EXHIBIT 10

Direct Testimony and Schedules
Ian R. Benson

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 No. PU-10-___
Exhibit___(IRB-1)

Transmission
Operations & Maintenance Expense
and Investments

December 20, 2010

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Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Ian R. Benson. I am Director, Transmission Business Relations and Asset Management for Xcel Energy Services Inc. ("XES" or "Service Company").

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have nearly 20 years of experience with XES and its predecessor Northern States Power Company, and have served in positions in retail electric marketing, wholesale power purchases and sales, and transmission. My current responsibilities include supervising department engineers in planning electric transmission system expansions, recommending specific construction projects to Xcel Energy management and the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO" or "MISO"), and overseeing transmission related agreements with MISO and other counterparties. My resume is included as Exhibit ___(IRB-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying on behalf of Northern States Power Company, a Minnesota corporation ("NSPM," "Xcel Energy." or the "Company"). First, I present the Transmission and Operating Services ("T&OS") budget for 2011 and demonstrate that it is reasonable for recovery from ratepayers because:

- These costs are necessary to meet demand for system growth and comply with mandatory reliability standards, and support new generation (including renewable generation) on our system; and

- We have engaged in efforts to minimize costs while ensuring our customers receive safe, reliable service.

Q. PLEASE GENERALLY DESCRIBE THE MAIN REASONS FOR THE INCREASES IN TRANSMISSION RELATED COSTS REFECTED IN THE COMPANY'S 2011 BUDGET.

A. The increases are largely the result of the following factors:

- *System Growth.* Although end use electric demand is growing relatively slowly, the Company's Transmission operation and maintenance ("O&M") expenses and capital investments are growing more rapidly than in historic periods as we install significant new transmission infrastructure to maintain or improve reliability and to interconnect and transmit new sources of generation.
- *Reliability Compliance.* The Company has needed to increase its expenditures to demonstrate and implement compliance with mandatory electric reliability standards adopted by the North American Electric Reliability Corporation ("NERC") and approved by the Federal Energy Regulatory Commission ("FERC") after enactment of the Energy Policy Act of 2005 ("EPAct 2005").

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. I present my testimony in four sections:

- Overview of the Transmission and Operating Services Business Unit,
- Operations and Maintenance Expense,
- Transmission System Investments,
- Summary and Conclusion.

II. OVERVIEW OF TRANSMISSION & OPERATING SERVICES

A. Integrated Transmission System

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S TRANSMISSION SYSTEM.

A. NSPM and Northern States Power Company, a Wisconsin corporation ("NSPW") (jointly the "NSP Companies") are vertically integrated jurisdictional electric utilities that own and operate electric transmission facilities in portions of North Dakota, South Dakota, Minnesota, Wisconsin and the Upper Peninsula of Michigan. The NSP Companies operate an integrated transmission system (the "NSP System") comprised of approximately 7,200 line miles of transmission facilities operated at voltages between 34.5 kilovolts ("kV") and 500 kV and approximately 560 transmission and distribution substations. The Company owns approximately 250 miles of transmission lines and 14 substations in North Dakota. The Company's system in North Dakota is interconnected with the Otter Tail Power Company ("Otter Tail"), Great River Energy ("GRE"), and Minnkota Power Cooperative ("Minnkota") transmission systems, among others.

T&OS conducts transmission planning for, and operates and maintains, the integrated NSP System to serve: (1) all NSP System loads, including retail native loads in North Dakota and other states; and (2) the loads of other investor-owned utilities, cooperatives and municipal load serving entities ("LSEs") connected to the NSP System. These wholesale LSE customers comprise approximately 15 percent of the total demand on the NSP System; the remaining demand reflects the retail native load customers of the NSP Companies. From a transmission planning and transmission service perspective, however, both our retail customers and the wholesale LSE

customers are "native load" customers.

The NSP Companies are transmission-owning members of the Midwest ISO. Access to the NSP System is available on a non-discriminatory wholesale basis through the Midwest ISO Tariff, and most wholesale customers access the NSP System under that Tariff. (Otter Tail and GRE are also Midwest ISO members.) Transmission system expansion plans are reviewed regionally by the Midwest ISO under its annual Transmission Expansion Plan ("MTEP") process before specific projects in North Dakota are proposed for a Certificate of Public Convenience and Necessity or Corridor Certificate, when required.

B. T&OS Business Unit

A. PLEASE DESCRIBE THE FUNCTIONS PERFORMED BY THE T&OS BUSINESS UNIT.

Q. The T&OS organization oversees the Transmission and Substation business of the NSP Companies and the other Xcel Energy Operating Companies ("Operating Companies").[1] T&OS centrally manages the transmission systems to provide safe and reliable transmission of energy resources from generating resources (owned or third party) to the distribution systems serving our retail and other native load customers. There are four main activities related to our Transmission and Substation business: (1) construction, operation and maintenance in support of new transmission lines and substations; (2) operation and maintenance of our existing system of lines and substations; (3) future transmission planning, including participation in MTEP and other regional planning processes; and (4) compliance actions as required

[1] The other Xcel Energy Operating Companies are Public Service Company of Colorado ("PSCo") and Southwestern Public Service Company ("SPS"), which operate in Colorado and Texas/New Mexico, respectively.

by NERC, FERC, and other regulatory authorities. Centrally managing the transmission functions for all four Operating Companies allows T&OS to efficiently apply transmission and substation resources. There are a total of approximately 2,000 operating company employees, Service Company employees, and contract personnel in the T&OS business unit. Of that total, approximately 850 NSPM, NSPW and Service Company employees and contract personnel are assigned or provide services to the NSP System.

In addition to the Transmission and Substation business areas, T&OS includes the System Performance and Standards and Vegetation Management oversight functions for the Operating Companies. T&OS provides management oversight of the Vegetation Management function because of the importance of that function to compliance with mandatory NERC reliability standards governing vegetation management for transmission systems, but the employees and contractors who perform or direct the work are within the Company's Distribution business area.

NSP System transmission O&M and capital costs, as well as transmission related revenues, are allocated between NSPM and NSPW under the Interchange Agreement, as discussed by Company witness Mr. John M. Felling.

III. OPERATIONS AND MAINTENANCE EXPENSE

A. 2011 Test-Year O&M Budget

Q. PLEASE SUMMARIZE THE 2011 TRANSMISSION & OPERATING SERVICES O&M BUDGET.

A. The 2011 T&OS budget for the NSPM legal entity is approximately $38.5 million, which includes a budget correction explained in the next portion of my testimony. A large portion of the T&OS 2011 budget is for internal and outside labor. Outside labor includes costs for contractors or consultants supporting the work of T&OS employees. Other cost categories include maintenance materials and supplies, transmission fees and land permits, transportation costs and other.

Q. DOES THE COMPANY'S 2011 TEST YEAR REFLECT ANY ADJUSTMENTS OR CORRECTIONS FROM THE T&OS INITIAL 2011 BUDGET?

A. Yes. In reviewing the 2011 budget documentation as we prepared rate case information, we identified one transmission maintenance item related to compliance with NERC requirements that had been budgeted to the incorrect account, which resulted in the costs being allocated to FERC account 513 (a generation account) instead of account 570 (a transmission account). A portion of the costs in the original generation account ($370,000) would have been allocated to Southern Minnesota Municipal Power Agency ("SMMPA") because it owns a portion of Sherco 3. Using the appropriate FERC account (570) results in the T&OS budget being correctly stated at $38.5 million. Mr. Felling's test-year cost of service reflects this correction.

Q. HAVE TRANSMISSION-RELATED O&M EXPENSES INCREASED SINCE 2008? IF SO, PLEASE EXPLAIN THE REASONS FOR THE INCREASE.

A. The T&OS business unit was approved for a 2011 O&M increase compared to 2008, 2009 and 2010 in recognition of the continuing growth of the Company's transmission system and the need to fulfill NERC reliability compliance obligations. The 2011 T&OS budget reflects an increase of about $9.0 million compared to 2008 actuals. However, as I will describe later in my testimony, a portion of this increase -- approximately $1.0 million -- is associated with an item that was previously recorded as a credit to expense from 2008 to 2010 and which is now recorded as revenue under FERC Order No. 668. The net increase from 2008 to 2011 after adjusting for this change is approximately $8.0 million. Of that amount, approximately $4.9 million of the increase since 2008 reflects increased labor and consulting costs. The overall 2011 T&OS budget includes the costs for nearly 170 new positions across the four Operating Companies, with the costs adjusted to reflect the expectation the positions will be filled over the course of the year. Table 1 provides a summary of the total NSPM T&OS 2011 budget compared to 2008 to 2010 costs adjusted for the change in accounting:

Table 1

	2008 Actual	2009 Actual	2010 Forecast	2011 Adjusted Budget
Total O&M	**$29,454,538**	**$32,729,938**	**$35,220,501**	**$38,544,840**
Adjusted O&M after removing MISO and other credits	$30,521,438	$34,153,898	$36,765,008	**$38,544,840**
Annual Percentage Growth (adjusted O&M)		11.9%	7.60%	4.80%

While the percentage cost increase for the T&OS business unit since 2008 is higher than some other Xcel Energy business units, the dollar magnitude is relatively small and reasonable given the transmission system growth and other obligations the Company is experiencing.

Q. PLEASE DESCRIBE WHY SYSTEM GROWTH RESULTS IN INCREASED COSTS FOR THE 2011 TEST YEAR, AND HOW CUSTOMERS BENEFIT FROM THESE EXPENDITURES.

A. After relatively modest investments in transmission in the 1990s, the Company has been making substantial new investments in its transmission facilities over the last few years. NSP System transmission rate base will have more than doubled over the last decade, from $605 million (2001) to $1.339 billion (2011 forecast). Investments are being made both in transmission upgrades or expansions to continue to provide or enhance the reliability of services to our customers, and to interconnect new generation in compliance with FERC Order No. 2003 and Order No. 890 requirements. As a result, the T&OS business unit is experiencing increased costs, including internal labor and consulting, for personnel to plan, engineer, construct, operate and maintain those new and upgraded transmission facilities.

Construction of new transmission facilities also increases the overall number of miles of transmission line and substations that need to be inspected, tested and maintained. The continued performance and reliability of our existing transmission and substation systems require O&M expenditures. Like other aging infrastructure (such as roads and bridges), O&M costs tend to increase for transmission facilities over time, and the vast majority of our system

consists of facilities that have been in service for many years.

Q. PLEASE DESCRIBE WHY NERC RELIABILITY STANDARDS COMPLIANCE COSTS HAVE INCREASED FOR 2011.

A. In response to the August 14, 2003 east coast blackout, EPAct 2005 granted FERC increased authority over electric grid reliability, replacing the voluntary compliance regime governed by NERC since shortly after the 1965 northeast blackout. In 2007, after conducting rulemaking proceedings, FERC approved 83 initial mandatory electric reliability standards that had been adopted through a NERC stakeholder process, effective June 18, 2007. Each standard includes multiple requirements. Since June 2007, NERC has continued to adopt new standards or requirements and modify existing ones, subject to FERC oversight. As a vertically integrated electric utility, the Company is subject to the expanded NERC reliability standards compliance requirements. While the Company incurred expenses to comply with the voluntary NERC requirements prior to June 2007, the mandatory compliance requirements are a new paradigm for the electric utility industry, and Xcel Energy needed to increase the resources dedicated to compliance.

Q. CAN YOU PROVIDE SOME PERSPECTIVE REGARDING THE EFFORTS TO MEET COMPLIANCE?

A. The NSP System is today responsible for compliance with approximately 320 specific NERC requirements, many with sub-requirements, set forth in more than 100 mandatory NERC standards. Although not every NERC standard applies to the NSP System, the Transmission and Substations function is the area of the Company subject to the most NERC requirements. The NSP System must be able to demonstrate and document compliance with each

NERC requirement in an audit, spot check or other compliance review. Xcel Energy operates under a policy that it will comply (or seek to comply) with all applicable federal and state statutes and regulations, including NERC standards. In addition, non-compliance can lead to substantial financial penalties or other enforcement action by NERC, FERC, or the Midwest Reliability Organization ("MRO"), the Regional Entity designated by NERC for oversight of compliance by the NSP System. The Company is therefore taking the actions necessary to fully comply with all applicable mandatory reliability standards, just as we comply, for example, with Sarbanes-Oxley financial reporting requirements, Nuclear Regulatory Commission and Environmental Protection Agency rules (and other federal regulations), and Commission rules.

These compliance efforts impose costs. The new reliability standards required T&OS to add personnel, draft new or upgraded procedures, add or develop new information systems to track detailed compliance information, and improve and expand employee training. The 2011 test year includes an increase of approximately $2.4 million over 2008 actuals related to NERC standards compliance and reliability enhancements. Exhibit___(IRB-1), Schedule 2 provides a summary of some of the specific NERC compliance initiatives causing increased costs in the 2011 test year.

Q. ARE THERE OTHER COSTS ASSOCIATED WITH COMPLIANCE?

A. Yes. In addition to these internal cost increases related to reliability compliance, the NSP System is billed fees by MRO for the cost of the MRO and NERC compliance regimes. The projected 2011 MRO and NERC fees

for the NSP System are $1.776 million, an increase of $545,000 over 2008 actuals.

Q. IS THE COMPANY ENGAGED IN OTHER INITIATIVES THAT IMPACT THE 2011 T&OS BUDGET?

A. Yes. The Company is engaged in extensive planning surrounding local, sub-regional, and regional transmission expansion in preparation for future potential system growth, such as the CapX2020 initiative. In addition, the Company is participating in various regional planning initiatives, such as the Eastern Interconnection Planning Collaborative ("EIPC") and the Strategic Midwest Area Renewable Transmission ("SMART Study"), which are examining the need for high voltage "overlay" transmission systems to allow delivery of renewable energy to wider markets and improve reliability. The Company participates in these planning processes to make sure any plans that may be developed are consistent with the interests of Xcel Energy and its ratepayers. The expanded planning initiatives require additional personnel and systems, and result in increased O&M costs.

In addition, the Company is enhancing its apprenticeship training to develop experienced technical personnel who can replace existing employees who may retire in the future, and developing formal system operator training plans to meet compliance training requirements.

Our efforts in these areas benefit ratepayers because we are working to ensure any future overlay projects are "right sized" to meet North Dakota's needs, and the Company proactively develops employees so we can continue to reliably operate and maintain our transmission system into the future.

Q. MR. FELLING DESCRIBES THE STEPS THE COMPANY HAS TAKEN TO IDENTIFY AND EXPLAIN COSTS THAT DEVIATE FROM PRIOR BUDGETS BY PLUS OR MINUS THREE PERCENT OR OVER $250,000. WHICH T&OS COST CATEGORIES MEET THOSE CRITERIA?

A. Exhibit___(IRB-1), Schedule 3 includes a summary of those specific cost categories meeting the criteria described by Mr. Felling. The narrative descriptions demonstrate that 2011 costs are increasing for the reasons I noted: primarily system growth and NERC reliability compliance.

Q. PLEASE EXPLAIN THE "OTHER" COST CATEGORY ON YOUR SCHEDULE 3, WHICH SHOWS A RATHER SIGNFICANT CHANGES?

A. The 2011 budget for Other shows a reduction in a revenue credit by a compound average of 20.7 percent or approximately $627,000 annually since 2008.

The activity captured in this account reflects the credits to the T&OS Substation organization for labor and material costs for work performed for other business areas within the Company, such as maintenance work on Energy Supply and Distribution substations. In addition, until recently the Company has recorded both costs and revenues associated with engineering studies requested by the Midwest ISO in this account. NSP System personnel perform technical studies for the Midwest ISO to supplement work performed directly by Midwest ISO personnel. When a study is complete, the labor costs incurred are billed to Midwest ISO and the Company collects revenue. The Company previously recorded the revenue as a credit to offset the labor costs incurred. To comply with FERC Order No. 668, these cost offsets are now

reflected as revenue. The revenue from MISO and other credits (approximately $1.7 million for 2011) continues to offset the labor costs, but is reflected in a revenue account rather than as a direct offset to study expense.

Because of the change in the accounting for the study revenues from MISO, and because T&OS expects to perform less work for Energy Supply and Distribution in 2011, the credit has decreased from more than $3 million per year in 2008 through 2010 to approximately $1.8 million in 2011, as shown in Exhibit___(IRB-1), Schedule 3.

B. Efficiency Initiatives

Q. PLEASE DESCRIBE COST SAVINGS THAT HAVE BEEN REALIZED IN THE TEST-YEAR BUDGET THROUGH T&OS EFFICIENCY AND PRODUCTIVITY INITIATIVES.

A. The T&OS area has been engaged for several years in a series of initiatives to more efficiently use available resources and control increases in costs. We believe these initiatives show that T&OS management is working aggressively to improve our business practices to minimize costs increases to ratepayers.

First, T&OS launched its Transmission Resource Optimization ("TRO") initiative in 2005 to improve management of transmission line construction activities. T&OS realized that it needed to improve project management when transmission construction activities increased dramatically after several years of relatively low level activity. The TRO process provides more standardized project planning, engineering, scheduling, and construction processes to identify emerging issues with projects and make midcourse adjustments so projects can be completed on time and within budget.

The T&OS business unit is now applying the TRO model to substation construction and maintenance activities in 2010, which will carry into the 2011 test year and future years. For example, T&OS has invested in new information systems to improve the collection and management of relay testing field data so the Company can both demonstrate compliance with NERC standards and manage our workload more cost effectively. The new system provides efficiencies by reducing paperwork handling costs for the relay technicians and office personnel, standardizing the data collection process, and by avoiding the labor costs associated with performing potentially duplicative relay maintenance and testing where the Company's paper records could not document compliance.

Additionally, the Company minimizes the cost of NERC compliance through the sharing of compliance activities with the other Operating Companies. A regional entity compliance audit requires an Operating Company to dedicate hundreds of labor hours by dozens of employees to prepare, organize and check thousands of pages of compliance documentation and participate in the on-site audit. Registered Entities are audited every three years. Since the various Regional Entities (like MRO) conduct their audits on a rotating basis, the Operating Companies can reduce costs by sharing centralized compliance resources. In addition, if one Operating Company develops or learns of a new technique or best practice to achieve compliance, that information can be shared and implemented across all of our operating companies. The Xcel Energy Operating Companies have been recognized by their various Regional Entities for this proactive approach to compliance.

IV. TRANSMISSION SYSTEM INVESTMENTS

A. The NSP System

Q. PLEASE DESCRIBE THE HISTORIC DEVELOPMENT OF THE TRANSMISSION FACILITIES THAT COMPRISE THE NSP SYSTEM.

A. A characteristic of the Upper Midwest region was that electric utilities (investor-owned, cooperatives, municipal utilities, etc.) worked together to develop a transmission network that would serve their respective native load customers. The current CapX2020 initiative is the most recent example of this cooperative planning. The basic principle was that a utility like the Company should invest in sufficient transmission facilities to serve its loads in the region. This cooperation provided benefits to NSP System customers by providing the transmission infrastructure needed to serve our loads at a lower cost than if the neighboring utilities constructed duplicative facilities to reach their respective service area loads. The Company's 2002/2003 investment in a 56 mile segment of the Harvey/Glenborough 230 kV transmission line is an example of this type of coordinated development. The line is not directly connected to any other NSP System transmission facilities, and is located in the Otter Tail local balancing authority, but the transmission capacity and reliability benefits of the Company's investment in the project (approximately $13 million) helps serve the needs of North Dakota loads generally, including the Company's loads.

Q. PLEASE PROVIDE AN OVERVIEW OF THE TRANSMISSION PLANNING PROCESS USED BY THE COMPANY.

A. As members of Midwest ISO, the NSP Companies fully participate in the annual MTEP process. Approval of the MTEP by the MISO Board of

Directors certifies the Midwest ISO's plan to meet the transmission needs of all stakeholders, subject to any required regulatory approvals. The MTEP is developed and discussed with MISO stakeholder committees in all the stages of its development, and incorporates the transmission plans for Midwest ISO utilities. All recent and future transmission investments by the NSP Companies have been, and will continue to be, planned and approved through the MTEP process.

The MTEP process is a "bottom-up/top-down" process, meaning the transmission plans of individual utilities are inputs to the MISO regional plan, but MISO staff, through its stakeholder process, studies various projects and can make independent project recommendations. For coordination purposes, NSP also reports its projects as part of the Northern MAPP Sub-regional Planning Group update to the 2010 Mid-Continent Area Power Pool ("MAPP") Regional Plan.

A. YOU MENTION THE COMPANY OPERATES AN INTEGRATED TRANSMISSION SYSTEM. HOW DOES THIS APPROACH BENEFIT NORTH DAKOTA CUSTOMERS?

Q. The integrated system approach is necessary due to the nature of how electricity moves on the system. Because of this interconnected nature, the system must be operated as a whole but also requires planning with an overall look at the infrastructure. In addition, investments to the system made in a coordinated manner allow resources to be used in the most optimal manner. By working in coordination with Otter Tail, Minnkota, Great River Energy and other regional transmission owners, the Company is able to serve its loads, including retail native loads in North Dakota, without constructing

duplicative transmission infrastructure, consistent with longstanding regulatory principles.

For example, by operating an integrated system and by partnering with other neighboring transmission owning utilities, investments in transmission, such as the upcoming CapX 2020 Projects, provide a series of benefits including:

1) Enhanced reliability throughout the region including North Dakota;
2) Added export capacity to the transmission system for generation within North Dakota;
3) Improved access to the Midwest ISO regional markets for North Dakota based generation;
4) Opportunities for the development of new generation, including wind based generation; and
5) Enhanced economic development in North Dakota.

Q. PLEASE EXPLAIN ENHANCED RELIABILITY.

A. The transmission system must be able to reliably deliver power to individual communities. Power must be able to flow to customer loads even if one of the most critical elements of the system fails. Transmission planners consider these "contingency" events because they can and will happen (e.g., a transmission line incurs damage from extremely high winds and must be taken out of service). Transmission planners monitor the performance of the system and identify limits that could affect power deliveries to individual communities or load centers on the system. System improvements can be targeted to address such emerging community service reliability issues.

In addition, regional reliability is related to the shared importance of an efficient and reliable transfer of bulk power across regions and between regions. New investments benefit the system as a whole because the additional connections created provide for a more robust transmission system that is able to better withstand system contingencies. A more robust bulk power system also enhances efficient transfer of power across and between regions. Efficient regional power transfers promote and support fair and competitive wholesale electric markets thereby assisting in meeting the needs of all regional market participants, rather than just those of the individual utility's customers or a specific generation resource type.

Q. HOW DO SYSTEM INVESTMENTS IMPROVE EXPORT CAPABILITY?

A. The transmission system in North Dakota is able to deliver local generation to local loads to meet peak demands, but there are constraints on the ability to move that generation to other regional load centers, particularly in periods of lower demand. If too much energy is transmitted, the system can become unstable. This constraint is referred to as the North Dakota Export Limit ("NDEX"), and is known as a "stability" constraint. New projects such as the CapX2020 regional projects will enhance export capability of all generation by alleviating some of the constraints of the NDEX boundary and facilitate Midwest ISO dispatch of North Dakota generation into the MISO energy markets.

Q. PLEASE EXPLAIN THE NDEX AND ITS SIGNIFICANCE.

A. The NDEX limitations on transmission outlet capability from North Dakota create an electrical "boundary" around North Dakota, northwestern Minnesota, and parts of South Dakota and Montana that imposes a maximum

generation outlet capability related to transmission lines that cross the boundary. The NDEX boundary limits the maximum amount of power that can be exported from North Dakota and these parts of Minnesota and South Dakota without adversely affecting regional system reliability. This is significant because even under peak load conditions, there is more generation than load within the NDEX boundary, leading to exports of power to load centers like the Twin Cities and points east. If large amounts of generation were developed without a simultaneous increase in transmission capacity, the generation would effectively be "trapped" in North Dakota.

In order for the transmission system to be operated reliably, generation and load must always be in balance. MISO operates as a centralized dispatcher of generation in its regional foot print, known as a "balancing authority", to make sure that the system remains in balance. Transmission projects that alleviate congestion on the system with an eastbound outlet allow MISO to more efficiently dispatch generation from the generation rich western portion of the MISO footprint, including North Dakota, into the load centers toward the east and south.

Q. IS IT BENEFICIAL FOR NORTH DAKOTA GENERATORS TO HAVE ACCESS TO THE MIDWEST ISO MARKET?

A. Yes. MISO prices energy based on "locational marginal pricing," or "LMP," which provides wholesale price signals that account for the additional costs of electricity caused by transmission congestion and line loss at various points on the regional electricity grid. Under the LMP pricing structure, areas on the grid which experience the least amount of congestion, have sufficient generation resources, and use low cost fuels have the lowest wholesale prices

for electricity. Expanded transmission investments that help mitigate the NDEX constraint should allow North Dakota based generation resources to serve a greater share of the energy demands within the Midwest ISO region.

Several of the CapX2020 Group 1 projects (the Fargo, Brookings, and Bemidji projects) will increase the NDEX limit, allowing more generation to physically leave the NDEX area without creating instability on the transmission system serving customers in North Dakota. However, smaller "network upgrades" also can help alleviate the NDEX constraints or allow delivery of new generation projects into the Midwest ISO market.

Q. HOW DOES TRANSMISSION INVESTMENT STIMULATE ECONOMIC DEVELOPMENT?

A. Transmission investment complements the development of North Dakota's wind generation resources, which creates the opportunity to contribute to the general economic development in the state with short- and long-term jobs, investments, landowner income, support services and manufacturing. North Dakota is already an electric energy exporter, and new transmission investments can facilitate greater electric exports.

Q. HAVE TRANSMISSION INVESTMENTS AFFECTED THE NEED FOR THE COMPANY'S REQUESTED INCREASE IN THIS PROCEEDING?

A. Yes. As shown in Table 2, transmission investments have continued since our last retail rate case (Case No. PU-07-776). In 2009, 2010 and 2011, the Company expects to add $431.4 million in new transmission plant in service for the NSPM System. Investments will continue at significant levels in 2012,

thus supporting the transmission component of the 2012 step-in increase addressed by Company witness Anne M. Heuer.

Table 2

Additions to Plant in Service ($ in millions)

Type of Project	2009 Actual	2010 Forecast	2011 Forecast	2012 Forecast
System Performance and Interconnection	$121.5	$99.80	$93.00	$73.10
Other Projects	$3.0	$19.00	$69.70	$66.10
Transmission Serving Generation Projects	$0	$4.60	$20.80	$0
TOTAL	$124.50	$123.40	$183.50	$139.20

B. System Performance and Interconnection Investments

Q. PLEASE DESCRIBE SYSTEM PERFORMANCE AND INTERCONNECTION INVESTMENTS.

A. System performance investments are the investments required to keep the transmission system operating reliably and safely while addressing load growth, infrastructure aging, obsolescence, deterioration, and replacement, along with other performance related issues. These investments also include line relocation projects. Interconnection investments include the investments in transmission network facilities that are necessary to interconnect a new generator or distribution substation to the transmission grid, as well as any capacity upgrades necessary to allow the generation to operate or the load to be served without placing a reliability risk on the transmission system.

Q. CAN YOU PROVIDE AN EXAMPLE OF A RECENT SYSTEM PERFORMANCE OR INTERCONNECTION INVESTMENT IN NORTH DAKOTA?

A. Yes. The Maple River-Red River, North Dakota Project increased the capacity of the 6 mile Maple River-Red River 115 kV line and included the installation

of a second 187 MVA 230/115 kV transformer at Maple River Substation near Fargo, North Dakota. This upgrade was necessary to accommodate load growth in the city of Fargo metropolitan area, and prevent overloads during transmission line outages. The cost of this project was $5.8 million.

Q. WHAT ARE THE SYSTEM PERFORMANCE AND INTERCONNECTION INVESTMENT LEVELS ASSUMED IN THIS RATE REQUEST?

A. Of the approximately $183 million of NSPM System transmission investments in 2011, system performance and interconnection investments will be $93 million. Exhibit___(IRB-1), Schedule 4 lists and describes some of the system performance transmission projects in the 2011 test year and the proposed 2012 step-in adjustment.

Q. ARE THERE TRANSMISSION-RELATED COSTS IN THE TEST YEAR RELATED TO INTERCONNECTION OF THE COMPANY'S MERRICOURT WIND GENERATION PROJECT IN NORTH DAKOTA?

A. Yes. The Company's new 150 MW Merricourt wind generation plant, being constructed in Dickey and McIntosh Counties in North Dakota, will be interconnected to the Montana Dakota Utilities ("MDU") transmission system. MDU is a Midwest ISO member subject to the Midwest ISO Tariff. Under the interconnection agreement, MDU will invest approximately $23 million in new transmission facilities to allow delivery of the Merricourt project wind generation to the MISO System for redelivery to NSP customers. The new MDU facilities, which were identified through the generation interconnection study process set forth in the MISO Tariff, include a new 230 kV interconnection substation, a new, approximately 30 mile long

230 kV transmission line, plus a new transformer and circuit breakers at an existing MDU substation.

As provided in the MISO Tariff, MDU has elected to collect the project's share of these costs over time as monthly payments. The Company will make payments (approximately $5.9 million per year) starting in October 2011 to compensate MDU for the installation of the interconnection facilities and network upgrades. Because of the payment method selected by MDU, these costs will not be capitalized. The Company is requesting recovery of these transmission service expenses as a part of our 2011 test year. In addition, Ms. Heuer proposes to include the annualized cost as a part of the 2012 Merricourt step-in adjustment.

C. 2012 Transmission Plant in Service

Q. MS. HEUER IS PROPOSING THAT RATES FOR 2012 INCLUDE A 2011 END OF YEAR LOOK AT TRANSMISSION RATE BASE. IS THERE ANY REASON TO EXPECT TRANSMISSION RATE BASE WILL BE LOWER IN 2012 THAN 2011?

A. No. Table 2 shows that transmission rate base will continue to increase in 2012 because there are a number of transmission capital projects underway that are expected to be placed in service during 2012. The Company expects to make transmission investments that will increase transmission plant in service by $139.2 million in 2012. Exhibit___ (IRB-1), Schedule 4 also lists some of the larger 2012 transmission capital projects proposed to be included in the 2012 step-in adjustment supported by Ms. Heuer.

Q. ARE THERE TRANSMISSION-RELATED COSTS RELATED TO THE CAPX2020 PROJECTS IN THE TEST YEAR?

A. There are minimal costs included in the 2011 test year related to the four CapX2020 projects. The total test year investment is approximately $650,000. Mr. Felling reflects these investments in the cost of service. The first CapX2020 transmission project is expected to be placed in service in 2011. As I understand, the Company is not seeking to recover Construction Work in Progress ("CWIP") related to the projects during the construction phase.

Q. HOW ARE MISO TRANSMISSION-RELATED AND ADMINISTRATIVE COSTS REFLECTED IN THE TEST YEAR?

A. MISO transmission service charges, Schedule 10, Schedule 16, Schedule 17, Schedule 24 and Schedule 26 charges are included as a test year expense by Mr. Felling. Off-setting transmission service revenues and Schedule 24 and Schedule 26 revenues are reflected as revenues by Mr. Felling. None of these costs or revenues is included in the Fuel Cost Rider ("FCR"). Consistent with the Commission's order in the Company's prior rate case, however, costs and revenues associated with the MISO energy and ancillary services markets are subject to FCR treatment.

D. Efforts to Control Transmission Investment Costs

Q. IS THE COMPANY TAKING INITIATIVES TO CONTROL TRANSMISSION INVESTMENT COSTS?

A. Yes. The T&OS business unit has implemented a number of programs to help control the cost of transmission investments. One is the creation of vendor alliances to control costs where we use competitive bidding processes to secure resources like contractors and materials to help ensure the reasonableness of overall costs.

Q. PLEASE DESCRIBE THESE STRATEGIC RELATIONSHIPS AND HOW THEY MAY SAVE TRANSMISSION INVESTMENT COSTS.

A. Strategic supplier relationships combine greater supplier involvement, collaboration and performance management with effective longer term contracts. These contracts drive savings in many ways, as appropriate based on the category of expenditure, to include transparency into materials and services costs, indexing to underlying commodities, and productivity improvement goals. Additionally, most categories are multiple sourced in order to maintain supply continuity and competitive rivalry within the strategic relationship framework. Some examples include:

- *Power Transformers.* Xcel Energy is participating in an alliance with four entities to provide all power transformers. The contracts were negotiated mid-2009. While prices under the contracts can escalate or de-escalate relative to raw commodity input costs (steel, copper, aluminum, oil, etc.) the base price savings are roughly 6 percent through the end of 2012, but varies by the size/type of transformer.
- *Cable and Wire.* Xcel Energy has contracted with a single vendor to provide all transmission conductors following a comprehensive RFP. The contract was renegotiated effective mid 2009. While the contract prices can still escalate or de-escalate relative to commodity costs (steel, aluminum), the base price savings are roughly 9 percent through the end of 2012.
- *Wood Poles.* Xcel Energy contracted with a new vendor (replacing another vendor) as the alliance wood pole provider starting in mid 2009. While the contract prices can still escalate or de-escalate with fuel costs, the base price savings are estimated to be 19 percent through mid 2014.

V. SUMMARY AND CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Costs related to the transmission component of the Company's cost of service have increased since our last rate case because of system growth, the costs of compliance with NERC mandatory reliability standards, and the costs of use of third-party transmission systems. Transmission and Operating Services is working to improve efficiencies in the construction, operation, and maintenance of the Company's transmission system to minimize those cost increases. The costs the Company proposes to recover in 2011 retail electric rates are reasonable, and cost recovery should be approved.

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

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

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

AFFIDAVIT OF
Ian R. Benson

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

Ian R. Benson

Subscribed and sworn to before me, this 15th day of December, 2010.

Notary Public

CHRISTINE SINN
Notary Public-Minnesota
My Commission Expires Jan 31, 2015

Statement of Qualifications
Ian R. Benson

Current Responsibilities

My responsibilities include: supervising engineers in planning the electric transmission systems for NSPM and Northern States Power Company, a Wisconsin corporation (NSP Companies) in Minnesota, North Dakota, South Dakota, Wisconsin and the Upper Peninsula of Michigan; overseeing the development of local and regional transmission system plans, including coordinated joint planning with the Midwest Independent Transmission System Operator, Inc. (Midwest ISO), and other utilities to ensure reliable transmission service; recommending the construction of such plans to Xcel Energy Inc. management and the Midwest ISO; participating in and supporting Midwest ISO sponsored transmission service studies, generation interconnection studies, long range regional plan development, load service planning and other transmission planning activities required by Midwest ISO to perform its obligations under the Midwest ISO Tariff and the Midwest ISO Transmission Owner's Agreement; and providing technical support for regulatory aspects of transmission system planning activities and contract development for the NSP Companies.

Education:

Bachelor of Geological Engineering - 1984
University of Minnesota

Bachelor of Science, Mathematics – 1991
University of Minnesota

Master of Business Administration – 2010
University of St Thomas

Previous Employment (1991 to 2010):

Senior Engineer - Northern States Power Company (1991-1994)
Lead Sales Representative - Northern States Power Company (1994-1998)
Mid-Term Marketing Representative - Northern States Power Company (1998-1999)
Manager, Mid-Term Markets - Northern States Power Company (1999-2000)
Director, Origination - Xcel Energy Services Inc. (XES) (2000 – 2004)
Director, Transmission Access - XES (2004 – 2009)
Director, Transmission Investment Development - XES (2009 – 2010)
Director, Transmission Business Relations and Asset Management - XES (2010 – present)

U.S. Navy

Active Duty: 1984 to 1989
Naval Reserve: 1989 to 2006

NERC Compliance Initiatives

The continuous evolution and expansion of NERC mandatory reliability standards regime since June 2007 requires an increase in the resources needed to support compliance related to:

- System Control Center training and coverage
- substation relay maintenance
- communications
- battery system maintenance
- interconnection relay coordination
- facility ratings
- vegetation management, and
- documentation management related to standards implementation tracking and reporting.

Activities incremental to 2009 include:

- the System Protection Engineering Initiative, which is an effort consolidating the management of power system and protection system modeling (relays);
  - 2010 costs incremental to 2009 are forecast at approximately $365,000 to support the Q3 addition of 4 Engineers and relay modeling consulting support. The $365,000 cost is the NSPM portion of the total.
  - 2011 costs incremental to 2010 are forecast at $572,000 to cover full year labor costs for 2010 hires noted above, O&M support costs and relay modeling consulting support. The $572,000 cost is the NSPM portion of the total.
- a NERC Compliance Documentation initiative which is a focused effort to document and support compliance for System Operations
  - 2010 costs incremental to 2009 are forecast at $80,000 for the addition of a Compliance Analyst
  - 2011 costs incremental to 2010 are forecast at $120,000 for the addition of two FTE positions to support all four Xcel Energy Operating Companies.
  - Labor costs and O&M support are directly allocated to each operating company.

- a multi-year Enhanced Transformer Oil Maintenance Program
  - 2010 costs incremental to 2009 are forecast at approximately $740,000 for NSPM to support contract labor costs at (80%) and material costs at (20%) to perform the additional maintenance planned under this initiative.
  - 2011 costs incremental to 2010 are forecast at approximately $248,000 for NSPM to support contract labor and materials at the same estimated split allocation as noted above.

The T&OS business unit is also implementing a Coordinated Training Program supporting the training required for System Control Center personnel to satisfy their continuing education and NERC certification requirements.

2008 and 2009 Actuals, 2010 Forecast, and 2011 Budget

NSPM Transmission O&M Trend[1]
Selected Cost Categories

	2008 Actuals	2009 Actuals	2010 Forecast	2011 Budget
Company Labor	$18,883,776	$19,988,951	$22,024,582	$21,511,818
Non-Company Labor	$1,150,162	$484,260	$884,615	$2,134,386
Consulting/ Professional Services	$2,033,245	$1,942,236	$2,790,880	$3,377,654
Other	($3,757,840)	($3,025,916)	($3,923,507)	($1,876,378)

- *Company Labor* increased by a compound average of 4.4 percent or $876,014 annually since 2008. The drivers behind this increase include a labor merit increase of approximately $500,000 for 2011 and additional engineering labor to support system growth and the System Protection Engineering Initiative for the substations maintenance and NERC reliability standards compliance effort. The four (4) Xcel Energy Operating Companies expect to add 80 new engineers, designers, drafters, land rights agents and technicians; four new planning engineers to support capital growth; and six (6) compliance coordinators. A portion of these new employees would serve the Company's system. The Operating Companies also expect to fill 43 new non-benefit and 44 union positions to support additional maintenance driven by system growth, construction, and NERC compliance. While the Company must comply with all mandatory NERC reliability standards, NERC and FERC have placed particular emphasis on transmission vegetation management and maintenance of system protection devices (such as relays) because lapses in those areas were found to be major causes of the August 14, 2003 east coast blackout. Given the emphasis on protection system maintenance by FERC and NERC, T&OS has been increasing engineering labor expenditures to improve relay system reliability and therefore compliance.

- *Non-Company Labor* increased by a compound average of 22.9 percent or $328,075 annually. T&OS uses third-party service providers to supplement

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[1] Amounts reflect Northern States Power Company (Minnesota) electric utility costs. The Regulatory area directly assigns or allocates costs to the State of North Dakota electric jurisdiction. In addition, the Regulatory area makes various test period adjustments to eliminate certain costs not included within the State of North Dakota electric jurisdiction cost of service. Thus these represent business area costs prior to adjustments, so not all of the costs are reflected in the cost of service, nor are the above costs all part of our request for rates.

the Company work force when necessary to complete required activities. The drivers behind this increase include an enhanced substation transformer oil maintenance program to respond to a NERC reliability compliance directive; and increased engineering O&M support for the Substation Compliance Maintenance Initiative and transmission capital projects.

- *Consulting/Professional Services* increased by a compound average of 18.4 percent or $448,136 annually. The Company also uses consultants or other professional service providers to supplement the Company's work force when necessary to complete required activities. The drivers behind this increase include engineering costs to conduct facilities studies for the Midwest ISO; these costs are offset by revenues from Midwest ISO; costs for substation civil engineering support to repair heaving foundations and drainage issues; increased costs for enhanced compliance and other training for the System Protection Group; support for documenting compliance with NERC standards as they are added or modified, and to prepare for compliance audits; and costs to support study requirements for new generation interconnection customers.

  Under the Midwest ISO Tariff and FERC Order Nos. 888 and 890, each generation interconnection request is subject to a three-step study process before the interconnection request can be approved (Feasibility Study, System Impact Study, and Facility Study). In addition, because of the highly interconnected transmission network in the Upper Midwest, the Company typically must study the effects on its system of requests to interconnect generation to neighboring transmission system. The Midwest ISO has received numerous requests to interconnect to the NSP System, particularly for wind generation. The Company must use consulting resources to perform certain of these studies to supplement Company resources. MISO reimburses the Company for certain of these consulting costs.

- *Other* decreased by a compound average of 20.7 percent or $627,154 annually. The activity captured in this account reflects the credits to the T&OS Substation organization for labor and material costs for work performed for the Energy Supply and Distribution areas of Xcel Energy. The corresponding debit is recorded in the account of the business area for which the work is performed. The inter-company elimination process nets this activity to zero in the general ledger and keeps the originating charges within the appropriate FERC account.

Additional activity recorded within this account is the offset for costs billed to Midwest ISO for requested engineering studies performed. The costs to perform the requested MISO studies by contract labor or consulting is recorded in the appropriate FERC account. When a study is complete and billed to MISO, the credit is recorded within the account offset with the invoiced receivable charge. While the Company will continue to collect reimbursements from MISO, the change in accounting reduces the credit in this object account.

System Performance/Interconnection Projects Affecting 2011 Test Year and 2012 Step-In Adjustment

Table 1
Additions to Plant in Service ($ in millions)

Project	2009	2010	2011	2012
New Ulm Expansion:		$13.3		
Mankato 115 kV Loop		$ 8.9		
Pleasant Valley – Byron*			$ 8.0	
North Mankato Project		$ 0.1	$ 1.5	$17.1
St. Cloud Loop**				$ 9.0
Midtown-Hiawatha**			$ 5.9	$ 8.9
Southwest Twin Cities Project**			$ 6.0	$13.2
Fenton 69 kV Tie			$ 7.2	
Chisago-Apple River Project		$15.4	$18.6	
Chanarambie 4th Collector Transformer	$ 5.0			
Buffalo Ridge Incremental Generation Outlet (BRIGO)	$68.6			

* In-service date now expected to be in 2012
** Additional plant in service investments are expected in 2013

1. New Ulm Expansion

This project constructs a five mile 115 kV line and 115-69 kV substation to the southwest side of the City of New Ulm, Minnesota. This project is required to provide network transmission service to the City's 52 MW of load and mitigate low voltages under transmission outages. The project is included in the 2011 test year.

2. Mankato 115 kV Loop

This project will construct 7.5 miles of new 115 kV transmission line and two 115-69 kV substations around the City of Mankato, Minnesota. This is part of a joint development with Great River Energy ("GRE"), and is required to meet load growth in Mankato and to eliminate low voltage and equipment overloads during transmission outages. The project is included in the 2011 test year.

3. Pleasant Valley-Byron

This project will construct a new 161 kV transmission line between GRE's Pleasant Valley Substation and the Southern Minnesota Municipal Power Agency ("SMMPA") Byron substation to increase the transmission system capacity to allow interconnection of a wind generation farm at Pleasant Valley substation near Rochester, Minnesota. This project includes approximately 20 miles of new 161 kV transmission line along with other substation upgrades by other Minnesota utilities. This project will allow for the development of up to approximately 300 MW of wind generation in the region south of Rochester.

4. North Mankato Project

This project will construct a new 345-115 kV and a new 115-69 kV substation plus associated transmission. This project is needed to mitigate unacceptable low voltages and line loadings on the

69 kV transmission system in LeSueur, Minnesota, and the surrounding area. This project results in investment added to plant in service in 2010 and 2011, which is included in the 2011 test year. In addition to the facilities placed in service in 2010-11, this project has additional investment added to plant in service in 2012.

5. St. Cloud Loop

This project involves upgrading 1.4 miles of 115 kV line to a higher capacity and building 4 miles of new 115 kV line in St. Cloud, Minnesota, along with reconfiguration of the existing Benton County-Granite City 115 kV double circuit line. This project is required to reduce transmission overloads and potential outages to customers during transmission outages in St. Cloud. This project is expected to be completed near the end of 2012 and adds investment to plant in service in 2012, although additional investments to plant in service are expected in 2013.

6. Midtown-Hiawatha

This project is to construct two new 115 KV substations located in south Minneapolis and approximately 2 miles of double circuit 115 kV transmission between the two substations. This project is to alleviate high distribution line loadings and area low voltages during high load periods and distribution equipment outages. This project is expected to be completed in 2013.

7. Southwest Twin Cities Project

This project is to re-construct 16 miles of 69 kV line to 115 kV between the City of Glencoe and the West Waconia substation and convert 20 miles of 69 kV line between Westgate and Scott County substations to 115 kV. This project is required due to load growth in this region, to serve the load at City of Glencoe and improve reliability in the region. This will alleviate low voltages and overloaded transmission during high load periods and transmission outages, and replace aging transmission equipment facing deteriorating reliability. This project is expected to be completed in 2013. This project results in investment added to plant in service in 2011, which is included in the 2011 test year. In addition, this project adds investment to rate base in 2012. Additional investment will be added in 2013.

8. Fenton 69 kV Tie

This project is to constructs a new 69 kV transmission source at the Fenton Substation located in Southwest Minnesota along the Buffalo Ridge. This project will build 3 new miles of 69 kV transmission to an existing line between Pipestone and Lyon County to prevent low voltages along the line in the event that one of those two sources are lost. It will add a new 47 MVA 115/69 kV transformer and associated bus work at Fenton substation to accommodate this new tie. This project results in investment added to the plant in-service in 2011, which is included in the 2011 test year.

9. Chisago to Apple River

This project is to convert the Chisago Co-St. Croix Falls-Apple River 69 kV line to a single 115 kV line in Minnesota and a single 161 kV line in Wisconsin. This project is located Northeast of the Twin Cities along the Minnesota-Wisconsin boarded. It is a joint project with Dairyland Power Cooperative. This project is required due to load growth in the region and to prevent low voltages and unacceptable line loadings during a system contingency. This project results in investment added to the plant in-service in 2011, which is included in the 2011 test year.

10. Chanarambie 4th Collector Transformer

This project constructed an expansion of the Chanarambie wind generation collector substation located on the Buffalo Ridge in Southwest Minnesota. This project allows for the interconnection of an additional 50 MW of wind generation. This project has been completed and went into service in 2009.

11. Buffalo Ridge Incremental Generation Outlet (BRIGO)

This project constructed three new 115 kV transmission lines in the Buffalo Ridge area located in Southwest Minnesota. This project was required to accommodate the large amounts of wind interconnection requests in the area. These three 115 kV line provide approximately 350 MW of additional outlet for wind generation from the area to the load centers in the east. This project has been completed and went into service in 2009.