EXHIBIT 21

Xcel Energy®

2302 Great N. Drive
Fargo, North Dakota
58402

October 7, 2011

<u>VIA ELECTRONIC AND U.S. MAIL</u>

Darrell Nitschke, Executive Secretary
North Dakota Public Service Commission
Department 408
600 East Boulevard Avenue
Bismarck, ND 58505-0480

Re: 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 Numbers PU-10-657 and PU-11-55
AND
PETITION FOR APPROVAL OF A CUSTOMER CREDIT MECHANISM FOR A DEPARTMENT OF ENERGY SETTLEMENT PAYMENT
Case Number PU-11-557

Dear Mr. Nitschke:

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") operating in North Dakota submits the enclosed Testimony by Ms. Laura McCarten supporting the proposed Settlement Agreement filed on September 15, 2011.

In addition, during a subsequent review of the Settlement Agreement by the Company, a non-substantive typo was discovered on page 10 and Table 2 of the Settlement Agreement. The correct subtotal of net refund adjustments shown in the table is $3,806,000, rather than $3,842,000.[1] Correcting this error is not a substantive change to the Settlement Agreement as none of the inputs to the refund calculation have changed and the total estimated customer refund of $6,971,000 shown in the table is correct.

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[1] $3,806,000 is the sum of the Minot Flood O&M ($862,000) and the DOE Settlement Proceeds $4,668,000.

We apologize for this inadvertent error. A corrected version of the Settlement Agreement will be presented for inclusion in the record at the October 18, 2011 hearing on the Settlement Agreement.

Please contact me with any questions at dave.sederquist@xcelenergy.com or . 701-241-8632.

Very truly yours,

David Sederquist
Sr. Regulatory Consultant

Encls.

cc: Service List
Michael Diller

Supporting Testimony and Schedule
Laura McCarten

Before the North Dakota Public Service Commission
State of North Dakota

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 Nos. PU-10-657 and PU-11-55

and

In the Matter of the Petition of Northern States Power Company, a Minnesota corporation For Approval of a Customer Credit Mechanism for a Department of Energy Settlement Payment along with Deferred Accounting and Rule Variance, as Necessary.

Case No. PU-11-557

Exhibit___(LM-2)

Testimony Supporting
The Settlement Agreement

October 7, 2011

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Laura McCarten. I am Regional Vice President for Northern States Power Company, a Minnesota corporation ("NSPM," "Xcel Energy" or "the Company") with electric and natural gas operations in North Dakota. My business address is 414 Nicollet Mall, Minneapolis, MN 55401.

Q. HAVE YOU PREVIOUSLY FILED DIRECT TESTIMONY AND SCHEDULES IN THIS PROCEEDING?

A. Yes, I have. I sponsored testimony providing: an overview of our rate case filing; the key factors driving the request; the relevance of our 2008 Rate Case Settlement to this case; and our proposals for cost recovery.

Q. WHAT IS THE PURPOSE OF THIS CURRENT TESTIMONY AND SCHEDULE?

A. The Company and the North Dakota Public Service Commission Advocacy Staff have reached a Settlement Agreement that resolves all issues in this rate case. The Settlement Agreement was filed with the North Dakota Public Service Commission on September 15, 2011. The purpose of this Testimony is to support the Settlement Agreement and explain why its approval is in the public interest.

In addition, I will provide factual support for the: (i) recovery of incremental operating and maintenance ("O&M") costs and capital investment costs incurred by the Company in responding to the 2011 Summer flood in our Minot, ND service area; (ii) Reliability Improvement commitments contained in the

Settlement Agreement; (iii) need for and reasonableness of the 2012 Revenue Adjustment; and (iv) proposed treatment of the Department of Energy ("DOE") Settlement proceeds.

II. THE SETTLEMENT AGREEMENT IS IN THE PUBLIC INTEREST

Q. WHY IS THE SETTLEMENT AGREEMENT IN THE PUBLIC INTEREST?

A. There are seven aspects of the Settlement Agreement that collectively make it in the public interest: (1) it provides a reasonable increase in revenues, covering our cost of providing service, including an adequate return on equity ("ROE"); (2) it avoids the need for a 2012 test year rate case; (3) it is based on the exhaustive review and proposed adjustments made by Advocacy Staff witnesses; (4) it provides a timely and efficient recovery mechanism for the costs incurred by the Company in response to the recent Minot Flood; (5) it provides for reasonable investments and changes in operations that are expected to improve reliability; (6) it provides for a speedy and efficient crediting to customers of current DOE Settlement proceeds; and (7) it employs a rate design that recovers the revenue requirement on a cost-causative basis.

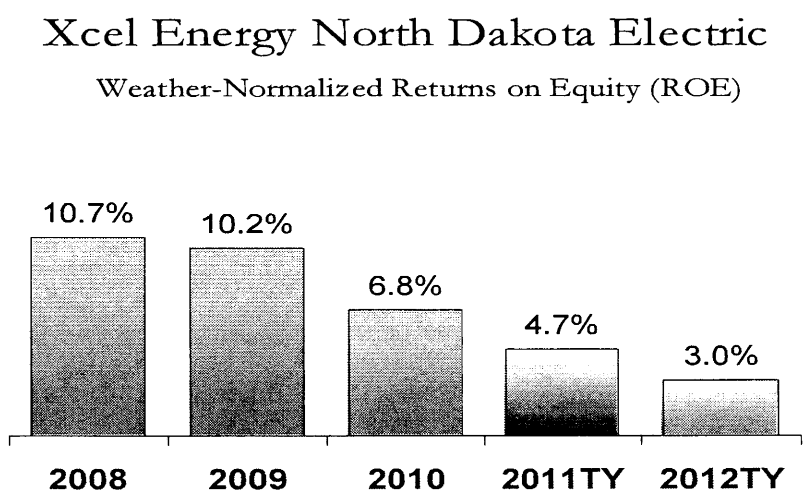
A. The Need for Additional Revenues

Q. PLEASE DESCRIBE THE COMPANY'S EARNINGS IN THE ABSENCE OF THE SETTLEMENT AGREEMENT?

A. The Company's previous general electric rate increase application was filed in December 2007 (Case No. PU-07-776). In 2010, Xcel Energy's earnings from its electric operations in North Dakota were substantially below the authorized ROE of 10.75 percent, as shown in the weather-normalized returns provided in

Figure 1 below. Projected ROEs for the 2011 and 2012 test years, absent rate relief, are 4.7 percent and 3.0 percent, respectively.

Figure 1



The increase in revenues provided under the Settlement Agreement is necessary to provide the Company with a reasonable opportunity to earn a fair rate of return while still keeping residential rates among the lowest in the region and much lower than the national average. Moreover, even with the increase contemplated in this Settlement Agreement, the Company's North Dakota rates will have increased, on average, about 2.2 percent per year over the past twenty years, which is below the average 2.4 percent annual rate of inflation during the same period.[1]

B. Avoiding a 2012 Test Year Rate Case

Q. WHAT PROVISIONS IN THE SETTLEMENT AGREEMENT MAKE IT POSSIBLE TO AVOID THE NEED FOR A 2012 TEST YEAR RATE CASE?

[1] Source: U. S. Dept. of Labor (Consumer Price Index).

A. First, as noted in Figure 1, our earnings in 2012 are projected to be even lower than earnings in 2011. The projected lower earnings in 2012 are based upon additional investment-related costs and recent information showing lower sales growth than expected. There are two provisions in the Settlement Agreement that address this problem: (1) the 2012 step increase of $1,995,000; and (2) the 2012 Sales True-up Adjustment.

Q. PLEASE FURTHER DESCRIBE THE 2012 STEP INCREASE.

A. The 2012 step increase allows the Company to recover its 2012 costs associated with certain capital projects that will be completed during the 2011 test year. Consequently, the full annualized impact of those projects on the cost of service does not occur until 2012. The capital projects at issue include: (1) the Monticello life cycle management\extended power uprate; (2) 2011 transmission investments; and (3) the 2012 nuclear outage amortization (this particular component of the 2012 step recovers costs incurred in 2010, 2011 and 2012). Ms Anne Heuer will be available to answer specific questions concerning the 2012 step increase at the October 18, 2011 hearing on the Settlement Agreement.

Q. PLEASE FURTHER DESCRIBE THE 2012 SALES TRUE UP ADJUSTMENT.

A. The second component of the Settlement Agreement that avoids the need for a 2012 test year rate case is the 2012 Sales True-up Adjustment. But for the Settlement Agreement, the Company's Rebuttal Testimony would have proposed recovery of an additional $1.2 million in lost electric retail revenue based on actual weather normalized sales during the 2011 test year. That adjustment would have been supported by replacing the first seven months of forecasted 2011 sales with seven months of actual weather normalized sales data (January through July 2011). The Settlement Agreement does not include a 2011 sales adjustment for this difference, but it does provide an opportunity for the Company to reflect any change in retail non-fuel revenues from the 2012 sales forecast, either increases or decreases. More specifically, the Settlement Agreement provides for an increase or decrease in weather normalized retail non-fuel revenues actually experienced in 2012 so as to match the 2012 forecast of retail non-fuel revenues of ~~$119,524,000~~ $119,410,000 resulting from the Settlement Agreement.[2]

While it is not possible to predict when economic and flood-impacted conditions will improve to the point that electric retail sales will return to normal levels, it is doubtful that a full recovery will occur in the near future. Therefore, due to the difficulty in forecasting retail revenues at this time, a retail revenue true-up will occur for the year ending 2012. Given the current trend in electric retail sales, the true-up is more likely to result in a customer surcharge rather than a bill credit. However, in either circumstance, the Company will collect no more and no less than its projected retail base revenues ~~$119,524,000~~ $119,410,000 for 2012, excluding the effects of weather. The Sales True-up Adjustment will be made through a one-time bill charge or refund. Refunds or charges will be determined on a per customer basis using the ratio of each customer's billed 2012 retail base revenues to the total 2012 billed retail base revenues, applied to the total amount of the true-up.

The Company will make a compliance filing by March 31, 2013 providing a comparison of weather-normalized retail non-fuel revenues to the Settlement

[2] Steven Huso Direct Testimony Exhibit___(SVH-1), Schedule 3, 2012 test year Base Revenues of $103,818,000 plus increased revenues resulting from this Settlement of ~~$15,706,000.~~ $15,592,000 (which does not include increases in non-retail operating revenues of $114,000).

Agreement 2012 projected retail non-fuel revenues of $119,524,000 and include supporting schedules calculating the customer bill impacts. The Company will use the same weather-normalization methodology used in this current rate case.

Ms Jannell Marks will be available to answer questions concerning sales forecasts and trends at the October 18, 2011 hearing on the Settlement Agreement. Additionally, Mr. John Felling will be available to answer Commission questions on the mechanics of the 2012 Sales True-up Adjustment.

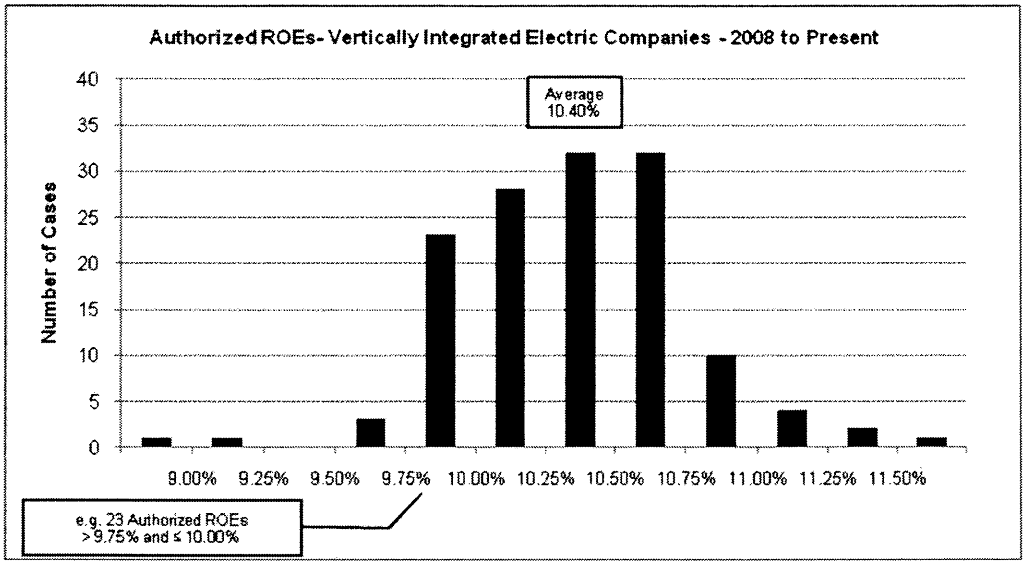
C. The Revenue Requirement is Reasonable

Q. WHY DO YOU BELIEVE THE RETURN ON EQUITY ("ROE") OF 10.4 PERCENT IS REASONABLE?

A. The Company requested an ROE of 11.25 percent. While we would have continued to advocate for a higher ROE than 10.4 percent in the absence of this Settlement Agreement, we believe a 10.4 percent ROE is reasonable in the context of a settlement for several reasons. First, a 10.4 percent ROE is at the midpoint between the Company's requested filed ROE and the ROE recommended by Advocacy Staff witness Mr. S. Keith Berry.

Second, as shown on Figure 2, the 10.4 percent ROE is at the middle of the range of ROE's awarded since 2008 for utilities like the Company that own generation assets. The Commission should note that 10.4 percent is 35 basis points lower than the 10.75 percent ROE awarded to the Company in the 2008 rate case, and recently awarded to Montana Dakota Utilities in the Commission's June 8, 2011 Order in Case No PU-10-124.

Figure 2



Finally, Figure 2 demonstrates that Mr. Berry's recommended range of 9.3 to 10.3 percent and his recommended 9.55 percent ROE is significantly below the range of almost all other awards during the last three years, including those awards made by the Commission.

In the absence of a settlement, Ms. Anne Bulkley was prepared to file Rebuttal Testimony on behalf of the Company refuting Mr. Berry's recommendations because:

- historical data was used, unlike the market, which bases investments on expected results;
- there was no consideration given to the Company's higher risk associated with its higher investments in generation and transmission;
- flotation costs were not included.

Ms. Bulkley will be available to answer questions concerning the ROE during the October 18, 2011 hearing on the Settlement Agreement.

Q. PLEASE DISCUSS THE MONTICELLO LIFE CYCLE MANAGEMENT AND EXTENDED POWER UPRATE PROJECT ADJUSTMENT.

A. If there had been no settlement, the Company would have included in its Rebuttal Testimony an adjustment reducing its requested revenue increase. The need for this adjustment was not known until after Advocacy Staff filed its Direct Testimony and, therefore, the adjustment is not reflected in their recommendations. For purposes of determining the overall revenue requirement and base rates, the Parties agree to reduce the 2011 test year revenue requirement and 2012 step increase to reflect the change in the Monticello life cycle management and extended power uprate project ("Monticello LCM/EPU").

The Monticello LCM/EPU project has been delayed due to: (1) problems in obtaining data from a vendor needed to complete a safety study required by the NRC as a condition of obtaining the amended license for the power uprate; and (2) the failure of a vendor's equipment to meet operating requirements. As a result, the amended license and completion of the Monticello LCM/EPU project are anticipated to occur in the Fall of 2012. This change in schedule reduces the 2011 test year revenue requirement by $480,000 and the 2012 step increase by $897,000. Mr. Dennis Koehl will be available to answer questions concerning the Monticello LCM/EPU project; and Mr. Felling will be available to discuss the resulting change in the revenue requirement during the October 18, 2011 hearing on the Settlement Agreement.

Q. ARE THERE ANY OTHER SIGNIFICANT REVENUE REQUIREMENT ADJUSTMENTS INCLUDED IN THIS SETTLEMENT AGREEMENT?

A. Yes. For purposes of determining the overall revenue requirement and base rates, the Settlement Agreement includes an additional adjustment that reduces the 2011 requested increase by $1,629,000. This additional adjustment incorporates approximately 85 percent of the amount of non-ROE adjustments recommended by Advocacy Staff witness Mr. Michael McGarry.

Q. WHY SHOULD THE COMMISSION ACCEPT THIS "ADDITIONAL ADJUSTMENT"?

A. The additional adjustment is based on Advocacy Staff's exhaustive review of the Company's financial information and inquiry into all material cost changes and cost allocations. It also results in a revenue requirement that favors our customers. But for this Settlement Agreement, the Company would have challenged a significant number of these non-ROE adjustments. Mr. Felling will be available to answer questions concerning the Advocacy Staff proposed financial adjustments at the October 18, 2011 hearing on the Settlement Agreement.

D. The Recovery of Minot Flood Costs

Q. THE SETTLEMENT AGREEMENT ALLOWS THE COMPANY TO RECOVER ITS COSTS OF RESPONDING TO THE SUMMER 2011 MINOT FLOOD. PLEASE DESCRIBE THE COMPANY'S EFFORTS TO MAINTAIN AND RESTORE SERVICE TO THE MINOT AREA.

A. We put forth a massive effort during the flood to maintain power so that critical city facilities and homes unaffected by flood waters would still have electrical service. From June 21 through the end of September, Xcel Energy mobilized and temporarily relocated 34 additional employees from eastern North Dakota, Minnesota and South Dakota to assist Minot-area employees in maintaining the

Company's system during the flood and reconnecting damaged services afterwards.

Xcel Energy was successful in keeping nearly all of its electrical system energized throughout the flood event. In particular, there was a need to maintain electric service to critical city infrastructure and maintain electrical service to areas that were not directly affected by the flood. However, a 25-mile feeder line that was responsible for serving western Minot and nearby Burlington, N.D. was directly flooded and unable to be used. In order to deliver reliable electric service to these areas, Xcel Energy constructed a tie line from a separate feeder line. The tie line was a three-day project, consisting of a seven pole, overhead 3-phase extension and 1,900 feet of high voltage underground feeder line.

While the Company was able to maintain electric service, due to the rapid influx of water and lack of time, it was not feasible to safely disconnect services within the mandatory evacuation areas nor remove or safeguard equipment on our electrical system in these areas prior to the arrival of damaging floodwaters.

Q. PLEASE DESCRIBE THE FLOOD DAMAGE TO THE COMPANY'S ELECTRICAL SYSTEM.

A. Our estimates of the flood damage include approximately 4,635 damaged electric meters, and 158 damaged transformers, some which were immersed in water for weeks. In addition, the Company's service center at 300 16^{th} St. SW in Minot was completely flooded, with water reaching about six and one-half feet high inside the building. However, the projected costs of refurbishing the service center have not been finalized yet and, therefore, are not included in this Settlement Agreement.

Q. WHAT WORK DID THE COMPANY PERFORM FOLLOWING THE FLOOD?

A After the water receded, Xcel Energy employees worked to de-energize the electrical system in flooded areas, removing meters one at a time. Once an electrical inspector determined a home or business could accept service safely, the Company re-energized the electrical services. The work performed by the Company included: (1) installing more than 1,300 temporary services; (2) restoring over 1,900 new and permanent services; and (3) replacing 158 transformers and cleaning a number of other transformers.

Q. PLEASE DESCRIBE THE COMPANY'S EFFORTS TO COMMUNICATE WITH CUSTOMERS DURING THE MINOT FLOODING.

A. The Company's communication efforts focused on ensuring public and employee safety. We communicated with our customers through news conferences, news releases and interviews with various media outlets. The Company worked with community leaders to develop public safety plans. Additionally, Xcel Energy used social media to provide flood updates and quick safety tips all through the flooding.

Throughout these weeks, Xcel Energy employees worked in the neighborhoods and answering customers' questions. Xcel Energy also extended the hours of its Builders' Call Line so that we could be accessible to electricians and inspectors during the reconnection process.

Q. IS THE RESTORATION WORK COMPLETE?

A. No. We estimate that work will continue through the rest of this calendar year with the majority of concentrated customer reconnect and temporary service connection activities completed by early October.

Q. THE SETTLEMENT AGREEMENT IDENTIFIES $862,000 IN INCREMENTAL OPERATING AND MAINTENANCE ("O&M") EXPENSE RELATED TO THE MINOT FLOOD RESTORATION EFFORTS. WHAT COSTS ARE INCLUDED IN THAT AMOUNT?

A. The incremental O&M costs are for additional labor, materials and other miscellaneous costs directly related to the Minot Flood restoration effort and are in addition to the normal O&M costs reflected in our 2011 test year revenue requirement. In particular, these costs reflect the additional labor, materials and other costs associated with: (1) overtime pay for our North Dakota-based employees (also referred to as "Local Resources"); and (2) Company employees temporarily relocated into North Dakota (also referred to as "non-ND-based Company employees") to assist with restoration efforts. Exhibit___(LM-2), Schedule 1 to my testimony provides a breakdown of how the $862,380 was calculated and demonstrates that all but a small portion of the $862,380 has been spent.

Q. HOW WAS THE LABOR COMPONENT OF THE INCREMENTAL $862,000 O&M EXPENSE DETERMINED?

A. The incremental labor costs reflect: (1) overtime work performed by North Dakota-based employees specifically related to Minot flood restoration efforts (no regular time wages or non-flood related labor costs are included); and (2) non-ND-based Company employees' regular time and overtime wages specifically related to Minot flood restoration efforts. For the labor component, we accounted for the type of work, as well as the type of workers who performed that work, in order to maintain and restore electric service. Those laborers included: (1) linemen; (2) designers; and (3) field meter technicians. We then calculated the amount of hours actually worked by these laborers for restoration efforts and estimated the number of hours needed to complete the restoration. We then multiplied the number of hours by the average hourly wage rate for each respective employee classification. Exhibit___(LM-2), Schedule 1, page 2 provides a breakdown of how the labor costs were calculated. As noted on Exhibit___(LM-2), Schedule 1, page 1, the total overtime labor costs of Local Resources was $229,450; and $444,217 was for the straight time, overtime, and transportation costs for non-ND-based Company employees.

Q. PLEASE EXPLAIN THE TYPES OF MATERIALS USED IN THE RESTORATION EFFORTS.

A. Exhibit___(LM-2), Schedule 1, page 2, provides weekly amounts for most of the material expense (excluding transformers and meters), which related to the work performed by Company linemen. The type of material required for the restoration work was:

- wire/conductor;
- splices;
- connectors;
- lightning arrestors;
- cutout fuses;
- poles;
- cross-arms; and
- miscellaneous associated pole hardware items.

The majority of the materials listed above were used by our linemen for running new service wire to homes and businesses affected by the flood. These costs were categorized as capital or O&M expenses in accordance with our Corporate Capitalization Policy.

Q. PLEASE DESCRIBE THE $32,900 IN MISCELLANEOUS COSTS.

A. As I noted earlier, numerous Company employees were brought in to North Dakota from out of state. The $32,900 relates to necessary employee expenses for the non-Minot North Dakota-based Company employees, such as lodging and meal expenses.

Q. IN ADDITION TO RECOVERING THE O&M EXPENSES THROUGH AN OFFSET TO THE INTERIM RATE REFUND, THE SETTLEMENT AGREEMENT ALSO ALLOWS RECOVERY OF CAPITAL INVESTMENT-RELATED COSTS ASSOCIATED WITH THE RESTORATION. PLEASE DESCRIBE THOSE CAPITAL COSTS.

A. Capital expenditures incurred as a result of the Minot flood were primarily for the replacement of meters and transformers. In particular, 158 transformers and 4,635 meters will be replaced as a part of the restoration efforts. In addition, as shown in Exhibit___(LM-2), Schedule 1, page 1, the Company estimates that approximately 10 percent of the total Distribution Operations costs related to restoration will be accounted for as capital expenditures (as opposed to O&M). This 10 percent portion amounts to $152,317. All three Distribution capital components (meters, transformers, and the 10 percent of Distribution Operations) add up to a little over $1.1 million.[3] As per standard utility

[3] $1,129,937 is the sum of Distribution Operations, $152,317; Transformers, $481,276; and Meters, $496,345.

accounting, the labor associated with repairing capital equipment is considered a capital cost.

E. The Reliability Provisions

Q. PLEASE DESCRIBE THE INITIATIVES AGREED TO BY THE PARTIES IN THE SETTLEMENT AGREEMENT TO IMPROVE THE RELIABILITY OF THE COMPANY'S ELECTRIC SYSTEM IN NORTH DAKOTA.

A. As described in the Settlement Agreement, the Company will implement three programs to address concerns expressed by the Commission earlier this year regarding Xcel Energy's distribution system reliability. First, during the first quarter of 2012, we will begin installing 25 "Intelliteam" automated switches in our Fargo, ND service area to reduce outage restoration times for customers impacted by feeder-level outages. Second, beginning in 2012 we will also increase our annual North Dakota vegetation management budget by approximately 25 percent to help ensure we are able to combat unusually rapid growing conditions and attain a four-year pruning cycle. Finally, we will provide $50 credits to customers who experience six or more sustained (5 minutes or longer) interruptions in a calendar year (excluding those caused by storms or public damage).

Q. PLEASE ELABORATE ON THESE INITIATIVES.

A. The Intelliteam switches will cover about 80 percent of the load in Fargo, including critical loads such as hospitals, the airport, and water treatment facilities, to name a few. In a feeder-level outage, these switches have the capability to automatically isolate a faulted section of a circuit and restore power to the unfaulted sections. Typically, about half of the customers being served by an Intelliteam-protected feeder will be restored within 45 seconds. In contrast, it would be necessary to mobilize a District Representative to drive the line searching for the fault. Once found, the District Representative would repair, or isolate the fault and call in a repair crew. This would materially increase the outage time. If the Intelliteam switches had been installed in 2009, we estimate the customer outage minutes for 2010 would have been reduced by approximately 1.2 million customer minutes or 32 percent. Outage information to date for 2011 supports a conclusion that the customer minute reductions realized for 2011 would have been about 12 percent. Because these switches only impact feeder level outages, the improvements realized will depend on the number of feeder level outage events experienced in a year.

Xcel Energy has successfully used this technology on its system in other states. We estimate the cost to install 25 switches will be approximately $2.5 million, and we expect to have them in service by mid-2012.

The Company will increase its 2012 vegetation management (e.g. tree pruning) operating expense budget by $212,000, which is approximately 25 percent more than current budget levels. This will permit us to increase our North Dakota vegetation management resources from 4 to 5 crews which will allow the Company to shorten its pruning cycle in North Dakota from the current 4.5 years to 4 years. The additional resources will also facilitate mid-cycle check-ups on higher growth or problematic areas of Xcel Energy's North Dakota system. This effort also addresses the high tree growth rates in recent years caused by excess moisture in the region.

Also, beginning January 1, 2012, Xcel Energy will implement a service quality program in North Dakota for customers experiencing multiple service interruptions. The program will, on an annual basis, provide $50 bill credits for customers who experience at least 6 sustained (5 minutes or longer) interruptions during the previous calendar year that are not caused by storms or public damage to our system. The credits will be awarded as a one-time bill credit after the data has been finalized, queried, and reviewed following the calendar year in question. The first bill credits will be issued early in 2013 to qualifying customers for interruptions occurring during the 2012 calendar year. We plan to provide a summary report each year to the Commission showing the number of customers impacted and the total credits paid under this program.

Q. HOW MUCH OF AN IMPACT WILL THESE INITIATIVES HAVE ON RELIABILITY IN NORTH DAKOTA IN 2012?

A. It is difficult to quantify with precision the improvements that will occur for any given year. However, as previously stated, we know from experience that during feeder-level outages, Intelliteam switches typically restore service to about half of the impacted customers in a matter of seconds rather than hours. This will significantly improve our overall CAIDI (Customer Average Interruption Duration Index) performance since the total minutes of outage time will be reduced. Enhancing our vegetation management efforts may not bring immediate results, but tree and branch interference with our system is one of our top causes of outages -- particularly during windy, snowy, and icy conditions. Therefore, we expect that the four-year pruning cycle, coupled with mid-cycle checks for rapid growth and of trouble areas, will produce reductions in vegetation-related outages.

Q. WHY IS THE PROVISION OF CUSTOMER CREDITS FOR MULTIPLE OUTAGES A PART OF THE COMPANY'S RELIABILITY ENHANCEMENT PLAN?

A. Reliability-based customer credits have two purposes. First, they send a clear signal to our customers that we are serious about providing safe, reliable electric service. If we fail to deliver we will acknowledge that with a bill discount. Second, the additional customer-focus will assist us to identify pockets of our system that may be experiencing extraordinary outage activity and find ways to resolve those issues in a timely manner.

Q. WHY IS INCLUDING THE RELIABILITY PLANS AS PART OF THIS SETTLEMENT AGREEMENT A GOOD IDEA?

A. We have been working collaboratively with Staff to address their questions and concerns about our reliability management plans and processes. After we identified and recommended to Staff specific reliability actions that we considered the most cost-effective and likely to improve customer satisfaction with our reliability, we still had the challenge of how to obtain cost recovery in a timely manner. The timing of this rate case and settlement discussions provided an excellent opportunity to include the costs of these initiatives in the Settlement Agreement and to begin implementing these programs right away in 2012.

F. The DOE Settlement Proceeds

Q. PLEASE DISCUSS THE TREATMENT OF THE DOE SETTLEMENT PROCEEDS IN THE SETTLEMENT AGREEMENT?

A. The Settlement Agreement uses the DOE Settlement proceeds to moderate the impact of the rate increase in 2011. The Settlement Agreement provides an efficient mechanism for crediting to customers $4,668,000 in DOE settlement payments, net of legal costs, for damages caused by the DOE's failure to take spent nuclear fuel during the period from 1998 to 2008. Rather than include the DOE Settlement credit as a one-time offset to the Company's 2011 revenue requirement and thereby affect base rates (which would complicate crediting the appropriate amount to customers over time), the Settlement Agreement proposes to simply add this customer credit to the existing 2011 interim rate refund. This will flow the DOE Settlement proceeds to customers through a one-time bill credit along with the 2011 interim rate refund, with no effect on base rates now or in the future. This provision also resolves the Company's DOE Settlement petition in Case No. PU-11-557, currently pending before the Commission. Thus, this is a timely and efficient crediting mechanism.

Q. HOW WILL FUTURE DOE SETTLEMENT PROCEEDS BE HANDLED?

A. The Settlement Agreement does not address the treatment of future DOE Settlement Proceeds. The Company expects to receive two additional payments in 2012 (one in the Spring and another in December), one payment in December of 2013, and another in 2014. At the time we receive the next DOE Settlement payment, the Company will renew its request for Commission approval of a refund mechanism, such as a one-time bill credit, an adjustment to the Fuel Cost Charge, or perhaps deferral to our next rate case to mitigate the rate impact in that case.

G. Rate Design

Q. PLEASE DESCRIBE THE PROPOSED RATE DESIGN.

A. The Parties agree to a revenue apportionment reflecting base rate percentage changes by customer class that are consistent with the Company's originally proposed class revenue allocation, as shown on Attachment C. The Settlement Agreement apportionment of the 2011 revenue requirement and 2012 Step increase among customer classes for the January 1, 2012 rate change is as follows:

1. Residential service: $5,729,000 or 8.7 percent;
2. Commercial (non-demand metered) service: $806,000 or 7.3 percent; and
3. Commercial (demand metered) service: $9,055,000 or 10.6 percent.

Q. HOW ARE THE OTHER TARIFF AND RATE DESIGN ISSUES RESOLVED IN THE SETTLEMENT AGREEMENT?

A. The Settlement Agreement rate design is generally unchanged from the Company's present rate design. The tariff changes proposed by the Company in its initial filing will be implemented as amended to reflect the change in revenue requirement contained in the Settlement Agreement. It should be noted that the Settlement Agreement maintains the Company's original proposal that there be no increase to the monthly fixed customer charges. Mr. Peppin and Mr. Huso will be available to answer Commission questions concerning rate design at the October 18, 2011 hearing on the Settlement Agreement.

III. CONCLUSION AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSION.

A. The Settlement Agreement is in the public interest for all of the reasons set forth in the Settlement Agreement and in my Testimony. We look forward to addressing the Commission's questions concerning the Settlement Agreement on October 18th. In addition to the Company witnesses I named above, all

Company witnesses that prefiled Direct Testimony in this proceeding will be available for questions during the hearing.

Q. DOES THIS CONCLUDE YOUR TESTIMONY IN SUPPORT OF THE SETTLEMENT AGREEMENT?

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 Nos. PU-10-657, PU-11-55, and PU-11-557

AFFIDAVIT OF
Laura McCarten

I, the undersigned, being duly sworn, depose and say that the foregoing is the Settlement Testimony of the undersigned, and that such Settlement 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

Laura McCarten

Subscribed and sworn to before me, this 5th day of October, 2011.

Anne Johnson

Notary Public

ANNE R. JOHNSON
Notary Public
State of Minnesota
My Commission Expires January 31, 2012

	TOTAL 2011 MINOT FLOOD COST IMPACT						
		Total Estimated Cost					
	Cost Area	Capital		O&M		Total	
	Distribution Operations	**$**	**152,317**	**$**	**1,370,850**	**$**	**1,523,166**
	Transformers	$	481,276	$	-	**$**	**481,276**
	First-Set Credits	$	-	$	(129,867)	**$**	**(129,867)**
	Meters	$	496,345	$	-	**$**	**496,345**
	First-Set Credits	$	-	$	(207,379)	**$**	**(207,379)**
	Sub-Total Distribution	**$**	**1,129,937**	**$**	**1,033,603**	**$**	**2,163,540**
	Facilities	$	3,351,351	$	347,553	**$**	**3,698,904**
	Estimated Insurance	$	(852,447)	$	(347,553)	**$**	**(1,200,000)**
	Net Facilities	$	2,498,904	$	-	**$**	**2,498,904**
1	**Grand Totals**	**$**	**3,628,841**	**$**	**1,033,603**	**$**	**4,662,444**

	Local Resource Breakdown - Distribution Operations Portion						
		Capital		O&M		Total	
2	Reg Labor	$	11,919	$	107,267	$	119,186
3	Labor Loads	$	3,251			$	3,251
4	Overtime	$	25,494	$	229,450	$	254,945
5	Material	$	17,313	$	155,813	$	173,125
6	Transportation	$	7,106	$	63,956	$	71,062
7	Misc.	$	3,656	$	32,900	$	36,556
8	**Total Local Resources**	**$**	**68,739**	**$**	**589,386**	**$**	**658,125**

9	**Grand Total less Local Resources:** Lines 1-8	$	3,560,103	$	444,217	**$**	**4,004,320**

Net Increment to ND Test Yr: Lines 4+5+7+9	**$**	**3,606,565**	**$**	**862,380**	**$**	**4,468,945**

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Lineman

Week	Reg Hrs	OT Hrs	Units	T&E Spend	Material	Total Spend	
30-May	142	105		$ 14,695.85	$ 798.00	$ 15,493.85	
6-Jun	5	0		$ 295.94	$ -	$ 295.94	
13-Jun	0	0		$ -	$ -	$ -	
20-Jun	509	769		$ 76,374.74	$ 17,536.00	$ 93,910.74	
27-Jun	706	781		$ 88,816.89	$ 26,974.00	$ 115,790.89	
4-Jul	418	668		$ 64,926.24	$ 5,669.00	$ 70,595.24	
11-Jul	503	668		$ 69,927.12	$ 3,102.00	$ 73,029.12	
18-Jul	627	951		$ 94,345.36	$ 7,451.00	$ 101,796.36	
25-Jul	616	1,032		$ 98,582.74	$ 21,965.00	$ 120,547.74	10 lineman at 16 hours/day, 7 days a week
1-Aug	578	894		$ 88,013.61	$ 20,000.00	$ 108,013.61	4 linemen at 12 hours/day, 7 days a week
8-Aug	320	507		$ 49,462.81	$ 20,000.00	$ 69,462.81	
15-Aug	340	464		$ 48,027.76	$ 15,000.00	$ 63,027.76	4 linemen at 16 hours/day, 7 days a week plus 4 linemen at 12 hours/day, 7 days per week
22-Aug	237	371		$ 36,302.98	$ 15,000.00	$ 51,302.98	
29-Aug	320	464		$ 46,874.11	$ 5,000.00	$ 51,874.11	
5-Sep	192	301		$ 29,473.00	$ 3,000.00	$ 32,473.00	
12-Sep	192	301		$ 29,473.00	$ 3,000.00	$ 32,473.00	
19-Sep	160	243		$ 24,111.32	$ 3,000.00	$ 27,111.32	4 linemen at 16 hours/day, 7 days a week plus 4 linemen at 12 hours/day, 7 days per week
26-Sep	160	243		$ 24,111.32	$ 3,000.00	$ 27,111.32	
3-Oct	160	243		$ 24,111.32	$ 1,000.00	$ 25,111.32	
Totals	**6,183**	**9,002**	**0**	**$ 907,926.10**	**$ 171,495.00**	**$ 1,079,421.10**	

Reg	$	59.19
OT	$	60.20

Design

Week	Reg Hrs	OT Hrs	Units	T&E Spend	Material	Total Spend
30-May	0	0		$ -		$ -
6-Jun	0	0		$ -		$ -
13-Jun	0	0		$ -		$ -
20-Jun	40	30		$ 3,645.43		$ 3,645.43
27-Jun	120	80		$ 10,352.16		$ 10,352.16
4-Jul	40	38		$ 4,197.12		$ 4,197.12
11-Jul	0	0		$ -		$ -
18-Jul	40	32		$ 3,807.69		$ 3,807.69
25-Jul	0	0		$ -		$ -
1-Aug	0	0		$ -		$ -
8-Aug	0	0		$ -		$ -
15-Aug	180	0		$ 7,788.46		$ 7,788.46
22-Aug	180	0		$ 7,788.46		$ 7,788.46
29-Aug	180	0		$ 7,788.46		$ 7,788.46
5-Sep	40	0		$ 2,367.52		$ 2,367.52
12-Sep	40	0		$ 2,367.52		$ 2,367.52
19-Sep	40	0		$ 2,367.52		$ 2,367.52
26-Sep	40	0		$ 2,367.52		$ 2,367.52
3-Oct	40	0		$ 2,367.52		$ 2,367.52
Totals	**980**	**179**	**0**	**$ 57,205.38**	**$ -**	**$ 57,205.38**

Reg	$	43.27
OT	$	64.90

Field Meter

Week	Reg Hrs	OT Hrs	Units	T&E Spend	Material	Total Spend	
30-May	32	48		$ 4,594.18		$ 4,594.18	
6-Jun	17	9		$ 1,439.32		$ 1,439.32	
13-Jun	2	0		$ 115.53		$ 115.53	
20-Jun	34	28		$ 3,508.15		$ 3,508.15	
27-Jun	40	43		$ 4,741.66		$ 4,741.66	
4-Jul	163	233		$ 22,715.15	$ 1,630.00	$ 24,345.15	
11-Jul	358	476		$ 47,879.34		$ 47,879.34	
18-Jul	341	439		$ 44,763.40		$ 44,763.40	
25-Jul	246	294		$ 30,975.71		$ 30,975.71	5 meter techs at 16 hours/day, 7 days a week
1-Aug	269	269		$ 30,868.45		$ 30,868.45	3 meter techs at 12 hours/day, 7 days a week
8-Aug	120	131		$ 14,367.71		$ 14,367.71	
15-Aug	107	130		$ 13,617.07		$ 13,617.07	
22-Aug	102	110		$ 12,155.59		$ 12,155.59	3 meter techs at 12 hours/day, 7 days per week
29-Aug	120	132		$ 14,482.40		$ 14,482.40	
5-Sep	80	88		$ 10,032.86		$ 10,032.86	
12-Sep	80	88		$ 10,032.86		$ 10,032.86	
19-Sep	80	88		$ 10,032.86		$ 10,032.86	2 meter techs at 12 hours/day, 7 days per week
26-Sep	80	88		$ 10,032.86		$ 10,032.86	
3-Oct	80	88		$ 10,032.86		$ 10,032.86	
Totals	**2,348**	**2,777**	**0**	**$ 296,387.93**	**$ 1,630.00**	**$ 298,017.93**	
Net Dist Oper	**9,511**	**11,959**	**0**	**$ 1,261,519.42**	**$ 173,125.00**	**$ 1,434,644.42**	
Misc / Ancillary						**$ 88,521.83**	
Grand Total Dist Oper						**$ 1,523,166.25**	

Reg	$	57.76
OT	$	57.20