

**LAURA MCCARTEN
POLICY
EVIDENTIARY HEARING OPENING STATEMENT
Case No. PU-12-813**

Commissioners Kalk, Christmann and Fedorchak, Judge Fetch and Commission Staff, good morning. I am Laura McCarten, Regional Vice President for Northern States Power Company. We appreciate the opportunity to come before the Commission today to explain our rate request and develop a full and thorough record on which the Commission can base its decision.

Our modified rate request seeks Commission approval for a \$14.9 million revenue requirement increase, based on updated financial information and a 10.25 percent return on equity. This rate request is necessary to support ongoing investments in our system to ensure safe and reliable electric service. These investments include life extensions for both our Prairie Island and Monticello nuclear power plants and a power uprate at Monticello. We are also seeking recovery of investments in our transmission and distribution systems. These investments are in our customers' interests, both in the near-term and long-term, as reliable electric service is one of the highest priorities for our customers and is a key factor in supporting economic growth.

We appreciate Advocacy Staff and the consultants' general support for the investments we are making. While Staff and their consultants do not agree on all aspects of our rate request, we are encouraged that the bulk of our request is not in dispute.

We recognize the cost impact these needed investments have on our customers, and we're eager to work with the Commission and Staff on ways to reduce, or mitigate,

this cost impact. To this end, I offered in my Rebuttal Testimony two proposals: first, the use of a (cost-smoothing mechanism) for our pension expense, and second, the use of a (capital step) to address future recovery of capital investments that we know we will be making. I also note that Commission approval of our proposed Transmission Cost Recovery Rider would help to mitigate the frequency of our general rate cases. I look forward to a full discussion of these possible mitigation mechanisms.

Although Staff and their consultants appear to support our system investments, we are concerned with the consultants' proposals to reverse long-standing ratemaking practices in North Dakota. We believe it is a better practice, is in the interests of our customers, and is consistent with current circumstances to use the ratemaking methodologies that this Commission has had in place for almost 20 years.

The most significant proposed change is the one to our (demand allocator.) As Company witness Scott Brockett will explain in more detail, using a 12 CP allocator remains the most appropriate jurisdictional allocation method for an integrated system such as ours, is consistent with standards of ratemaking and consistent with this Commission's precedent. The record supports the continuation of this method in this case.

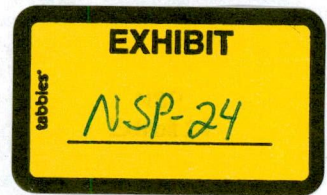
We recognize the concerns of Staff and this Commission regarding the energy policy differences between states and how those differences may impact our North Dakota customers. We have been complying with our commitments to this Commission with respect to these issues and believe (we are making resource decisions that are prudent and are in the interests of all of our customers.) We will continue to meet these commitments to ensure the Commission's concerns are met while allowing the Company to recover its costs of service and earn a reasonable rate of return.

Other recommendations of Staff and their consultants relate to (costs that are not part of our rate request.) For example, Dr. Pavlovic recommends disallowance of further recovery in our Fuel Cost Rider of the costs of certain Power Purchase Agreements that have been in place for several years. Because these costs are recovered in the Fuel Cost Rider, they are by definition not part of base rates and so not part of our rate request. Should the Commission want to address recovery of the costs of these Power Purchase Agreements, the appropriate way to do so would be in a separate proceeding and on the basis of a complete record. We are willing to work with the Commission and Staff to ensure that the Commission has the timely opportunity to fully review the costs we would seek to recover through our Fuel Clause Rider.

Similarly, Staff's recommendation to disallow certain costs of new wind acquisitions should be addressed in their respective ADP Cases, as these projects are not part of this rate case.

Finally, I want to acknowledge the Commission's interest in and concerns with the new Minnesota (solar standards). I commit to you that we will make every effort to mitigate the impact of this Minnesota requirement on our North Dakota customers.

In summary, we appreciate the general agreement of the parties on the prudence of the necessary investments that are driving this case. However, the areas of disagreement are significant in terms of both importance and magnitude. We believe that application of long-standing ratemaking principles in North Dakota will result in an outcome that is fair, consistent with this Commission's precedent and with current circumstances, and that appropriately balances the interests of our customers and the Company. And, beyond this rate case, we look forward to a continued cooperative effort, working with the Staff and the Commission on the Fuel Clause Rider issue and other energy policy issues that could affect our North Dakota customers. Thank you.



STEPHEN FOSS
OPERATIONS AND SYSTEM INVESTMENTS
EVIDENTIARY HEARING OPENING STATEMENT
Case No. PU-12-813

My testimony discusses the 2013 capital and O&M budgets for the Operations organization, which includes Energy Supply, Transmission and Distribution. Operations is focused on excellence in employee and public safety, continuous improvement, and efficiency. Our goal is to provide the safe and reliable service our customers expect.

While each major function within Operations has a slightly different planning and budgeting process due to the business they manage, overall our processes are extensive and comprehensive and entail significant analysis and review. The 2013 capital and O&M budgets reflected in this rate application include expenditures we expected at the time to incur. Since the original filing we have made changes to some projects and the appropriate adjustments were made and described in Ms. Heuer's rebuttal testimony.

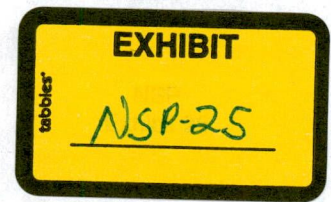
One of these adjustments was to remove the emissions chemicals and avoidable O&M costs at Unit 3 of our largest coal plant, the Sherco facility, for the first nine months of the 2013. As discussed in our status reports to the Commission, the turbine failure in November 2011 caused major damage to the plant. We have managed the massive repair effort with two fundamental objectives in mind: First, doing the job right, so Sherco 3 can provide safe and reliable service for many years to come; and second, protecting the interests of our customers.

The Sherco 3 project work is progressing well. The extensive investigation of the event indicates that the original cause was a failure of the mechanical connections between the low pressure turbine blades and the rotor. The failure was not one we could have predicted or prevented. All major equipment restoration and reassembly work has been completed and we are in the final stages of testing. We expect the plant to be back in service and in use to serve our customers around the end of September.

Maintaining and improving reliability for our North Dakota customers is an important priority for our Operations area. The reliability of our North Dakota operations continues to be the best in the NSP System. As part of our Settlement Agreement in the last rate case, several reliability-based commitments were made, each of which has been completed or is in process, including the establishment of a North Dakota-focused "Reliability Performance Plan" approved in late 2012.

The investments and costs that we have included in the test year for the Operations organization are what we believe to be necessary to maintain the high quality, safe, and reliable service our North Dakota customers expect.

Commissioners, I appreciate the opportunity to be here today, and I will do my very best to answer any questions you or your Staff may have about my testimony in this case. Thank you.



TIM O'CONNOR
NUCLEAR OPERATIONS
EVIDENTIARY HEARING OPENING STATEMENT
Case No. PU-12-813

Good morning. I am Tim O'Connor, Chief Nuclear Officer for Xcel Energy.

The Company has made and continues to make significant investment in the Prairie Island and Monticello nuclear facilities to maximize the clean, reliable energy produced over their extended operating lives. The investments are necessary to keep the units operating and available as round-the-clock, carbon-free base load resources.

The Company is ensuring that it is efficiently using its nuclear plants by performing work necessary to extend the operating lives of all plants and also increasing the generating capacity at Monticello. The Monticello extended power uprate/life cycle management project will allow us to provide safe, reliable, low cost energy to our customers through 2030. We are currently waiting for our power uprate license approval by the Nuclear Regulatory Commission, and have removed the licensing costs from our rate request. However, all investments and plant upgrades to date are in service and being used today to generate power and customers are currently benefiting from those investments. Therefore, as explained in my rebuttal testimony, the operating and maintenance costs for Monticello are not avoided due to the license delay. Rather all of these costs are currently being incurred as Monticello is in-service and providing electricity to all of our customers.

The nuclear operations arena is changing as safety continues to be redefined. Safe nuclear power operations is compliance-driven by an independent

regulator, the Nuclear Regulatory Commission, promulgating regulations in response to lessons learned from day-to-day operations of all nuclear plants operating world wide. The Fukushima event is an example of a world wide event reshaping nuclear safety and certainly USA nuclear operations. Public health and safety standards in nuclear operations are not stagnant as demonstrated by increased regulatory requirements. The license requirements under life extension are more stringent than those under the original license and we are responding accordingly, to ensure the safety and the long term availability of these key resources through their extended operating lives.

In addition, nuclear employee retention is a significant issue. The nuclear industry is facing a decline in experienced nuclear workers as well as increased competition globally for those remaining experienced workers, which has contributed to a shortage of specialized, skilled labor. We have implemented a practical and necessary plan for recruiting and retaining the highly qualified workforce to assure workforce stability as our customers are better served by retaining the employees with the experience and skill sets necessary to keep our plants operating safely, efficiently, and effectively.

I appreciate the opportunity to be here today and am available to answer any questions you may have.

SHARON L. KOENIG
INCENTIVE COMPENSATION
EVIDENTIARY HEARING OPENING STATEMENT
Case No. PU-12-813



My purpose in this proceeding is to provide testimony to demonstrate the reasonableness of the Company's annual incentive program and nuclear retention program costs. For individual but related reasons, these programs are necessary to attract, retain and engage the highly-skilled employees that help provide reliable electric service throughout our system each day.

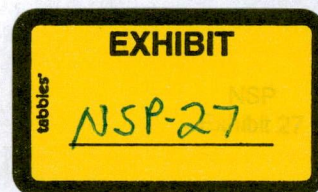
Delivering safe and reliable electric service to our North Dakota customers is dependent upon attracting talented employees to our Company in the present – and upon planning for the long-term success of the utility. I'm concerned that we would not be able to attract and retain capable employees in a consistent manner unless we continue to offer total cash compensation – meaning a combination of base salary and incentive compensation – that is competitive with what is offered elsewhere in the market. We therefore utilize industry best practices to compare our total cash compensation for a position to what is offered in the marketplace for the same or similar jobs. By that objective measure, we know that without annual incentive, our employees' cash compensation would be 14 to 17 percent below that which comparable utilities pay. That would be like paying our employees \$85 for a job that elsewhere would pay \$100.

Furthermore, the annual incentive is a prevalent compensation tool used by corporations and utilities alike for the dual purposes of motivating employees to attain business goals that benefit customers, and managing the overall cost of employee compensation. Because incentive compensation must be newly earned each year, and because certain employee benefit costs increase as base pay amounts increase, our annual incentive is more cost-effective than providing cash compensation solely

through base salary. As a human resources professional, I am concerned about any potential inability to recover incentive compensation costs that are designed to help us fairly compensate and motivate employees, and at the same time serve to manage the overall cost of employee compensation.

To further manage costs and provide value for our North Dakota customers, we are not seeking 100 percent of our annual incentive costs. Instead, we propose to cap our recovery of these costs at 25 percent of base pay. This cap essentially precludes rate recovery of the costs of providing incentive compensation to executive-level employees, while recognizing that it is reasonable to recover the cost of incentives for those skilled employees in a variety of other jobs so they have the opportunity to receive market-level cash compensation. We have also aligned our annual incentive program with goals that benefit our customers, such as safety and reliability standards. For each of these reasons, I believe that our annual incentive program provides significant overall benefits to our customers, that program costs are reasonable both in the nature and amount of the costs, and that rate recovery in North Dakota is appropriate.

Similarly, our nuclear incentive programs are designed to help us retain employees who are in key positions in our nuclear business. My testimony provides information about our recent experiences with critical nuclear employees leaving the Company, and describes the limited pool of skilled nuclear industry employees for which we compete. While we have had some success when utilizing retention programs for our nuclear programs, we have struggled to hire needed employees where other utilities were able to implement retention programs ahead of us. In combination with the annual incentive, our nuclear retention programs align employee interests with nuclear operational goals, reduce the significant costs of employee turnover, and ensure employee stability in this particularly complex and highly unique area of our business.



LISA H. PERKETT
NUCLEAR DECOMMISSIONING AND DEPRECIATION
EVIDENTIARY HEARING OPENING STATEMENT
Case No. PU-12-813

I am the Director of Capital Asset Accounting for Xcel Energy Services. I have over 32 years of experience in utility accounting. I am responsible for managing our capital asset accounting, including accounting and tax records, reporting and regulatory requirements, and the capital investment cost recovery process.

In my Direct Testimony I discuss two topics. First, I sponsor our North Dakota Specific depreciation study. This is the first study we have filed that is specific to North Dakota assets, and reflects direction we received from Staff in our last rate case to prepare a North Dakota specific study. It is appended to my Direct Testimony as Schedule 7. While Mr. Majoros questions the results of the removal costs included in our Depreciation Study, Mr. Majoros has not identified any facts relied upon in the Depreciation Study that are incorrect; and the Advisory Staff proposed adjustments to the revenue requirement that are inconsistent with long-standing regulatory and accounting practices. If adopted, Mr. Majoros' recommendations would cause future ratepayers to pay the removal costs of assets after retirement when the assets would no longer be providing any benefits. Depreciation is expressly designed to recover the investment and net removal costs over the lives of the assets so that the customers who benefit from the asset pay those costs.

Second, I sponsor our nuclear decommissioning expense included in the 2013 test year, and our proposal to use Department of Energy payments related to nuclear fuel storage cost damages to help fund the decommissioning. Currently, the decommissioning fund accrual is set to zero, and no funds are being collected from North Dakota customers. We propose using a 60-year decommissioning period and

propose to maintain the accrual at zero by placing all of the 2012 and 2013 DOE settlement payments into the external escrow fund to cover the increase in accrual that would otherwise need to be collected from North Dakota customers beginning in 2013. Under our proposal, there is no impact to North Dakota customers for the test year. Advisory Staff consultant Mr. Michael Majoros recommends approval of our decommissioning proposal.

My Rebuttal Testimony responds to Mr. Majoros' recommendations concerning depreciation expense. Mr. Majoros lists three recommendations on page 3 of his Testimony

First, he recommends that the Company refund the difference between the actual depreciation reserve and the theoretical depreciation reserve for our Transmission, Distribution and General Assets. There is, on a total Company basis, a surplus of \$176.6 million. In my Direct Testimony, I explain how the surplus has been generated (essentially as a result of increased service lives and changes in the cost of removal). I also explain our proposal to use the surplus to lower depreciation rates over the remaining lives of the assets. This proposal is consistent with the use of straight line depreciation. This proposal results in an approximately \$4.2 million annual reduction in depreciation expense at the Total Company level.

Mr. Majoros' other two recommendations, on page 3 of his Direct, would limit recovery of removal cost to those items that qualify as legal AROs. My Rebuttal testimony explains that the distinction between legal AROs and non-legal AROs is based on financial reporting requirements and not based on operating, accounting or regulatory requirements. In my Rebuttal Testimony, at page 13, I presented a table that lists all of the types of legal AROs that apply to the Company.

Production

Asbestos

Wells

Ash ponds and landfills (including evaporation ponds)

Underground and aboveground storage tanks

Mercury in old control panels

Lead paint

Coal yard at certain facilities on rivers

Transmission and Distribution

Asbestos

Pole top or pad mounted transformers with PCB oil
(expected to be less than 5% of equipment)

Substation transformers and capacitors with PCB oil and
the carcass that held the oil (expected to be a very small
percentage of equipment)

Underground and aboveground storage tanks

Meters with lithium batteries

Paper-insulated, lead-covered underground cable
(mostly in the State of Minnesota)

General Plant

Asbestos

Lead paint

Lithium batteries in equipment

There are many expected removal activities and components that are not legal AROs, including buildings, transmission lines and poles, distribution lines and poles, which are only examples of a few major categories of assets that are not legal AROs and which cannot be retired in place.

For example, there is no legal ARO to remove retired distribution lines and poles or retired transmission lines and poles; but we could not abandon those dead poles and wires in place. Since we need to remove those poles and wires, we should recover

those costs and those costs should be recovered from the customers who benefit from the use of those assets to provide electric service.

Similarly, when we retire a plant or other building, only a small portion of the removal is covered as a legal ARO (for example, removal of asbestos). But we need to remove the entire building and plant, not just the asbestos component. If we don't recover the cost of removal during the life of an asset we would need to recover the costs after the asset is retired. Removal costs should be paid for by the customers who benefit from using the asset.

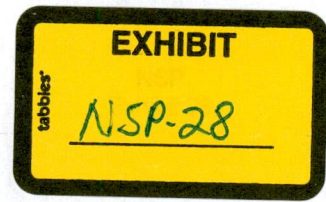
Mr. Majoros' assertion that there is no requirement to remove non-legal AROs is not true. In Case No PU-07-776, we expressly agreed to the creation of a regulatory liability. More specifically, the Commission approved Settlement states: "Both parties agree that, unless directed otherwise by the Commission, rate recovery – past, present, and future – for the removal and retirement of Company utility property will be used solely for the retirement of the Company's utility property and recognized as a regulatory liability."

Mr. Majoros states that we have not reported the accumulated non-legal ARO in our financial statements, in FERC Form 1, or in our North Dakota annual earnings reports. We have reported the financial information we are required to report by the SEC, FERC and the Commission. We have reported the total amounts recovered for retirement and removal of both legal and non-legal AROs in our 10K, in our FERC Form 1, and in our North Dakota earnings reports. Non-legal AROs shown as a liability for financial reporting is included as part of accumulated depreciation for rate making. Furthermore, accumulated depreciation, including the amount recovered for cost of removal, is used to reduce rate base and cost of service. If the Commission

wants more financial reporting information we can provide it, but that is not a current requirement and additional reporting would have no impact on the cost of service.

Finally, Mr. Majoros asserts that the Company uses an inappropriate methodology for determining removal costs. The Company uses its historical removal costs to determine the current cost of removal. Prior to his Supplemental Direct, Mr. Majoros argued that we should use a five-year historical average to determine the current cost of removal. He has abandoned that approach because, as I indicated in my Rebuttal Testimony, using a five year average would increase the cost of removal. In an effort to respond to our specific removal cost study, he makes broad general arguments based on mistaken assumptions without identifying any facts relied upon in the Depreciation Study that are incorrect.

For these reasons, Mr. Majoros' recommendations concerning nuclear decommissioning and depreciation expenses should not be accepted.



SCOTT BROCKETT
JURISDICTIONAL DEMAND ALLOCATOR
EVIDENTIARY HEARING OPENING STATEMENT
Case No. PU-12-813

I am Director of Regulatory Administration and Compliance for Xcel Energy Services Inc.

In my Rebuttal Testimony, I explain why the Commission should continue to use the “12 CP” method to determine the North Dakota jurisdictional portion of costs for our production and transmission facilities. I also explain why the Commission should not adopt the “1 CP” method recommended by the Advocacy Staff Consultant, Karl R. Pavlovic. As part of his recommendation, Dr. Pavlovic proposes a \$20 million reduction in the test year revenue requirement. As a result, use of the right jurisdictional allocator is a critical financial issue for the Company.

As part of an integrated system, our production and transmission facilities are used to provide service to more than one state. As a result, it is necessary to determine the North Dakota portion of the costs of these facilities as part of the process of setting our North Dakota rates.

The Commission has historically applied three criteria for selecting a method for allocating costs to the North Dakota retail jurisdiction: accuracy, stability, and consistency with other jurisdictions. The weighted 12 CP method we recommend meets all of the Commission’s criteria and should continue to be used in this case.

Accuracy is the Commission’s primary criteria. The 12 CP method we have used in North Dakota for about 20 years and again proposed in this case most accurately captures the drivers of our fixed production costs. The 12 CP method recognizes that

our fixed production costs are incurred not only to ensure reliable service, but also to minimize overall system energy costs over the course of a year. Specifically, the 12 CP method considers loads in all 12 months, thereby recognizing that loads in all months contribute to our overall system costs. The 12 CP method recognizes that the costs incurred to ensure reliable service (demand related costs) cannot be allocated to any specific hourly load in any specific month, or even to a single season because we design and operate our system to ensure reliable service at the least costs in all months. As a result, potential loads in many different summer hours, as well as hours outside the summer season, also contribute to the need for production capacity. The 12 CP method gives more weight to summer peak loads, but also recognizes the significance of peak demands in other months.

The 12 CP method also better captures the drivers of our fixed transmission costs. The Company designs the various segments of its transmission system to meet the peak demands of the specific regions served by each segment of the system. These regional peak demands are not necessarily coincident with the NSPM coincident peak, and may occur in the winter. Moreover, MISO uses the 12 CP method as a basis for its monthly transmission billings.

The Commission has found that it is appropriate to recognize peak usage in all 12 months with a weighting that recognizes the added significance of higher usage months. The 12 CP method, which reflects peak loads in all months with an added weighting of higher usage months, meets these Commission criteria for accuracy.

The Commission has also recognized that the 1 CP method was an inappropriate method to determine the drivers of the Company's costs because it ignores the costs that off-peak customers impose on the Company's system.

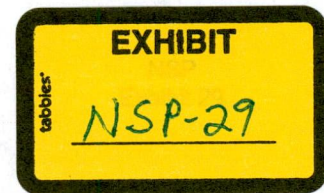
The 12 CP method also yields more stable results (the Commission's second criterion) than the 1 CP method, because the 12 CP method takes into consideration peak loads throughout the year. As a result, year to year changes are smaller than the changes under the "1 CP method" that has been recommended by the Staff consultant in this case. Such variability can have a significant impact on test-year revenue requirements and, ultimately, electric rates.

The Commission's third criterion is consistency with the approach used by other jurisdictions. The 12 CP method is used by the other four NSP system states and MISO. While this factor may be less significant to the Commission, it nevertheless points to the 12 CP method as the best approach under the Commission's criteria.

Finally, as Staff consultant Dr. Pavlovic's Supplemental Testimony recognizes, the NARUC manual focuses on which "method best reflects the utility's actual system planning and operation." My Rebuttal Testimony explains that the 12 CP best reflects: (1) our planning and operation of production facilities both to ensure very high levels of reliability during the entire year and to minimize system energy costs; and (2) the effects of loads other than the system annual coincident peak demand on our transmission planning, given the need for each transmission facility to meet the peak demand on that particular facility.

We submit that the 12 CP method that has been in place for many years in North Dakota and elsewhere should again be approved because it best meets the three Commission criteria. It is accurate, yields stable results, and is more consistent with the methods approved by other jurisdictions. In contrast, the Staff consultant has proposed the 1 CP method, which the Commission has previously found to be

inappropriate and has rejected. Accordingly, the 12 CP method should be adopted in this case.



ANN E. BULKLEY
RETURN ON EQUITY
EVIDENTIARY HEARING OPENING STATEMENT
Case No. PU-12-813

My name is Ann E. Bulkley. In my Rebuttal Testimony, I demonstrate that the range for the cost of equity for NSP's North Dakota operations is between 10.00 percent and 10.50 percent. Within that range, I conclude that a Return on Equity of 10.25 percent is reasonable, if not conservative.

The cost of equity is based on the return that investors require to make an investment, which depends on what investors can earn from comparable alternative investments. As this Commission has recognized in prior decisions, the determination of the ROE is not a simple mathematical exercise. Rather, other factors that investors would consider in establishing their return requirements should also be taken into consideration. Therefore, while I have applied well accepted ROE estimation methodologies, using widely available indicators of investors' expectations, my recommendation also takes into consideration several other factors. Those factors include: current market conditions, authorized ROEs available to investors for other vertically integrated electric companies in other jurisdictions, the Commission's history of moderation in adjusting ROEs, and the significance of the Company's extensive capital investment plan.

There is currently a great amount of uncertainty in the equity markets related to when the Federal Reserve will begin to reduce its purchases of long-term Treasury bonds. The result of that anticipated change in Federal policy has been an increase in the yields on Treasury bonds and a decline in the stock market indexes in general, and in the utility sector in particular. I believe it is important to consider this rising interest

rate environment when determining the appropriate ROE for NSP from within the range of results established using traditional ROE estimation models.

My recommended ROE of 10.25 percent is consistent with recently authorized ROE's for other vertically-integrated electric utilities. My testimony shows that ROEs available from other jurisdictions support my analysis and recommendation, and show that Mr. King's recommendation of 9.00 percent is below all but one authorized ROE for vertically-integrated electric utilities in the U.S since January 2012. That single 9.00 percent ROE that was recently authorized was reduced in a settlement context based on the particular facts of that case.

In contrast to Mr. King's 9.00 percent suggested ROE, my proposed 10.25 percent ROE is also consistent with the moderate approach demonstrated by the Commission over several recent decisions. While interest rates have declined and the Commission has reduced ROEs, those changes have been gradual and moderate. That measured approach to regulation has been noted by industry analysts as constructive regulation and is consistent with the fair return standard.

Finally, I explain the significance of the ROE to the Company's ability to continue to access capital markets on favorable terms, which will have long-run effects on the Company's cost of capital and the corresponding costs of service and rates. Awarding a very low authorized ROE sends a signal to investors that the regulatory environment in that jurisdiction is less constructive than other jurisdictions and as a result an investment in other jurisdictions with more constructive regulation would be more desirable.

I appreciate the opportunity to appear before the Commission, and I look forward to answering your questions regarding my analysis and testimony.

Thank you.



STEVE WISHART
RECOVERY OF PURCHASED POWER COSTS
EVIDENTIARY HEARING OPENING STATEMENT
Case No. PU-12-813

Commissioners, Judge Fetch and Commission Staff, good afternoon. I am Steve Wishart, Director of Resource Planning for the Company.

My testimony addresses the Company's recovery of the costs for the Prairie Rose Project as well as Staff's consultants' concerns regarding 17 other Power Purchase Agreements, or PPAs, the costs of which we currently recover through our Fuel Cost Recovery tariff. We agree with the Staff consultant's assessment that the Prairie Rose Project is prudent. And that therefore the Company should be able to recover all of its costs for the project. We also believe that continued recovery of the 17 other PPAs is appropriate. However, the PPAs that I address are not included in base rates. While we appreciate the Commission's interest in these PPAs, the issues raised by Staff should be reviewed in a separate proceeding.

We understand the Commission's concerns and, as Ms. McCarten has stated, we have committed to providing the Commission with the opportunity to fully review our resource decisions in a timely manner. I look forward to working with Commission staff on our next long term resource plan, making sure that our strategy is fully vetted with them and that the desires and concerns of North Dakota are incorporated.

In my rebuttal testimony I point out that most of the purchased power contracts identified by Dr. Pavlovic have been operating on our system for

several years and were included in the fuel cost rider in compliance with the established rules. The criticism of these contracts is based on 20/20 hindsight and does not consider all of the factors that were in place at the time the decisions were made. Such retrospective judgment does not comply with longstanding practice in North Dakota. We make our business decisions based on the best information available at the time. Many of the identified contracts were acquired at a time when natural gas was at an all time high and our assessment was that the contracts could be a cost effective way to protect our customers from the volatile natural gas market.

We do want to work with the Commission and Staff to respond to the concerns raised. If the Commission would like to review these PPAs further, the appropriate place to do so is in a separate proceeding reviewing our FCR and the PPAs we recover through it. This would also provide an opportunity for Commission review of our FCR mechanism and the information we provide so that we can ensure it meets the Commission's needs and that projects are reviewed on a prospective basis.

Fundamentally, we manage our system to serve all of our customers in our five different jurisdictions. I believe that the benefits of the integrated system far outweigh policy differences between states. NSP offers an incredibly diverse portfolio of resources that has delivered reliable power to all five states in the NSP System at a lower cost than any one state could have achieved with isolated resources of its own. We are happy to work with the Commission and their staff on a prospective basis to ensure that we meet their expectations and that the integrated system continues to benefit North Dakota ratepayers.

I appreciate opportunity to be here today and I will do my best to answer questions about these issues and any other resource planning related questions that parties may have.



ANNE E. HEUER
REVENUE REQUIREMENTS
EVIDENTIARY HEARING OPENING STATEMENT
Case No. PU-12-813

I am Manager of Revenue Analysis for Xcel Energy Services Inc. My primary role in this proceeding is to provide the Company's financial data in support of its request for a general rate increase. Our request for an increase has decreased from \$16.9 million to \$14.9 million. The decrease reflects the Company's request for a lower return on equity of 10.25 percent and adjustments to individual expenses and revenues. Those adjustments, other than the ROE, have been agreed to by Advocacy Staff Consultants.

The remaining proposed adjustments by the Staff Consultants' and the ROE remain contested. Many of the Staff Consultants' adjustments are addressed by other Company witnesses and are then reflected by me in the overall revenue requirement calculation. Some of the Staff Consultants' adjustments are addressed directly by me. Of those, I will provide comments on four contested adjustments in this Opening Statement.

Average Three-Year Historical Operating Expenses

I testified against Mr. Dante Mugrace's proposal to replace all of the 2013 Operating Expenses with a historical three year average of 2010, 2011 and 2012 expense. That proposal is inconsistent with fundamental ratemaking in several respects:

- Although the Company is allowed under North Dakota statute to use a 2013 projected test year, Mr. Mugrace eliminates any consideration of 2013 operating expenses. He provided no testimony challenging the accuracy of our projected 2013 expenses.

- Instead, Mr. Mugrace uses a three-year historical average of operating expenses which is inconsistent with his use of a 2013 sales forecast. Further, his approach is also inconsistent with the ratemaking standard that develops the test year using 12 consecutive months of revenues and expenses.
- In addition, his recommended three year average expense is lower than the operating expenses approved for the 2011 test year used to set rates in our last rate case, and the Company's earnings in 2011 were well below authorized levels.

Demand Allocator

Mr. Scott Brockett explains why a 1CP is an inappropriate demand allocator. I testify about the additional problems with the manner in which Dr. Karl Pavlovic calculated the 1CP demand allocator and the application of the 1CP allocator by Mr. Mugrace. I list five additional errors in Dr. Pavlovic's and Mr. Mugrace's analysis, each of which is contrary to fundamental ratemaking. The two most significant errors are:

- Dr. Pavlovic used 2010, 2011, and 2012 data to calculate the 1CP allocator. Consequently he does not capture the changes in relative demand for North Dakota occurring in 2013. In contrast, Dr. Pavlovic accepted the use of 2013 data for the calculation of each of our other jurisdictional allocators, which is an additional inconsistency.
- Mr. Mugrace applied the 1CP allocator to some expenses and not others, and applied the 1 CP allocator to the general expense category while accepting the full value of adjustments made by the Company. This creates yet another mismatch and inconsistency.

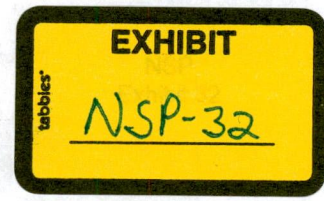
Expense Amortization

The Company proposes to amortize several test year expenses over three years. However, Mr. Mugrace reduces the revenue requirement by one-third based on his assumption that we will recover one-third of the expense through interim rates. This is inconsistent with fundamental ratemaking, which uses the final revenue requirement for the test year to calculate whether to make an interim rate refund. Under Mr. Mugrace's proposal one-third of the revenues collected under interim rates would be refunded and final rates would not recover the unrecovered costs. The net result is that we would only recover two-thirds of these legitimate expenses.

Net Plant In Service

The last item I wish to address is the calculation of net plant in service. For a 2013 test year, ratemaking fundamentals require the use of the *end of year* 2012 net plant balances as the starting point. Contrary to this principle, Mr. Mugrace uses as his starting point the *average* 2012 net plant balances. In addition, Mr. Mugrace uses a number of inconsistent approaches to arrive at his recommended 2013 net plant.

In conclusion, based on consistent application of fundamental ratemaking principles, the Company has appropriately determined the 2013 test year revenues, expenses and rate base necessary to provide service to customers in North Dakota.



MICHAEL A. PEPPIN
CLASS COST OF SERVICE
EVIDENTIARY HEARING OPENING STATEMENT
Case No. PU-12-813

I'm employed by Xcel Energy as a Principal Pricing Analyst in the Regulatory Analysis Department.

The reason for my appearance today is that I am responsible for conducting the Class Cost of Service Studies for the Company's rate cases. In general, the purpose of a Class Cost of Service Study is to take detailed costs that have been allocated to a given jurisdiction, in this case North Dakota, and then allocate those costs to each customer class using Class allocation factors. The ultimate goal that we strive for in our Class Cost of Service Study is to identify and develop Class Cost Allocation factors that most accurately reflect what caused each cost to occur. For example, the cost of electric meters is directly driven by the number of customers in each customer class along with the average cost of meters for each customer class.

In general, the methods we used in our Class Cost of Service Study were the same methods that we've used for over 20 years with some minor revisions. Those revisions are detailed on pages 2 through 4 of my Direct Testimony.

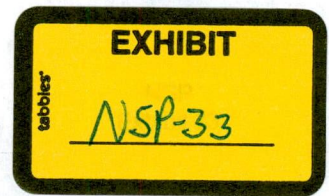
The final results of the Class Cost of Service Study are then used by Company witness Mr. Steven Huso as a guide when designing retail rates.

We believe our CCOSS is an appropriate ratemaking tool because it is theoretically sound in that it:

- Properly recognizes that our investments in baseload generation provide benefits to all customers, particularly our energy-intensive customers and, therefore, it allocates production costs as partially capacity and partially energy driven.
- Accurately reflects the value of our peaking capacity, transmission and distribution facilities.
- Recognizes the differing impact that time usage patterns can have on the cost of service

In addition to the Class Cost of Service Study, my testimony supports a rate design change to our voltage discounts to better reflect cost, and a minor wording change to one of our tariffs.

Thank you



STEVEN HUSO
RATE DESIGN
EVIDENTIARY HEARING OPENING STATEMENT
Case No. PU-12-813

I am a Pricing Consultant for the Company. My Direct Testimony supports the current revenue forecast based on sales and customers under the current rate schedules. I also recommend class revenue responsibility and a proposed rate design to recover the test year revenue requirement. I also sponsor the Company's proposed rate schedules and tariffs, including the rate design structure for a new Transmission Cost Rider.

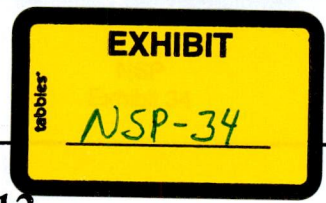
Proposed class revenues were based on the results of our jurisdictional cost study allocated to rate classes using our class cost of service study. Individual rates for the rate schedules were based on cost as developed by the class cost of service study moderated where appropriate for rate moderation and other pricing considerations. My proposed customer class revenue recommendation, along with the cost-based rate design proposals in my direct testimony were supported by Advocacy Staff Consultant Dr. Pavlovic. Dr. Pavlovic recognized the value of giving our customers reasonable and accurate price signals.

My Rebuttal Testimony responds to Dr. Pavlovic's recommendations to eliminate certain time of day rate schedules, to establish a single customer charge for Residential customers, and to simplify our rate schedules and the language used to describe our rates.

I do not support eliminating those rate options that currently have no customers, and instead recommend closing those rates. Closing the rates

without eliminating them would provide us with an opportunity to evaluate whether those rate options should be permanently closed or whether the rates should instead be maintained or modified. I do not agree the Residential TOD rate should be eliminated, but would like to work with Commission Staff to identify and address their concerns about this rate option. The Company does not object to having a single residential customer charge if it is set at an appropriate level, and I offer two alternative rates that would be reasonable. I propose working with Commission Staff to identify more specifically the concerns with our current rate structure and descriptions and to making improvements as appropriate.

Thank you and I look forward to answering your questions.



Northern+States+Power+Co.+--+MN 10-K 12/31/2012

Section 1: 10-K (NORTHERN STATES POWER COMPANY 10-K 12-31-2012)

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549**

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2012

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission file number 001-31387

NORTHERN STATES POWER COMPANY

(Exact name of registrant as specified in its charter)

Minnesota
(State or other jurisdiction of incorporation or organization)

41-1967505
(I.R.S. Employer Identification No.)

414 Nicollet Mall, Minneapolis, Minnesota 55401
(Address of principal executive offices)

Registrant's telephone number, including area code: 612-330-5500

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulations S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting

NSP-MINNESOTA AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(amounts in thousands, except share and per share data)

	Dec. 31	
	2012	2011
Assets		
Current assets		
Cash and cash equivalents	\$ 28,842	\$ 26,005
Restricted cash		95,287
Accounts receivable, net	325,143	314,577
Accounts receivable from affiliates	26,660	18,033
Accrued unbilled revenues	229,664	231,303
Inventories	260,758	301,848
Regulatory assets	156,223	141,709
Derivative instruments	56,232	51,517
Prepayments and other	94,019	45,219
Total current assets	1,177,541	1,225,498
Property, plant and equipment, net	9,546,968	8,982,834
Other assets		
Nuclear decommissioning fund and other investments	1,514,156	1,357,538
Regulatory assets	1,039,675	872,014
Derivative instruments	66,480	80,689
Other	56,438	36,638
Total other assets	2,676,749	2,346,879
Total assets	\$ 13,401,258	\$ 12,555,211
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	\$ 2	\$ 450,000
Short-term debt	221,000	26,000
Borrowings under utility money pool arrangement		65,000
Accounts payable	367,021	322,979
Accounts payable to affiliates	69,739	47,651
Taxes accrued	175,929	158,919
Accrued interest	58,135	68,362
Dividend payable to parent	58,757	58,054
Derivative instruments	20,117	65,781
Regulatory liabilities	53,159	132,574
Other	102,915	164,736
Total current liabilities	1,126,774	1,559,456
Deferred credits and other liabilities		
Deferred income taxes	1,944,910	1,666,005
Deferred investment tax credits	30,304	31,743
Asset retirement obligations	1,655,402	1,581,896
Regulatory liabilities	432,471	439,029
Pension and employee benefit obligations	422,496	413,755
Derivative instruments	174,471	184,190
Other	89,423	65,464
Total deferred credits and other liabilities	4,749,477	4,382,082
Commitments and contingencies		
Capitalization		
Long-term debt	3,488,638	2,888,897
Common stock – 5,000,000 shares authorized of \$0.01 par value; 1,000,000 shares outstanding at Dec. 31, 2012 and 2011	10	10
Additional paid-in capital	2,581,501	2,366,391
Retained earnings	1,478,057	1,372,727
Accumulated other comprehensive loss	(23,199)	(14,352)
Total common stockholder's equity	4,036,369	3,724,776
Total liabilities and equity	\$ 13,401,258	\$ 12,555,211

See Notes to Consolidated Financial Statements

Index

NSP-Minnesota Notice of Violation (NOV) — In 2011, NSP-Minnesota received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the CAA at the Sherco plant and Black Dog plant in Minnesota. The NOV alleges that various maintenance, repair and replacement projects at the plants in the mid 2000s should have required a permit under the NSR process. NSP-Minnesota believes it has acted in full compliance with the CAA and NSR process. NSP-Minnesota also believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. NSP-Minnesota disagrees with the assertions contained in the NOV and intends to vigorously defend its position. It is not known whether any costs would be incurred as a result of this NOV.

Asset Retirement Obligations

Recorded AROs — AROs have been recorded for plant related to nuclear production, steam production, wind production, electric transmission and distribution, natural gas transmission and distribution and office buildings. The steam production obligation includes asbestos, ash containment facilities, radiation sources and decommissioning. The asbestos recognition associated with the steam production includes certain plants. NSP-Minnesota also recorded asbestos recognition for its general office building. This asbestos abatement removal obligation originated in 1973 with the CAA, which applied to the demolition of buildings or removal of equipment containing asbestos that can become airborne on removal. AROs also have been recorded for NSP-Minnesota steam production related to ash-containment facilities such as bottom ash ponds, evaporation ponds and solid waste landfills. The origination dates on the ARO recognition for ash-containment facilities at steam plants was the in-service date of the various facilities. Additional AROs have been recorded for NSP-Minnesota steam production plant related to radiation sources in equipment used to monitor the flow of coal, lime and other materials through feeders. NSP-Minnesota has also recorded AROs for the retirement and removal of assets at certain wind production facilities for which the land is leased and removal is required by contract, with the origination dates being the in-service date of the various facilities.

NSP-Minnesota has recognized AROs for the retirement costs of natural gas mains and for the removal of electric transmission and distribution equipment, which consists of many small potential obligations associated with PCBs, mineral oil, storage tanks, treated poles, lithium batteries, mercury and street lighting lamps. These electric and natural gas assets have numerous in-service dates for which it is difficult to assign the obligation to a particular year. Therefore, the obligation was measured using an average service life.

For the nuclear assets, the AROs associated with the decommissioning of the NSP-Minnesota nuclear generating plants, Monticello and Prairie Island, originated with the in-service date of the facility. See Note 12 for further discussion of nuclear obligations.

A reconciliation of NSP-Minnesota's AROs is shown in the tables below for the years ended Dec. 31, 2012 and 2011, respectively:

(Thousands of Dollars)	Beginning Balance Jan. 1, 2012	Accretion	Revisions to Prior Estimates	Ending Balance Dec. 31, 2012 ^(a)
Electric plant				
Steam production asbestos	\$ 10,479	\$ 459	\$ 1,851	\$ 12,789
Steam production ash containment	30,989	1,065	15,872	47,926
Steam production radiation sources	42	3	-	45
Nuclear production decommissioning	1,482,741	75,301	(11,684)	1,546,358
Wind production	40,515	2,068	(9,647)	32,936
Natural gas plant	15,700	570	(2,432)	13,838
Gas transmission and distribution	295	18	-	313
Common and other property				
Common general plant asbestos	1,135	62	-	1,197
Total liability	\$ 1,581,896	\$ 79,546	\$ (6,040)	\$ 1,655,402

(a) There were no new ARO liabilities recognized or settled during the 12 months ended Dec. 31, 2012.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$1.5 billion as of Dec. 31, 2012, consisting of external investment funds.

In 2012, NSP-Minnesota incurred revisions for nuclear decommissioning, asbestos, ash-containment facilities, wind facilities and electric transmission and distribution AROs due to revised estimated cash flows.

Index

(Thousands of Dollars)	Beginning Balance Jan. 1, 2011	Accretion	Revisions to Prior Estimates	Ending Balance Dec. 31, 2011 ^(a)
Electric plant				
Steam production asbestos	\$ 10,041	\$ 438	\$ -	\$ 10,479
Steam production ash containment	12,814	508	17,667	30,989
Steam production radiation sources	37	3	2	42
Nuclear production decommissioning	809,474	57,641	615,626 ^(b)	1,482,741
Wind production	38,553	1,962	-	40,515
Electric transmission and distribution	3,087	153	12,460	15,700
Natural gas plant				
Gas transmission and distribution	278	17	-	295
Common and other property				
Common general plant asbestos	1,077	58	-	1,135
Total liability	<u>\$ 875,361</u>	<u>\$ 60,780</u>	<u>\$ 645,755</u>	<u>\$ 1,581,896</u>

- (a) There were no new ARO liabilities recognized or settled during the 12 months ended Dec. 31, 2011.
- (b) The increase is primarily due to the completion of NSP-Minnesota's triennial nuclear decommissioning study, which reflects an increase in the estimated cost of retirement, increase in the escalation rates for each nuclear unit and a decrease in the discount rate used to calculate the net present value of the future cash flows.

The aggregate fair value of NSP-Minnesota's legally restricted assets, for purposes of funding future nuclear decommissioning, was \$1.3 billion as of Dec. 31, 2011, including external and internal investment funds.

In 2011, NSP-Minnesota incurred revisions for nuclear decommissioning, radiation sources, ash-containment facilities and electric transmission and distribution AROs due to revised estimated cash flows.

Removal Costs — NSP-Minnesota records a regulatory liability for the plant removal costs of steam and other generation, transmission and distribution facilities. Generally, the accrual of future non-ARO removal obligations is not required. However, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long time periods over which the amounts were accrued and the changing of rates over time, NSP-Minnesota has estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Removal costs as of Dec. 31, 2012 and 2011 were \$377 million and \$382 million, respectively.

Nuclear Insurance

NSP-Minnesota's public liability for claims resulting from any nuclear incident is limited to \$12.6 billion under the Price-Anderson amendment to the Atomic Energy Act. NSP-Minnesota has secured \$375 million of coverage for its public liability exposure with a pool of insurance companies. The remaining \$12.2 billion of exposure is funded by the Secondary Financial Protection Program, available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to \$117.5 million per reactor per accident for each of its three licensed reactors, to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is \$17.5 million per reactor during any one year. These maximum assessment amounts are both subject to inflation adjustment by the NRC and state premium taxes. The NRC's last adjustment was effective April 2010.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are \$2.25 billion for each of NSP-Minnesota's two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately \$16.5 million for business interruption insurance and \$35.8 million for property damage insurance if losses exceed accumulated reserve funds.

Index

The components of regulatory liabilities shown on the consolidated balance sheets of NSP-Minnesota at Dec. 31, 2012 and 2011 are:

(Thousands of Dollars)	See Note(s)	Remaining Amortization Period	Dec. 31, 2012		Dec. 31, 2011	
			Current	Noncurrent	Current	Noncurrent
Regulatory Liabilities						
Plant removal costs	1, 11	Plant lives	\$ -	\$ 377,107	\$ -	\$ 382,089
DOE Settlement	11	One to two years	17,071	1,131	80,249	-
Deferred income tax adjustment	1, 6	Various	-	29,715	-	31,518
Conservation programs (b)	1	Less than one year	1,823	-	5,382	-
Investment tax credit deferrals	1, 6	Various	-	22,821	-	23,802
Contract valuation adjustments (a)	1, 9	Term of related contract	25,139	-	20,976	-
Deferred electric energy costs	1	Less than one year	6,424	-	10,582	-
Renewable resources and environmental initiatives	10, 11	Less than one year	256	-	4,358	-
Other		Various	2,446	1,697	11,027	1,620
Total regulatory liabilities			\$ 53,159	\$ 432,471	\$ 132,574	\$ 439,029

- (a) Includes the fair value of certain long-term purchase power agreements used to meet energy capacity requirements and valuation adjustments on natural gas commodity purchases.
- (b) Includes costs for conservation programs, as well as incentives allowed in certain jurisdictions.

At Dec. 31, 2012, approximately \$115 million of NSP-Minnesota's regulatory assets represented past expenditures not currently earning a return. This amount primarily includes Prairie Island EPU costs and recoverable purchased natural gas costs.

14. Segments and Related Information

Operating results from the regulated electric utility and regulated natural gas utility are each separately and regularly reviewed by NSP-Minnesota's chief operating decision maker. NSP-Minnesota evaluates performance based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each reportable segment.

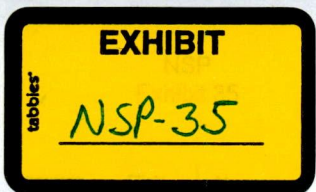
NSP-Minnesota has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- NSP-Minnesota's regulated electric utility segment generates electricity which is transmitted and distributed in Minnesota, North Dakota and South Dakota. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes NSP-Minnesota's commodity trading operations.
- NSP-Minnesota's regulated natural gas utility segment transports, stores and distributes natural gas in portions of Minnesota and North Dakota.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include appliance repair services, nonutility real estate activities and revenues associated with processing solid waste into refuse-derived fuel.

Asset and capital expenditure information is not provided for NSP-Minnesota's reportable segments because as an integrated electric and natural gas utility, NSP-Minnesota operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

To report income from continuing operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

The accounting policies of the segments are the same as those described in Note 1.



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Sat, Aug 24, 2013, 2:05pm EDT - US Markets are closed

Dow ↑0.31% Nasdaq ↑0.52%

More On ^TYX

QUOTES

Summary

Components

Options

Historical Prices

CHARTS

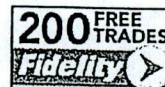
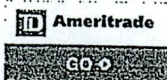
Interactive

Basic Chart

Basic Tech. Analysis

NEWS & INFO

Headlines



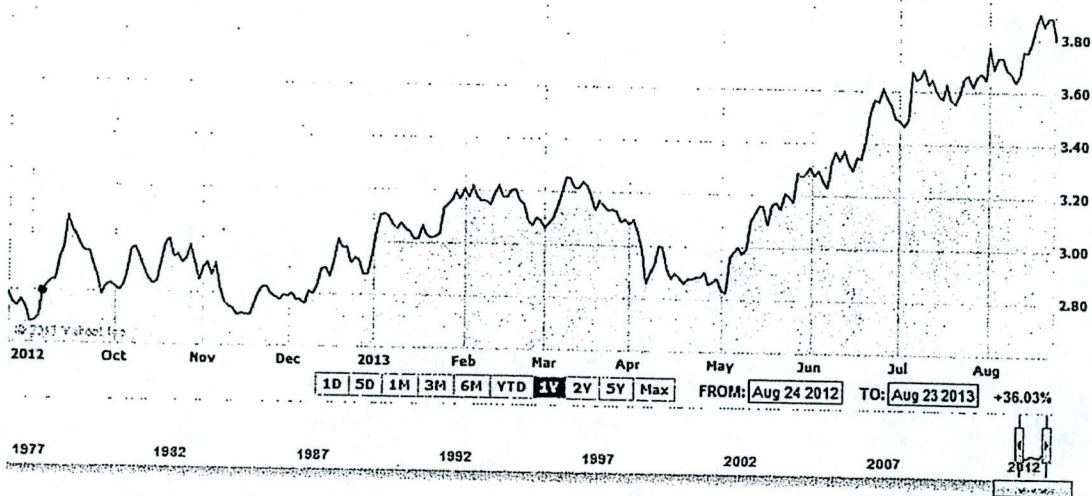
Treasury Yield 30 Years (^TYX) - Chicago Options

Add to Portfolio

3.7980 ↓0.0870 (2.24%) Aug 23

Enter name(s) or symbol(s) GET CHART COMPARE EVENTS TECHNICAL INDICATORS CHART SETTINGS RESET

Sep 6, 2012: ^TYX 2.7990



Basic Chart | Full Screen | Print | Share | Send Feedback

Treasury Yield 30 Years (^TYX) - Chicago Options

Prev Close:	3.89	Day's Range:	3.7920 - 3.8960
Open:	3.89	52wk Range:	2.66 - 3.93

Quotes delayed, except where indicated otherwise. Currency in USD.

Headlines

No Headlines available for ^TYX at this time.

Ad Topics That Might Interest You...

- | | |
|-----------------------------|---------------------------------|
| 1. Stocks to Buy Now | 5. Fixed Income Investments |
| 2. Highest Dividend Stocks | 6. Best Performing Mutual Funds |
| 3. 5 Dividend Stocks to Buy | 7. Top Rated Medicare Plans |
| 4. High Yield Stocks to Buy | 8. Best Income Mutual Funds |

Feedback



Stocks soar--but some wealthy citizens are preparing for the next collapse. Here's why...
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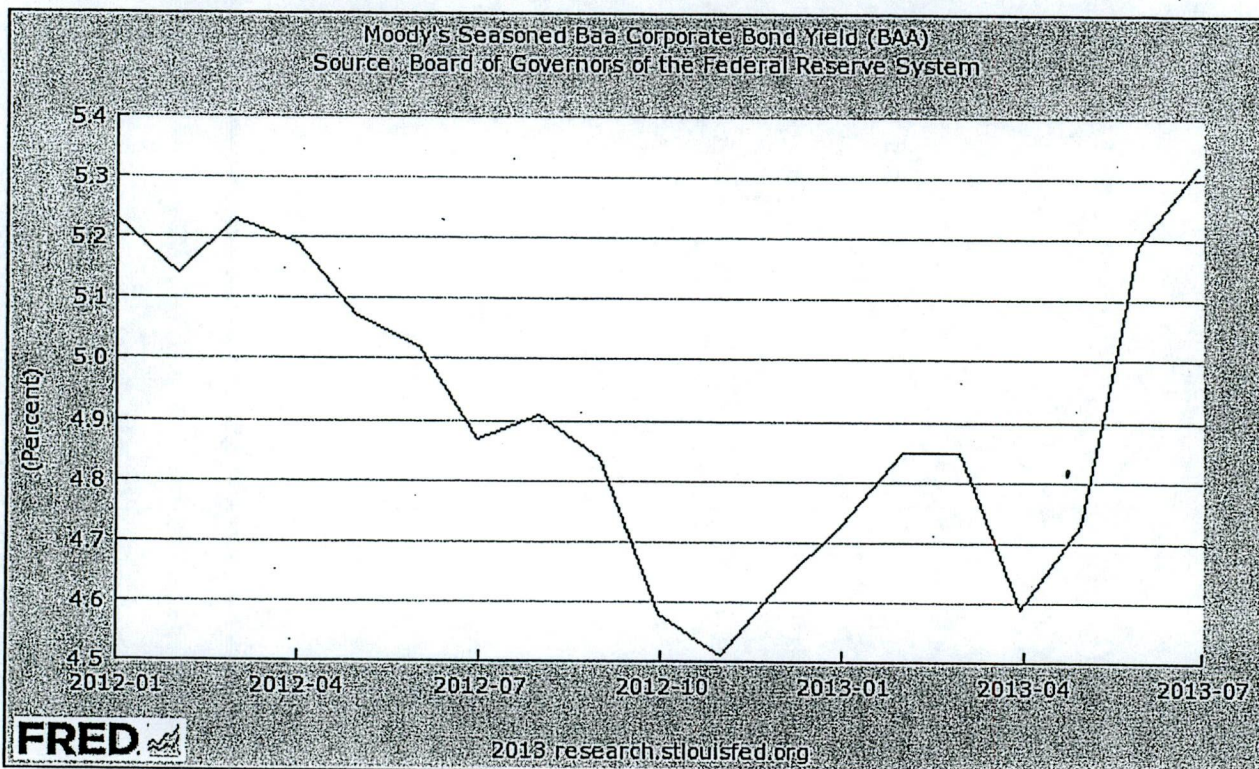


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Graph

Line 1: Moody's Seasoned Baa Corporate Bond Yield (BAA)

Scale: Line Style: Line Width: Mark Type: Mark W

Observation Date Range: to

Observation Quick Range: Custom 1yr 5yrs 10yrs Max

Frequency:

Federal Reserve Bank of St. Louis, One Federal Reserve Bank Plaza, St. Louis, MO 63102



- Non Public Document – Contains Trade Secret Data
- Public Document – Trade Secret Data Excised
- Public Document

Xcel Energy
 Docket No.: PU-12-813
 Response To: North Dakota Public Service Commission
 Requestor: Michael Diller & Sara Cardwell
 Date Received: February 26, 2013

SUPPLEMENT
 Data Request No. NDPSC-1-004

Question:
 NDCC 49-05-04.1 1. C. states that a public utility selecting a future test year must file data for the twelve consecutive months immediately preceding the future test year and that period is the “current period” for the public utility. Please provide the Commission with the date this information will be available for 2012 and update all information within the filing using this data for the current period. Compare and contrast these results to the Company’s original proposal.

Response:
 As has been customary in recent rate cases, the Company will file its annual jurisdictional financial report for 2012 on May 1, 2013. The report will be made part of the record in this rate case.

When we file our jurisdictional financial report, the Company will also provide a supplement to our filing which includes a “current period” jurisdictional Cost of Service Study for the 2012 year. This Study will be similar in format and content to Exhibit ___(AEH-1), Schedule 3.

The Company respectfully objects to the requests to “update all information within the filing” and “compare and contrast these results to the Company’s original proposal” as overly broad and unduly burdensome.

SUPPLEMENT:
 Please see Attachment A for a jurisdictional Cost of Service Study reflecting 2012 weather normalized actual results.

Witness: Anne E. Heuer
 Preparer: Charles Burdick
 Title: Principal Rate Analyst
 Department: Revenue Requirements North
 Telephone: 612-330-6646
 Date: April 11, 2013

SUPPLEMENT: May 2, 2013

ROE = 8.92%
Deficiency = \$4,285
% Increase = 2.38%
Required ROE = 10.40%

**Northern States Power Company (ND)
Electric Utility - North Dakota Retail Jurisdiction
Cost of Service Study
2012 Actual W/N**

Summary Reports

May 2, 2013

Rate Base Summary

	<u>Total Company Electric</u>			<u>ND Retail Electric</u>			<u>All Other</u>		
	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>	<u>Beginning Balance</u>	<u>Ending Balance</u>	<u>Average Balance</u>
1 Plant Investment	14,119,988	14,574,482	14,347,235	768,243	793,076	780,660	13,351,745	13,781,406	13,566,575
2 Depreciation Reserve	<u>(6,685,653)</u>	<u>(6,958,294)</u>	<u>(6,821,974)</u>	<u>(373,248)</u>	<u>(385,512)</u>	<u>(379,380)</u>	<u>(6,312,405)</u>	<u>(6,572,782)</u>	<u>(6,442,594)</u>
3 Net Utility Plant	7,434,335	7,616,188	7,525,261	394,995	407,564	401,280	7,039,340	7,208,624	7,123,981
4 C.W.I.P.	41,493	62,369	51,931	2,355	3,517	2,936	39,138	58,852	48,995
5 Accumulated Deferred Taxes	(1,582,831)	(1,768,599)	(1,675,715)	(73,790)	(85,855)	(79,822)	(1,509,041)	(1,682,744)	(1,595,893)
Other Rate Base:									
6 Cash Working Capital	0	0	0	0	0	0	0	0	0
7 Materials & Supplies	128,683	128,683	128,683	7,471	7,471	7,471	121,212	121,212	121,212
8 Fuel Inventory	90,424	90,424	90,424	5,634	5,634	5,634	84,790	84,790	84,790
9 Non-Plant Assets & Liab	(25,425)	(100,811)	(63,118)	(1,499)	(6,052)	(3,776)	(23,926)	(94,759)	(59,342)
10 Prepays & Other	62,734	95,681	79,208	3,913	5,688	4,801	58,821	89,993	74,407
11 Total Rate Base	6,149,413	6,123,935	6,136,674	339,079	337,967	338,524	5,810,334	5,785,968	5,798,150

Income Statement Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<u>Operating Revenues</u>			
1 Retail	3,106,982	180,349	2,926,633
2 CIP Adjustment to Program Costs	0	-	0
3 Interdepartmental	532	-	532
4 Other Operating	673,326	39,949	633,377
5 Gross Earnings Tax	0	-	0
6 Total Operating Revenues	3,780,840	220,298	3,560,542
<u>Expenses</u>			
Operating Expenses:			
7 Fuel & Purchased Energy	1,242,746	77,805	1,164,941
8 Power Production	727,894	42,550	685,344
9 Transmission	210,577	12,309	198,268
10 Distribution	111,134	6,387	104,747
11 Customer Accounting	53,705	4,128	49,577
12 Customer Service & Information	103,566	370	103,196
13 Sales, Econ Dvlp & Other	68	2	66
14 Administrative & General	222,349	12,969	209,380
15 Total Operating Expenses	2,672,039	156,520	2,515,519
16 Depreciation	364,429	19,869	344,560
17 Amortization	19,892	531	19,361
Taxes:			
18 Property	151,204	6,690	144,514
19 Gross Earnings	0	-	0
20 Deferred Income Tax & ITC	149,497	10,044	139,453
21 State & Federal Income (see Page 3)	0	(0)	0
22 Payroll & Other	31,462	1,866	29,596
23 Total Taxes	332,163	18,600	313,563
24 Total Expenses	3,388,523	195,520	3,193,003
25 AFUDC	0	-	0
26 Total Operating Income	392,317	24,778	367,539

Income Tax Summary

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>	
Income Before Taxes				
1	Total Operating Revenues	3,780,840	220,298	3,560,542
2	less: Total Operating Expenses	(2,672,039)	(156,520)	(2,515,519)
3	Book Depreciation & Amortization	(384,321)	(20,400)	(363,921)
4	Taxes (Other Than Current Income)	(332,163)	(18,600)	(313,563)
5	Total Before Tax Book Income	392,317	24,778	367,539
Tax Additions				
6	Book Depreciation	364,429	19,869	344,560
7	Deferred Income Taxes & ITC	149,497	10,044	139,453
8	Nuclear Fuel Burn (ex D&D)	114,221	6,574	107,647
9	Nuclear Outage Accounting	54,528	3,468	51,060
10	Avoided Tax Interest	30,012	1,728	28,284
11	Open Line	0	0	0
12	Open Line	0	0	0
13	Open Line	0	0	0
14	Open Line	0	0	0
15	Open Line	0	0	0
16	Other Book Additions	0	0	0
17	Total Tax Additions	712,687	41,683	671,004
Tax Deductions				
18	Debt Interest Expense	160,167	8,835	151,332
19	Tax Depreciation & Removal	1,024,516	62,391	962,125
20	Manufacture Production Deduction	0	0	0
21	Open	0	0	0
22	Open	0	0	0
23	Open	0	0	0
24	Other Tax/Book Timing Differences	(79,679)	(4,765)	(74,914)
25	Net Preferred Stock Deduction	0	0	0
26	Total Tax Deductions	1,105,004	66,461	1,038,543
27	State Taxable Income	0	(0)	0
28	State Income Tax Rate	9.08%	5.15%	N/A
29	State Taxes before Credits	0	(0)	0
30	State Credits	0	0	0
31	Total State Income Taxes	0	(0)	0
32	Federal Taxable Income	0	(0)	0
33	Federal Income Tax Rate	35.00%	35.00%	35.00%
34	Federal Tax before Credits	0	(0)	0
35	Federal Tax Credits	0	0	0
36	Total Federal Income Taxes	0	(0)	0
37	Total Federal & State Income Taxes	0	(0)	0

(Dollars in Thousands)

Revenue Requirement & Return Summary

	<u>Capital Structure</u>	<u>Rate</u>	<u>Ratio</u>	<u>Weighted Cost</u>	<u>Composite Income Tax Rates</u>	
1	Long Term Debt	5.7072%	45.3838%	2.5900%	State of North Dakota Tax rate	5.15%
2	Short Term Debt	0.9830%	1.8365%	0.0200%	Federal Statutory Tax rate	35.00%
3	Preferred Stock	0.0000%	0.0000%	0.0000%	Federal Effective Tax Rate (1-State Rate*Fed Rate)	33.20%
4	Common Equity	10.4000%	52.7797%	5.4900%	Total North Dakota Composite Tax Rate	38.35%
5	Required Rate of Return			8.1000%	Total Corporate Composite Tax Rate	40.90%

	<u>Total Company Electric</u>	<u>ND Retail Electric</u>	<u>All Other</u>
<u>Rate of Return (ROR)</u>			
6	Total Operating Income	392,317	24,778
7	Total Average Rate Base	6,136,674	338,524
8	ROR (Operating Income / Rate Base)	6.39%	7.32%

<u>Return on Equity (ROE)</u>			
9	Total Operating Income	392,317	24,778
10	Debt Interest (Rate Base * Weighted Debt Cost)	(160,167)	(8,835)
11	Preferred Stock (Rate Base * Weighted Preferred Cost)	0	0
12	Earnings Available for Common	232,150	15,943
13	Equity Rate Base (Rate Base * Equity Ratio)	3,238,918	178,672
14	ROE (Earnings for Common / Equity Rate Base)	7.17%	8.92%

<u>Revenue Deficiency</u>			
15	Require Operating Income (Rate Base * Required Return)	497,071	27,420
16	Operating Income	392,317	24,778
17	Operating Income Deficiency	104,753	2,642
18	Revenue Conversion Factor (1/(1-Composite Tax Rate))	1.69207	1.62201
19	Revenue Deficiency (Income Deficiency * Conversion Factor)	177,250	4,285

<u>Total Retail Revenue Requirements</u>			
20	Retail Related Revenues	3,107,514	180,349
21	Revenue Deficiency	177,250	4,285
22	Total Retail Revenue Requirements	3,284,764	184,634

23	<u>Percentage Increase (Decrease)</u>	5.70%	2.38%	5.91%
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Rate Base Detail - Cash Working Capital

Expenses	Lead Days	Total Company Electric		ND Retail Electric		All Other	
		Dollars	Dollar x Days	Dollars	Dollar x Days	Dollars	Dollar x Days
<u>Fuel Expenses</u>							
1	Coal & Rail Transport	0.00	0	0	0	0	0
2	Gas for Generation	0.00	0	0	0	0	0
3	Oil	0.00	0	0	0	0	0
4	Nuclear & EOL	0.00	0	0	0	0	0
5	Nuclear Disposal	0.00	0	0	0	0	0
6							
<u>Purchased Power</u>							
7	Purchases	0.00	0	0	0	0	0
8	Interchange	0.00	0	0	0	0	0
<u>Labor & Related Costs</u>							
9	Regular Payroll	0.00	(10,255)	0	(9)	(10,246)	0
10	Incentive Compensation	0.00	(10,255)	0	(613)	(9,642)	0
11	Pension & Benefits	0.00	0	0	0	0	0
12	Subtotal Labor & Related		(20,510)		(622)	(19,888)	0
13							
14	All Other Operating Expenses	0.00	2,692,549	0	157,142	2,535,407	0
15	Property Tax	0.00	151,204	0	6,690	144,514	0
16	Employer's Payroll Taxes	0.00	31,462	0	1,868	29,596	0
17	Gross Earnings Tax	0.00	0	0	0	0	0
18	Federal Income Tax	0.00	0	0	(0)	0	0
19	State Income Tax	0.00	0	0	(0)	0	0
20	State Sales Tax Customer Billings	0.00	0	0	0	0	0
21	Total Expenses	0.00	2,854,705	0	165,076	2,689,629	0
22	Net Annual Expense Amount		0		0	0	0
<u>Revenues</u>							
23	Computer Billing	100.00%	3,108,982	0	180,349	2,926,633	0
24	Hand Billed	0.00%	0	0	0	0	0
25	Retail Revenue Adjustments	0.00	0	0	0	0	0
26	Interdepartmental	0.00	532	0	0	532	0
27	Late Payment	0.00	4,897	0	295	4,602	0
28	Connect and Trouble Charges	0.00	2,413	0	342	2,071	0
29	CIP Incentive	0.00	0	0	0	0	0
30	Rentals	0.00	4,211	0	266	3,945	0
31	Interchange Revenues	0.00	448,668	0	26,836	422,032	0
32	Sales for Resale	0.00	79,861	0	4,922	74,939	0
33	Production Associated Revenues	0.00	5,862	0	365	5,497	0
34	MISO	0.00	10,183	0	588	9,597	0
35	Point to Point Firm	0.00	63,588	0	3,659	59,909	0
36	Services & Facilities	0.00	8,760	0	500	8,260	0
37	Ancillary	0.00	37,983	0	2,185	35,778	0
38	Distribution Associated Revenues	0.00	142	0	0	142	0
39	Other	0.00	17,229	0	655	16,574	0
40	JOA - Rev fr/to PSC	0.00	(10,631)	0	(662)	(9,969)	0
41	(blank)	0.00	0	0	0	0	0
42	(blank)	0.00	0	0	0	0	0
43	(blank)	0.00	0	0	0	0	0
44	Total Revenues	0.00	3,780,640	0	220,298	3,560,542	0
45	Net Annual Amount		0		0	0	0
46	Expense / Revenue Factor		0.7550		0.7493		
47	Allocated Revenue Amount		0		0		
48	Net Cash Working Capital		0		0		0