
Great Plains Energy Inc.	GXP	$23.14	$0.87	6.19%	6.06%	5.93%	5.80%	5.66%	5.53%	5.40%	9.56%
Hawaiian Electric Industries, Inc.	HE	$26.66	$1.24	2.40%	2.90%	3.40%	3.90%	4.40%	4.90%	5.40%	9.46%
IDACORP, Inc.	IDA	$48.10	$1.52	2.00%	2.57%	3.13%	3.70%	4.27%	4.83%	5.40%	8.04%
Otter Tail Corporation	OTTR	$29.65	$1.19	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.79%
Pinnacle West Capital Corporation	PNW	$57.67	$2.18	4.45%	4.61%	4.77%	4.93%	5.08%	5.24%	5.40%	9.15%
Portland General Electric Company	POR	$30.86	$1.10	3.50%	3.82%	4.13%	4.45%	4.77%	5.08%	5.40%	8.72%
Southern Company	SO	$45.72	$2.03	4.50%	4.65%	4.80%	4.95%	5.10%	5.25%	5.40%	9.82%
Westar Energy, Inc.	WR	$32.62	$1.36	3.90%	4.15%	4.40%	4.65%	4.90%	5.15%	5.40%	9.40%
MEAN											9.27%
FLOTATION COST											0.24%
											9.51%

Notes

[1] Source: Bloomberg. Based on indicated number of days historical average.
[2] Source: Bloomberg.
[3] Minimum of EPS Growth Rates from Value Line, Zacks, and First Call
[4] Interpolating Growth Rates: Col. [3] - ((Col. [3] - Col. [5])/ 6) * (Year - 5))
[5] Long-term GDP Growth Rate
[6] Calculated ROE

180-DAY MULTI-STAGE DCF -- LOW GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[4]	[4]	[4]	[4]	[5]	[6]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$45.99	$1.90	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.92%
American Electric Power Company, Inc.	AEP	$45.68	$1.96	3.56%	3.87%	4.17%	4.48%	4.79%	5.09%	5.40%	9.43%
Cleco Corporation	CNL	$44.02	$1.45	5.50%	5.48%	5.47%	5.45%	5.43%	5.42%	5.40%	8.89%
Empire District Electric Company	EDE	$21.57	$1.00	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	9.60%
FirstEnergy Corporation	FE	$41.36	$2.20	0.60%	1.40%	2.20%	3.00%	3.80%	4.60%	5.40%	9.54%
Great Plains Energy Inc.	GXP	$22.08	$0.87	6.19%	6.06%	5.93%	5.80%	5.66%	5.53%	5.40%	9.76%
Hawaiian Electric Industries, Inc.	HE	$26.25	$1.24	2.40%	2.90%	3.40%	3.90%	4.40%	4.90%	5.40%	9.52%
IDACORP, Inc.	IDA	$46.17	$1.52	2.00%	2.57%	3.13%	3.70%	4.27%	4.83%	5.40%	8.16%
Otter Tail Corporation	OTTR	$27.63	$1.19	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.11%
Pinnacle West Capital Corporation	PNW	$55.00	$2.18	4.45%	4.61%	4.77%	4.93%	5.08%	5.24%	5.40%	9.33%
Portland General Electric Company	POR	$29.24	$1.10	3.50%	3.82%	4.13%	4.45%	4.77%	5.08%	5.40%	8.91%
Southern Company	SO	$44.77	$2.03	4.50%	4.65%	4.80%	4.95%	5.10%	5.25%	5.40%	9.92%
Westar Energy, Inc.	WR	$31.01	$1.36	3.90%	4.15%	4.40%	4.65%	4.90%	5.15%	5.40%	9.61%
MEAN											9.44%
FLOTATION COST											0.24%
											9.68%

Notes

[1] Source: Bloomberg. Based on indicated number of days historical average.
[2] Source: Bloomberg.
[3] Minimum of EPS Growth Rates from Value Line, Zacks, and First Call
[4] Interpolating Growth Rates: Col. [3] - ((Col. [3] - Col. [5])/ 6) * (Year - 5))
[5] Long-term GDP Growth Rate
[6] Calculated ROE

30-DAY MULTI-STAGE DCF -- HIGH GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[4]	[4]	[4]	[4]	[5]	[6]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.06	$1.90	7.00%	6.73%	6.47%	6.20%	5.93%	5.67%	5.40%	9.90%
American Electric Power Company, Inc.	AEP	$45.10	$1.96	4.50%	4.65%	4.80%	4.95%	5.10%	5.25%	5.40%	9.73%
Cleco Corporation	CNL	$45.75	$1.45	8.00%	7.57%	7.13%	6.70%	6.27%	5.83%	5.40%	9.33%
Empire District Electric Company	EDE	$22.15	$1.00	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	10.04%
FirstEnergy Corporation	FE	$37.56	$2.20	3.50%	3.82%	4.13%	4.45%	4.77%	5.08%	5.40%	10.91%
Great Plains Energy Inc.	GXP	$22.71	$0.87	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	9.72%
Hawaiian Electric Industries, Inc.	HE	$25.09	$1.24	5.50%	5.48%	5.47%	5.45%	5.43%	5.42%	5.40%	10.64%
IDACORP, Inc.	IDA	$48.15	$1.52	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	8.43%
Otter Tail Corporation	OTTR	$28.25	$1.19	21.50%	18.82%	16.13%	13.45%	10.77%	8.08%	5.40%	15.77%
Pinnacle West Capital Corporation	PNW	$55.72	$2.18	5.45%	5.44%	5.43%	5.43%	5.42%	5.41%	5.40%	9.53%
Portland General Electric Company	POR	$30.59	$1.10	6.53%	6.34%	6.15%	5.97%	5.78%	5.59%	5.40%	9.47%
Southern Company	SO	$43.98	$2.03	4.67%	4.79%	4.91%	5.04%	5.16%	5.28%	5.40%	10.05%
Westar Energy, Inc.	WR	$31.50	$1.36	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.12%
MEAN											10.28%
FLOTATION COST											0.24%
											10.52%

Notes
[1] Source: Bloomberg. Based on indicated number of days historical average.
[2] Source: Bloomberg.
[3] Maximum of EPS Growth Rates from Value Line, Zacks, and First Call
[4] Interpolating Growth Rates: Col. [3] - ((Col. [3] - Col. [5])/ 6) * (Year - 5))
[5] Long-term GDP Growth Rate
[6] Calculated ROE

90-DAY MULTI-STAGE DCF -- HIGH GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[4]	[4]	[4]	[4]	[5]	[6]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.34	$1.90	7.00%	6.73%	6.47%	6.20%	5.93%	5.67%	5.40%	9.88%
American Electric Power Company, Inc.	AEP	$47.65	$1.96	4.50%	4.65%	4.80%	4.95%	5.10%	5.25%	5.40%	9.50%
Cleco Corporation	CNL	$46.46	$1.45	8.00%	7.57%	7.13%	6.70%	6.27%	5.83%	5.40%	9.27%
Empire District Electric Company	EDE	$22.30	$1.00	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	10.01%
FirstEnergy Corporation	FE	$41.38	$2.20	3.50%	3.82%	4.13%	4.45%	4.77%	5.08%	5.40%	10.39%
Great Plains Energy Inc.	GXP	$23.14	$0.87	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	9.64%
Hawaiian Electric Industries, Inc.	HE	$26.66	$1.24	5.50%	5.48%	5.47%	5.45%	5.43%	5.42%	5.40%	10.33%
IDACORP, Inc.	IDA	$48.10	$1.52	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	8.43%
Otter Tail Corporation	OTTR	$29.65	$1.19	21.50%	18.82%	16.13%	13.45%	10.77%	8.08%	5.40%	15.35%
Pinnacle West Capital Corporation	PNW	$57.67	$2.18	5.45%	5.44%	5.43%	5.43%	5.42%	5.41%	5.40%	9.39%
Portland General Electric Company	POR	$30.86	$1.10	6.53%	6.34%	6.15%	5.97%	5.78%	5.59%	5.40%	9.43%
Southern Company	SO	$45.72	$2.03	4.67%	4.79%	4.91%	5.04%	5.16%	5.28%	5.40%	9.87%
Westar Energy, Inc.	WR	$32.62	$1.36	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.96%
MEAN											10.11%
FLOTATION COST											0.24%
											10.35%

Notes
[1] Source: Bloomberg. Based on indicated number of days historical average.
[2] Source: Bloomberg.
[3] Maximum of EPS Growth Rates from Value Line, Zacks, and First Call
[4] Interpolating Growth Rates: Col. [3] - ((Col. [3] - Col. [5])/ 6) * (Year - 5))
[5] Long-term GDP Growth Rate
[6] Calculated ROE

180-DAY MULTI-STAGE DCF -- HIGH GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[4]	[4]	[4]	[4]	[5]	[6]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$45.99	$1.90	7.00%	6.73%	6.47%	6.20%	5.93%	5.67%	5.40%	10.20%
American Electric Power Company, Inc.	AEP	$45.68	$1.96	4.50%	4.65%	4.80%	4.95%	5.10%	5.25%	5.40%	9.67%
Cleco Corporation	CNL	$44.02	$1.45	8.00%	7.57%	7.13%	6.70%	6.27%	5.83%	5.40%	9.48%
Empire District Electric Company	EDE	$21.57	$1.00	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	10.17%
FirstEnergy Corporation	FE	$41.36	$2.20	3.50%	3.82%	4.13%	4.45%	4.77%	5.08%	5.40%	10.39%
Great Plains Energy Inc.	GXP	$22.08	$0.87	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	9.84%
Hawaiian Electric Industries, Inc.	HE	$26.25	$1.24	5.50%	5.48%	5.47%	5.45%	5.43%	5.42%	5.40%	10.41%
IDACORP, Inc.	IDA	$46.17	$1.52	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	8.56%
Otter Tail Corporation	OTTR	$27.63	$1.19	21.50%	18.82%	16.13%	13.45%	10.77%	8.08%	5.40%	15.96%
Pinnacle West Capital Corporation	PNW	$55.00	$2.18	5.45%	5.44%	5.43%	5.43%	5.42%	5.41%	5.40%	9.59%
Portland General Electric Company	POR	$29.24	$1.10	6.53%	6.34%	6.15%	5.97%	5.78%	5.59%	5.40%	9.65%
Southern Company	SO	$44.77	$2.03	4.67%	4.79%	4.91%	5.04%	5.16%	5.28%	5.40%	9.97%
Westar Energy, Inc.	WR	$31.01	$1.36	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.20%
MEAN											10.32%
FLOTATION COST											0.24%
											10.55%

Notes
[1] Source: Bloomberg. Based on indicated number of days historical average.
[2] Source: Bloomberg.
[3] Maximum of EPS Growth Rates from Value Line, Zacks, and First Call
[4] Interpolating Growth Rates: Col. [3] - ((Col. [3] - Col. [5])/ 6) * (Year - 5))
[5] Long-term GDP Growth Rate
[6] Calculated ROE

CAPITAL ASSET PRICING MODEL

	[4]	[5]	[6]	[7]
	Risk Free Rate	Average Beta	Market DCF Derived	ROE Estimate
PROXY GROUP VALUE LINE BETA				
[1] Current 30-day average of the 30-Year Treasury Yield	3.46%	0.712	9.77%	10.41%
[2] Projected 30-Year Treasury (Q3 2013-Q4 2014)	3.73%	0.712	9.49%	10.49%
[3] Projected 30-Year Treasury (2015-2019)	5.20%	0.712	8.03%	10.91%
			Mean	10.60%
PROXY GROUP BLOOMBERG BETA				
[1] Current 30-day average of the 30-Year Treasury Yield	3.46%	0.727	9.77%	10.56%
[2] Projected 30-Year Treasury (Q3 2013-Q4 2014)	3.73%	0.727	9.49%	10.64%
[3] Projected 30-Year Treasury (2015-2019)	5.20%	0.727	8.03%	11.04%
			Mean	10.74%

Notes:
[1] Source: Bloomberg
[2] Source: Aspen Publishers, Blue Chip Financial Forecasts, Vol. 32, No. 7 July 1, 2013, p. 2
[3] Source: Aspen Publishers, Blue Chip Financial Forecasts, Vol. 32, No. 6 June 1, 2013, p. 14
[4] See Notes [1], [2], and [3]
[5] Source: Value Line & Bloomberg
[6] Source: Rebuttal Exhibit__(AEB-1), Schedule-4.0, p. 2
[7] Equals Col. [4] + (Col. [5] x Col. [6])

ESTIMATED MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1]	[2]	[3]
Estimated Weighted Index Dividend Yield	Weighted Index Long-Term Growth Rate	S&P 500 Est. Required Market Return
2.11%	11.00%	13.23%

	Risk-Free Rate [4]	Implied Market Risk Premium [5]
Current 30-day average Treasury Yield	3.46%	9.77%
Near-Term Projected 30-Year Treasury (Q3 2012-Q4 2013)	3.73%	9.49%
Projected 30-Year Treasury (2015-2019)	5.20%	8.03%

[6] Percent of Index Capitalization Represented by Estimate:	98.39%

STANDARD AND POOR'S 500 INDEX

		[7]	[8]	[9]	[10]	[11]
Name	**Ticker**	**Weight in Index**	**Long-Term Growth Est.**	**Cap-Weighted Long-Term Growth Est.**	**Estimated Dividend Yield**	**Cap-Weighted Dividend Yield**
3M Co	MMM	0.51%	11.88%	0.06%	2.21%	0.01%
Abbott Laboratories	ABT	0.36%	11.40%	0.04%	1.59%	0.01%
AbbVie Inc	ABBV	0.46%	6.25%	0.03%	3.55%	0.02%
Abercrombie & Fitch Co	ANF	0.03%	16.13%	0.00%	1.57%	0.00%
Accenture PLC	ACN	0.31%	12.75%	0.04%	2.15%	0.01%
ACE Ltd	ACE	0.21%	9.17%	0.02%	2.18%	0.00%
Actavis Inc	ACT	0.11%	11.28%	0.01%	n/a	n/a
Adobe Systems Inc	ADBE	0.16%	11.80%	0.02%	n/a	n/a
ADT Corp/The	ADT	0.06%	9.33%	0.01%	1.16%	0.00%
Advanced Micro Devices Inc	AMD	0.02%	10.75%	0.00%	n/a	n/a
AES Corp/VA	AES	0.06%	7.96%	0.00%	1.27%	0.00%
Aetna Inc	AET	0.16%	10.75%	0.02%	1.26%	0.00%
Aflac Inc	AFL	0.18%	11.75%	0.02%	2.37%	0.00%
Agilent Technologies Inc	A	0.10%	6.73%	0.01%	1.05%	0.00%
AGL Resources Inc	GAS	0.03%	2.94%	0.00%	4.20%	0.00%
Air Products & Chemicals Inc	APD	0.13%	9.33%	0.01%	2.94%	0.00%
Airgas Inc	ARG	0.05%	12.19%	0.01%	1.91%	0.00%
Akamai Technologies Inc	AKAM	0.05%	14.80%	0.01%	n/a	n/a
Alcoa Inc	AA	0.06%	6.50%	0.00%	1.48%	0.00%
Alexion Pharmaceuticals Inc	ALXN	0.14%	23.75%	0.03%	n/a	n/a
Allegheny Technologies Inc	ATI	0.02%	15.00%	0.00%	2.63%	0.00%
Allergan Inc/United States	AGN	0.17%	12.92%	0.02%	0.22%	0.00%
Allstate Corp/The	ALL	0.15%	8.88%	0.01%	1.96%	0.00%
Altera Corp	ALTR	0.07%	12.40%	0.01%	1.71%	0.00%
Altria Group Inc	MO	0.48%	7.59%	0.04%	4.77%	0.02%
Amazon.com Inc	AMZN	0.90%	33.19%	0.30%	n/a	n/a
Ameren Corp	AEE	0.06%	2.00%	0.00%	4.51%	0.00%
American Electric Power Co Inc	AEP	0.15%	4.35%	0.01%	4.21%	0.01%
American Express Co	AXP	0.56%	11.40%	0.06%	1.17%	0.01%
American International Group Inc	AIG	0.45%	10.75%	0.05%	n/a	n/a
American Tower Corp	AMT	0.20%	19.47%	0.04%	1.39%	0.00%
Ameriprise Financial Inc	AMP	0.11%	9.50%	0.01%	2.40%	0.00%
AmerisourceBergen Corp	ABC	0.09%	11.60%	0.01%	1.44%	0.00%
Amgen Inc	AMGN	0.50%	8.52%	0.04%	1.80%	0.01%
Amphenol Corp	APH	0.09%	15.00%	0.01%	0.49%	0.00%
Anadarko Petroleum Corp	APC	0.29%	11.21%	0.03%	0.40%	0.00%
Analog Devices Inc	ADI	0.10%	12.00%	0.01%	2.81%	0.00%
Aon PLC	AON	0.13%	10.00%	0.01%	1.04%	0.00%
Apache Corp	APA	0.21%	7.11%	0.01%	0.97%	0.00%
Apartment Investment & Management C	AIV	0.03%	11.35%	0.00%	3.11%	0.00%
Apple Inc	AAPL	2.58%	20.49%	0.53%	2.86%	0.07%
Applied Materials Inc	AMAT	0.13%	9.67%	0.01%	2.40%	0.00%
Archer-Daniels-Midland Co	ADM	0.15%	10.00%	0.02%	2.09%	0.00%
Assurant Inc	AIZ	0.03%	9.67%	0.00%	1.88%	0.00%
AT&T Inc	T	1.24%	5.43%	0.07%	5.03%	0.06%
Autodesk Inc	ADSK	0.05%	11.60%	0.01%	n/a	n/a
Automatic Data Processing Inc	ADP	0.23%	9.57%	0.02%	2.37%	0.01%
AutoNation Inc	AN	0.04%	22.99%	0.01%	n/a	n/a
AutoZone Inc	AZO	0.10%	15.98%	0.02%	n/a	n/a
AvalonBay Communities Inc	AVB	0.12%	10.10%	0.01%	3.05%	0.00%
Avery Dennison Corp	AVY	0.03%	7.00%	0.00%	2.60%	0.00%
Avon Products Inc	AVP	0.06%	18.75%	0.01%	1.06%	0.00%
Baker Hughes Inc	BHI	0.14%	13.00%	0.02%	1.22%	0.00%
Ball Corp	BLL	0.04%	10.00%	0.00%	1.15%	0.00%
Bank of America Corp	BAC	0.96%	14.50%	0.14%	0.29%	0.00%
Bank of New York Mellon Corp/The	BK	0.23%	12.50%	0.03%	2.00%	0.00%
Baxter International Inc	BAX	0.25%	9.85%	0.02%	2.70%	0.01%
BB&T Corp	BBT	0.16%	9.05%	0.01%	2.64%	0.00%
Beam Inc	BEAM	0.07%	10.85%	0.01%	1.38%	0.00%
Becton Dickinson and Co	BDX	0.13%	8.01%	0.01%	1.94%	0.00%
Bed Bath & Beyond Inc	BBBY	0.11%	13.19%	0.01%	n/a	n/a
Bemis Co Inc	BMS	0.03%	7.00%	0.00%	2.51%	0.00%
Berkshire Hathaway Inc	BRK/B	0.85%	n/a	n/a	n/a	n/a
Best Buy Co Inc	BBY	0.07%	9.70%	0.01%	2.29%	0.00%
Biogen Idec Inc	BIIB	0.35%	18.84%	0.07%	n/a	n/a
BlackRock Inc	BLK	0.29%	13.84%	0.04%	2.49%	0.01%
BMC Software Inc	BMC	0.04%	15.00%	0.01%	n/a	n/a
Boeing Co/The	BA	0.50%	11.50%	0.06%	1.90%	0.01%

Name	Ticker	Weight in Index	Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.	Estimated Dividend Yield	Cap-Weighted Dividend Yield
BorgWarner Inc	BWA	0.07%	15.00%	0.01%	n/a	n/a
Boston Properties Inc	BXP	0.11%	6.94%	0.01%	2.36%	0.00%
Boston Scientific Corp	BSX	0.08%	9.09%	0.01%	n/a	n/a
Bristol-Myers Squibb Co	BMY	0.49%	7.61%	0.04%	3.06%	0.01%
Broadcom Corp	BRCM	0.12%	13.75%	0.02%	1.26%	0.00%
Brown-Forman Corp	BF/B	0.06%	12.50%	0.01%	1.41%	0.00%
CA Inc	CA	0.09%	7.50%	0.01%	3.34%	0.00%
Cablevision Systems Corp	CVC	0.03%	17.63%	0.00%	3.19%	0.00%
Cabot Oil & Gas Corp	COG	0.10%	35.00%	0.03%	0.11%	0.00%
Cameron International Corp	CAM	0.10%	17.00%	0.02%	n/a	n/a
Campbell Soup Co	CPB	0.09%	6.20%	0.01%	2.54%	0.00%
Capital One Financial Corp	COF	0.25%	8.50%	0.02%	1.80%	0.00%
Cardinal Health Inc	CAH	0.11%	11.17%	0.01%	2.44%	0.00%
CareFusion Corp	CFN	0.05%	9.93%	0.01%	n/a	n/a
CarMax Inc	KMX	0.07%	13.03%	0.01%	n/a	n/a
Carnival Corp	CCL	0.14%	14.83%	0.02%	2.77%	0.00%
Caterpillar Inc	CAT	0.37%	10.33%	0.04%	2.75%	0.01%
CBRE Group Inc	CBG	0.05%	11.67%	0.01%	n/a	n/a
CBS Corp	CBS	0.20%	10.57%	0.02%	0.91%	0.00%
Celgene Corp	CELG	0.36%	23.62%	0.09%	n/a	n/a
CenterPoint Energy Inc	CNP	0.07%	5.60%	0.00%	3.40%	0.00%
CenturyLink Inc	CTL	0.14%	3.13%	0.00%	5.96%	0.01%
Cerner Corp	CERN	0.11%	18.33%	0.02%	n/a	n/a
CF Industries Holdings Inc	CF	0.07%	9.00%	0.01%	0.87%	0.00%
CH Robinson Worldwide Inc	CHRW	0.06%	14.50%	0.01%	2.42%	0.00%
Charles Schwab Corp/The	SCHW	0.18%	20.45%	0.04%	1.11%	0.00%
Chesapeake Energy Corp	CHK	0.09%	21.88%	0.02%	1.65%	0.00%
Chevron Corp	CVX	1.55%	5.11%	0.08%	3.22%	0.05%
Chipotle Mexican Grill Inc	CMG	0.08%	20.38%	0.02%	n/a	n/a
Chubb Corp/The	CB	0.15%	9.00%	0.01%	2.01%	0.00%
Cigna Corp	CI	0.14%	11.03%	0.02%	0.05%	0.00%
Cincinnati Financial Corp	CINF	0.05%	n/a	n/a	3.31%	0.00%
Cintas Corp	CTAS	0.04%	10.60%	0.00%	1.33%	0.00%
Cisco Systems Inc	CSCO	0.90%	10.57%	0.09%	2.62%	0.02%
Citigroup Inc	C	1.00%	10.83%	0.11%	0.08%	0.00%
Citrix Systems Inc	CTXS	0.08%	14.04%	0.01%	n/a	n/a
Cliffs Natural Resources Inc	CLF	0.02%	5.00%	0.00%	3.56%	0.00%
Clorox Co/The	CLX	0.07%	8.09%	0.01%	3.31%	0.00%
CME Group Inc/IL	CME	0.17%	15.00%	0.03%	2.33%	0.00%
CMS Energy Corp	CMS	0.05%	6.00%	0.00%	3.65%	0.00%
Coach Inc	COH	0.11%	11.44%	0.01%	2.29%	0.00%
Coca-Cola Co/The	KO	1.18%	8.02%	0.09%	2.73%	0.03%
Coca-Cola Enterprises Inc	CCE	0.07%	8.89%	0.01%	2.17%	0.00%
Cognizant Technology Solutions Corp	CTSH	0.14%	18.57%	0.03%	n/a	n/a
Colgate-Palmolive Co	CL	0.36%	9.14%	0.03%	2.30%	0.01%
Comcast Corp	CMCSA	0.61%	17.61%	0.11%	1.75%	0.01%
Comerica Inc	CMA	0.05%	6.64%	0.00%	1.63%	0.00%
Computer Sciences Corp	CSC	0.05%	8.00%	0.00%	1.67%	0.00%
ConAgra Foods Inc	CAG	0.10%	7.00%	0.01%	2.73%	0.00%
ConocoPhillips	COP	0.51%	5.55%	0.03%	4.26%	0.02%
CONSOL Energy Inc	CNX	0.04%	12.00%	0.00%	1.81%	0.00%
Consolidated Edison Inc	ED	0.11%	3.20%	0.00%	4.16%	0.00%
Constellation Brands Inc	STZ	0.06%	13.62%	0.01%	n/a	n/a
Corning Inc	GLW	0.14%	11.50%	0.02%	2.66%	0.00%
Costco Wholesale Corp	COST	0.33%	12.81%	0.04%	1.06%	0.00%
Covidien PLC	COV	0.18%	9.43%	0.02%	1.75%	0.00%
CR Bard Inc	BCR	0.06%	10.70%	0.01%	0.76%	0.00%
Crown Castle International Corp	CCI	0.15%	23.00%	0.03%	n/a	n/a
CSX Corp	CSX	0.16%	12.10%	0.02%	2.46%	0.00%
Cummins Inc	CMI	0.14%	10.33%	0.01%	2.17%	0.00%
CVS Caremark Corp	CVS	0.48%	13.50%	0.07%	1.48%	0.01%
Danaher Corp	DHR	0.30%	13.00%	0.04%	0.15%	0.00%
Darden Restaurants Inc	DRI	0.04%	9.34%	0.00%	4.36%	0.00%
DaVita HealthCare Partners Inc	DVA	0.08%	12.40%	0.01%	n/a	n/a
Deere & Co	DE	0.21%	9.25%	0.02%	2.43%	0.01%
Dell Inc	DELL	0.15%	5.50%	0.01%	2.40%	0.00%
Delphi Automotive PLC	DLPH	0.11%	12.50%	0.01%	1.24%	0.00%
Denbury Resources Inc	DNR	0.04%	n/a	n/a	n/a	n/a
DENTSPLY International Inc	XRAY	0.04%	9.80%	0.00%	0.60%	0.00%
Devon Energy Corp	DVN	0.15%	5.22%	0.01%	1.58%	0.00%
Diamond Offshore Drilling Inc	DO	0.06%	18.00%	0.01%	4.85%	0.00%
DIRECTV	DTV	0.23%	15.95%	0.04%	n/a	n/a
Discover Financial Services	DFS	0.16%	10.50%	0.02%	1.57%	0.00%
Discovery Communications Inc	DISCA	0.08%	18.81%	0.02%	n/a	n/a
Dollar General Corp	DG	0.11%	15.85%	0.02%	n/a	n/a
Dollar Tree Inc	DLTR	0.08%	15.80%	0.01%	n/a	n/a
Dominion Resources Inc/VA	D	0.22%	5.69%	0.01%	3.83%	0.01%
Dover Corp	DOV	0.09%	15.00%	0.01%	1.73%	0.00%
Dow Chemical Co/The	DOW	0.27%	8.76%	0.02%	3.75%	0.01%
DR Horton Inc	DHI	0.05%	5.23%	0.00%	0.66%	0.00%
Dr Pepper Snapple Group Inc	DPS	0.06%	7.18%	0.00%	3.20%	0.00%
DTE Energy Co	DTE	0.08%	4.75%	0.00%	3.80%	0.00%
Duke Energy Corp	DUK	0.32%	4.48%	0.01%	4.45%	0.01%
Dun & Bradstreet Corp/The	DNB	0.03%	n/a	n/a	1.49%	0.00%
E*TRADE Financial Corp	ETFC	0.02%	28.83%	0.01%	n/a	n/a
Eastman Chemical Co	EMN	0.07%	7.67%	0.01%	1.62%	0.00%
Eaton Corp PLC	ETN	0.21%	11.12%	0.02%	2.46%	0.01%
eBay Inc	EBAY	0.48%	14.59%	0.07%	n/a	n/a
Ecolab Inc	ECL	0.17%	13.64%	0.02%	1.02%	0.00%
Edison International	EIX	0.10%	4.84%	0.00%	2.79%	0.00%

Name	Ticker	Weight in Index	Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.	Estimated Dividend Yield	Cap-Weighted Dividend Yield
Edwards Lifesciences Corp	EW	0.05%	17.80%	0.01%	n/a	n/a
EI du Pont de Nemours & Co	DD	0.32%	7.84%	0.03%	3.31%	0.01%
Electronic Arts Inc	EA	0.05%	16.93%	0.01%	n/a	n/a
Eli Lilly & Co	LLY	0.37%	1.36%	0.01%	3.81%	0.01%
EMC Corp/MA	EMC	0.34%	13.29%	0.04%	1.60%	0.01%
Emerson Electric Co	EMR	0.27%	9.71%	0.03%	2.87%	0.01%
Ensco PLC	ESV	0.09%	16.00%	0.01%	3.32%	0.00%
Entergy Corp	ETR	0.08%	-0.49%	0.00%	4.68%	0.00%
EOG Resources Inc	EOG	0.25%	10.97%	0.03%	0.52%	0.00%
EQT Corp	EQT	0.08%	30.00%	0.02%	0.15%	0.00%
Equifax Inc	EFX	0.05%	11.33%	0.01%	1.44%	0.00%
Equity Residential	EQR	0.14%	7.37%	0.01%	2.73%	0.00%
Estee Lauder Cos Inc/The	EL	0.11%	14.18%	0.01%	1.05%	0.00%
Exelon Corp	EXC	0.17%	-0.40%	0.00%	3.99%	0.01%
Expedia Inc	EXPE	0.05%	14.05%	0.01%	0.82%	0.00%
Expeditors International of Washington Ir	EXPD	0.05%	11.13%	0.01%	1.50%	0.00%
Express Scripts Holding Co	ESRX	0.34%	16.77%	0.06%	n/a	n/a
Exxon Mobil Corp	XOM	2.68%	15.32%	0.41%	2.70%	0.07%
F5 Networks Inc	FFIV	0.04%	14.38%	0.01%	n/a	n/a
Family Dollar Stores Inc	FDO	0.05%	11.55%	0.01%	1.52%	0.00%
Fastenal Co	FAST	0.09%	17.97%	0.02%	2.12%	0.00%
FedEx Corp	FDX	0.21%	12.45%	0.03%	0.59%	0.00%
Fidelity National Information Services Inc	FIS	0.09%	12.40%	0.01%	1.95%	0.00%
Fifth Third Bancorp	FITB	0.11%	12.98%	0.01%	2.53%	0.00%
First Solar Inc	FSLR	0.03%	0.00%	0.00%	n/a	n/a
FirstEnergy Corp	FE	0.10%	4.50%	0.00%	5.87%	0.01%
Fiserv Inc	FISV	0.08%	11.83%	0.01%	n/a	n/a
FLIR Systems Inc	FLIR	0.03%	12.50%	0.00%	1.23%	0.00%
Flowserve Corp	FLS	0.05%	12.33%	0.01%	1.01%	0.00%
Fluor Corp	FLR	0.06%	12.15%	0.01%	1.04%	0.00%
FMC Corp	FMC	0.05%	11.34%	0.01%	0.87%	0.00%
FMC Technologies Inc	FTI	0.09%	15.33%	0.01%	n/a	n/a
Ford Motor Co	F	0.43%	6.18%	0.03%	2.34%	0.01%
Forest Laboratories Inc	FRX	0.08%	34.64%	0.03%	n/a	n/a
Fossil Group Inc	FOSL	0.04%	16.37%	0.01%	n/a	n/a
Franklin Resources Inc	BEN	0.20%	15.10%	0.03%	0.81%	0.00%
Freeport-McMoRan Copper & Gold Inc	FCX	0.19%	7.00%	0.01%	4.46%	0.01%
Frontier Communications Corp	FTR	0.03%	4.03%	0.00%	9.93%	0.00%
GameStop Corp	GME	0.03%	13.88%	0.00%	2.55%	0.00%
Gannett Co Inc	GCI	0.04%	4.50%	0.00%	3.00%	0.00%
Gap Inc/The	GPS	0.14%	12.76%	0.02%	1.33%	0.00%
Garmin Ltd	GRMN	0.05%	6.54%	0.00%	4.96%	0.00%
General Dynamics Corp	GD	0.19%	5.28%	0.01%	2.71%	0.01%
General Electric Co	GE	1.59%	9.75%	0.15%	3.20%	0.05%
General Mills Inc	GIS	0.21%	7.83%	0.02%	2.98%	0.01%
General Motors Co	GM	0.32%	12.50%	0.04%	n/a	n/a
Genuine Parts Co	GPC	0.09%	7.89%	0.01%	2.53%	0.00%
Genworth Financial Inc	GNW	0.04%	5.00%	0.00%	n/a	n/a
Gilead Sciences Inc	GILD	0.57%	25.39%	0.14%	n/a	n/a
Goldman Sachs Group Inc/The	GS	0.47%	10.05%	0.05%	1.25%	0.01%
Goodyear Tire & Rubber Co/The	GT	0.03%	24.02%	0.01%	n/a	n/a
Google Inc	GOOG	1.62%	15.32%	0.25%	n/a	n/a
H&R Block Inc	HRB	0.05%	13.50%	0.01%	2.61%	0.00%
Halliburton Co	HAL	0.27%	14.67%	0.04%	1.12%	0.00%
Harley-Davidson Inc	HOG	0.08%	12.33%	0.01%	1.50%	0.00%
Harman International Industries Inc	HAR	0.02%	17.50%	0.00%	2.17%	0.00%
Harris Corp	HRS	0.04%	2.00%	0.00%	2.86%	0.00%
Hartford Financial Services Group Inc	HIG	0.09%	9.00%	0.01%	1.86%	0.00%
Hasbro Inc	HAS	0.04%	8.00%	0.00%	3.36%	0.00%
HCP Inc	HCP	0.14%	4.53%	0.01%	4.53%	0.01%
Health Care REIT Inc	HCN	0.12%	5.68%	0.01%	4.56%	0.01%
Helmerich & Payne Inc	HP	0.04%	9.00%	0.00%	3.05%	0.00%
Hershey Co/The	HSY	0.10%	8.50%	0.01%	1.83%	0.00%
Hess Corp	HES	0.16%	5.36%	0.01%	0.56%	0.00%
Hewlett-Packard Co	HPQ	0.33%	3.00%	0.01%	2.22%	0.01%
Home Depot Inc/The	HD	0.76%	16.38%	0.12%	1.94%	0.01%
Honeywell International Inc	HON	0.42%	11.16%	0.05%	1.99%	0.01%
Hormel Foods Corp	HRL	0.07%	8.50%	0.01%	1.66%	0.00%
Hospira Inc	HSP	0.04%	10.11%	0.00%	n/a	n/a
Host Hotels & Resorts Inc	HST	0.09%	12.50%	0.01%	2.45%	0.00%
Hudson City Bancorp Inc	HCBK	0.03%	n/a	n/a	1.64%	0.00%
Humana Inc	HUM	0.09%	10.21%	0.01%	1.26%	0.00%
Huntington Bancshares Inc/OH	HBAN	0.05%	5.25%	0.00%	2.40%	0.00%
Illinois Tool Works Inc	ITW	0.21%	9.28%	0.02%	2.11%	0.00%
Ingersoll-Rand PLC	IR	0.11%	10.00%	0.01%	1.42%	0.00%
Integrys Energy Group Inc	TEG	0.03%	5.33%	0.00%	4.50%	0.00%
Intel Corp	INTC	0.77%	9.16%	0.07%	3.77%	0.03%
IntercontinentalExchange Inc	ICE	0.08%	18.00%	0.02%	n/a	n/a
International Business Machines Corp	IBM	1.38%	9.40%	0.13%	1.98%	0.03%
International Flavors & Fragrances Inc	IFF	0.04%	7.33%	0.00%	1.70%	0.00%
International Game Technology	IGT	0.03%	14.25%	0.00%	2.04%	0.00%
International Paper Co	IP	0.14%	5.50%	0.01%	2.49%	0.00%
Interpublic Group of Cos Inc/The	IPG	0.04%	14.50%	0.01%	1.91%	0.00%
Intuit Inc	INTU	0.12%	13.00%	0.02%	1.05%	0.00%
Intuitive Surgical Inc	ISRG	0.11%	15.50%	0.02%	n/a	n/a
Invesco Ltd	IVZ	0.09%	13.75%	0.01%	2.83%	0.00%
Iron Mountain Inc	IRM	0.03%	13.00%	0.00%	3.83%	0.00%
Jabil Circuit Inc	JBL	0.03%	12.00%	0.00%	1.46%	0.00%
Jacobs Engineering Group Inc	JEC	0.05%	13.80%	0.01%	n/a	n/a
JC Penney Co Inc	JCP	0.02%	11.70%	0.00%	n/a	n/a

Name	Ticker	Weight in Index	Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.	Estimated Dividend Yield	Cap-Weighted Dividend Yield
JDS Uniphase Corp	JDSU	0.02%	15.00%	0.00%	n/a	n/a
JM Smucker Co/The	SJM	0.07%	8.18%	0.01%	1.96%	0.00%
Johnson & Johnson	JNJ	1.63%	6.46%	0.11%	2.93%	0.05%
Johnson Controls Inc	JCI	0.16%	12.78%	0.02%	2.06%	0.00%
Joy Global Inc	JOY	0.04%	8.10%	0.00%	1.36%	0.00%
JPMorgan Chase & Co	JPM	1.34%	10.13%	0.14%	2.77%	0.04%
Juniper Networks Inc	JNPR	0.07%	14.20%	0.01%	n/a	n/a
Kansas City Southern	KSU	0.08%	17.00%	0.01%	0.76%	0.00%
Kellogg Co	K	0.16%	7.81%	0.01%	2.77%	0.00%
KeyCorp	KEY	0.07%	5.00%	0.00%	1.87%	0.00%
Kimberly-Clark Corp	KMB	0.25%	7.61%	0.02%	3.24%	0.01%
Kimco Realty Corp	KIM	0.06%	5.10%	0.00%	3.76%	0.00%
Kinder Morgan Inc/DE	KMI	0.27%	2.50%	0.01%	3.99%	0.01%
KLA-Tencor Corp	KLAC	0.06%	10.00%	0.01%	2.98%	0.00%
Kohl's Corp	KSS	0.08%	9.14%	0.01%	2.62%	0.00%
Kraft Foods Group Inc	KRFT	0.22%	6.60%	0.01%	3.53%	0.01%
Kroger Co/The	KR	0.13%	8.82%	0.01%	1.59%	0.00%
L Brands Inc	LTD	0.10%	12.13%	0.01%	2.32%	0.00%
L-3 Communications Holdings Inc	LLL	0.05%	3.07%	0.00%	2.44%	0.00%
Laboratory Corp of America Holdings	LH	0.06%	11.25%	0.01%	n/a	n/a
Lam Research Corp	LRCX	0.05%	11.00%	0.01%	n/a	n/a
Legg Mason Inc	LM	0.03%	14.95%	0.00%	1.59%	0.00%
Leggett & Platt Inc	LEG	0.03%	15.00%	0.00%	3.59%	0.00%
Lennar Corp	LEN	0.04%	8.00%	0.00%	0.43%	0.00%
Leucadia National Corp	LUK	0.06%	n/a	n/a	0.93%	0.00%
Life Technologies Corp	LIFE	0.08%	9.53%	0.01%	n/a	n/a
Lincoln National Corp	LNC	0.07%	9.00%	0.01%	1.21%	0.00%
Linear Technology Corp	LLTC	0.06%	10.51%	0.01%	2.61%	0.00%
Lockheed Martin Corp	LMT	0.23%	6.60%	0.02%	4.09%	0.01%
Loews Corp	L	0.11%	n/a	n/a	0.55%	0.00%
Lorillard Inc	LO	0.11%	12.23%	0.01%	4.77%	0.01%
Lowe's Cos Inc	LOW	0.30%	16.26%	0.05%	1.64%	0.00%
LSI Corp	LSI	0.03%	15.33%	0.00%	n/a	n/a
LyondellBasell Industries NV	LYB	0.26%	10.45%	0.03%	2.86%	0.01%
M&T Bank Corp	MTB	0.10%	12.50%	0.01%	2.38%	0.00%
Macerich Co/The	MAC	0.06%	5.23%	0.00%	3.64%	0.00%
Macy's Inc	M	0.12%	9.70%	0.01%	2.02%	0.00%
Marathon Oil Corp	MRO	0.17%	12.67%	0.02%	1.85%	0.00%
Marathon Petroleum Corp	MPC	0.15%	11.00%	0.02%	1.91%	0.00%
Marriott International Inc/DE	MAR	0.08%	15.14%	0.01%	1.63%	0.00%
Marsh & McLennan Cos Inc	MMC	0.15%	12.00%	0.02%	2.40%	0.00%
Masco Corp	MAS	0.05%	8.00%	0.00%	1.45%	0.00%
Mastercard Inc	MA	0.45%	17.91%	0.08%	0.40%	0.00%
Mattel Inc	MAT	0.10%	9.50%	0.01%	3.06%	0.00%
McCormick & Co Inc/MD	MKC	0.06%	8.25%	0.00%	1.90%	0.00%
McDonald's Corp	MCD	0.66%	9.59%	0.06%	3.03%	0.02%
McGraw Hill Financial Inc	MHFI	0.10%	15.60%	0.02%	1.95%	0.00%
McKesson Corp	MCK	0.18%	13.00%	0.02%	0.67%	0.00%
Mead Johnson Nutrition Co	MJN	0.10%	10.80%	0.01%	1.83%	0.00%
MeadWestvaco Corp	MWV	0.04%	10.00%	0.00%	2.77%	0.00%
Medtronic Inc	MDT	0.35%	6.67%	0.02%	2.10%	0.01%
Merck & Co Inc	MRK	0.95%	3.56%	0.03%	3.54%	0.03%
MetLife Inc	MET	0.35%	5.25%	0.02%	2.24%	0.01%
Microchip Technology Inc	MCHP	0.05%	12.00%	0.01%	3.59%	0.00%
Micron Technology Inc	MU	0.09%	12.27%	0.01%	n/a	n/a
Microsoft Corp	MSFT	1.93%	8.50%	0.16%	2.57%	0.05%
Molex Inc	MOLX	0.02%	12.50%	0.00%	3.21%	0.00%
Molson Coors Brewing Co	TAP	0.05%	7.61%	0.00%	2.50%	0.00%
Mondelez International Inc	MDLZ	0.35%	10.63%	0.04%	1.71%	0.01%
Monsanto Co	MON	0.35%	15.05%	0.05%	1.46%	0.01%
Monster Beverage Corp	MNST	0.06%	14.00%	0.01%	n/a	n/a
Moody's Corp	MCO	0.09%	n/a	n/a	1.31%	0.00%
Morgan Stanley	MS	0.33%	6.78%	0.02%	0.77%	0.00%
Mosaic Co/The	MOS	0.11%	6.76%	0.01%	1.78%	0.00%
Motorola Solutions Inc	MSI	0.10%	12.50%	0.01%	1.75%	0.00%
Murphy Oil Corp	MUR	0.08%	13.00%	0.01%	1.94%	0.00%
Mylan Inc/PA	MYL	0.08%	8.87%	0.01%	n/a	n/a
Nabors Industries Ltd	NBR	0.03%	10.00%	0.00%	1.08%	0.00%
NASDAQ OMX Group Inc/The	NDAQ	0.04%	12.63%	0.00%	1.52%	0.00%
National Oilwell Varco Inc	NOV	0.20%	11.33%	0.02%	1.43%	0.00%
NetApp Inc	NTAP	0.09%	13.17%	0.01%	1.53%	0.00%
Netflix Inc	NFLX	0.09%	20.00%	0.02%	n/a	n/a
Newell Rubbermaid Inc	NWL	0.05%	8.83%	0.00%	2.22%	0.00%
Newfield Exploration Co	NFX	0.02%	11.50%	0.00%	n/a	n/a
Newmont Mining Corp	NEM	0.09%	2.00%	0.00%	5.10%	0.00%
News Corp	NWSA	0.04%	10.00%	0.00%	n/a	n/a
NextEra Energy Inc	NEE	0.23%	5.94%	0.01%	3.14%	0.01%
Nielsen Holdings NV	NLSN	0.08%	16.47%	0.01%	1.86%	0.00%
NIKE Inc	NKE	0.29%	11.83%	0.03%	1.32%	0.00%
NiSource Inc	NI	0.06%	4.00%	0.00%	3.30%	0.00%
Noble Corp	NE	0.07%	13.67%	0.01%	1.29%	0.00%
Noble Energy Inc	NBL	0.15%	7.00%	0.01%	0.87%	0.00%
Nordstrom Inc	JWN	0.08%	11.90%	0.01%	1.93%	0.00%
Norfolk Southern Corp	NSC	0.15%	11.60%	0.02%	2.66%	0.00%
Northeast Utilities	NU	0.09%	7.60%	0.01%	3.40%	0.00%
Northern Trust Corp	NTRS	0.10%	14.52%	0.01%	2.02%	0.00%
Northrop Grumman Corp	NOC	0.13%	7.50%	0.01%	2.77%	0.00%
NRG Energy Inc	NRG	0.06%	n/a	n/a	1.68%	0.00%
Nucor Corp	NUE	0.09%	7.33%	0.01%	3.28%	0.00%
NVIDIA Corp	NVDA	0.05%	10.40%	0.01%	2.05%	0.00%

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NYSE Euronext	NYX	0.07%	10.00%	0.01%	2.87%	0.00%
O'Reilly Automotive Inc	ORLY	0.08%	19.20%	0.02%	n/a	n/a
Occidental Petroleum Corp	OXY	0.47%	7.09%	0.03%	2.84%	0.01%
Omnicom Group Inc	OMC	0.11%	7.70%	0.01%	2.41%	0.00%
ONEOK Inc	OKE	0.06%	9.00%	0.01%	3.34%	0.00%
Oracle Corp	ORCL	0.93%	10.89%	0.10%	1.54%	0.01%
Owens-Illinois Inc	OI	0.03%	8.67%	0.00%	n/a	n/a
PACCAR Inc	PCAR	0.13%	10.25%	0.01%	1.41%	0.00%
Pall Corp	PLL	0.05%	11.55%	0.01%	1.42%	0.00%
Parker Hannifin Corp	PH	0.10%	6.20%	0.01%	1.82%	0.00%
Patterson Cos Inc	PDCO	0.03%	9.75%	0.00%	1.61%	0.00%
Paychex Inc	PAYX	0.09%	9.57%	0.01%	3.55%	0.00%
Peabody Energy Corp	BTU	0.03%	12.00%	0.00%	2.13%	0.00%
Pentair Ltd	PNR	0.08%	12.50%	0.01%	1.64%	0.00%
People's United Financial Inc	PBCT	0.03%	6.50%	0.00%	4.28%	0.00%
Pepco Holdings Inc	POM	0.03%	5.17%	0.00%	5.34%	0.00%
PepsiCo Inc	PEP	0.84%	8.22%	0.07%	2.69%	0.02%
PerkinElmer Inc	PKI	0.02%	9.95%	0.00%	0.83%	0.00%
Perrigo Co	PRGO	0.08%	11.61%	0.01%	0.28%	0.00%
PetSmart Inc	PETM	0.05%	15.45%	0.01%	0.92%	0.00%
Pfizer Inc	PFE	1.32%	4.06%	0.05%	3.33%	0.04%
PG&E Corp	PCG	0.13%	5.88%	0.01%	4.00%	0.01%
Philip Morris International Inc	PM	0.95%	9.97%	0.09%	3.79%	0.04%
Phillips 66	PSX	0.24%	10.00%	0.02%	2.12%	0.01%
Pinnacle West Capital Corp	PNW	0.04%	4.69%	0.00%	3.77%	0.00%
Pioneer Natural Resources Co	PXD	0.14%	17.92%	0.02%	0.05%	0.00%
Pitney Bowes Inc	PBI	0.02%	7.00%	0.00%	5.37%	0.00%
Plum Creek Timber Co Inc	PCL	0.05%	5.00%	0.00%	3.63%	0.00%
PNC Financial Services Group Inc/The	PNC	0.26%	4.40%	0.01%	2.35%	0.01%
PPG Industries Inc	PPG	0.15%	8.76%	0.01%	1.55%	0.00%
PPL Corp	PPL	0.12%	-0.57%	0.00%	4.83%	0.01%
Praxair Inc	PX	0.22%	10.64%	0.02%	2.05%	0.00%
Precision Castparts Corp	PCP	0.22%	11.87%	0.03%	0.05%	0.00%
priceline.com Inc	PCLN	0.31%	18.67%	0.06%	n/a	n/a
Principal Financial Group Inc	PFG	0.07%	11.50%	0.01%	2.37%	0.00%
Procter & Gamble Co/The	PG	1.44%	8.64%	0.12%	2.95%	0.04%
Progressive Corp/The	PGR	0.10%	8.25%	0.01%	1.10%	0.00%
Prologis Inc	PLD	0.13%	7.01%	0.01%	2.87%	0.00%
Prudential Financial Inc	PRU	0.23%	10.67%	0.02%	2.05%	0.00%
Public Service Enterprise Group Inc	PEG	0.11%	0.76%	0.00%	4.34%	0.00%
Public Storage	PSA	0.18%	5.67%	0.01%	3.14%	0.01%
PulteGroup Inc	PHM	0.05%	52.20%	0.03%	n/a	n/a
PVH Corp	PVH	0.07%	13.28%	0.01%	0.11%	0.00%
QEP Resources Inc	QEP	0.03%	15.00%	0.01%	0.27%	0.00%
QUALCOMM Inc	QCOM	0.69%	14.19%	0.10%	2.26%	0.02%
Quanta Services Inc	PWR	0.04%	20.63%	0.01%	n/a	n/a
Quest Diagnostics Inc	DGX	0.06%	10.88%	0.01%	2.02%	0.00%
Ralph Lauren Corp	RL	0.07%	12.80%	0.01%	0.88%	0.00%
Range Resources Corp	RRC	0.08%	27.00%	0.02%	0.21%	0.00%
Raytheon Co	RTN	0.15%	9.00%	0.01%	3.17%	0.00%
Red Hat Inc	RHT	0.06%	17.00%	0.01%	n/a	n/a
Regeneron Pharmaceuticals Inc	REGN	0.16%	22.71%	0.04%	n/a	n/a
Regions Financial Corp	RF	0.09%	6.00%	0.01%	1.20%	0.00%
Republic Services Inc	RSG	0.08%	2.30%	0.00%	2.67%	0.00%
Reynolds American Inc	RAI	0.18%	8.01%	0.01%	4.91%	0.01%
Robert Half International Inc	RHI	0.03%	13.33%	0.00%	1.85%	0.00%
Rockwell Automation Inc	ROK	0.08%	12.00%	0.01%	2.29%	0.00%
Rockwell Collins Inc	COL	0.06%	9.45%	0.01%	1.77%	0.00%
Roper Industries Inc	ROP	0.08%	15.00%	0.01%	0.51%	0.00%
Ross Stores Inc	ROST	0.09%	11.56%	0.01%	1.01%	0.00%
Rowan Cos Plc	RDC	0.03%	13.00%	0.00%	n/a	n/a
Ryder System Inc	R	0.02%	9.50%	0.00%	2.24%	0.00%
Safeway Inc	SWY	0.04%	8.41%	0.00%	3.26%	0.00%
SAIC Inc	SAI	0.03%	6.83%	0.00%	3.40%	0.00%
Salesforce.com Inc	CRM	0.16%	29.48%	0.05%	n/a	n/a
SanDisk Corp	SNDK	0.10%	18.50%	0.02%	n/a	n/a
SCANA Corp	SCG	0.05%	5.00%	0.00%	3.98%	0.00%
Schlumberger Ltd	SLB	0.66%	17.00%	0.11%	1.63%	0.01%
Scripps Networks Interactive Inc	SNI	0.05%	12.58%	0.01%	0.83%	0.00%
Seagate Technology PLC	STX	0.11%	6.17%	0.01%	3.25%	0.00%
Sealed Air Corp	SEE	0.03%	5.50%	0.00%	1.89%	0.00%
Sempra Energy	SRE	0.13%	6.75%	0.01%	3.01%	0.00%
Sherwin-Williams Co/The	SHW	0.12%	12.50%	0.02%	1.07%	0.00%
Sigma-Aldrich Corp	SIAL	0.07%	7.24%	0.00%	1.02%	0.00%
Simon Property Group Inc	SPG	0.33%	7.59%	0.02%	2.82%	0.01%
SLM Corp	SLM	0.07%	n/a	n/a	2.56%	0.00%
Snap-on Inc	SNA	0.04%	10.00%	0.00%	1.63%	0.00%
Southern Co/The	SO	0.25%	4.86%	0.01%	4.51%	0.01%
Southwest Airlines Co	LUV	0.06%	18.72%	0.01%	1.19%	0.00%
Southwestern Energy Co	SWN	0.09%	n/a	n/a	n/a	n/a
Spectra Energy Corp	SE	0.15%	5.50%	0.01%	3.43%	0.01%
St Jude Medical Inc	STJ	0.09%	10.21%	0.01%	2.07%	0.00%
Stanley Black & Decker Inc	SWK	0.09%	12.50%	0.01%	2.38%	0.00%
Staples Inc	SPLS	0.07%	8.52%	0.01%	2.87%	0.00%
Starbucks Corp	SBUX	0.34%	18.00%	0.06%	1.20%	0.00%
Starwood Hotels & Resorts Worldwide Ir	HOT	0.08%	13.19%	0.01%	1.87%	0.00%
State Street Corp	STT	0.20%	11.80%	0.02%	1.51%	0.00%
Stericycle Inc	SRCL	0.07%	16.00%	0.01%	n/a	n/a
Stryker Corp	SYK	0.16%	8.34%	0.01%	1.57%	0.00%
SunTrust Banks Inc	STI	0.12%	9.54%	0.01%	1.18%	0.00%

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Symantec Corp	SYMC	0.11%	7.00%	0.01%	2.52%	0.00%
Sysco Corp	SYY	0.14%	9.00%	0.01%	3.15%	0.00%
T Rowe Price Group Inc	TROW	0.13%	13.76%	0.02%	1.96%	0.00%
Target Corp	TGT	0.30%	11.22%	0.03%	2.37%	0.01%
TE Connectivity Ltd	TEL	0.13%	15.00%	0.02%	2.11%	0.00%
TECO Energy Inc	TE	0.02%	4.50%	0.00%	5.01%	0.00%
Tenet Healthcare Corp	THC	0.03%	10.25%	0.00%	n/a	n/a
Teradata Corp	TDC	0.06%	14.80%	0.01%	n/a	n/a
Teradyne Inc	TER	0.02%	11.75%	0.00%	n/a	n/a
Tesoro Corp	TSO	0.05%	26.32%	0.01%	1.45%	0.00%
Texas Instruments Inc	TXN	0.27%	9.67%	0.03%	2.99%	0.01%
Textron Inc	TXT	0.05%	13.95%	0.01%	0.29%	0.00%
Thermo Fisher Scientific Inc	TMO	0.22%	9.77%	0.02%	0.68%	0.00%
Tiffany & Co	TIF	0.06%	13.05%	0.01%	1.77%	0.00%
Time Warner Cable Inc	TWC	0.22%	11.42%	0.02%	2.26%	0.00%
Time Warner Inc	TWX	0.37%	10.03%	0.04%	1.86%	0.01%
TJX Cos Inc	TJX	0.24%	11.69%	0.03%	1.11%	0.00%
Torchmark Corp	TMK	0.04%	9.00%	0.00%	0.98%	0.00%
Total System Services Inc	TSS	0.03%	11.67%	0.00%	1.56%	0.00%
Travelers Cos Inc/The	TRV	0.20%	5.90%	0.01%	2.38%	0.00%
TripAdvisor Inc	TRIP	0.05%	17.50%	0.01%	n/a	n/a
Twenty-First Century Fox Inc	FOXA	0.30%	14.84%	0.04%	0.56%	0.00%
Tyco International Ltd	TYC	0.11%	11.00%	0.01%	1.82%	0.00%
Tyson Foods Inc	TSN	0.05%	8.50%	0.00%	0.74%	0.00%
Union Pacific Corp	UNP	0.48%	13.80%	0.07%	1.72%	0.01%
United Parcel Service Inc	UPS	0.40%	11.54%	0.05%	2.88%	0.01%
United States Steel Corp	X	0.02%	6.00%	0.00%	1.11%	0.00%
United Technologies Corp	UTX	0.59%	12.86%	0.08%	2.14%	0.01%
UnitedHealth Group Inc	UNH	0.45%	12.17%	0.05%	1.65%	0.01%
Unum Group	UNM	0.05%	9.50%	0.01%	1.84%	0.00%
Urban Outfitters Inc	URBN	0.04%	17.61%	0.01%	n/a	n/a
US Bancorp/MN	USB	0.45%	14.01%	0.06%	2.44%	0.01%
Valero Energy Corp	VLO	0.13%	6.71%	0.01%	2.23%	0.00%
Varian Medical Systems Inc	VAR	0.05%	11.95%	0.01%	n/a	n/a
Ventas Inc	VTR	0.13%	4.61%	0.01%	3.80%	0.01%
VeriSign Inc	VRSN	0.04%	12.33%	0.01%	n/a	n/a
Verizon Communications Inc	VZ	0.93%	7.91%	0.07%	4.09%	0.04%
VF Corp	VFC	0.14%	12.00%	0.02%	1.74%	0.00%
Viacom Inc	VIAB	0.20%	11.21%	0.02%	1.67%	0.00%
Visa Inc	V	0.64%	18.88%	0.12%	0.69%	0.00%
Vornado Realty Trust	VNO	0.10%	6.18%	0.01%	3.36%	0.00%
Vulcan Materials Co	VMC	0.04%	8.75%	0.00%	0.08%	0.00%
Wal-Mart Stores Inc	WMT	1.64%	9.20%	0.15%	2.42%	0.04%
Walgreen Co	WAG	0.30%	13.14%	0.04%	2.58%	0.01%
Walt Disney Co/The	DIS	0.78%	11.63%	0.09%	1.12%	0.01%
Washington Post Co/The	WPO	0.02%	n/a	n/a	1.90%	0.00%
Waste Management Inc	WM	0.13%	6.05%	0.01%	3.47%	0.00%
Waters Corp	WAT	0.06%	11.26%	0.01%	n/a	n/a
WellPoint Inc	WLP	0.17%	11.00%	0.02%	1.76%	0.00%
Wells Fargo & Co	WFC	1.46%	9.32%	0.14%	2.81%	0.04%
Western Digital Corp	WDC	0.10%	5.00%	0.01%	1.47%	0.00%
Western Union Co/The	WU	0.06%	11.14%	0.01%	2.86%	0.00%
Weyerhaeuser Co	WY	0.11%	5.50%	0.01%	2.98%	0.00%
Whirlpool Corp	WHR	0.06%	26.04%	0.02%	2.03%	0.00%
Whole Foods Market Inc	WFM	0.13%	17.62%	0.02%	0.71%	0.00%
Williams Cos Inc/The	WMB	0.15%	6.25%	0.01%	4.17%	0.01%
Windstream Corp	WIN	0.03%	-3.12%	0.00%	12.27%	0.00%
Wisconsin Energy Corp	WEC	0.06%	4.67%	0.00%	3.20%	0.00%
WPX Energy Inc	WPX	0.03%	n/a	n/a	n/a	n/a
WW Grainger Inc	GWW	0.12%	15.00%	0.02%	1.40%	0.00%
Wyndham Worldwide Corp	WYN	0.05%	19.70%	0.01%	1.93%	0.00%
Wynn Resorts Ltd	WYNN	0.09%	9.00%	0.01%	3.06%	0.00%
Xcel Energy Inc	XEL	0.09%	4.80%	0.00%	3.82%	0.00%
Xerox Corp	XRX	0.08%	n/a	n/a	2.34%	0.00%
Xilinx Inc	XLNX	0.07%	12.75%	0.01%	2.33%	0.00%
XL Group PLC	XL	0.06%	10.00%	0.01%	1.75%	0.00%
Xylem Inc/NY	XYL	0.03%	7.70%	0.00%	1.60%	0.00%
Yahoo! Inc	YHOO	0.19%	9.16%	0.02%	n/a	n/a
Yum! Brands Inc	YUM	0.21%	12.16%	0.02%	1.90%	0.00%
Zimmer Holdings Inc	ZMH	0.09%	10.57%	0.01%	1.01%	0.00%
Zions Bancorporation	ZION	0.04%	7.75%	0.00%	0.53%	0.00%
Zoetis Inc	ZTS	0.10%	12.85%	0.01%	0.83%	0.00%

Notes:

[1] Equals sum of Col. [11]
[2] Equals sum of Col. [9]
[3] Equals Col. [1] x (1 +(0.5 x (Col. [2]))) + Col. [2]
[4] Source: Bloomberg and Blue Chip Financial Forecasts
[5] Equals Col. [3] − Col. [4]
[6] Equals sum of Col. [7] if Col. [8] ≠ n/a
[7] Equals weight in S&P 500 based on market capitalization
[8] Source: Bloomberg
[9] Equals Col. [7] x Col. [8] if Col. [8] ≠ n/a, otherwise equals zero
[10] Source: Bloomberg
[11] Equals Col. [7] x Col. [10] if Col. [8] ≠ n/a, otherwise equals zero

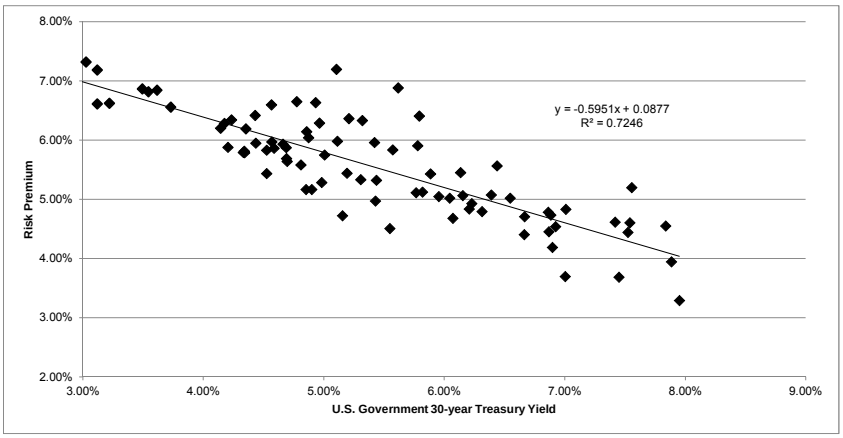
BETAS
VALUE LINE AND BLOOMBERG

		Value Line	Bloomberg	Average
ALLETE, Inc.	ALE	0.70	0.80	0.75
American Electric Power Company, Inc.	AEP	0.65	0.63	0.64
Cleco Corporation	CNL	0.65	0.77	0.71
Empire District Electric Company	EDE	0.65	0.75	0.70
FirstEnergy Corporation	FE	0.75	0.66	0.70
Great Plains Energy Inc.	GXP	0.80	0.79	0.80
Hawaiian Electric Industries, Inc.	HE	0.70	0.72	0.71
IDACORP, Inc.	IDA	0.70	0.84	0.77
Otter Tail Corporation	OTTR	0.90	0.78	0.84
Pinnacle West Capital Corporation	PNW	0.70	0.74	0.72
Portland General Electric Company	POR	0.75	0.78	0.76
Southern Company	SO	0.55	0.52	0.53
Westar Energy, Inc.	WR	0.75	0.68	0.72
Average Beta		0.712	0.727	0.719

Sources: Value Line and Bloomberg

Bond Yield Risk Premium

	[1] Average Authorized Electric ROE	[2] U.S. Govt. 30-year Treasury	[3] Risk Premium
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	10.15%	4.34%	5.81%
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	10.45%	4.59%	5.86%
2010.2	10.08%	4.20%	5.87%
2010.3	10.29%	3.73%	6.56%
2010.4	10.34%	4.14%	6.20%
2011.1	9.96%	4.53%	5.44%
2011.2	10.12%	4.33%	5.79%
2011.3	10.36%	3.54%	6.82%
2011.4	10.34%	3.03%	7.32%
2012.1	10.30%	3.12%	7.18%
2012.2	9.92%	2.84%	7.08%
2012.3	9.78%	2.68%	7.10%
2012.4	10.05%	2.87%	7.18%
2013.1	9.73%	3.12%	6.61%
2013.2	9.84%	3.22%	6.62%
MEAN	10.93%	5.33%	5.60%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.851
R Square	0.725
Adjusted R Square	0.721
Standard Error	0.005
Observations	86

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.0051	0.0051	221.0291	0.0000
Residual	84	0.0019	0.0000		
Total	85	0.0070			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.088	0.0022	39.93	0.0000	0.0833	0.0921	0.0833	0.0921
U.S. Govt. 30-year Treasury	-0.595	0.0400	-14.87	0.0000	-0.6747	-0.5155	-0.6747	-0.5155

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] Authorized ROE
Current 30-Day Average [4]	3.46%	6.71%	10.17%
Blue Chip Consensus Forecast (Q3 2013-Q4 2014) [5]	3.73%	6.55%	10.28%
Blue Chip Consensus Forecast (2015-2019) [6]	5.20%	5.67%	10.87%
AVERAGE			10.44%

Notes:
[1] Source: Regulatory Research Associates, accessed July 22, 2013
[2] Source: Bloomberg Professional, quarterly bond yields are the average of the last trading day of each month in the quarter
[3] Equals Column [1] − Column [2]
[4] Source: Bloomberg Professional
[5] Source: Blue Chip Financial Forecasts, Vol. 32, No. 7, July 1, 2013, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 32, No. 6, June 1, 2013, at 14
[7] *See notes [4], [5] & [6]*
[8] Equals 0.087684 + (-0.595141 x Column [7])
[9] Equals Column [7] + Column [8]

CHARLES W. KING METHODOLOGY
NORTHERN STATES POWER COMPANY
ADJUSTED EQUITY RETURN DETERMINATION

Methodology	Source [1]	Indication	Weighting [2]	Weighting Indication [3]	Composite Indication
Constant Growth DCF					
Mean	Schedule 7	9.22%			
Median	Schedule 7	9.21%			
Average		9.22%	5	46.08%	
3-Step DCF	Schedule 8	8.55%	0	0.00%	
Sustainable Growth DCF					
Mean	Schedule 9	8.58%			
Median	Schedule 9	8.59%			
Average		8.58%	0	0.00%	
CAPM	Schedule 11	9.63%	2	19.26%	
Risk Premium	Schedule 5	10.44%	3	31.32%	
Recent ROE Awards	Schedule 13	10.04%	2	20.08%	
Total			12	116.75%	9.73%
Flotation Cost	Schedule 2				0.24%
Adjusted Total					9.97%

Notes:
[1] Source: Exhibit_(AEB-2), schedule noted above.
[2] Source: Exhibit CWK-2, Schedule-9
[3] Source: Charles W. King weighting methodology (Exhibit CWK-2, Schedule-9)

CORRECTION TO CHARLES W. KING METHODOLOGY
60-DAY CONSTANT GROWTH DCF

Company Name	Ticker	[1] Div'd Decl'd per Share 2013	[2] Div'd Decl'd per Share 2014	[3] Div'd Decl'd per Share Average	[4] Stock Price	[5] Dividend Yield	[6] Value Line Earnings Growth	[7] Zacks Earnings Growth	[8] Yahoo! Finance Earnings Growth	[9] Average Growth Rate	[10] ROE	[11] Adjusted ROE
ALLETE, Inc.	ALE	$1.90	$1.96	$1.93	$49.33	3.91%	7.00%	7.00%	6.00%	6.67%	10.58%	10.58%
Alliant Energy Corporation	LNT	$1.88	$1.96	$1.92	$50.68	3.79%	5.00%	6.00%	5.93%	5.64%	9.43%	9.43%
Cleco Corporation	CNL	$1.43	$1.58	$1.51	$46.44	3.24%	5.50%	8.00%	8.00%	7.17%	10.41%	10.41%
Duke Energy Corporation	DUK	$3.09	$3.15	$3.12	$69.43	4.49%	4.00%	5.00%	4.17%	4.39%	8.88%	8.88%
El Paso Electric	EE	$1.06	$1.14	$1.10	$36.43	3.02%	3.00%	-1.00%	3.70%	1.90%	4.92%	
Empire District Electric Company	EDE	$1.00	$1.00	$1.00	$22.15	4.51%	5.00%	3.00%	3.00%	3.67%	8.18%	8.18%
Great Plains Energy Inc.	GXP	$0.88	$0.96	$0.92	$23.13	3.98%	6.50%	5.00%	6.26%	5.92%	9.90%	9.90%
IDACORP, Inc.	IDA	$1.56	$1.68	$1.62	$48.13	3.37%	2.00%	4.00%	4.00%	3.33%	6.70%	
NorthWestern Corporation	NWE	$1.52	$1.56	$1.54	$40.97	3.76%	3.00%	5.00%	5.00%	4.33%	8.09%	8.09%
PG&E Corporation	PCG	$1.82	$1.82	$1.82	$45.46	4.00%	4.00%	2.00%	3.12%	3.04%	7.04%	
Pinnacle West Capital Corporation [12]	PNW	$2.21	$2.28	$2.25	$57.85	3.88%	5.00%	5.00%	6.00%	5.33%	9.21%	9.21%
Portland General Electric Company	POR	$1.11	$1.15	$1.13	$30.97	3.65%	3.50%	7.00%	5.69%	5.40%	9.05%	9.05%
Southern Company	SO	$2.01	$2.08	$2.05	$45.26	4.52%	4.50%	5.00%	4.84%	4.78%	9.30%	9.30%
Westar Energy, Inc.	WR	$1.36	$1.40	$1.38	$32.32	4.27%	6.00%	5.00%	4.83%	5.28%	9.55%	9.55%
Wisconsin Energy Corporation	WEC	$1.36	$1.52	$1.44	$42.05	3.42%	5.50%	5.00%	4.93%	5.14%	8.57%	8.57%
Xcel Energy Inc.	XEL	$1.11	$1.15	$1.13	$29.42	3.84%	4.50%	5.00%	5.09%	4.86%	8.70%	8.70%
MEAN						3.85%	4.63%	4.75%	5.04%	4.80%	8.66%	9.22%
MEDIAN						3.86%	4.75%	5.00%	4.97%	5.00%	8.96%	9.21%

Notes:
[1] Source: Value Line (Exhibit CWK-2, Schedule-2)
[2] Source: Value Line (Exhibit CWK-2, Schedule-2)
[3] Equals Average ([1], [2])
[4] Source: Yahoo! Finance, equals 60-day average as of June 25, 2013 (Exhibit CWK-2, Schedule-2)
[5] Equals [3] / [4]
[6] Source: Value Line (Exhibit CWK-2, Schedule-2)
[7] Source: Zacks (Exhibit CWK-2, Schedule-2)
[8] Source: Yahoo!Finance (Exhibit CWK-2, Schedule-2)
[9] Equals Average ([6], [7], [8])
[10] Equals [5] + [9]
[11] Equals [5] + [9] if [10] $\geq$ 7.23%
[12] Adjusted to include an additional dividend of $0.55 per share. The Value Line projection for 2013 only includes 3 dividend payments because 5 dividend payments were paid out in 2012.

RECREATION/CORRECTION TO CHARLES W. KING METHODOLOGY
60-DAY MULTI-STAGE DCF

Company	Ticker	[1] Stock Price	[2] Div'd Decl'd per Share 2013	[3] Div'd Decl'd per Share 2014	[4] Div'd Decl'd per Share Average	[5] Dividend Yield	[6] First Stage Growth	[7] Second Stage Growth	[8] Third Stage Growth	[9] Total Growth	[10] ROE	[11] Adjusted ROE
ALLETE, Inc.	ALE	$49.33	$1.90	$1.96	$1.93	3.91%	3.50%	5.55%	4.43%	4.49%	8.41%	8.41%
Alliant Energy Corporation	LNT	$50.68	$1.88	$1.96	$1.92	3.79%	4.50%	5.04%	4.43%	4.66%	8.44%	8.44%
Cleco Corporation	CNL	$46.44	$1.43	$1.58	$1.51	3.24%	10.00%	5.80%	4.43%	6.74%	9.98%	9.98%
Duke Energy Corporation	DUK	$69.43	$3.09	$3.15	$3.12	4.49%	2.00%	4.41%	4.43%	3.61%	8.11%	8.11%
El Paso Electric	EE	$36.43	$1.06	$1.14	$1.10	3.02%	NMF	3.17%	4.43%	3.80%	6.82%	
Empire District Electric Company	EDE	$22.15	$1.00	$1.00	$1.00	4.51%	3.50%	4.05%	4.43%	3.99%	8.51%	8.51%
Great Plains Energy Inc.	GXP	$23.13	$0.88	$0.96	$0.92	3.98%	6.00%	5.18%	4.43%	5.20%	9.18%	9.18%
IDACORP, Inc.	IDA	$48.13	$1.56	$1.68	$1.62	3.37%	7.00%	3.88%	4.43%	5.10%	8.47%	8.47%
NorthWestern Corporation	NWE	$40.97	$1.52	$1.56	$1.54	3.76%	4.00%	4.38%	4.43%	4.27%	8.03%	8.03%
PG&E Corporation	PCG	$45.46	$1.82	$1.82	$1.82	4.00%	2.50%	3.74%	4.43%	3.56%	7.56%	7.56%
Pinnacle West Capital Corporation [12]	PNW	$57.85	$2.21	$2.28	$2.25	3.88%	2.00%	4.88%	4.43%	3.77%	7.65%	7.65%
Portland General Electric Company	POR	$30.97	$1.11	$1.15	$1.13	3.65%	3.50%	4.91%	4.43%	4.28%	7.93%	7.93%
Southern Company	SO	$45.26	$2.01	$2.08	$2.05	4.52%	3.50%	4.61%	4.43%	4.18%	8.70%	8.70%
Westar Energy, Inc.	WR	$32.32	$1.36	$1.40	$1.38	4.27%	3.00%	4.85%	4.43%	4.09%	8.36%	8.36%
Wisconsin Energy Corporation	WEC	$42.05	$1.36	$1.52	$1.44	3.42%	12.00%	4.79%	4.43%	7.07%	10.50%	10.50%
Xcel Energy Inc.	XEL	$29.42	$1.11	$1.15	$1.13	3.84%	4.50%	4.65%	4.43%	4.53%	8.37%	8.37%
MEAN						3.85%	4.77%	4.62%	4.43%	4.58%	8.44%	8.55%
EXHIBIT CWK-2 SCHEDULE 3						3.85%	4.77%	4.62%	4.43%	4.60%	8.46%	8.46%

Notes

[1] Source: Yahoo! Finance, equals 60-day average as of June 25, 2013 (Exhibit CWK-2, Schedule-2)
[2] Source: Value Line (Exhibit CWK-2, Schedule-2)
[3] Source: Value Line (Exhibit CWK-2, Schedule-2)
[4] Equals Average ([2], [3])
[5] Equals [4] / [1]
[6] Source: Value Line (Exhibit CWK-2, Schedule-3)
[7] Equals Average ([8], Rebuttal Exhibit_(AEB-1), Schedule-7, col. [9])
[8] Source: Congressional Budget Office and Social Security Administration (Exhibit CWK-2, Schedule-3)
[9] Equals Average ([6], [7], [8])
[10] Equals [5] + [9]
[11] Equals [5] + [9] if [10] $\geq$ 7.23%
[12] Adjusted to include an additional dividend of $0.55 per share. The Value Line projection for 2013 only includes 3 dividend payments because 5 dividend payments were paid out in 2012.

CHARLES W. KING METHODOLOGY
SUSTAINABLE BOOK VALUE GROWTH DCF FORMULATION
BASED ON 2013 VALUE LINE DATA

Company	Ticker	[1] Earnings per Share 2013	[2] Dividend per Share 2013	[3] Earnings Retention "b"	[4] Book Value per Share 2013	[5] 2013 Return on Book Value "r"	[6] % Retained Return "b x r"	[7] "s x v" Factor	[8] Sustainable Growth	[9] Dividend Yield	[10] ROE	[11] Adjusted ROE
ALLETE, Inc.	ALE	2.75	1.90	30.91%	31.60	8.70%	2.69%	2.99%	5.68%	3.91%	9.59%	9.59%
Alliant Energy Corporation	LNT	3.30	1.88	43.03%	29.00	11.38%	4.90%	0.68%	5.58%	3.79%	9.37%	9.37%
Cleco Corporation	CNL	2.50	1.43	42.80%	25.85	9.67%	4.14%	0.18%	4.32%	3.24%	7.56%	7.56%
Duke Energy Corporation	DUK	4.05	3.09	23.70%	58.90	6.88%	1.63%	0.05%	1.68%	4.49%	6.17%	
El Paso Electric Company	EE	2.35	1.06	54.89%	21.80	10.78%	5.92%	0.15%	6.07%	3.02%	9.09%	9.09%
Empire District Electric Company	EDE	1.40	1.00	28.57%	17.25	8.12%	2.32%	0.35%	2.67%	4.51%	7.18%	
Great Plains Energy Inc.	GXP	1.60	0.88	45.00%	22.40	7.14%	3.21%	0.01%	3.22%	3.98%	7.20%	
IDACORP, Inc.	IDA	3.30	1.56	52.73%	36.55	9.03%	4.76%	0.21%	4.98%	3.37%	8.34%	8.34%
NorthWestern Corporation	NWE	2.45	1.52	37.96%	26.40	9.28%	3.52%	1.30%	4.83%	3.76%	8.59%	8.59%
PG&E Corporation	PCG	1.95	1.82	6.67%	31.30	6.23%	0.42%	2.55%	2.97%	4.00%	6.97%	
Pinnacle West Capital Corporation [13]	PNW	3.50	2.21	36.86%	37.25	9.40%	3.46%	0.63%	4.10%	3.88%	7.98%	7.98%
Portland General Electric Company	POR	1.90	1.11	41.58%	23.60	8.05%	3.35%	0.08%	3.43%	3.65%	7.07%	
Southern Company	SO	2.70	2.01	25.56%	21.35	12.65%	3.23%	0.29%	3.52%	4.52%	8.04%	8.04%
Westar Energy, Inc.	WR	2.25	1.36	39.56%	25.00	9.00%	3.56%	0.35%	3.91%	4.27%	8.18%	8.18%
Wisconsin Energy Corporation	WEC	2.40	1.36	43.33%	18.70	12.83%	5.56%	-0.29%	5.27%	3.42%	8.69%	8.69%
Xcel Energy Inc.	XEL	1.90	1.11	41.58%	19.20	9.90%	4.11%	0.99%	5.10%	3.84%	8.94%	8.94%
MEAN									4.21%	3.85%	8.06%	8.58%
MEDIAN									4.21%	3.86%	8.11%	8.59%

Notes
[1] Source: Value Line
[2] Source: Value Line
[3] Equals 1 - ([2] / [1])
[4] Source: Value Line
[5] Equals [1] / [4]
[6] Equals [3] x [5]
[7] Source:Exhibit__(AEB-2), Schedule-9, p. 2, col. [7]
[8] Equals [6] + [7]
[9] Equals Average ([2], Exhibit__(AEB-2), Schedule-7, col. [2]) / Exhibit__(AEB-2), Schedule-9, p. 2, col. [1]
[10] Equals [8] + [9]
[11] Equals [8] + [9] if [10] $\geq$ 7.23%
[12] Adjusted to include an additional dividend of $0.55 per share. The Value Line projection for 2013 only includes 3 dividend payments because 5 dividend payments were paid out in 2012.

CHARLES W. KING METHODOLOGY
SUSTAINABLE BOOK VALUE GROWTH DCF FORMULATION
CALCULATION OF "s x v"

Company	Ticker	[1] Stock Price	[2] Book Value 2013	[3] Market/ Book Ratio	[4] Shares Outstanding 2012 (millions)	[5] Shares Outstanding 2013 (millions)	[6] Shares Out. Annual % Increase	[7] "s x v" Factor
ALLETE, Inc.	ALE	49.33	31.60	1.56	39.40	41.50	5.33%	2.99%
Alliant Energy Corporation	LNT	50.68	29.00	1.75	110.99	112.00	0.91%	0.68%
Cleco Corporation	CNL	46.44	25.85	1.80	60.36	60.50	0.23%	0.18%
Duke Energy Corporation	DUK	69.43	58.90	1.18	704.00	706.00	0.28%	0.05%
El Paso Electric Company	EE	36.43	21.80	1.67	40.11	40.20	0.22%	0.15%
Empire District Electric Company	EDE	22.15	17.25	1.28	42.48	43.00	1.22%	0.35%
Great Plains Energy Inc.	GXP	23.13	22.40	1.03	153.53	154.00	0.31%	0.01%
IDACORP, Inc.	IDA	48.13	36.55	1.32	50.16	50.50	0.68%	0.21%
NorthWestern Corporation	NWE	40.97	26.40	1.55	37.22	38.10	2.36%	1.30%
PG&E Corporation	PCG	45.46	31.30	1.45	430.72	455.00	5.64%	2.55%
Pinnacle West Capital Corporation	PNW	57.85	37.25	1.55	109.74	111.00	1.15%	0.63%
Portland General Electric Company	POR	30.97	23.60	1.31	75.56	75.75	0.25%	0.08%
Southern Company	SO	45.26	21.35	2.12	867.77	870.00	0.26%	0.29%
Westar Energy, Inc.	WR	32.32	25.00	1.29	126.50	128.00	1.19%	0.35%
Wisconsin Energy Corporation	WEC	42.05	18.70	2.25	229.04	228.50	-0.24%	-0.29%
Xcel Energy Inc.	XEL	29.42	19.20	1.53	487.96	497.00	1.85%	0.99%

Notes
[1] Source: Yahoo! Finance, equals 60-day average as of June 25, 2013 (Exhibit CWK-2, Schedule-4, p. 2)
[2] Value Line
[3] Equals [1] / [2]
[4] Value Line
[5] Value Line
[6] Equals ([5] / [4]) - 1
[7] Equals ([3] -1) x [6]

PROXY GROUP OF CHARLES W. KING
VALUE LINE PROJECTED RETURN ON BOOK EQUITY

Company	Ticker	Value Line Report Date	Return on Shr. Equity 2016 - 2018
ALLETE, Inc.	ALE	6/21/2013	9.50%
Alliant Energy Corporation	LNT	6/21/2013	10.50%
Cleco Corporation	CNL	6/21/2013	11.00%
Duke Energy Corporation	DUK	5/24/2013	8.00%
El Paso Electric Company	EE	5/3/2013	10.50%
Empire District Electric Company	EDE	6/21/2013	8.50%
Great Plains Energy Inc.	GXP	6/21/2013	8.00%
IDACORP, Inc.	IDA	5/3/2013	8.50%
NorthWestern Corporation	NWE	5/3/2013	9.50%
PG&E Corporation	PCG	5/3/2013	9.00%
Pinnacle West Capital Corporation	PNW	5/3/2013	10.00%
Portland General Electric Company	POR	5/3/2013	8.00%
Southern Company	SO	5/24/2013	12.50%
Westar Energy, Inc.	WR	6/21/2013	9.50%
Wisconsin Energy Corporation	WEC	6/21/2013	14.00%
Xcel Energy Inc.	XEL	5/3/2013	10.00%
MEAN			9.81%

CHARLES W. KING METHODOLOGY
CAPITAL ASSET PRICING MODEL
USING PROJECTED TREASURY YIELDS

[1]	Projected 30-Year Treasury (2015-2019)	5.20%
	Market Return	
[2]	Historical 1929-2010	11.88%
[3]	Prospective Appreciation Potential 3-5 years	45.00%
[4]	Prospective Appreciation Potential Annualized @ 4 yrs	9.73%
[5]	Median of Estimated Dividend Yields	2.10%
[6]	Prospective DCF Return	11.83%
[7]	Average	11.86%
[8]	Market Risk Premium	6.66%
[9]	Average beta, Comparison Company Group	0.67
[10]	Risk Premium for Comparison Company Group	4.43%
[11]	CAPM Rate of Return	9.63%

Notes:
[1] Source: Aspen Publishers, Blue Chip Financial Forecasts, Vol. 32, No. 6 June 1, 2013, p. 14 (Exhibit_(AEB-2), Schedule-4.0, p. 1)
[2] Source: Morningstar (Exhibit CWK-2, Schedule-6)
[3] Source: Value Line (Exhibit CWK-2, Schedule-6)
[4] Equals ((1 + [3]) ^ .25) - 1
[5] Value Line (Exhibit CWK-2, Schedule-6)
[6] Equals [4] + [5]
[7] Equals Average ([2], [6])
[8] Equals [7] - [1]
[9] Source: Value Line (Exhibit CWK-2, Schedule-6)
[10] Equals [8] x [9]
[11] Equals [1] +[10]

PROXY GROUP OF CHARLES W. KING
CURRENT AUTHORIZED ROE

			[1]	[1]	[1]	[1]
				RRA		
			Requested Date	Requested ROE	Authorized Date	Authorized ROE
ALLETE, Inc.	ALLETE (Minnesota Power)	Minnesota	11/2/2009	10.38%	11/2/2010	10.38%
	Superior Water, Light and Power Company	Wisconsin				
Alliant Energy Corporation	Interstate Power and Light Company	Iowa	3/10/2010	10.85%	12/15/2010	10.44%
		Minnesota	5/7/2010	10.50%	8/12/2011	10.35%
	Wisconsin Power and Light Company	Wisconsin	5/3/2012	10.40%	6/15/2012	10.40%
Cleco Corp.	Cleco Power LLC	Louisiana	7/14/2008	12.25%	10/14/2009	10.70%
Duke Energy Corporation	Duke Energy Carolinas, LLC	North Carolina	7/1/2011	11.25%	1/27/2012	10.50%
		South Carolina	8/5/2011	11.50%	1/25/2012	10.50%
	Duke Energy Florida, Inc.	Florida	3/20/2009	12.54%	3/5/2010	10.50%
	Duke Energy Indiana, Inc.	Indiana	12/30/2002	11.20%	5/18/2004	10.50%
	Duke Energy Kentucky, Inc.	Kentucky	5/31/2006	11.50%	12/21/2006	N/A
	Duke Energy Ohio, Inc.	Ohio	7/9/2012	10.60%	5/1/2013	9.84%
	Duke Energy Progress, Inc.	North Carolina	10/12/2012	11.25%	5/30/2013	10.20%
		South Carolina	3/1/1988		8/29/1988	
El Paso Electric Company	El Paso Electric Company	New Mexico	5/29/2009	11.50%	12/10/2009	N/A
		Texas	2/1/2012	10.60%	5/18/2012	N/A
Empire District Electric Company	Empire District Electric Company	Arkansas				
		Kansas	11/4/2009	11.30%	6/23/2010	N/A
		Oklahoma				
		Missouri	7/6/2012	10.60%	2/27/2013	N/A
	Empire District Gas Company	Missouri				
Great Plains Energy, Inc.	Kansas City Power & Light Company	Kansas	4/20/2012	10.40%	12/13/2012	9.50%
		Missouri	2/27/2012	10.30%	1/9/2013	9.70%
	KCP&L Greater Missouri Operations Company	Missouri	2/27/2012	10.30%	1/9/2013	9.70%
IDACORP, Inc.	Idaho Power Co.	Idaho	6/1/2011	10.50%	12/30/2011	N/A
		Oregon	7/29/2011	10.50%	2/23/2012	9.90%
NorthWestern Corporation	NorthWestern Corporation	Wyoming				
		Nebraska				
		Montana	10/16/2009	10.90%	12/9/2010	10.25%
		South Dakota	11/5/1980		4/17/1981	
PG&E Corporation	Pacific Gas and Electric Company	California	4/20/2012	11.00%	12/20/2012	10.40%
Pinnacle West Capital Corp.	Arizona Public Service Company	Arizona	6/1/2011	11.00%	5/15/2012	10.00%
Portland General Electric Company	Portland General Electric Company	Oregon	2/16/2010	10.50%	12/17/2010	10.00%
Southern Company	Alabama Power Company	Alabama	3/9/1982		10/12/1982	
	Georgia Power Company	Georgia	7/1/2010	11.95%	12/29/2010	11.15%
	Gulf Power Company	Florida	7/8/2011	11.70%	2/27/2012	10.25%
	Mississippi Power Company	Mississippi	1/25/2013	9.70%	3/5/2013	9.70%
Westar Energy, Inc.	Kansas Gas and Electric Company	Kansas	8/25/2011	10.60%	4/18/2012	N/A
	Westar Energy (KPL)	Kansas	8/22/2011	10.60%	4/18/2012	N/A
Wisconsin Energy Corporation	Wisconsin Electric Power Company	Michigan	7/5/2011	10.40%	6/26/2012	10.10%
		Wisconsin	3/23/2012	10.40%	11/28/2012	10.40%
	Wisconsin Gas LLC	Wisconsin				
Xcel Energy Inc.	Northern States Power Company - MN	Minnesota	11/2/2012	10.60%	7/3/2013	9.83%
		North Dakota [5]				
		South Dakota	6/29/2012	10.65%	4/18/2013	N/A
	Northern States Power Company - WI	Michigan				
		Wisconsin	6/1/2012	10.40%	12/14/2012	10.40%
	Public Service Company of Colorado	Colorado	11/22/2011	10.75%	4/26/2012	10.00%
	Southwestern Public Service Company	New Mexico	2/28/2011	11.25%	12/28/2011	N/A
		Texas	11/15/2012	10.65%	6/6/2013	N/A
Proxy Group Average				10.88%		10.21%

Notes
[1] Source: Regulatory Research Associates, July 26, 2013
[2] Database represents the cases covered by Regulatory Research Associates
[3] Excluded Natural Gas Rate Cases
[4] Excluded Rate Case Decisions that occurred before January 1, 2000
[5] ROE excluded since it is the subject of this proceeding.

ELECTRIC UTILITY RATE CASE AWARDS
SINCE JANUARY 1, 2012

Line No.	State	Utility	Parent Company Ticker	Case Identification	Date (Authorized)	Regulated Generation (Yes/No)	Authorized ROE
1	Arizona	Arizona Public Service Co.	PNW	D-E-01345A-11-0224	5/15/2012	Yes	10.00%
2	Arizona	Tucson Electric Power Co.	UNS	D-E-01933A-12-0291	6/11/2013	Yes	10.00%
3	California	California Pacific Electric Co	AQN	A-12-02-014	11/29/2012	No	9.88%
4	California	Pacific Gas and Electric Co.	PCG	Ap-12-04-018 (Elec)	12/20/2012	Yes	10.40%
5	California	San Diego Gas & Electric Co.	SRE	Ap-12-04-016 (Elec)	12/20/2012	Yes	10.30%
6	California	Southern California Edison Co.	EIX	Ap-12-04-015	12/20/2012	Yes	10.45%
7	Colorado	Public Service Co. of CO	XEL	D-11AL-947E	4/26/2012	Yes	10.00%
8	District of Columbia	Potomac Electric Power Co.	POM	FC-1087	9/26/2012	No	9.50%
9	Delaware	Delmarva Power & Light Co.	POM	D-11-528	11/29/2012	No	9.75%
10	Florida	Florida Power & Light Co.	NEE	D-120015-EI	12/13/2012	Yes	10.50%
11	Florida	Gulf Power Co.	SO	D-110138-EI	2/27/2012	Yes	10.25%
12	Hawaii	Hawaii Electric Light Co	HE	D-2009-0164	4/4/2012	Yes	10.00%
13	Hawaii	Hawaiian Electric Co.	HE	D-2010-0080	6/29/2012	Yes	10.00%
14	Hawaii	Maui Electric Company Ltd	HE	D-2011-0092	5/31/2013	Yes	9.00%
15	Hawaii	Maui Electric Company Ltd	HE	D-2009-0163	5/2/2012	Yes	10.00%
16	Idaho	Avista Corp.	AVA	C-AVU-E-12-08	3/27/2013	Yes	9.80%
17	Illinois	Ameren Illinois	AEE	D-12-0293	12/5/2012	No	9.71%
18	Illinois	Ameren Illinois	AEE	D-12-0001	9/19/2012	No	10.05%
19	Illinois	Commonwealth Edison Co.	EXC	D-12-0321	12/19/2012	No	9.71%
20	Illinois	Commonwealth Edison Co.	EXC	D-11-0721	5/29/2012	No	10.05%
21	Indiana	Indiana Michigan Power Co.	AEP	Ca-44075	2/13/2013	Yes	10.20%
22	Kansas	Kansas City Power & Light	GXP	D-12-KCPE-764-RTS	12/13/2012	Yes	9.50%
23	Kentucky	Kentucky Utilities Co.	PPL	C-2012-00221	12/20/2012	Yes	10.25%
24	Kentucky	Louisville Gas & Electric Co.	PPL	C-2012-00222 (elec.)	12/20/2012	Yes	10.25%
25	Louisiana	Southwestern Electric Power Co	AEP	D-U-32220	2/27/2013	Yes	10.00%
26	Maryland	Baltimore Gas and Electric Co.	EXC	C-9299 (elec)	2/22/2013	No	9.75%
27	Maryland	Delmarva Power & Light Co.	POM	C-9285	7/20/2012	No	9.81%
28	Maryland	Potomac Electric Power Co.	POM	C-9311	7/12/2013	No	9.36%
29	Maryland	Potomac Electric Power Co.	POM	C-9286	7/20/2012	No	9.31%
30	Michigan	Consumers Energy Co.	CMS	C-U-17087	5/15/2013	Yes	10.30%
31	Michigan	Consumers Energy Co.	CMS	C-U-16794	6/7/2012	Yes	10.30%
32	Michigan	Indiana Michigan Power Co.	AEP	C-U-16801	2/15/2012	Yes	10.20%
33	Michigan	Wisconsin Electric Power Co.	WEC	C-U-16830	6/26/2012	Yes	10.10%
34	Minnesota	Northern States Power Co. - MN	XEL	D-E-002/GR-10-971	3/29/2012	Yes	10.37%
35	Missouri	Kansas City Power & Light	GXP	C-ER-2012-0174	1/9/2013	Yes	9.70%
36	Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-2012-0175 (L&P)	1/9/2013	Yes	9.70%
37	Missouri	KCP&L Greater Missouri Op Co	GXP	C-ER-2012-0175 (MPS)	1/9/2013	Yes	9.70%
38	Missouri	Union Electric Co.	AEE	C-ER-2012-0166	12/12/2012	Yes	9.80%
39	Mississippi	Mississippi Power Co.	SO	D-2013-UN-0014	3/5/2013	Yes	9.70%
40	North Carolina	Duke Energy Carolinas LLC	DUK	D-E-7, Sub 989	1/27/2012	Yes	10.50%
41	North Carolina	Duke Energy Progress Inc.	DUK	D-E-2, Sub 1023	5/30/2013	Yes	10.20%
42	North Carolina	Virginia Electric & Power Co.	D	D-E-22, Sub 479	12/21/2012	Yes	10.20%
43	North Dakota	Northern States Power Co. - MN	XEL	C-PU-10-657	2/29/2012	Yes	10.40%
44	New Jersey	Atlantic City Electric Co.	POM	D-ER-12121071	6/21/2013	No	9.75%
45	New Jersey	Atlantic City Electric Co.	POM	D-ER-11080469	10/23/2012	No	9.75%
46	New York	Niagara Mohawk Power Corp.	-	D-12-E-0201	3/14/2013	No	9.30%
47	New York	Orange & Rockland Utlts Inc.	ED	C-11-E-0408	6/14/2012	No	9.40%
48	Ohio	Duke Energy Ohio Inc.	DUK	C-12-1682-EL-AIR	5/1/2013	Yes	9.84%
49	Oklahoma	Oklahoma Gas and Electric Co.	OGE	Ca-PUD201100087	7/9/2012	Yes	10.20%
50	Oregon	Idaho Power Co.	IDA	D-UE-233	2/23/2012	Yes	9.90%
51	Oregon	PacifiCorp	BRK.A	D-UE-246	12/20/2012	Yes	9.80%
52	Pennsylvania	PPL Electric Utilities Corp.	PPL	D-R-2012-2290597	12/5/2012	No	10.40%
53	Rhode Island	Narragansett Electric Co.	-	D-4323 (electric)	12/20/2012	No	9.50%
54	South Carolina	Duke Energy Carolinas LLC	DUK	D-2011-271-E	1/25/2012	Yes	10.50%
55	South Carolina	South Carolina Electric & Gas	SCG	D-2012-218-E	12/19/2012	Yes	10.25%
56	South Dakota	Northern States Power Co. - MN	XEL	D-EL11-019	6/19/2012	Yes	9.25%
57	Texas	Cross Texas	-	D-40604	1/16/2013	No	9.60%
58	Texas	Entergy Texas Inc.	ETR	D-39896	9/13/2012	Yes	9.80%
59	Texas	Lone Star Transmission LLC	NEE	D-40020	10/12/2012	No	9.60%
60	Texas	Wind Energy Transmission Texas	-	D-40606	1/16/2013	No	9.60%
61	Utah	PacifiCorp	BRK.A	D-11-035-200	9/19/2012	Yes	9.80%
62	Washington	Avista Corp.	AVA	D-UE-120436	12/26/2012	Yes	9.80%
63	Washington	Puget Sound Energy Inc.	-	D-UE-130137	6/25/2013	Yes	9.80%
64	Washington	Puget Sound Energy Inc.	-	D-UE-111048	5/7/2012	Yes	9.80%
65	Wisconsin	Madison Gas and Electric Co.	MGEE	D-3270-UR-118 (elec)	11/9/2012	Yes	10.30%
66	Wisconsin	Northern States Power Co - WI	XEL	D-4220-UR-118 (elec)	12/14/2012	Yes	10.40%
67	Wisconsin	Wisconsin Electric Power Co.	WEC	D-05-UR-106 (WEP-Elec)	11/28/2012	Yes	10.40%
68	Wisconsin	Wisconsin Power and Light Co	LNT	D-6680-UR-118 (elec)	6/15/2012	Yes	10.40%
69	Wisconsin	Wisconsin Public Service Corp.	TEG	D-6690-UR-121 (Elec)	10/24/2012	Yes	10.30%
70	Wyoming	Cheyenne Light Fuel Power Co.	BKH	D-20003-114-ER-11 (elec)	6/18/2012	Yes	9.60%
71	Wyoming	PacifiCorp	BRK.A	D-20000-405-ER-11	7/16/2012	Yes	9.80%
72	Average (Regulated Generation= Yes)						10.04%

Notes
[1] Source: SNL Financial

TEST YEAR - 2013 FORECASTED SHORT TERM DEBT AND COST [1]

		Cost of Short Term Debt			
	Month End Balances	Average Of Month End Balances [2]	Monthly Interest Expense [3]	Monthly Fees Expense [4]	Average Short Term Debt Cost
Jan-13	$315,968,796	$305,631,665	$131,591	54,134	
Feb-13	$286,574,492	$301,271,644	$117,161	49,016	
Mar-13	$269,885,092	$278,229,792	$119,793	54,134	
Apr-13	$314,527,474	$292,206,283	$97,402	52,428	
May-13	$64,388,373	$189,457,923	$65,258	54,134	
Jun-13	$114,902,537	$89,645,455	$29,882	52,428	
Jul-13	$186,650,076	$150,776,307	$51,934	54,134	
Aug-13	$131,177,760	$158,913,918	$54,737	54,134	
Sep-13	$103,724,368	$117,451,064	$39,150	52,428	
Oct-13	$197,684,110	$150,704,239	$51,909	54,134	
Nov-13	$227,714,066	$212,699,088	$70,900	52,428	
Dec-13	$217,260,508	$222,487,287	$76,635	54,134	
Average	$202,538,138	$205,789,555			
Total			$906,352	$637,666	
			0.44%	0.31%	0.75%

Notes:

[1] Company provided data

[2] January Through December Average of Month End Balances

[3] Monthly Interest Expense based on weighted average of short term debt outstanding. Interest Rates based on July 2012 Global Insights Inc. Forecast.

[4] Ongoing fees for NSP-MN's five-year credit facility that was re-syndicated July 27, 2012. Credit facility is used primarily as back up for commercial paper and letters of credit. Upfront expenses for the five year credit facility are amortized over the life of the facility and are included in the cost of long term debt. This expense represents the monthly cost of NSP-MN unused portion of the credit facility.

ND Electric Jurisdiction -- Actual Weather Normalized Returns

	2012	2011	2010 [1]	2009	2008
Weather-Normal Rate of Return on Rate Base (ROR):	7.32%	7.65%	4.13%	8.37%	8.70%
Weather-Normalized Return on Equity (ROE):	8.92%	9.05%	2.19%	10.16%	10.73%

Notes:

[1] 2010: Reported Actual and weather-normalized Returns on Equity (ROE) reflect a one time deferred fuel expense write-off of $11,125,000. Adjusting for this item would result in an actual ROE of 6.81%.
[2] Source: Company annual filings with Noth Dakota Public Service Commission

Rebuttal Testimony
Steven W. Wishart

Before the North Dakota Public Service Commission
State of North Dakota

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

Case No. PU-12-813
Exhibit___(SWW-2)

Recovery of Purchased Power Costs

August 12, 2013

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Steven W. Wishart. I am the Director of Resource Planning and Bidding for Xcel Energy Services Inc.

Q. HAVE YOU PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed Supplemental Direct Testimony in support of the reasonableness of the Prairie Rose Wind, LLC Power Purchase Agreement.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony will address Commission Advocacy Staff and Consultant recommendations with respect to the Company's recovery of certain Power Purchase Agreement costs recovered through our Commission-approved Fuel Cost Rider (FCR).

II. SUMMARY AND ORGANIZATION

Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY.

A. The Company manages a diverse portfolio of generation resources for its integrated NSP System, which serves all of our customers in Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. Our resource mix includes nuclear, coal, hydro, natural gas, wind, and various other renewable resources. Some of these resources are Company-owned generating facilities, and some are Power Purchase Agreements (PPAs). We have legitimately incurred the costs associated with our PPAs and have been recovering those

costs through our Commission-approved FCR tariff, pursuant to the Commission's Rules.

Staff Consultant ~~Mr. Dante Mugrace~~ Dr. Pavlovic recommends that certain long-term PPAs the Company previously entered into now be excluded from cost recovery in North Dakota. Disallowing the recovery of these costs would:

- be contrary to general ratemaking principles;
- result in North Dakota customers receiving a portion of their energy and capacity for free;
- prevent recovery of legitimately-incurred costs of providing utility service, causing financial harm to the Company; and
- impair our ability to prudently plan our system.

For these reasons, we do not believe adoption of ~~Mr. Mugrace's~~ Dr. Pavlovic's recommendations related to PPA cost recovery are appropriate.

My testimony also responds to ~~Mr. Mugrace's~~ Dr. Pavlovic's recommendation that Prairie Rose Wind costs incurred up to the implementation of final rates in this case should be disallowed, even though he concludes that the project is acceptably-priced and reasonable over the long term. I also discuss our agreement with Advocacy Staff's recommendation to provide a proportionate North Dakota customer refund stemming from disputed costs related to the St. Paul Cogeneration PPA

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- *PPA Cost Recovery*, discussing the PPAs recommended for exclusion from cost recovery and the basis for these recommendations, the Commission Rules governing recovery of these costs and our corresponding FCR, the impact this action would have on our ability to effectively plan our system going forward, and how the appropriate allocation of system costs should result in North Dakota customers paying their share of energy and capacity resources provided by the integrated system.
- *Prairie Rose Wind Project,* responding to the recommendation to exclude certain Prairie Rose Wind costs even though ~~Mr. Mugrace~~ Dr. Pavlovic concludes the PPA is reasonably prices over the long term; and
- *St. Paul Cogeneration PPA*, discussing our commitment to a refund of St. Paul Cogeneration PPA costs to North Dakota customers.

III. PPA COST RECOVERY

A. Power Purchase Agreements

Q. WHAT IS ~~MR. MUGRACE'S~~ DR. PAVLOVIC'S RECOMMENDATION REGARDING RECOVERY OF CERTAIN PPA COSTS?

A. Mr. Mugrace recommends that the Commission exclude North Dakota jurisdictional costs for 17 renewable energy PPAs from ongoing cost recovery through our Commission-approved FCR tariff, which is based on Commission rules. The identified PPAs for biomass, wind, and solar energy resources are currently being recovered through the FCR. ~~Mr. Mugrace~~ Dr. Pavlovic reasons that the costs of these PPAs should now be disallowed, arguing that the Commission should signal its concern with the Company's utilization of

these resources, their perceived cost-effectiveness, and belief that their design only benefits local Minnesota communities.

Q. DO YOU AGREE WITH THIS RECOMMENDATION?

A. No. The Company appropriately entered into these agreements and followed all applicable Rules and Tariff requirements in recovering our legitimately-incurred costs of providing service. To use the benefit of hindsight and change past practice with respect to existing resources by disallowing the recovery of these costs would cause financial harm to the Company and result in our North Dakota customers effectively receiving free energy.

To the extent the Commission wants to change its rules with regard to certain resources, we believe those changes should be prospective and applied to new resources. To accomplish this, the Company is willing to work with the Commission and Staff to implement appropriate mechanisms to ensure timely Commission oversight of new resources we may recover through the FCR.

Q. WERE THESE PURCHASED POWER COSTS PART OF THE COMPANY'S CURRENT RATE REQUEST?

A. No. We recover the costs of these PPAs through the FCR, and these costs do not impact base rates. As Company Witness Ms. Laura McCarten discusses in her Rebuttal Testimony, we are aware of the Commission's concerns with our recovery of the costs of certain renewable energy resources and would like to work with the Commission to address these concerns. Because the FCR mechanism is separate from base rates, we believe it would be appropriate to address these issues in a separate proceeding related to our FCR. However,

because ~~Mr. Mugrace~~ has raised the issue in this case, we are providing additional information in this proceeding.

Q. PLEASE DISCUSS THE BIOMASS PPAS IDENTIFIED BY ~~MR. MUGRACE~~ IN MORE DETAIL.

A. The four biomass PPAs ~~Mr. Mugrace~~ recommends be excluded from further recovery represent 120 MW of baseload resources. These biomass resources were acquired through competitive processes, and their addition to our resource portfolio was an explicit condition of the continuation of our nuclear plants, which I discuss further in Section C below.

The consultant did not discuss any consideration of the contribution and customer benefits of our nuclear resources in our generation portfolio, or provide analysis to support the claim that the price for these the biomass PPAs is too high.

Q. DO YOU BELIEVE DISALLOWING RECOVERY OF THE BIOMASS PPA COSTS IS APPROPRIATE?

A. No. These resources have been and continue to be an important part of our resource portfolio especially when considered in light of their role to the continued operation of the 1100 MW Prairie Island nuclear facility. The Company has appropriately recovered the costs of these resources through our Commission approved FCR. To the extent the Commission wants to change the way the Company recovers its costs of renewable resources in the future, we welcome further discussion of this issue. However, these are legitimately-incurred costs of the integrated NSP System that provide service

to North Dakota customers and we should be able to continue to recover these costs while those discussions proceed.

DR. PAVLOVIC

Q. PLEASE DISCUSS THE WIND AND SOLAR PPAS IDENTIFIED BY ~~MR. MUGRACE~~ IN MORE DETAIL.

Dr. Pavlovic

A. ~~Mr. Mugrace~~ recommends excluding approximately 200 MW of wind resources from further cost recovery. The majority of these wind resources were acquired through competitive processes, and were generally acquired during the timeframe where there was justified concern over exposure to natural gas market volatility. Because wind was recognized by the industry as a valuable hedge against such natural gas price volatility, the average cost of wind power at that time was higher than in previous years – and certainly more than the prices we are seeing now.

Also identified are two small solar projects totaling less than 3 MW. These projects represent the Company's initial steps in exploring solar power and its potential as a viable, cost-effective resource. These projects will provide valuable information regarding how the technology performs in our region, and how the power can be integrated into our system. The cost of solar power has been steadily decreasing over the past several years, and we believe there is value in making small investments in new technologies that have the potential to meet significant portions of customer demands in the future. This strategy has led to the diverse portfolio of resources that our customers enjoy today.

Q. DO YOU BELIEVE DISALLOWING RECOVERY OF THE WIND AND SOLAR PPA COSTS IS APPROPRIATE?

A. No. The recommendation in this case to exclude these PPAs from future cost recovery to send a signal to the Company due to their price is based on hindsight. Excluding these costs would also result in free resources being provided to our North Dakota customers. To the extent the Commission wishes to change the way the Company recovers its costs of renewable resources in the future, we welcome further discussion of that issue. However, these resources are currently generating power, and we should continue to recover these legitimately-incurred costs of the integrated NSP System that provides service to North Dakota customers.

DR. PAVLOVIC'S

* Q. PLEASE SUMMARIZE THE COMPANY'S RESPONSE TO ~~MR. MUGRACE'S~~ PPA RECOMMENDATION?

A. The retrospective view that the consultant recommends, which would disallow ongoing recovery of legitimately-incurred costs, is inconsistent with general ratemaking principles and past Commission practice, which allows the Company to recovery legitimate costs of providing service. Further, it would result in our North Dakota customers receiving a portion of their energy and capacity for free, and it would raise policy and practical issues with regard to the Company's ability to plan its system with an appropriate and necessary long-term view.

As Ms. Laura explains in her Rebuttal Testimony, the Company is aware of the Commission's concerns regarding renewable resource additions on the NSP System, and has been working to address them. We welcome ongoing discussion regarding prospective cost recovery of new renewable resources.

B. Purchased Power Tariff and Rule Requirements

Q. PLEASE EXPLAIN HOW THE COMPANY'S RECOVERY OF THE COSTS OF THESE PPAS THROUGH THE FCR IS CONSISTENT WITH THE COMMISSION'S RULES.

A. As I explained in my Supplemental Testimony, the Commission's rules (N.D. Admin. Code § 69-09-02-39) provide for "automatic adjustment clauses" to be included in utility tariffs that allow for increases or decreases in rates, without prior hearing, to recover increases or decreases in fuel and purchased energy costs incurred by an electric utility. Theses costs include the net costs of energy from a renewable energy source, including solar, hydropower, wood, wind power, and biomass.

Pursuant to its automatic adjustment clause rules, the Commission has approved the Company's FCR, which allows, among other things, for the Company to include the costs of its purchases of renewable energy in our rates. The PPAs identified by Staff's consultant are energy resources that meet the requirements for recovery of both our Commission approved FCR and the Commission's automatic adjustment rules. Therefore, it is reasonable for the Company to expect to recover the costs of these PPAs through the FCR.

Q. DOES THE COMMISSION REVIEW PPAS PRIOR TO RECOVERING THEIR COSTS THROUGH THE FCR?

A. The Commission's rules do not specifically provide for Commission approval of purchased power costs prior to their inclusion in the FCR. The Commission is afforded the opportunity to perform a review when the Company makes its monthly FCR filings. We are willing to work with the Commission and Staff to implement other means to facilitate this review.

However, if a resource qualifies for recovery under the FCR, the terms of the approved tariff allow the Company to include these resources for recovery through that mechanism without pre-review by the Commission. That said, in response to statutory changes in 2005 and ongoing discussions with the Commission, we have made commitments to file for an Advance Determination of Prudence (ADP) from the Commission for PPAs from generation resources of at least 50 MW, which explicitly affords the Commission an opportunity to review the Company's purchases from new resources.

We note that the ADP statute, N.D.C.C. § 49-05-16, does not require an ADP application be filed nor does it specify the necessary timing of an ADP application. As we have submitted ADP Applications, we have worked to understand the Commission's expectations regarding the timing of these filings, and are now providing them within two weeks of making similar filings in Minnesota, consistent with our commitment to the Commission in Case No. PU-12-59.

Q. DID THE COMPANY FILE AN APPLICATION FOR AN ADP FOR ANY OF THE PPAS IDENTIFIED BY ~~MR. MUGRACE~~DR. PAVLOVIC?

A. No. None of the PPAs identified by ~~Mr. Mugrace~~Dr. Pavlovic are above the 50 MW threshold for which we have committed to file ADPs. Further, some of the PPAs identified pre-date the ADP statute and the Company's commitment to utilize it. Consequently, the Company has complied with the terms of our Commission-approved FCR tariff, and appropriately recovered the costs of these PPAs through that mechanism.

Q. CAN YOU PROVIDE SOME EXAMPLES OF HOW THE COMPANY HAS COMPLIED WITH ITS TARIFF AND THE COMMISSION'S RULES?

A. Yes. The biomass PPAs provide a good example. The biomass PPAs identified by ~~Mr. Mugrace~~ Dr. Pavlovic are long-standing agreements that predate both our commitment to file for ADPs and even the ADP statute itself. The Laurentian PPA was originally executed in 1998 and then replaced in 2005. The St. Paul Cogeneration PPA was executed in 2000, replacing a 1998 contract and the Fibrominn PPA was also executed in 2000. This means that we have been relying on these contracts for more than a decade. At the time we entered into these contracts, we were no Commission requirement or statute that would provide for prospective review of these contracts.

Q. WHAT RECOMMENDATION DOES ADVOCACY STAFF MAKE RELATED TO AN FCR INCENTIVE MECHANISM

A. Advocacy Staff suggests the Commission consider an incentive mechanism that would reward or penalize the Company for its resource and fuel procurement costs – and references related discussions with parties in Minnesota.

Q. DOES THE COMPANY SUPPORT THIS RECOMMENDATION?

A. Our support of such a mechanism would depend on its form. We believe that any incentive mechanism must: (1) reward desired actions and outcomes; (2) focus on measurable results; (3) be transparent; (4) limit risks to both our customers and our shareholders; (5) be subject to evaluation and modification; and (6) be compatible with the current business climate. The Commission's own guidelines set forth in Case No. PU-439-94-590, provide additional characteristics for such an approach.

At its core, the FCR is intended to allow recovery of the reasonable cost of fuel and purchased energy (costs which fluctuate month-to-month); we earn no return through the FCR. We believe that the Commission currently has significant authority to review our FCR costs, and that if the Commission chooses to change its review practice, it should do so prospectively to ensure that the Company does not rely on long-term settled recovery of costs about which the Commission may have a concern.

As no specific incentive mechanism has been proposed, we cannot provide specific comments in this case. We are, however, willing to work with the Commission and Staff to address concerns and develop appropriate processes for prospective review of our costs. As part of these discussions, we are also willing to explore a potential incentive mechanism for our overall fuel procurement and resource costs that balances our interests with those of the Commission and our customers.

C. System Resource Planning

DR. PAVLOVIC

Q. PLEASE EXPLAIN THE IMPACT THAT ~~MR. MUGRACE~~ RECOMMENDATION HAS ON THE COMPANY'S RESOURCE PLANNING EFFORTS.

Dr. Pavlovic

A. The PPAs identified by ~~Mr. Mugrace~~ are part of our portfolio of resources we utilize to serve all of our customers in all of the NSP System jurisdictions – Michigan, Minnesota, North Dakota, South Dakota, and Wisconsin. We necessarily assume the availability of these resources to serve all of our customers when we plan for the future needs of our system.

Dr. Pavlovic's

The implication of ~~Mr. Mugrace's~~ recommendation is that at any time after a resource decision is made – even ten years later – the Commission can choose

to disallow the costs of that resource. This creates significant uncertainty for which there is no remedy. In order to plan our system to ensure safe, reliable, and cost-effective service to all of our customers, we need some level of certainty that once a resource decision is made, prudently-incurred costs of that resource are recoverable. Without such certainty, we cannot reasonably apply a long-term view to planning for additional resources as our system grows, which delivers cost benefits to all customers.

Q. WHAT ARE THE BENEFITS OF THE COMPANY'S DIVERSIFIED PORTFOLIO OF LONG-TERM RESOURCES?

A. The NSP System provides a well-balanced portfolio of resources that includes nuclear, coal, hydro, natural gas, and various renewable resources. Our portfolio is made up of Company-owned generating facilities and both long-term and short-term PPAs. The balanced resource diversity and long-term nature of our portfolio protects customers from short-term spikes in energy and capacity costs.

However, it is the assurance of cost recovery that allows us to take this long-term view of constructing facilities with expected lives of over 30 years, and entering PPAs with contract terms of 20 years and longer. This benefits our customers through long-term price stability and mitigation of risks that would be associated with over-reliance on a single resource type or short-term resources.

Q. PLEASE DISCUSS THE PRACTICAL IMPLICATIONS TO THE COMPANY'S LONG-TERM PLANNING THAT WOULD RESULT FROM ~~MR. MUGRACE'S~~ DR. PAVLOVIC'S RECOMMENDATION.

A. The disallowance recommended by ~~Mr. Mugrace~~ Dr. Pavlovic would impact the Company's ability to plan for the future because any long-term resources could be denied recovery at any time. Without assurance that we could continue to fully recover prudently incurred costs of long-term resources, the Company would be incentivized to take a short-term view to limit our exposure to retrospective changes in policy.

A diverse portfolio of long-term resources is essential in order to provide customers with reliable service at stable prices. If any resource could be disallowed at any time, our best strategy might be to only procure resources on a short-term basis. That way, the Company's exposure to the financial harm that stems from retrospective policy changes with regard to a specific resource would be minimized. The action recommended by ~~Mr. Mugrace~~ Dr. Pavlovic would set a precedent to possibly disallow the cost of our resources in the event that circumstances change from the time we originally procured those resources. This is not consistent with general standards of prudence review, and we believe that taking a retrospective view of existing resources would harm both customers and the Company. As such, we do not believe this is an appropriate ratemaking practice.

Q. DOES THE COMMISSION HAVE THE ABILITY TO DISALLOW COST RECOVERY OF CERTAIN PPAS?

A. Yes. The Commission has the authority to approve or deny resource additions to the NSP System. However, as I have discussed, this is best done on a prospective basis, so that the Company can acquire a diverse portfolio of long-term resources with stable prices for all the states we serve. We are willing to work with the Commission and its Staff to identify or develop the

appropriate mechanisms to accommodate this prospective review of PPAs and resource additions.

Q. WHAT DOES THE COMPANY RECOMMEND IN RESPONSE TO THE CONSULTANT'S RECOMMENDATION?

A. While we acknowledge that the Commission's automatic adjustment rules allow for Commission review of the costs included in our FCR at any time, the Company relies on continued recovery of costs so that we may maintain a long-term diversified portfolio of resources for our customers. We recommend that the Commission adhere to past practice, which supports long-standing expectations with respect to resource costs recovered through the FCR, and take an appropriate view that considers all circumstances of a particular resource decision.

Our biomass PPAs provide a good example. We recognize that our biomass resources are part of the Commission's concerns with respect to energy policy issues. However, we acquired these resources as doing so was a specific condition to the continuation of our nuclear plants from approximately 15 years ago. Accordingly, these agreements are explicitly linked to our ability to provide safe, reliable, and cost-effective nuclear power to our North Dakota customers. The agreements stem from Minn. Stat. § 216B.2424, which makes clear that the Company, as a public utility operating a nuclear plant in Minnesota, must contract for a minimum of 125 MW of biomass capacity.[1] Dr. Pavlovic's ~~Mr. Mugrace's~~ review of our biomass PPAs does not take into consideration these circumstances, which we believe ultimately benefit our North Dakota

[1] The biomass mandate was revised in 2003 from 125 MW to 100 MW. 2003 Minn. 1st Special Session Law Ch. 11.

customers through our continued ability to provide cost-effective nuclear power as part of our portfolio.

For these reasons, we do not believe it would be in the interests of customers or the Company if the Commission were to abruptly reverse course on existing resources now. To the extent the Commission desires a different process for new resource additions, we would be willing to work with the Commission and Staff toward a process that balances the Commission's objectives with the Company's need for a diverse resource portfolio that meets its compliance and reliability obligations that ultimately benefits our customers.

D. Replacement Resource Costs

DR. PAVLOVIC'S

* Q. ~~MR. MUGRACE'S~~ PROPOSAL TO DISALLOW RECOVERY OF CERTAIN COSTS DOES NOT ADDRESS THE FACT THAT POWER WOULD BE PROVIDED TO NORTH DAKOTA CUSTOMERS WITHOUT COST. PLEASE EXPLAIN HOW THIS MAKES HIS PROPOSAL IS INCOMPLETE.

Dr. Pavlovic's

* A. ~~Mr. Mugrace's~~ proposal to disallow the recovery of certain PPA costs in North Dakota does not address the fact that the energy and capacity from these resources will still be used to serve our North Dakota customers through the integrated NSP System. This action would not allow the Company to recover its reasonable cost of service, and would instead result in our North Dakota customers receiving a portion of their energy and capacity for free.

Because he does not identify a mechanism to replace the resources that he proposes to disallow in North Dakota, his recommendation is incomplete. I

also addressed this situation in my Supplemental Testimony in this case with respect to the effects of the disallowance of the costs of the Prairie Rose Wind project.

Q. WHAT DOES THE COMPANY RECOMMEND IN RESPONSE TO HIS RECOMMENDATION?

A. We believe that retrospective disallowance of legitimately-incurred costs (abruptly excluding costs for PPAs that are already being recovered through the FCR) is not consistent with established regulatory practices – and the precedent created would fundamentally impair our ability to provide the benefits of a long-term diversified portfolio of resources to our customers. We believe that the Commission has significant authority to review our fuel and energy costs and if the Commission chooses to exercise this authority, it should do so prior to our initial recovery to ensure that the Company does not rely on long-settled recovery of costs for which the Commission may have concern. As discussed previously, should the Commission wish to revisit established FCR procedures, we would be willing to work with the Commission and Staff to develop regulatory processes that will allow for timely review of important resource decisions.

IV. PRAIRIE ROSE WIND PROJECT

Dr. Pavlovic

* Q. PLEASE DESCRIBE ~~MR. MUGRACE'S~~ RECOMMENDATION WITH RESPECT TO THE PRAIRIE ROSE WIND (PRW) PROJECT.

Dr. Pavlovic

* A. ~~Mr. Mugrace~~ found that the PRW Project is acceptably priced and reasonable over the long-term. However, he recommends that the Company not recover the costs of the Project incurred from the time it was placed into service until

the conclusion of this rate case. This recommendation is based on his view that the ADP was not timely-filed.

Q. WHAT IS THE COMPANY'S RESPONSE TO THIS RECOMMENDATION?

A. We believe this recommendation is contradictory, and that its basis is inappropriately retrospective. Adoption of this recommendation would result in North Dakota customers receiving the long-term benefits of the Project, but not having to pay the near-term costs. This is inconsistent with cost allocation principles that require an appropriate sharing of costs between North Dakota customers and the other customers who share the NSP System with North Dakota.

Further, in justifying his recommendation, the consultant applies a timeframe for filing of the Company's ADP application that the Company was not aware of at the time the PRW resource was acquired, and observes that its price is more expensive than current prices. Prudent ratemaking practices would evaluate a project and decide if it is reasonable and was prudently acquired.

It is appropriate for the Commission to evaluate a proposed project and decide if the project is reasonable and was acquired prudently and if the project should be included in our rates. However, we do not believe it is reasonable or appropriate to review a contract and the underlying bargain and only approve cost recovery of certain parts that are most favorable while all customers will receive the full benefits that a project will generate.

Finally, I note that the $1.3 million in savings claimed by Advocacy Staff is actually reflecting the full cost of the contract and not the net cost of the

removal mechanism agreed to by parties. The net impact on the North Dakota FCR will be much smaller, on the order of only $300,000.

V. ST. PAUL COGENERATION PPA

DR. PAVLOVIC'S

Q. WHAT IS ~~MR. MUGRACE'S~~ RECOMMENDING WITH RESPECT TO THE REFUND THE COMPANY PROVIDED FOR SOME DISPUTED COSTS UNDER THE ST. PAUL COGENERATION PPA WHICH WERE REFUNDED TO MINNESOTA CUSTOMERS?

Dr. Pavlovic

A. ~~Mr. Mugrace~~ is recommending that the Company provide a refund to our North Dakota customers proportionate to the refund the Company provided to our Minnesota customers. We believe that it would be equitable to refund the North Dakota a similar portion of the cost differential to our North Dakota customers.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

Dr. Pavlovic's

A. The Company disagrees with ~~Mr. Mugrace's~~ recommendation to disallow future recover of the costs of certain PPAs through the Company's Commission-approved FCR because: (1) we do not believe sending a signal is an appropriate basis for setting rates; (2) our recovery of these costs is consistent with our Tariff and the Commission's rules; (3) his recommendation could incent the Company to deviate from longer term planning which would expose our customers to more pricing risk; and (4) his recommendation would lead to our North Dakota customers receiving energy for which they do not pay and would therefore not allow the Company to recover its legitimately-incurred cost of service.

Further, we disagree with his recommendation with respect to the costs of the PRW Project. We believe that full recovery of these is appropriate since he has found the Project costs to be reasonable over the long term.

Finally, we agree with his recommendation to refund our North Dakota customers proportionate to the refund the Company provided to our Minnesota customers related to the St. Paul Cogeneration PPA.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota Corporation For Authority to Increase Rates for Electric Service in North Dakota	))))	Case No. PU-12-813

AFFIDAVIT OF
Steven W. Wishart

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

Steven W. Wishart

Subscribed and sworn to before me, this 2nd day of August, 2013.

Notary Public
My Commission Expires: 3/30/2015

EDNA G. MATHEIS NOTARY PUBLIC STATE OF COLORADO MY COMMISSION EXPIRES MARCH 30, 2015