Direct Testimony and Schedules
Ian R. Benson

Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. E002/GR-15-826
Exhibit___(IRB-1)

Transmission

November 2, 2015

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Ian Benson. I am the Director of Transmission Planning and Business Relations for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company, a Minnesota Corporation (NSPM or the Company) and an operating company of Xcel Energy Inc. (Xcel Energy).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over 20 years of experience in the utility industry and have served in positions in nuclear generation, retail electric marketing, wholesale power purchases and sales, and transmission. In my current position as Director of Transmission Planning and Business Relations, my responsibilities include: supervising department engineers in planning electric transmission system expansions, recommending specific construction projects to Xcel Energy management and the Midcontinent Independent System Operator, Inc. (MISO), overseeing transmission related agreements with MISO and other counterparties, and resolving wholesale customer transmission service concerns. My resume is attached as Exhibit___(IRB-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I present and support the Company's capital forecasts and operation and maintenance (O&M) expense requests for the Transmission organization for purposes of determining electric revenue requirements and final rates in this proceeding. I also provide information which responds to the following Order point from the Company's last electric rate case:

Order Point 30- In its next electric rate case, the Company shall:

a. present a new key performance indicator (KPI) for transmission O&M costs;
b. provide a comparison study of its transmission O&M costs by using appropriate peer companies, along with justification for why certain utilities were included or excluded; and
c. propose a new cost control KPI at the vice-presidential level for overall transmission costs.

Q. PLEASE PROVIDE AN OVERVIEW OF THE TRANSMISSION ORGANIZATION AND A SUMMARY OF YOUR TESTIMONY.

A. The Transmission organization is responsible for the maintenance, management, and construction of Xcel Energy's transmission systems so that energy is safely and reliably transmitted from generating resources (both Company-owned and third-party-owned) to the distribution systems serving our customers.

The NSP Companies, NSPM and Northern States Power Company – Wisconsin (NSPW) own and operate an integrated transmission system that has facilities in portions of Minnesota, North Dakota, South Dakota, Wisconsin, and the upper peninsula of Michigan (NSP System). The Transmission organization is focused on ensuring that this integrated transmission system is both robust and reliable.

First and foremost, we seek to maintain and improve the reliability of our transmission system. To that end, the North American Electric Reliability

Corporation (NERC) and the Federal Energy Regulatory Commission (FERC) continue to develop and approve a growing list of mandatory standards aimed at maintaining the reliability of the Bulk Electric System. These standards require incremental capital investments for all utilities that own transmission facilities to maintain compliance. We are continually studying our system to identify necessary facilities to both maintain the reliability of our system and our NERC compliance.

Another aspect to maintaining reliability is addressing the age and condition of our transmission assets. Many of our transmission facilities were placed in-service during the 1960s and 1970s and are reaching the end of their useful life. Over the next years, we will continue to examine our existing facilities and make the necessary upgrades to ensure reliability is not jeopardized. As we upgrade these aging assets, we will do so with an eye towards modernization by installing facilities that allow operators to monitor and respond quickly to outages on the system.

The reliability of our transmission system also depends on the physical security and resiliency of the system. In 2013, a sniper attack in California knocked out 17 large transformers that powered Silicon Valley. This attack spurred our Company and other utilities to assess the physical security of our system and its ability to respond to these types of threats. We are evaluating and securing our system while also complying with new NERC standards in this area.

Further, we seek to ensure that the transmission system is robust and reliable enough to promote efficient and competitive electricity markets, which hold down prices for consumers. Our investments in large regional transmission projects enable reliable access to a more diverse mix of generation resources, which in turn allows customers access to the least expensive power available at any given time. This access to a variety of generation resources will become even more important as states develop plans to comply with the U.S. Environmental Protection Agency's (EPA) Clean Power Plan. The Clean Power Plan is expected to significantly shift the country's generation mix. Managing generation retirements, while at the same time integrating new renewable energy resources, will increase the need for new and upgraded transmission assets. The Company has and will continue to work with other regional utilities to develop and construct transmission solutions to ensure that the regional transmission grid is robust enough to meet these challenges.

In my Direct Testimony, I will discuss the Transmission organization and the NSP System. I will also describe the numerous entities, in addition to the Minnesota Public Utilities Commission, that regulate the transmission system.

I will explain that the Transmission organization is proposing capital additions of approximately $137.4 million for 2016, $167.4 million for 2017, and $204.7 million for 2018 for NSPM. These capital additions include transmission projects for which the Company will seek rate recovery through the Transmission Cost Recovery (TCR) Rider. Company witness Ms. Anne E. Heuer will discuss the TCR Rider in greater detail. I will describe the six capital budget groupings that are driving these investments and the importance of these investments in maintaining a safe and reliable transmission system.

I will also discuss the Transmission O&M budget for 2016, which is driven by internal labor, contract labor and consulting, fees, materials, and fleet. I explain why our O&M budget is reasonable and provides for the expenses that are needed each year to construct and maintain the transmission system. I also address our rate case request for Transmission O&M in 2017 and 2018, identifying some of the anticipated key drivers of our O&M budget in those years.

Further, as required by the Commission's last rate case Order, I present a new benchmarking study that examines Transmission's O&M costs as compared to other regional peer utilities. The results of this study show that our O&M costs are trending downward and we are performing in the both the first (O&M per Gross Plant and O&M per Net Plant) and second quartile (O&M per Line Mile) in the three metrics measured as compared to our peer utilities.

Finally, I address the Commission's requirement that the Company must justify the KPIs that form the basis of our incentive compensation to employees. I also propose two new KPIs: one related to O&M costs, which is tied to our benchmarking study performance, and one related to overall transmission cost, as required by the Commission's last rate case Order. I explain that both our existing and proposed KPIs are appropriately challenging and developed to result in customer benefits.

Q. DO YOU PROVIDE ANY ADDITIONAL INFORMATION RELATED TO TRANSMISSION?

A. Yes. Appendix A provides a list of relevant information requests from the Company's last rate cases in Docket Nos. E002/GR-12-961 and E002/GR-

13-868, and indicates whether the responsive information is included in my testimony or schedules, or if it is provided in Appendix A. Where information was requested for a particular historical timeframe in the last case, the Company has updated the dates to provide information for a comparable timeframe in relation to the filing date of this case.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- *Section II* – NSP System and Transmission Business Unit.
- *Section III* – Capital Investments
- *Section IV* – O&M Budget
- *Section V* – Third-Party Transmission Expenses and Wholesale Revenues
- *Section VI* – Completeness Information
- *Section VII* – Conclusion

II. NSP SYSTEM AND TRANSMISSION SYSTEM BUSINESS UNIT

Q. PLEASE DESCRIBE THE TRANSMISSION BUSINESS UNIT.

A. The Transmission organization centrally manages the combined transmission systems of NSPM and NSPW, Public Service Company of Colorado, and Southwestern Public Service Company so that energy is safely and reliably transmitted from generating resources (both Company-owned and third-party owned) to the distribution systems serving our customers and other Load Serving Entities (LSEs). There are a total of approximately 2,400 operating company employees, XES employees, and contract personnel in the Transmission business area. Of that total, over 1,600 NSPM and XES employees and contract personnel are assigned to, or provide services to NSPM.

Q. PLEASE DESCRIBE THE DEPARTMENTS WITHIN THE TRANSMISSION ORGANIZATION AND THEIR KEY FUNCTIONS.

A. There are 10 different departments within the Transmission organization and each department reports to the Senior Vice-President of Transmission. The key functions of these departments are as follows:

- <u>Substation Operations & Maintenance</u> is responsible for substation field engineering which includes routine and emergency maintenance and operational activities for all Xcel Energy substations. The organization also provides construction support for capital projects, field implementation of certain NERC and Critical Infrastructure Protection (CIP) compliance activities, and "commissioning" new substation facilities. Commissioning of Xcel Energy substation facilities involves ensuring that our substation facilities meet the operational and reliability requirements of FERC and NERC as well as Xcel Energy. The Quality Assurance/Quality Control (QA/QC) process performed by Xcel Energy Commissioning Engineers and Technicians thoroughly tests the equipment and control systems of our electric substations prior to energizing. These processes establish the baseline performance expected by our operations and maintenance organizations and confirm the performance for compliance standards.
- <u>Transmission Planning and Business Relations</u> is responsible for (1) life cycle planning, transmission system planning, and associated capital budgeting; (2) negotiating transmission service related contracts with generators, transmission owners, and distribution utilities; and (3)

resolving wholesale customer transmissions service concerns. I serve as the Director for this organizational area.

- Field Operations provides field services for construction, maintenance, and emergency repairs for transmission assets.
- Strategic Transmission Initiatives manages Xcel Energy's participation in key regional projects throughout its service territory, such as the CapX2020 transmission expansion initiative, as well as other regional projects on and adjacent to Xcel Energy's transmission systems, including the NSP System.
- System Sustainability provides, among other things, electric material and design standards for the design, construction, and maintenance of our transmission assets by interpreting industry standards such as the American National Standards Institute (ANSI). System Sustainability is also responsible for developing Xcel Energy's reliability-centered maintenance programs that ensure the health and reliability of existing assets.
- Transmission Portfolio Delivery is responsible for managing capital projects, programs, and portfolios, including designing and engineering transmission assets, managing third-party contractors, and securing and managing transmission land rights.
- System Operations primarily is responsible for the NERC Balancing Authority and Transmission Operations function for all Xcel Energy transmission systems, including the NSP System.
- Transmission Business Operations directs the Transmission business unit's efforts pertaining to compliance with NERC CIP requirements and directs business performance achievement efforts.

- Transmission Investment Development focuses on Xcel Energy's policies and procedures in the competitive transmission acquisition processes pursuant to various requirements of FERC Order 1000.
- Productivity Through Technology (PTT) is responsible for ensuring business unit workflow functionality needs are incorporated in enterprise process development for asset management, work planning, work management, scheduling, and work execution.

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

A. NSPM and NSPW (jointly the NSP Companies) are vertically-integrated electric utilities that own and operate electric transmission facilities in portions of Minnesota, North Dakota, South Dakota, Wisconsin, and the upper peninsula of Michigan. Together, the NSP Companies own an integrated transmission system (NSP System) comprised of approximately 7,700 miles of transmission facilities operating at voltages between 23.9 kilovolts (kV) and 500 kV, and approximately 557 transmission and distribution substations. The NSP Companies are transmission-owning members of MISO. The NSP System is planned and operated on an integrated basis, and has been under the functional control of MISO since it began operations in February 2002. Transmission service over the NSP System is open access and transmission service reservations can be requested and approved under the terms of the MISO Tariff.

Q. CAN YOU DESCRIBE THE CUSTOMERS SERVED BY THE NSP SYSTEM?

A. The NSP System serves the following two customer groups: (1) retail native loads in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan; and (2) the loads of other investor-owned utilities, cooperatives, and municipal

LSEs, or wholesale customers. The wholesale customers comprise approximately 16 percent of the total demand on the NSP System with the remaining demand comprised of retail native load customers. From a transmission planning and transmission service perspective, our retail customers and the wholesale customers require the same level of service, and as a result the system is planned to serve the needs of each type of customer equally.

Q. OTHER THAN STATE REGULATORY COMMISSIONS, SUCH AS THE MINNESOTA PUBLIC UTILITIES COMMISSION, WHAT OTHER ENTITIES REGULATE THE NSP SYSTEM?

A. The NSP System is regulated primarily by three entities other than state regulatory commissions. First is FERC. FERC is a federal independent agency that regulates the interstate transmission of electricity, natural gas, and oil. The Energy Policy Act of 2005 gave FERC additional responsibilities. As part of that responsibility related to electric transmission, FERC:

- Regulates the transmission and wholesale sales of electricity in interstate commerce;
- Reviews the siting applications for electric transmission projects under limited circumstances;
- Protects the reliability of the high voltage interstate transmission system through mandatory reliability standards;
- Enforces FERC regulatory requirements through imposition of civil penalties and other means; and
- Administers accounting and financial reporting regulations and conduct of regulated companies.

Second is NERC. NERC's primary role is to assure the reliability of the country's bulk transmission system. NERC does this by issuing and enforcing reliability standards which transmission operators, including the Company, are required to comply with; annually assessing seasonal and long-term reliability; monitoring the Bulk Electric System through system awareness; and educating, training, and certifying industry personnel. As the certified Electric Reliability Organization (ERO), NERC is subject to oversight by FERC.

Third is the Midwest Reliability Organization (MRO). MRO is a non-profit organization dedicated to ensuring the reliability and security of the bulk power system in the north central region of North America, including parts of both the United States and Canada. MRO is one of eight regional entities in North America operating under authority from regulators in the United States through a delegation agreement with NERC, and in Canada through arrangements with provincial regulators. The primary purpose of MRO is to ensure compliance with reliability standards and perform regional assessments of the grid's ability to meet the demands for electricity. MRO audits the NSP Companies for compliance with NERC's reliability standards.

Q. PLEASE DESCRIBE MISO AND ITS ROLE WITH RESPECT TO THE NSP SYSTEM.

A. NSPM and NSPW are transmission-owning members of MISO. This means that while the NSP Companies own and maintain their transmission assets, MISO operates the NSP System, in conjunction with the transmission systems of the other 50 transmission owners. Furthermore, MISO establishes: (1) the process and rules for wholesale customers to access the NSP System on a non-discriminatory basis; (2) the annual transmission planning process for expanding or upgrading the regional transmission system, which includes the

NSP System (i.e., MISO Transmission Expansion Plan (MTEP)); and (3) the policies and procedures that provide for the allocation of costs incurred to construct certain transmission upgrades and the distribution of revenues associated with those costs.

III. CAPITAL INVESTMENTS

A. Overview

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I illustrate capital budget trends for Transmission and discuss key capital projects for 2016, 2017 and 2018. I will also provide details regarding how the Transmission business unit develops its annual capital budget and correspondingly identifies and prioritizes Transmission capital projects within the confines of the capital budget. I will also discuss how Transmission monitors and controls spending on capital projects as they move from approval through construction.

Q. GENERALLY SPEAKING, WHAT TYPE OF CAPITAL ADDITIONS ARE PROVIDED BY TRANSMISSION?

A. Our capital additions fall into two types. The first are large capital projects that are often multi-year projects. These projects are capital intensive and are aimed at improving the transmission system, upgrading existing facilities to meet NERC compliance requirements and to accommodate new generation, replacing aging facilities, and making improvements to communication infrastructure and physical security.

In addition to these larger capital projects, Transmission also completes many smaller capital projects each year. These smaller projects make up a majority of the total number of projects that we complete each year. However, these smaller projects make up only a minor part of our overall capital budget. Some examples of these smaller projects include replacement of one to two structures or cross-arms due to age, condition, or storm damage. Figures 1 and 2 below depict this breakdown for 2016 for NSPM. As shown, our capital projects with greater than $10 million in capital additions make up 72 percent of our capital additions each year for NSPM, but comprise only 32 percent of our total number of projects.

Figure 1

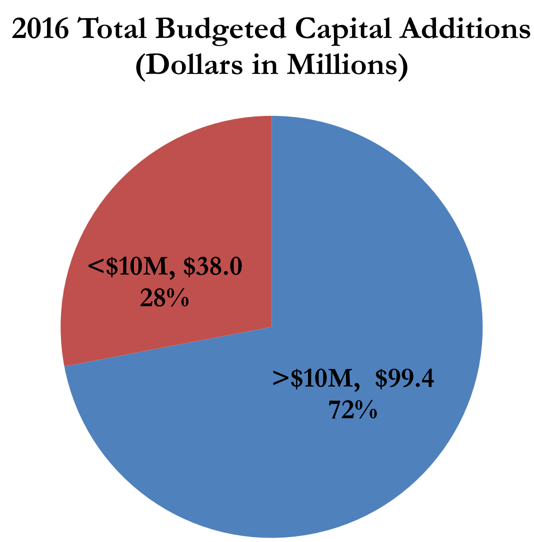
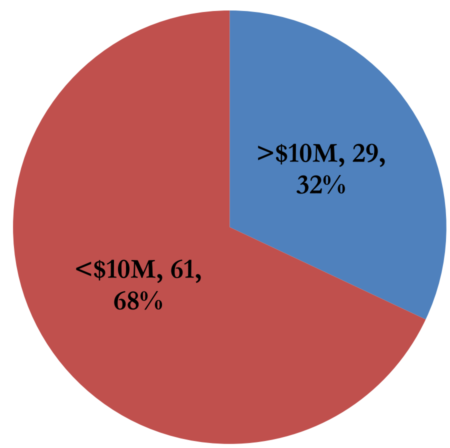


Figure 2

2016 Total Count of Capital Projects
(Dollars in Millions)



Both of these types of capital projects require investments in transmission line components, such as poles, conductors, gang-operated switches, and land rights for transmission line easements. They also include investments in substation components such as transformers, capacitor banks, circuit breakers, remote terminals and real property.

Q. FOR 2012-14, WHAT WERE TRANSMISSION'S KEY STRATEGIC GOALS AND FOCUS DRIVING YOUR CAPITAL INVESTMENTS?

A. Transmission is focused on maintaining the reliability and resilience of the transmission system. Since 2012, much of our planned capital expenditures have been attributed to major capital investments in Regional Expansion projects such as the CapX2020 group of projects (CapX Bemidji, CapX La Crosse, CapX Brookings, and CapX Fargo). These are major 345 kV transmission line projects that provide necessary upgrades to the regional transmission system to support local reliability, regional reliability, and renewable generation outlet. Prior to the CapX projects, there had not been a major upgrade to the upper Midwest's electric transmission grid in nearly 40 years, and these Regional Expansion projects were developed and vetted through regional transmission planning processes.

While the capital additions for these Regional Expansion projects began in 2012 with the completion of the CapX Bemidji project, the peak of capital additions for Regional Expansion projects was reached in 2014 with total capital additions of approximately $436.2 million. These additions were for portions of the following projects that were in-serviced in that year: CapX Fargo, CapX Brookings and CapX La Crosse.

Another component of maintaining system reliability involves compliance with NERC reliability standards. In 2007, FERC granted NERC the legal authority to enforce reliability standards on all transmission owners. There are now over 100 mandatory reliability standards and over 1,000 sub-requirements and NERC is actively engaged in assessing penalties, both monetary and non-monetary for noncompliance. To comply with NERC reliability standards, we continuously study the system because changes in load growth, generation mix, and existing transmission infrastructure can occur each year. These changes can impact whether upgrades are needed to maintain NERC compliance. Between 2012 and 2014, we completed several transmission upgrade projects designed to ensure NERC compliance. For instance, in 2014 the Company completed the Black Dog – Savage 115 kV Project which involved reconstructing four miles of 115 kV double-circuit line between the Black Dog Generating Station and the Savage substation in the southern Twin Cities area to a higher capacity to avoid a violation of NERC's TPL-003 standard.

While our investment spending between 2012 and 2014 has been focused on these Regional Expansion projects and reliability requirement projects, we have also been making incremental investments in asset renewal. However, in 2014 as our investments in Regional Expansion projects peaked, Transmission deferred several of our planned asset renewal investments to 2015 and beyond, to the extent these projects could be deferred without affecting the immediate reliability of our system, to minimize the effect of this investment cycle on customers. Generally speaking, transmission assets have long expected lives. Many of our existing transmission lines, particularly in Minnesota, were placed in-service during the 1960s and 1970s. Our facilities in Wisconsin are even older. Nearly 30 percent of our transmission lines in Wisconsin were placed in-service in the 1940s or earlier. From an asset management perspective, the long asset life of transmission facilities requires on-going monitoring of the health of our assets. A long asset life also allows some flexibility as to when replacements are made. This allows the opportunity to prioritize replacements to deal with unplanned replacements due to storms or budget pressures. However, persistent delay in asset renewal investments can lead to a substantial backlog of replacement needs, higher maintenance expenses, higher risk of equipment failure and obsolescence. Thus, we have tried to maintain steady investments in this area to maintain the reliability of our system.

Q. AND HOW DID YOUR CAPITAL INVESTMENTS BREAK INTO CAPITAL BUDGET GROUPINGS THAT REFLECTED THOSE GOALS?

A. Based on the drivers that I discussed above, our capital projects fall into six capital budget groupings depending on the main purpose of the project. These grouping are:

Regional Expansion: This category includes major high voltage transmission line projects that are developed through the regional planning process and seek to serve multiple needs including regional and local reliability and renewable energy outlet. Generally, these are multi-year initiatives and the types of projects for which we seek a Certificate of Need (CON) and/or Route Permit from the Commission. Examples of Regional Expansion projects include the CapX2020 projects and Multi-Value Projects (MVP) developed through MISO's MTEP process.

Reliability Requirement: Reliability Requirement projects are constructed to ensure that the transmission system is compliant with all NERC reliability standards. The Transmission organization is continually studying the transmission system to assess compliance with NERC standards. These studies analyze the impacts of forecasted load growth, existing and anticipated generation and transmission assets, and firm imports and exports from neighboring systems on the transmission system to determine whether upgrades are necessary. Compliance with NERC reliability standards is mandatory for all users, owners, and operators of the Bulk Electric System. FERC, NERC, and regional reliability entities monitor and enforce compliance. Any entity found non-compliant may be subject to fines of up to $1 million per day per violation.

This category also includes investments related to the implementation of the CIP Version 5 standards. In April 2014, FERC adopted the NERC's Critical CIP Version 5 standards for cybersecurity which will become effective in April 2016. Cybersecurity addresses threats to utility data and control systems

Asset Renewal: This category is primarily for managing the health and performance of transmission assets. The main goal is to ensure that critical assets including transmission lines, substations, and other related assets meet reliability and capacity requirements, while minimizing life-cycle costs. This includes planned replacement of aging transmission lines and substation equipment and unplanned replacement of lines or equipment damaged by storms. This category also includes additions to, or replacement of aging fleet vehicles and tools that support capital additions and line relocations due to road projects.

Interconnection: This category includes projects that we are required to construct under the FERC Open Access Transmission Tariff (OATT) to accommodate interconnection requests from generators, transmission lines, and new load.

Communication Infrastructure: This category includes the fiber optic build-out on the transmission system to improve connectivity for all business areas. This category also includes required communication infrastructure upgrade projects to allow movement of Supervisory Control and Data Acquisition (SCADA) data as telecommunication service providers are retiring the existing obsolete "frame relay" and analog connections.

Physical Security and Resiliency: Grid security has two critical aspects, physical security and grid resiliency. While physical security addresses threats to utility infrastructure, such as transmission lines and substations, grid resiliency addresses the Company's ability to monitor and recover from incidents occurring on our system to limit disturbances that may leave our service territory exposed to prolonged outages. The decision to implement a category relating to this group of projects was instigated by FERC's decision to adopt NERC's CIP-014 in May 2014 which included reliability standards to address physical security threats and vulnerabilities. This category includes projects intended to address these NERC standards and to improve the physical security and grid resiliency of our transmission grid.

I note that many of our capital projects serve multiple purposes but for budgeting purposes we classify the capital project according to its primary purpose.

Q. ARE THERE ANY UNIQUE FEATURES OF TRANSMISSION'S CAPITAL INVESTMENTS?

A. Yes. Unlike other business areas, Transmission is distinct in that many of our capital projects are often several years in development and construction before they are placed in-service as capital additions. This is especially true for these large Regional Expansion projects. Planning, site selection, permitting, site preparation, and then construction can often take three years or more. Thus, the Company may have capital expenditures for a particular project that span multiple years, with an in-service date several years after the first expenses are incurred. For instance, the Big Stone – Brookings Project, which will be described later in my testimony, was approved by MISO in December 2011 and is not expected to be in-service until 2017. This results in greater variability in capital additions as compared to capital expenditures from year to year. However, Company witness Ms. Lisa H. Perkett discusses how, at an overall level, the Company's capital additions tend fundamentally reflect our capital addition forecasts on a year-over-year basis.

Another unique feature of Transmission investments is that a single transmission projects often consist of multiple sub-projects. For example, a project may consist of multiple transmission line segments and substation components. These project's segments and components are often times constructed, energized, and sequentially placed in-service at different times; thus, a single transmission project may have multiple sub-projects with different in-service dates that can span over several different years

Q. FOR 2012 TO 2014, CAN YOU PROVIDE A SUMMARY OF HOW YOUR INVESTMENTS FELL INTO THOSE CAPITAL BUDGET GROUPINGS?

A. Table 1 and Figure 3 below show the breakdown of capital additions by each capital budget grouping for 2012 to 2014. All dollar figures I present throughout my testimony are at the NSPM and NSPW level. The State of Minnesota jurisdictional figures for each capital addition are included in Exhibit___(IRB-1), Schedule 2. In addition, the amounts presented in my testimony include costs recovered or intended to be recovered through the TCR Rider. Ms. Heuer will discuss the TCR Rider in greater detail. I am including these amounts here as these projects are part of our overall transmission capital budget.

Table 1

2012-2014 Capital Plant Additions (Includes AFUDC) (Dollars in Millions)			
NSPM Transmission – Business Unit	**2012**	**2013**	**2014**
Regional Expansion	$42.8	$47.8	$436.2
Reliability Requirement	$42.5	$74.6	$114.8
Asset Renewal	$66.0	$57.6	$35.7
Communication Infrastructure	-	-	-
Interconnection	$1.6	($0.5)	$0.1
Physical Security and Resiliency	-	-	-
Totals	**$152.9**	**$179.5**	**$586.8**

*Amounts may not total due to rounding.

Figure 3

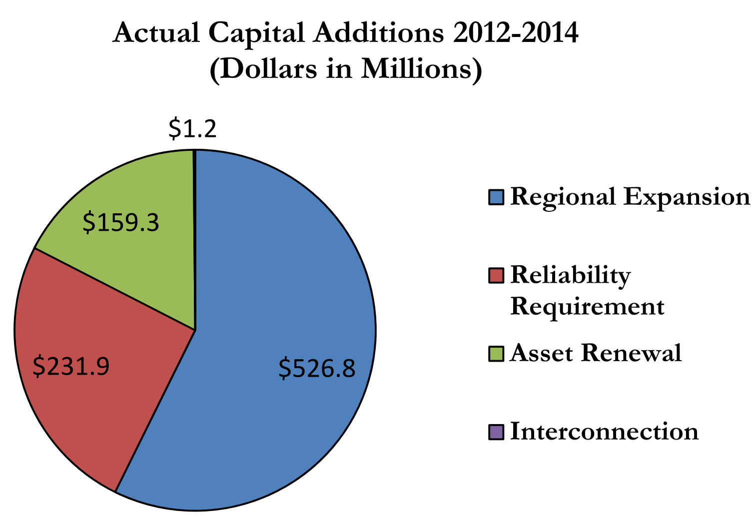


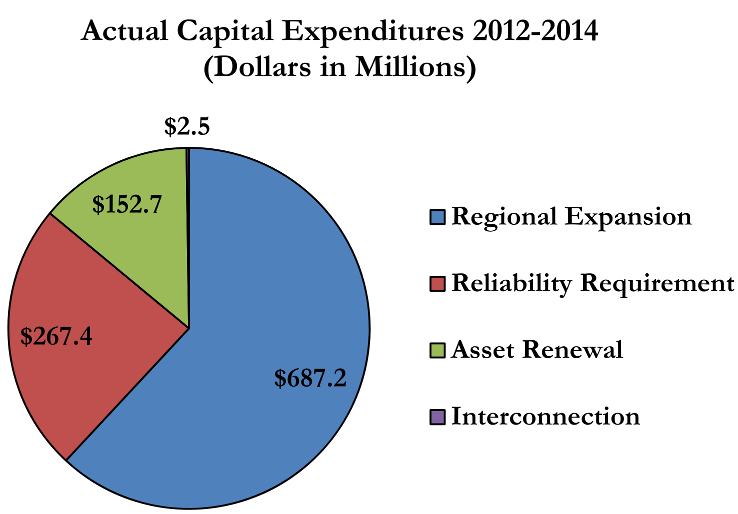
Table 2 and Figure 4 below shows the breakdown of capital expenditures by each capital budget grouping for 2012 to 2014.

Table 2

2012-2014 Capital Expenditures (Excludes AFUDC) (Dollars in Millions)			
NSPM Transmission – Business Unit	**2012**	**2013**	**2014**
Regional Expansion	$169.1	$307.0	$211.1
Reliability Requirement	$75.4	$93.5	$98.6
Asset Renewal	$58.4	$64.2	$30.2
Communication Infrastructure	-	-	-
Interconnection	$2.0	($1.0)	$1.5
Physical Security and Resiliency	-	-	-
Totals	**$304.9**	**$463.7**	**$341.4**

*Amounts may not total due to rounding.

Figure 4



Q. CAN YOU EXPLAIN WHY THE PERCENTAGES OF YOUR INVESTMENTS IN THESE GROUPINGS CHANGED OVER THESE THREE YEARS?

A. Yes. Our investments in for Regional Expansion projects increased through this time period and our capital additions in this grouping were quite considerable in 2014 due to the in-servicing of several portions of the CapX La Crosse, CapX Brookings and CapX Fargo projects. In addition, our investments in Reliability Requirement projects increased during this period as we made capital upgrades to remain in compliance with NERC reliability standards. On the other hand, we deferred a number of Asset Renewal projects between 2012 and 2014 to accommodate our increased investments in these areas.

Q. HOW DID YOUR TOTAL CAPITAL INVESTMENTS OVER THESE YEARS COMPARE TO YOUR BUDGETS?

A. Transmission's NSPM 2012 and 2014 capital additions were seven and eight percent higher than the budget in those years, respectively.

However, in 2013, Transmission's capital additions were 47 percent below budget due to delayed in-service dates for several projects that were the result of unanticipated events. This included portions of the St. Cloud Loop 115 kV project that was to be placed in-service in 2013 to in part, serve the load from the Verso Paper Mill in Sartell, Minnesota. The St. Cloud Loop project was cancelled after a fire at the Verso Paper Mill on May 29, 2012 that eventually resulted in permanent closure of the plant. Two other projects, the Highway 212 Conversion project and the Midtown – Hiawatha project were both delayed due to longer than anticipated permitting activities. But the largest contributor for the under budget performance in 2013 was the delayed in-servicing of a segment of line for the CapX Brookings project. The particular line segment was energized in 2013 however changes in industry accepted guidelines for line galloping modeling required this segment to be re-engineered to provide for the addition of anti-galloping devices to portions of the transmission line determined to be most susceptible to galloping. Galloping can cause phase-to-phase contact causing in unplanned outages. These anti-galloping devices could not be completely installed before the end of 2013, and the project was not fully placed in-service until May 31, 2014. As a result of this delay, there was a $109.1 million negative variance against our 2013 capital addition budget. When this negative variance became apparent, we accelerated several Asset Renewal projects to lessen the impact of the CapX Brooking project's delay. However, given the timing of this delay, and the fact that many of Transmission's capital additions take more than one year to develop and construct, we were unable to completely close this gap for 2013.

Transmission's capital expenditures for NSPM were three percent and eight percent under budget for 2012 and 2013, respectively, and two percent higher than budget for 2014. In 2012, our expenditures were higher than budget in part due to higher than anticipated interconnection requests. The Company receives payment for these interconnections from the requesting interconnection party and these payments exceeded our budgeted amounts. Similar to the 2013 capital additions deficiency, the major contributing factors to the expenditure deficiency for NSPM in 2013 was the elimination of the St. Cloud Loop project and the CapX Brookings project costs were lower than budgeted amounts. Transmission was able to close a portion of this gap by accelerating capital expenditures for steel poles on the CapX Fargo project, purchasing additional matting required to support the construction of several capital projects, and again accelerated several Asset Renewal projects.

Later in my testimony I provide more detail into how our budgets are created, proposed, and managed. I also explain the process of budget rebalancing and project reprioritization in response to budget thresholds established at a corporate level.

Q. LOOKING AT THIS HISTORY, WHAT DO YOU CONCLUDE?

A. In 2013, Transmission faced several unanticipated challenges related to the loss of a large industrial customer and changes in industry practice that caused our capital additions and expenditures for that year to fall below our budgeted amounts. This one-year anomaly is not representative of Transmission's overall investment performance. In 2012 and 2014, our capital additions slightly exceeded our budgets to in-service those projects necessary to maintain the reliability and resiliency of the transmission grid. Regardless of our performance in any particular year, we have made investments in each year that were necessary to meet the Company's overall goals of providing safe, reliable, environmentally sound energy that meets our customers' needs and expectations. Therefore, the Commission can have confidence that our budgets are representative of our actual investment levels and these budgets can be relied on to set just and reasonable rates.

Q. WHAT ARE THE COMPANY'S FORECASTED CAPITAL ADDITIONS FOR 2015?

A. In 2015, we are forecasting approximately $324.2 million of our total $582.8 million capital additions in Regional Expansion projects primarily consisting of portions of the CapX La Crosse, CapX Brookings and CapX Fargo projects. We are also forecasting approximately $176.7 million in capital additions for Reliability Requirement projects and the remainder of our total 2015 capital additions being spread between our other four capital budget groupings.

Q. LOOKING AHEAD, WHAT ARE YOUR CAPITAL FORECASTS FOR 2016-2018 BY CAPITAL BUDGET GROUPING?

A. Over the next several years, Transmission's investment in Regional Expansion projects will begin to levelize as many of our CapX projects will have been placed in-service. The trend for investment in this category for 2016 and 2017 will be centered around the completion of the final segment for CapX La Crosse in 2016 and Big Stone – Brookings in 2017 both described later in my testimony. Our investment in Regional Expansion will trend far below its height of investment in 2014 and 2015 which will allow for Transmission to execute Reliability Requirement and Asset Renewal projects that were deferred into the 2016-2018 period.

Our capital additions forecasts for 2016 through 2018 are set forth in Table 3 and Figure 5. Our capital expenditure forecasts for 2016 through 2018 are set forth in Table 4 and Figure 6. I note that the amounts presented in these tables and figures include costs recovered or intended to be recovered through the TCR Rider. Ms. Heuer will discuss the TCR Rider in greater detail. I am including the TCR Rider projects in my testimony as these projects are part of our overall transmission capital budgets.

Table 3

2016-2018 Forecasted Capital Plant Additions (Includes AFUDC) (Dollars in Millions)			
NSPM Transmission – Business Unit	**2016**	**2017**	**2018**
Regional Expansion	$65.1	$83.8	$3.0
Reliability Requirement	$48.0	$29.5	$137.2
Asset Renewal	$13.9	$15.9	$36.7
Communication Infrastructure	$0.1	$11.3	$11.4
Interconnection	$10.3	$7.0	$5.8
Physical Security and Resiliency	$0.0	$19.9	$10.6
Totals	**$137.4**	**$167.4**	**$204.7**

*Amounts may not total due to rounding.

Figure 5

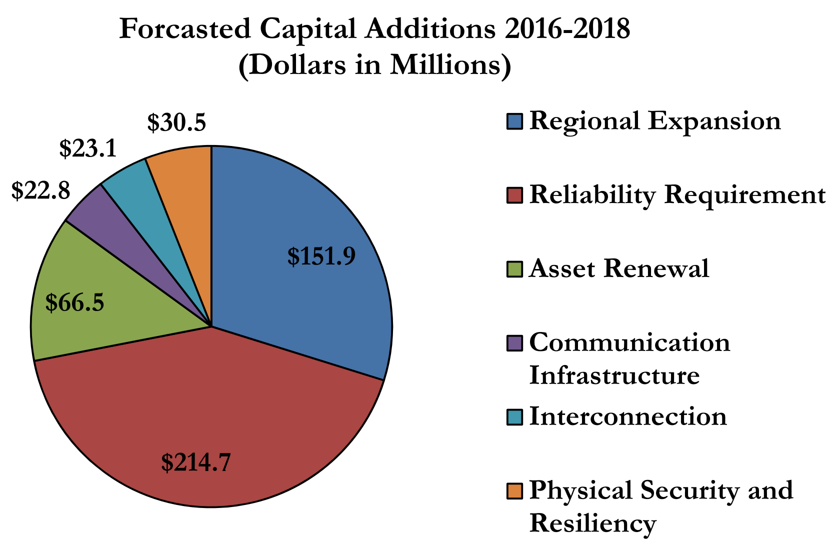


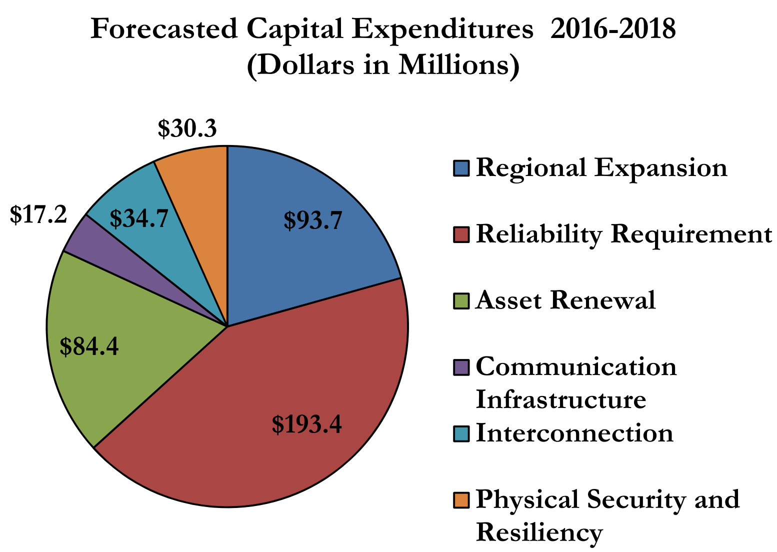
Table 4 and Figure 6 below illustrate those trends in planned capital expenditures.

Table 4

2016-2018 Forecasted Capital Expenditures (Excludes AFUDC) (Dollars in Millions)			
NSPM Transmission – Business Unit	**2016**	**2017**	**2018**
Regional Expansion	$60.9	$29.8	$3.0
Reliability Requirement	$38.0	$82.0	$73.4
Asset Renewal	$18.4	$12.6	$53.4
Communication Infrastructure	$3.4	$2.2	$11.6
Interconnection	$12.5	$13.9	$8.3
Physical Security and Resiliency	$3.7	$16.0	$10.6
Totals	**$137.0**	**$156.5**	**$160.3**

*Amounts may not total due to rounding.

Figure 6



Q. PLEASE EXPLAIN WHY CAPITAL INVESTMENTS ARE DECREASING IN 2016 AND 2017 AS COMPARED TO 2014 AND 2015.

A. During 2014 and 2015, Transmission will in-service a number of large transmission projects, in particular several CapX2020 projects. Coming out of this investment cycle, the Company decided to defer investments in 2016 and

2017 with an understanding that such deferment was not a permanent solution given the ongoing reliability needs of the system. As a result, our forecasted 2016 and 2017 investments are lower than we would typically expect. While this strategy can be accommodated in the short-term, over the long-term it is not possible to delay necessary investments in our transmission infrastructure. As a result, our 2018 capital investments begin to increase as we begin to address the needs that were deferred in 2016 and 2017. An example of a project that was deferred from the 2016 and 2017 budget but that will be completed in 2018 is our rebuild of Line 0734. This project is discussed later in my testimony.

Q. WHAT KEY PROJECTS WILL YOU BE INVESTING IN OVER THIS TIME PERIOD?

A. In addition to the completion of two Regional Expansion projects, CapX La Crosse in 2016 and Big Stone – Brookings in 2017, we will also be investing in several Reliability Requirement projects in Wisconsin and North Dakota in part to maintain NERC compliance in light of increases in peak demand growth in select areas of the NSP System. These projects include: Prairie Substation Expansion, Cedar Falls – Menomonie, Gravel Island Substation, and Minot Load Serving.

Q. WHY ARE THESE INVESTMENTS IN WISCONSIN AND NORTH DAKOTA NECESSARY?

A. The reliability of the NSP System depends not just on the reliability of the transmission facilities located in this state but, due to the integrated nature of the grid, the facilities located in other states. The shared nature and interaction between generation and load throughout the NSP System is one reason why Reliability Requirement projects in one area provide benefit across the larger electric grid, since a deficiency in one area can impact other areas if the issue such as a line tripping out of service were to cascade to other facilities.

In the past few years, there have been major projects and transmission investment located in Minnesota, most significantly the CapX facilities. In total, we, along with our CapX partners, added over 700 miles of new transmission to Minnesota between 2010 and 2015. Part of the next phase of larger transmission build out includes two additional larger 345 kV lines located outside of Minnesota. An additional CapX facility, the Big Stone-Brookings project in South Dakota, and the La Crosse – Madison project which is being jointly developed with American Transmission Company (ATC) in Wisconsin.

In addition to these large Regional Expansion projects, Reliability Requirement investments are needed in North Dakota and Wisconsin in 2016 to 2018. Both North Dakota and Wisconsin have experienced load growth over the past several years driven in part by a strong economy in North Dakota and by new sand mine and pipeline pumping loads in Wisconsin. This load growth is one factor driving the need for Reliability Requirement projects located in these states. Ms. Heuer and Company witness Mr. Charles R. Burdick discuss how costs for NSP System improvements are allocated between the operating companies.

Q. WHAT OTHER PROJECTS DO YOU EXPECT TO DRIVE YOUR INVESTMENTS OVER THESE YEARS?

A. In addition to these Regional Expansion and Reliability Requirement projects, beginning in 2015, we will start work on several projects in the Communications Infrastructure and Physical Security and Resiliency capital budget groupings. Our Communications Infrastructure investments will be focused on replacing third-party owned telecommunication facilities that are necessary for SCADA and teleprotection with Company-owned facilities. Our Physical Security and Resiliency grouping was created to foster investments that will fortify the grid against potential events and identifiable risks that have the potential to cause major grid disruptions. One of our investments in this area will be the purchase of a spare high voltage transformer in 2017 so that the Company is able to quickly restore service in the event one of these transformers is taken out-of-service.

Our 2012 through 2018 capital additions and capital expenditures are set forth in Tables 5 and 6 below. As these tables illustrate, our capital investments will trend downward after 2015 as the many of the Regional Expansion projects are placed in-service. For 2016 to 2018, we will shift our focus toward Reliability Requirement and Asset Health projects but our overall capital additions and expenditures are less than the peak of our investment cycle.

Table 5

2012-2018 Capital Plant Additions (Includes AFUDC) (Dollars in Millions)							
NSPM Business Unit - Transmission	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Regional Expansion	$42.8	$47.8	$436.2	$324.2	$65.1	$83.8	$3.0
Reliability Requirement	$42.5	$74.6	$114.8	$176.7	$48.0	$29.5	$137.2
Asset Renewal	$66.0	$57.6	$35.7	$75.1	$13.9	$15.9	$36.7
Communication Infrastructure	$0.0	$0.0	$0.0	$1.7	$0.1	$11.3	$11.4
Interconnection	$1.6	($0.5)	$0.0	$2.2	$10.3	$7.0	$5.8
Physical Security and Resiliency	$0.0	$0.0	$0.0	$2.9	$0.0	$19.9	$10.6
Totals	**$152.9**	**$179.5**	**$586.7**	**$582.8**	**$137.4**	**$167.4**	**$204.7**

*Amounts may not total due to rounding.

Table 6

2012-2018 Actual and Forecasted Capital Expenditures (Excludes AFUDC) (Dollars in Millions)							
NSPM Business Unit – Transmission	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Regional Expansion	169.1	307.0	211.	83.5	60.9	29.8	3.0
Reliability	75.4	93.5	98.6	129.9	38.	82.0	73.4
Asset Renewal	58.4	64.2	30.2	65.8	18.4	12.6	53.4
Communication Infrastructure	-	-	-	6.7	3.4	2.2	11.6
Interconnection	2.0	(1.0)	1.5	1.3	12.5	13.9	8.3
Physical Security and Resiliency	-	-	-	3.0	3.7	16.0	10.6
Total	**304.9**	**463.7**	**341.4**	**290.3**	**137.0**	**156.5**	**160.3**

*Amounts may not total due to rounding.

Q. WHAT KINDS OF CHANGES COULD OCCUR THAT MAY LEAD TO A RE-PRIORITIZATION OF YOUR INVESTMENTS AND CHANGE THE PERCENTAGES THAT YOU INVEST IN EACH CAPITAL BUDGET GROUPING?

A. There are several reasons why we may need to reprioritize capital investments in a particular year or over several years. For instance, a large unanticipated load addition, such as a data center or a sand mine, at certain portions of our system could require a new Reliability Requirement project to meet NERC reliability standards. In addition, NERC could develop a new reliability or physical security standard that will require us to make new investments to ensure compliance.

Q. WHY IS THE ABILITY TO CHANGE THESE INVESTMENT PERCENTAGES IMPORTANT TO THE COMPANY AND YOUR CUSTOMERS?

A. Given that the needs of the transmission system can change based on new load additions and new NERC reliability requirements, Transmission must have the flexibility to address these emerging needs.

Q. IS IT NECESSARY FOR TRANSMISSION TO ADJUST PROJECT PLANNING ON A REGULAR BASIS?

A. Yes, for the reasons noted above. As a recent example, a line rebuild project for Line 0734, in our Asset Renewal capital budget grouping was removed from our 2017 budget. This existing 69 kV line is planned to be rebuilt because of age and condition of the existing line and the fact that the rebuilt line will provide additional capacity to support projected load growth in the western Twin Cities. This project was moved from our 2017 budget to our 2018 budget because it is not necessary to address an imminent NERC compliance issue and there were other more pressing needs in 2017. Thus, while this project (and the other projects that have been deferred from our budget) will provide a benefit to our customers by increasing our overall reliability to the transmission system, it is not mandated by a compliance obligation which is why it was deferred through our budget reprioritization process to a later date.

Q. SHOULD CUSTOMERS BE CONCERNED THAT SPECIFIC PROJECT PLANS EVOLVE?

A. No. When we make adjustments to our capital investment plans, we do so to better serve our customers' and our Company's most urgent needs in the most cost-effective way. When the need arises to accelerate a project or develop a new project, we assess the situation to make sure we are doing so for the right reasons and in a prudent way. Similarly, we assess potential project delays or cancellations to make sure we are still meeting business and customer needs in a reasonable way.

Q. EVEN IF YOUR INVESTMENT PERCENTAGES CHANGE FROM THE CURRENT FORECAST, WILL TRANSMISSION STILL MANAGE ITS OVERALL CAPITAL INVESTMENTS TO ITS OVERALL BUDGET?

A. Yes. While our investments in particular capital budget groupings may change to address unanticipated issues, ultimately, we will invest as necessary to meet our overall goals of safe and reliable transmission of energy for our customers.

Q. SO WHAT DO YOU CONCLUDE ABOUT TRANSMISSION'S 2016 – 2018 CAPITAL INVESTMENT FORECASTS?

A. I conclude that our capital forecasts represent an accurate and reasonable picture of our investments over these years. Therefore, these forecasts can be relied on to set just and reasonable rates for our customers.

B. Transmission Investment Strategy

1. Reasonableness of Overall Budget

Q. PLEASE MAKE THE BUSINESS CASE FOR TRANSMISSION'S CAPITAL PROGRAM.

A. The transmission network constructed and maintained by the Transmission business unit includes the facilities that link electricity to flow from generation resources to our customers. Resiliency is built into the transmission system, creating a network to provide electric companies with alternative operating procedures for power paths and to efficiently access electricity generation across the MISO system—even from other power suppliers. Reliable electric service depends on a strong transmission system. The Transmission organization has and continues to make cost-effective investments in needed and beneficial transmission infrastructure. These investments ensure the reliable electric service that homes and businesses expect, while also supporting competitive wholesale electricity markets and a diverse generation portfolio. The Transmission capital program is designed to provide a reliable, modern grid in a cost-effective manner. This dedication to build a transmission grid to support 21st century demands provides numerous consumer benefits.

Without ongoing investments in our transmission system, we put the reliability and efficiency of this system at risk. The Transmission organization also realizes that the Company's overall budget is limited and we seek to prioritize projects in a manner that achieves an appropriate balance in maintaining the health and reliability of our transmission system but also making long-term cost-effective investments for our customers. We have also employed processes to control costs.

Q. HOW DOES TRANSMISSION ESTABLISH A REASONABLE CAPITAL BUDGET FOR A GIVEN YEAR?

A. The appropriate annual capital budget for Transmission is based on a collaboration between corporate management of overall Company finances and the business needs that are identified by Transmission. Company witness Mr. Gregory J. Robinson explains how the Company establishes overall business area capital spending guidelines and budgets based on financing availability, specific needs of business areas, and overall needs of the Company.

At the same time, Transmission employs a "bottom up" budgeting process to identify the capital projects that we need to complete within a specific year for our business area. All of our capital projects are executed under our Capital Project Governance Process. This governance process has policies and procedures in place that enable Transmission to prioritize and balance our budget such that we appropriately allocate funds. Our capital budgeting process includes four main steps:

1. Identification of potential projects;
2. Vetting of potential projects;
3. Prioritization of potential projects; and
4. Rebalancing and reprioritization of projects based on corporate budget requirements.

I will explain the Transmission budgeting process in more detail below.

2. *Transmission Capital Budget Policies and Procedures*

Q. CAN YOU PROVIDE AN OVERVIEW OF TRANSMISSION'S CAPITAL BUDGET POLICIES?

A. Yes. Transmission has developed a set of policies and procedures to establish and manage our capital project portfolio. The purpose of these policies and procedures is to define how capital projects are identified, estimated, approved, executed, monitored and controlled, and changed as they move from origination to completion. These policies also help to ensure that we manage and time our capital investments appropriately to keep costs reasonably level over time. Our policies and procedures are aligned with the Corporate governance approval requirements that Mr. Robinson addresses.

Q. CAN YOU PROVIDE AN INTRODUCTION TO TRANSMISSION'S ANNUAL BUDGETING PROCESS AND SPECIFICALLY HOW NEW AND EXISTING PROJECTS ARE ADDRESSED IN PREPARING TRANSMISSION'S CAPITAL BUDGET?

A. Yes. Existing projects are defined as projects that were previously approved based on the Corporate governance approval requirements that Company witness Mr. Robinson describes. New projects are defined as projects that have not been previously approved. Preparing transmission's annual budget is a very dynamic process where new project needs and financial requirements are prioritized and compete against existing projects that most often take multiple years from initial budget approval to construction complete.

a. *New Project Identification*

Q. WHAT IS THE FIRST STEP IN YOUR BUDGETING PROCESS?

A. We begin our budgeting process by identifying and assessing the potential work that is proposed for integration into the current five-year budget period.

New projects must satisfy a clearly defined purpose and need. The criteria used to identify and assess transmission projects are based on the six capital budget groupings I discussed earlier.

Q. HOW ARE RELIABILITY REQUIREMENT PROJECTS IDENTIFIED?

A. NERC requires utilities to perform annual assessments of their transmission system for the 10-year planning horizon. The Company performs this annual assessment working through the Minnesota Transmission Assessment and Compliance Team (MN TACT), which is a group of transmission-owning utilities in Minnesota and surrounding states. NERC requires utilities to demonstrate plans to keep the transmission system within limits (voltage, thermal, and stability) throughout the 10-year planning period. MN TACT participants work together to analyze the transmission system for deficiencies (high voltage, low voltage, lines or transformers beyond their rated capability, etc.), and when deficiencies are identified, plans are created to manage the transmission system to stay within limits. To the extent that keeping the transmission system within limits requires a new capital investment such as a transmission line or transformer upgrade to increase the capability of the transmission system, the timing of that needed upgrade is identified (i.e., the year the thermal overload shows up in the analysis is the year the project is needed) and a capital project is identified to address the issue. As part of the planning process, various system solutions are evaluated to meet the identified needs and planners select the alternative that provides the best long-term cost-effective solution to meet the NERC standard.

Q. HOW ARE REGIONAL EXPANSION PROJECTS IDENTIFIED?

A. As I mentioned earlier, the Company takes part in regional transmission planning efforts to identify needed Regional Expansion projects. In the past, the Company has been involved with the CapX2020 initiative. This joint initiative of 11 transmission-owning utilities, including the NSP Companies, in the Upper Midwest identified projects to expand the electric transmission grid to ensure continued reliable service to 2020 and beyond. The Company also takes part in the MISO's yearly MTEP which works with all MISO transmission owners and stakeholders to identify Regional Expansion projects.

Through these regional transmission planning processes, regional system needs are identified and possible solutions are developed and vetted. The solutions that best meet the long-term needs of the regional transmission system are then approved. In the MISO MTEP process, this requires approval from the MISO Board of Directors.

Q. HOW DO YOU IDENTIFY ASSET RENEWAL PROJECTS?

A. Our System Sustainability group identifies facilities in need of replacement or refurbishment based on a variety of factors. For transmission lines, these factors include: the importance of a particular line to being able to reliably serve customers, the line's age and condition, and the line's reliability history. These factors receive different weights to determine which lines are in the greatest need for replacement. Generally speaking, those lines that will impact the most customers if they fail are placed higher on the list for replacement. For substation assets, a similar matrix is used. The System Sustainability group then uses these lists to determine the urgency of each replacement and identifies specific projects for possible inclusion in the budget.

Asset Renewal projects also include relocations required by road construction projects and we work with federal, state, and local highway and road departments to identify any needed relocations.

In addition, our Asset Renewal projects include additions, repairs, and replacement of our existing fleet of vehicles. Each year field operations and fleet managers along with the Transmission construction directors examine our existing fleet. The Company uses an "Old Fleet Strategy" where it performs continued maintenance to our fleet without regard to life expectancy or depreciation value of the assets until maintenance costs of the asset become cost prohibitive, i.e., the cost of a single repair exceeds the value of the asset. Also, as a part of this strategy the Company uses the average age of fleet assets being retired (specific to Class) to determine the baseline for which it estimates single unit replacement costs as the unit approaches the baseline for replacement within the five-year budget.

Q. HOW DO YOU DEVELOP AN INITIAL LIST OF INTERCONNECTION PROJECTS FOR THE BUDGETING PROCESS?

A. Our transmission planning department gathers all available information from interconnection requests submitted to the Company, either internally where our Company is requesting to interconnect a new or modify an existing substation, or from other utilities, and from MISO who administers generation interconnections, and from any transmission interconnection requests received from other companies.

Q. DO YOU DEVELOP A BUDGET TO ACCOUNT FOR PREVIOUSLY UNIDENTIFIED INTERCONNECTION REQUESTS?

A. Yes. The Company typically receives interconnection requests year-round, some of which will require specific funding in years that were not previously planned for in our typical budget cycle. For these projects, not taken into account in our typical budget cycle, the Company holds funding in its budget based on historical averages and known demand (i.e., fracking sand mining industry) of Interconnection project requests that were not known at the time of budget create in a program called Interconnection Agreement (IA) Tariff Fund. As the Company receives these previously unknown interconnection requests, funding is diverted from the IA Tariff fund to a specific interconnection project that is created and results in a net zero expenditure impact to the overall Interconnection budget.

Q. HOW ARE COMMUNICATION INFRASTRUCTURE PROJECTS FIRST IDENTIFIED?

A. Our Substation Communication engineering group identifies and assesses projects based on a specific rubric that takes into account issues like Bulk Electric System criticality, past performance of systems currently in-service, O&M costs associated with existing leased connections, telecommunication companies phasing out certain technology, benefit to other business areas, and integration into existing company-owned infrastructure. Based on this analysis, the Substation Communication engineering group identifies certain projects for possible inclusion in the budget.

Q. HOW ARE PHYSICAL SECURITY AND RESILIENCY PROJECTS IDENTIFIED?

A. Based on the 2014 NERC CIP-014 standard, the Company performed a vulnerability analysis of all of our Bulk Electric System substations within the

NSP System. While we are awaiting third-party review of this study, as required by NERC, we did identify critical physical security improvements and these projects were identified for inclusion in our most recent capital budget. CIP-014 requires that we reevaluate our system every two years so we anticipate that this biennial study will help us identify these capital projects.

b. New Project Vetting

Q. AFTER THE LIST OF POSSIBLE CAPITAL PROJECTS IS DEVELOPED WITHIN THESE SIX CAPITAL BUDGET GROUPINGS FOR INTEGRATION INTO THE BUDGET, WHAT IS THE NEXT STEP IN THE BUDGETING PROCESS?

A. The project originator develops a proposed statement of work for each project normally consisting of the proposed preliminary scope, project description, necessity description, alternatives and proposed option, consequences of not doing the project, and a basic electric circuit diagram.

A multi-disciplinary project team whose members have functional skills including financial management, project management, design & engineering, system operations, construction, siting & land rights, scheduling, vegetation management and planning are assembled to develop the project's detailed preliminary scope and schedule with supporting documentation. The project team may prepare multiple indicative estimates to evaluate alternatives and select the preferred option.

Q. WHAT IS AN INDICATIVE COST ESTIMATE?

A. An indicative estimate is used to assess different system solutions and compare proposed solutions against other alternatives as well as to identify the most reasonable electrical and financial solution that meets transmission needs as part of overall resource planning. It is done before engineering, permitting and land acquisition has started. It is based on historical experience and its broad range of accuracy is due to the fact that an indicative estimate measures the cost of large asset units, i.e., cost/mile of a 115 kV transmission line. This is consistent with the purpose of the indicative estimate – to preliminarily identify the financial impact to Transmission's budget and to make very high-level decisions on system solution options. For example, an indicative estimate is used to compare the efficacy of building a double circuit 115 kV line versus a single circuit 230 kV line.

Indicative estimates are occasionally used for anticipated, but preliminary, projects proposed for the latter years of Transmission's five-year budget plan. These projects are preliminary because there may be an electrical need but the project scope and/or need date have not been finalized due to a variety of reasons. For example, an electrical system deficiency is identified but more time is needed to validate the project need, scope, need date, and ultimately the project cost. The purpose of indicative estimates for these projects is to show a preliminary view of financial demand for corporate budget planning. During ensuing budget cycles these projects are either negated or are advanced based on need with a more refined scope, schedule, and cost estimate.

Q. WHY IS COST ESTIMATING IMPORTANT TO THE BUDGET PROCESS?

A. Cost estimates are a critical element in the budgeting process and help decision makers evaluate projects and make informed decisions. Cost estimates also provide a crucial role in the continuous evaluation and integration of Transmission's five-year budget plan by providing a financial outlook for both new and ongoing projects within our budget constraints.

For new projects, they provide a critical look into the future financial needs to reliably operate the transmission system. For ongoing projects, as they progress; cost estimates provide more detailed and developed earned value estimates that allow us to integrate, manage, and time our capital investments appropriately to keep costs reasonably level over time.

The general purposes of cost estimates are:

- Help evaluate and select alternative solutions;
- Support the budget process by providing estimates for proposed and the earned value for ongoing projects;
- Establish a project performance baseline of cost, scope and schedule; and
- Support approval for acquisition of materials, services and contracts.

A cost estimate package also addresses and documents the project's scope and schedule, including items such as estimate assumptions, methodology and rationale, and the results of the risk analysis. Therefore, a good cost estimate – while taking the form of a single number – is supported by detailed documentation that describes how it was derived and how the expected funding will be spent to achieve the project's objective.

Q. WHAT IS 'EARNED VALUE' ESTIMATING?

A. Simply defined, earned value management is the method of cost management that incorporates the actual cost of capital work in progress (CWIP) with the budgeted estimate of work to be performed to forecast the total estimated cost at completion (EAC). The earned value management of projects plays a very important part when considering the integration of new budget projects to the transmission budget to quantify alignment with corporate budget directives.

Q. WHAT HAPPENS AFTER THE PRELIMINARY SCOPE IS DEVELOPED?

A. The proposed project is presented for preliminary scope approval at the regular occurring Constructability (C1) Meeting. All projects must pass through this C1 gate before proceeding to the next project phase. At this C1 Meeting, the project's preliminary scope is peer reviewed by employees from relevant functional areas of the transmission organization (including project management, engineering design, transmission planning, siting and land rights, construction, and operations). The objective of this meeting is to review and challenge the project need and the proposed preliminary scope while looking for fatal flaws or better solutions. Project alternatives are reviewed to determine whether the proposed solution is the most cost-effective and provides the most long-term value for our customers.

Approval at the C1 Meeting allows the project to pass through the C1 gate to the next step in the process. Projects not approved at the C1 Meeting are either cancelled or returned to the project origination phase for further need and preliminary scope development based on peer review feedback at the C1 Meeting. The project may be re-presented at a future C1 Meeting for approval.

Q. IF A PROJECT IS APPROVED AT A C1 MEETING, WHAT IS THE NEXT STEP?

A. The project proceeds to the scoping estimate package development phase. The Project Manager initiates this phase by requesting a scoping estimate package based on the C1 approved preliminary scope.

The scoping estimate is used to further develop the impact of the capital component to Transmission's corporate budget, further assess proposed system solutions against other alternatives, and to make the internal decision to proceed to the permitting process. These are also the cost estimates we present in the CON stage of the transmission permitting process, when a CON is required from the Commission. The cost estimate at this stage incorporates a range of +/- 30 percent.

The scoping estimate is produced before detailed engineering design and siting & land rights activity has begun or is only approximately five percent complete. The estimate will be based on typical conditions encountered on past construction projects and may utilize historical cost data from other comparable projects. Each identified project part should be estimated separately. For example, a transmission line segment and substation would each have their own estimate. The estimate must include costs for:

- project management;
- permitting (including regulatory and legal work);
- engineering and design;
- equipment and material purchase;
- construction and removal, testing, and commissioning;
- repair of land and crop damages;
- vegetation management;
- land and land rights acquisition; and
- any other costs directly associated with the project.

The cost estimate is created using Hard Dollar which is a commercial estimating software that meets these objectives:

- a standard enterprise-wide estimating tool;
- capability to store estimates in a searchable database for reporting, research and use for future estimates;
- standard estimating templates/formats for consistency; and
- the ability to accurately estimate capital projects and track estimating and construction performance.

The scoping estimate package typically includes the project scope, assumptions, risks, major milestone schedule with durations, electric circuit configuration diagram, and detailed cost components including overheads, allowance for funds during construction (AFUDC), escalation and contingencies.

The scoping estimate package is routed for management approval. After management approval the project passes through the Scoping Estimate Package Approval gate.

Q. WHAT IS THE NEXT STEP AFTER APPROVAL OF THE SCOPING ESTIMATE PACKAGE?

A. New projects proposed to be integrated into the budget enter into the Budget Approval phase, which aligns with the budgeting and budget governance process that Mr. Robinson addresses in his testimony. Each business unit including Transmission works closely with corporate Financial Performance and Reporting to develop capital budgets. Transmission management is responsible for developing its capital budget proposal and applying the Corporate budget instructions.

The first activity for Transmission in the Budget Approval phase involves the Project Manager entering the new proposed project attributes, proposed monthly cash flow, and in-service date into Transmission's budgeting and forecast software tool called Tamcasting. Also, previously approved project estimates and in-service dates are validated and continuously updated throughout the year in Tamcasting.

c. Existing Project Cost Estimates

Q. HOW ARE EXISTING PROJECTS INCLUDED IN THE TRANSMISSION BUDGET?

A. Once a project is approved for inclusion in the budget, each project will be assigned a forecasted spending plan of expenditures through the project's in-service date. These cost estimates are refined depending on the specific life-cycle stage of the project.

Q. DESCRIBE THE LIFE-CYCLE STAGES FOR A TRANSMISSION PROJECT.

A. These life-cycle stages are generally described as: developing, planned, final engineering, and under construction. The cost estimates produced at each of these stages reflect the correlating scope and earned value cost estimate with respect to the varying stages of project implementation. Transmission's five-year budget plan integrates capital cost estimates for projects in all four stages of implementation. For example, the first one to three years of the existing budget will typically include a high volume of project estimates that reflect the "final engineering" or "under construction" phase. Conversely, projects in years three to five typically include project estimates correlating to the "developing" or "planned" phases depending on the activities needed to complete the project by the needed in-service date.

Q. WHAT ARE THE FOUR TYPES OF COST ESTIMATES THAT CORRELATE WITH THESE DIFFERENT LIFE-CYCLE STAGES?

A. The four estimates we use are:

- Indicative estimate (+/- 50 percent) – used to assess system solutions and weigh proposed solutions against other alternatives as well as to identify the most reasonable electrical and financial solution that meets transmission needs as part of overall resource planning. Indicative estimates may be included in the latter years of Transmission's five-year budget plan to identify an electrical and financial need for 'developing' projects.
- Scoping estimate (+/- 30 percent) – primarily used to develop the capital component of Transmission's five-year corporate budget, further assess proposed system solutions against other alternatives and make internal decisions to proceed to the permitting process. These are also the cost estimates we present in a CON application, when a CON is required. Projects with a scoping estimate are typically in the 'planned' phase of implementation meaning the project either has or is awaiting the appropriate corporate governance approval or permit approval to proceed.

  Additionally a project in the budget with a scoping estimate may be at a point where all approvals have been received but the activities required to execute the project by the needed in-service date does not necessitate the need to begin 'final engineering'. When this is the case the scoping estimate is refreshed, at a minimum annually, to reflect changes caused by orders received through the approval processes and to update for current commodity and labor costs. Often projects that are at the scoping estimate phase and have been previously integrated into the budget are the first to be weighed against proposed projects for prioritization because their critical path activities leading to their proposed in-service date have not begun.

- Appropriation estimate (+/- 20 percent) – used to refine the scoping estimate once corporate governance approval and all permits (including final Route Permit) are received and actual location of the project is known. An appropriation estimate requires a higher degree of rigor by all stakeholders for its development and is also subject to the highest degree of peer and managerial approval of the scope. Appropriation estimates are typically associated with the late stages of the 'planned' phase and the early stages of the 'final engineering'. It is at this point when a project's final in-service date is set based on the critical path of activities required to meet that in-service date.
- Engineering estimate (+/- 10 percent) – used to incorporate up-to-date material and labor costs into the project budget prior to actual construction. This estimate brings a project to the 'final engineering' phase of project implementation.

d. Project Prioritization

Q. AFTER ALL POSSIBLE PROJECTS ARE PLACED IN TAMCASTING, WHAT IS THE NEXT STEP?

A. Our directors and managers, along with other key employees review all possible projects that are entered into Tamcasting and represent our proposed budget to determine whether they should be implemented and included in the Transmission budget.

As many of our Regional Expansion and Reliability Requirement projects are multi-year projects, once these projects have commenced, it is difficult to halt or defund these projects in subsequent budget years. We do, however, examine all capital expenditures for a given year to determine whether they are necessary to carry out the final execution of those projects. As a result, these projects often receive higher priority in our budgeting process as they move forward toward completion. Similarly, given our Tariff obligations, we do not have much latitude to deny specific Interconnection projects from being included in our budget.

After we determine the portion of our budget that is committed to these projects, we examine our remaining budget and determine how to prioritize the remaining proposed projects and previously planned projects. We prioritize those projects based on the risk and urgency of a particular project.

After a series of meetings to discuss all of the potential projects and the appropriate prioritization given funding availability, the result is an initial capital budget for Transmission.

Q. AFTER THE INITIAL BUDGET IS DETERMINED, WHAT IS THE NEXT STEP?

A. Transmission's proposed capital budget moves through the corporate budgeting process discussed by Mr. Robinson. Based on the corporate budgeting process, a higher or lower percentage of the Company's overall budget may be allocated to Transmission depending on the priority of needs at the Company level. Once the corporate budgeting process is complete, Transmission may be able to maintain its capital budget as proposed or it may need to adjust based on the thresholds established at a corporate level.

e. Reprioritization of Projects

Q. WHAT HAPPENS IF TRANSMISSION DOES NOT RECEIVE ALL OF ITS REQUESTED FUNDING?

A. The capital projects that Transmission identifies as necessary in a particular year often exceed the budget thresholds established at a corporate level. When this occurs, our directors and managers reexamine our budget and reprioritize our capital projects based on the new thresholds. During the reprioritization process we carefully evaluate all of the system risks associated with each of these budget reduction scenarios and reevaluate all mitigation plans that may mean a suboptimal operation of the transmission system but ensure our compliance with all mandated system reliability standards.

Q. CAN YOU PROVIDE AN EXAMPLE OF A PROJECT THAT WAS ELIMINATED FROM TRANSMISSION'S CAPITAL BUDGET BASED ON THIS REPRIORITIZATION?

A. Our Wilson Substation Conversion project was proposed for inclusion in our 2016 budget but it was ultimately deferred until 2019 due to reprioritization.

Q. IF YOU ARE ABLE TO DEFER THIS PROJECT, IS IT EVEN NECESSARY?

A. This planned project is needed; but it is not needed to address an imminent NERC compliance issue and thus can be deferred. This project eliminates a suboptimal substation configuration that does not meet the Company's current substation design standards. By reconfiguring this substation design, this project will eliminate maintenance outage challenges, decrease our system reliability exposure of radializing the high profile loads at our East Bloomington and Airport substations, and will address potential NERC TPL-003 compliance needs in the future. So, while this project (and the other projects that have been deferred from our budget) will provide benefit to our customers by increasing our overall reliability to the transmission system, they are not mandated by a real-time compliance violation, which makes them uniquely qualified for deferral due to budgeting constraints.

Q. DOES THIS BUDGETING PROCESS THAT YOU HAVE DESCRIBED ENSURE THAT TRANSMISSION'S CAPITAL ADDITIONS ARE REASONABLE AND NECESSARY IN EACH YEAR OF THIS MULTI-YEAR RATE PLAN?

A. Yes. This budgeting process results in a reasonable budget that is representative of the capital investments needed to maintain the reliability of the transmission system used to provide electric service to our customers, provide necessary upgrades to the regional transmission system, comply with NERC reliability requirements and other policy drivers, meet system capacity needs, and ensure the health of existing assets.

f. Project Performance

Q. PLEASE EXPLAIN THE PROCESS YOU FOLLOW TO MANAGE CAPITAL EXPENDITURES AFTER BUDGET APPROVAL.

A. From a financial perspective, capital projects are reviewed on a monthly basis after approval to compare the monthly budget to actual funds spent. We perform a monthly project forecasting exercise to ensure we have a steady and dependable flow of financial information regarding capital expenditures. Through this process, the entire Transmission project portfolio is reviewed and consolidated each month. Any variances are immediately addressed. All projects that indicate they may be outside of allowed variances are reevaluated and assessed internally by the Transmission business unit and may be escalated to the corporate level. For larger projects, greater than or equal to $10 million, we adhere to the corporate guidelines to seek "re-approval" of projects outside allowed variances of 20 percent.

Review is also performed to compare year-to-date actual performance with year-to-date and year-end forecasts. Deviations are identified and recommendations to meet financial targets are reviewed and approved. Changes are reported to the Financial Performance and Planning group, which monitors capital spending.

The Transmission business unit is expected to manage its capital additions to its capital budget once that budget has been developed, fully-vetted, and approved. The budgeting process and accountability tools allow us to do so. With the implementation of the budgeting process certain metrics measuring individual project performance can become skewed as a variance in a single project can create changes to other projects. For instance, if one project is delayed, other projects may be moved forward to fill the gap to maintain the overall capital budget. Through this process, Transmission performs well at an overall budget level providing comfort to our stakeholders that our budgets are just and reasonable as well as reliable.

C. Major Planned Investments

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. This section of my testimony discusses the major planned investments Transmission anticipates in 2016 through 2018. All dollar figures I present throughout my testimony are at the NSPM and NSPW level. The State of Minnesota jurisdictional figures for each capital addition are included in Schedule 2.

Q. HOW DID TRANSMISSION IDENTIFY ITS MAJOR PLANNED INVESTMENTS OVER THE PLAN PERIOD?

A. To identify these investments, we looked for those unique projects that require a greater than normal quantity of Transmission resources to complete and that contribute to our overall major planned investments.

Q. WHAT MAJOR PLANNED INVESTMENTS DOES TRANSMISSION ANTICIPATE COMPLETING OVER THE PERIOD OF THIS MULTI-YEAR RATE PLAN?

A. As depicted in Table 7, we anticipate undertaking four major planned investments between 2016 and 2018. These projects include four of our Regional Expansion projects: CapX La Crosse, CapX Brookings, La Crosse – Madison, and Big Stone – Brookings.

Table 7

Project	NSPM Capital Additions (Includes AFUDC) (Dollars in Millions)		
	2016	2017	2018
CapX La Crosse (NSPM)	$61.1	-	-
CapX Brookings	$3.5	$(1.0)	-
Big Stone-Brookings	$0.4	$84.8	$2.5
Total	**$65.0**	**$83.8**	**$2.5**

Project	NSPW Capital Additions (Includes AFUDC) (Dollars in Millions)		
	2016	2017	2018
CapX La Crosse (NSPW)	$0.5	-	-
La Crosse – Madison	$7.2	$8.2	200.9
Total	**$7.7**	**$8.2**	**$200.9**

These projects will continue over multiple years, with portions of the projects placed in-service as they are put to use each year. These major planned investments, as well as the additional key capital projects we anticipate completing in 2016, 2017 and 2018 are discussed in more detail below.

Q. WHY IS THE CAPX FARGO PROJECT NOT CONSIDERED A MAJOR PLANNED INVESTMENT?

A. The CapX Fargo Project is currently in-service and has no capital additions during the plan period (2016-2018).

Q. DOES THE COMPANY PLAN TO RECOVER FOR ANY OF THESE PROJECTS THROUGH THE TCR RIDER?

A. Yes. The CapX La Crosse, La Crosse – Madison, and the Big Stone – Brookings projects are or will be recovered through the TCR. I am only including them here as they also qualify, for ratemaking purposes, as major planned investments during the plan period. Ms. Heuer will provide additional information on TCR recovery of these projects.

Q. IS THE COMPANY PROPOSING TO MOVE ANY INVESTMENT RECOVERY FOR THESE INVESTMENTS FROM THE TCR INTO BASE RATES ?

A. Two projects currently in the TCR, CapX2020 Fargo and CapX2020 Brookings, are in-service and will be transferred from the TCR to recovery in base rates with the implementation of final rates. Ms. Heuer will provide additional information regarding this roll-in.

D. 2016 Capital Additions

Q. WHAT CAPITAL ADDITIONS IS THE COMPANY PROPOSING TO MAKE IN 2016?

A. The total NSPM Transmission 2016 capital additions are budgeted to be approximately $137.4 million. This capital additions budget includes a number of projects that are categorized below in Table 8 according to the capital budget groupings I described earlier.

Table 8

2016 Transmission Capital Additions	Total NSPM (Includes AFUDC) (Dollars in Millions)
Regional Expansion	$65.1
Reliability Requirement	$48.0
Asset Renewal	$13.9
Communication Infrastructure	$0.1
Interconnection	$10.3
Physical Security and Resiliency	$0.0
Total	**$137.4**

1. Regional Expansion Projects

Q. WHAT IS DRIVING TRANSMISSION'S REGIONAL EXPANSION INVESTMENTS?

A. The Company has been working internally and with other regional peers through both the CapX2020 initiative and the MTEP to identify regional transmission projects to address reliability issues on the regional bulk transmission system, to alleviate congestion on the grid to reduce overall energy costs, and enable greater generation outlet, in particular renewable energy.

Access to renewable generation is becoming increasingly important. In August 2015 the EPA issued final rules and standards for its Clean Power Plan. The Clean Power Plan establishes state-by-state targets for carbon emissions reductions and renewable energy sources will play a key role in enabling states to meet these targets.

The CapX2020 initiative involved collaboration between 11 transmission-owning utilities in Minnesota, North Dakota, South Dakota, and Wisconsin to study and plan for the future of the regional transmission system. The result was multiple transmission planning studies that supported the development of the CapX Bemidji, CapX Fargo, CapX Brookings, CapX La Crosse, and CapX Big Stone – Brookings projects. The Company and its CapX partners have obtained all necessary state regulatory approvals for these projects and these projects are either currently under construction or they are completed. The final CapX2020 project, CapX Big Stone – Brookings, is scheduled to be placed in-service in 2017.

Outside of the CapX2020 initiative, the Company also engages in the MTEP process. Each year, MISO and its members develop the MTEP report. Each transmission project included in the MTEP report undergoes extensive evaluation and stakeholder review and is approved by the MISO Board of Directors. The Big Stone – Brookings and the La Crosse – Madison projects were approved by MISO in the MTEP11 under the first MVP portfolio, and these projects are scheduled to be placed in-service in 2017 and 2018, respectively.

These Regional Expansion projects are large scale transmission projects that sometimes span over a decade from first identification to in-service date, and are quite capital extensive. It is the construction of these projects that is driving our capital investment in this category.

Q. WHAT ARE THE KEY REGIONAL EXPANSION PROJECTS TRANSMISSION ANTICIPATES PLACING IN-SERVICE IN 2016?

A. There are two key Regional Expansion projects that have capital additions of at least $3 million in 2016. These two projects are:

- CapX La Crosse; and
- CapX Brookings.

As I stated above, the CapX La Crosse project will remain in the TCR while the CapX Brookings project will roll-out of the TCR and into base rates with the implementation of final rates.

Q. PLEASE DESCRIBE THE CAPX LA CROSSE PROJECT.

A. This project is to construct approximately 129 miles of new 345 kV transmission line and 27 miles of new 161 kV transmission line between Hampton, Minnesota and La Crosse, Wisconsin. All but one of the segments are expected to go in-service by the end of 2015. The last segment, from the Company's Hampton substation southeast of the Twin Cities, to the Company's North Rochester substation near Pine Island, Minnesota, will consist of approximately 37 miles of single circuit 345 kV transmission line and will be placed in-service in 2016. This project is designed to bolster local reliability, especially reliability in the Rochester and Winona, Minnesota and La Crosse, Wisconsin areas. The project will enhance the region's transmission system, reduce congestion, and provide improved access to affordable energy sources.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2016?

A. This project has a total plant addition for 2016 of about $61.1 million. This cost estimate is an engineering estimate as described above. This project is currently under construction with an anticipated final in-service date of September 2016.

Q. PLEASE DESCRIBE THE CAPX BROOKINGS PROJECT.

A. This project is to construct 248 miles of new 345 kV transmission line and four miles of new 115 kV transmission line between the Company's Brookings County substation in Brookings County, South Dakota and the new Hampton substation in the southeast corner of the Twin Cities. The project will help meet projected electric growth in southern and western Minnesota, as well as the growing areas south of the Twin Cities metro area, particularly Scott and Dakota counties. The project also connects to new renewable generation resources in southern and western Minnesota and in the Dakotas to the Twin Cities load center.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2016?

A. The CapX Brookings project was energized in the first quarter of 2015 and is substantially in-service. The remaining 2016 addition of $3.5 million represents the Company's share of easement acquisition settlement payments to landowners affected by this project.

2. Reliability Requirement Projects

Q. WHAT IS DRIVING THE COMPANY'S INVESTMENTS IN RELIABILITY REQUIREMENT PROJECTS?

A. NERC develops and enforces reliability standards on all transmission owners, operators, and users. The Company performs transmission planning studies to identify necessary upgrades to the system to ensure compliance with NERC standards. Through these studies, transmission planners evaluate all various alternatives to meet the identified electrical needs for the system and select the option that considers the incremental impact of the project for future needs in the area and best meets the long-term electrical needs of the area in a cost-effective manner.

Q. WHAT WOULD BE THE IMPACT OF EITHER FOREGOING OR DEFERRING A RELIABILITY REQUIREMENT PROJECT?

A. If a Reliability Requirement project is either deferred or cancelled, the Company could be found to be in violation of NERC reliability standards. In addition, as NERC standards are in place to promote the health and reliability of the transmission system, deferring or foregoing a necessary Reliability Requirement project could impact system reliability.

Q. WHAT ARE THE CAPITAL ADDITIONS RELATED TO RELIABILITY REQUIREMENT PROJECTS IN 2016?

A. There are seven reliability requirement projects that have capital additions of at least $3 million in 2016. These seven projects are:

- Bluff Creek Substation;
- Prairie Substation Expansion;
- Tremval Substation;

- Couderay-Osprey 161 kV;
- T-Corners Substation Expansion;
- W3404 Cedar Falls – Menomonie; and
- W3445 Rebuild Merrillan Jackson.

These projects are described in detail below. Unless otherwise stated, all dollar figures are at the NSPM or NSPW level. The State of Minnesota jurisdictional amounts for these capital additions are included in Schedule 2. For those projects that required a CON, I will compare the actual costs of the project to the costs identified in the CON.

a. Bluff Creek Substation

Q. PLEASE DESCRIBE THIS PROJECT.

A. This project is one of the necessary components of the larger Scott County – Westgate 115 kV project and involves expansion of the existing Bluff Creek substation in Chanhassen, Minnesota. This expansion will allow the substation to accommodate a new 115-69 kV transformer, four 115 kV line terminations, and eleven circuit breakers for a breaker-and-half configuration. This project will improve the reliability of transmission service to the southwestern suburbs of Eden Prairie, Chanhassen, Minnetonka, and Chaska. Based on the results of a 2009 transmission study, Company transmission planners identified that the existing transmission system is susceptible to thermal overloads and low voltages during loss of a single transmission asset, the Eden Prairie-Westgate 115/115 kV transmission line. Expansion of the Bluff Creek substation is needed to accommodate a new 115 kV line that is being energized as part of the Scott County – Westgate 115 kV project to address the overload and low voltage issues and to meet the NERC TPL-003 standard. NERC TPL-003 requires the system to be able to withstand loss of two or more system elements while maintaining proper voltage levels.

Q. DID THE COMPANY OBTAIN A CON FOR THIS PROJECT?

A. No. A CON was not required for this scope of work.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2016?

A. This project has a total plant addition for 2016 of $12.9 million. This cost estimate is an engineering estimate, as described above. The Bluff Creek substation project has been final engineered and is currently under construction. The project is expected to be complete and in-service by August 1, 2016.

b. Prairie Substation Expansion

Q. PLEASE DESCRIBE THIS PROJECT.

A. The project involves installing a third 230-115 kV 336 MVA transformer and the relocation of an existing transformer at the existing Prairie substation near Grand Forks, North Dakota. This additional transformer is needed to avoid severe low voltages on the 115 kV system and severe thermal overloads on the 69 kV system in the Grand Forks area during the loss of the two existing 230/115 kV transformers at the Prairie substation as required by NERC's TPL-003 standard. The Company conducted the Grand Forks Load Serving Study to evaluate two options to prevent the voltage problems in the Grand Forks area. The other option was to increase the transformer capacity at Western Area Power Administration's Grand Forks substation and rebuild the 69 kV transmission line between the Prairie and Gateway substations. The addition of a third transformer at the Prairie substation was determined to be a more cost-effective and long-term solution.

Q. WHAT, IF ANY, REGULATORY APPROVALS DID THE COMPANY OBTAIN FOR THIS PROJECT?

A. The Company obtained a Certificate of Public Convenience and Necessity (CPCN) from the North Dakota Public Service Commission (NDPSC) on May 28, 2014 in Case No. PU-14-126.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2016?

A. This project has a total plant addition for 2016 of $11.5 million. This cost estimate is an engineering estimate as this project has been final engineered and is under construction. This project will is expected to be placed in-service by June 1, 2016.

c. Tremval Substation

Q. PLEASE DESCRIBE THIS PROJECT.

A. This project is comprised of improvements to the Tremval substation near Blair, Wisconsin. The project includes installation of a 161 kV breaker-and-a-half row, the replacement of an existing 161-70.6 kV 112 MVA transformer, the addition of a second 161-70.6 kV 112 MVA transformer, and the expansion of the 69 kV portion of the substation. The project includes grading, fencing, equipment, structures, and bus work required to accommodate these additions to the substation. These improvements are needed to meet NERC's TPL-002 standard. TPL-002 requires the transmission system to be able to withstand the loss of a single element, such as loss of a transformer, and maintain adequate voltage levels. As a result of increased peak demand in this area related to sand mine development, this area has reliability issues when certain elements of the system are out of service. Specifically, one of the existing transformers at the Tremval substation will overload when either a transformer at the Jackson substation is out of service or the Jackson – Tremval 161 kV line is out of service. The improvements at the Tremval substation will alleviate these concerns.

Q. WHAT, IF ANY, REGULATORY APPROVALS DID THE COMPANY OBTAIN FOR THIS PROJECT?

A. The Company was not required to obtain any regulatory approvals from the Public Service Commission of Wisconsin (PSCW) for this scope of work.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2016?

A. The plant addition for 2016 for this project is approximately $6.8 million with a planned in-service date of December 15, 2016. This cost estimate is an appropriations estimate as this project is at the beginning of its final engineering stage. Civil and structural engineering have completed their final design for this project and construction of certain aspects of this project will begin in the fourth quarter of 2015.

d. Couderay-Osprey 161 kV

Q. PLEASE DESCRIBE THIS PROJECT.

A. This project will replace an existing 35.5 mile 69 kV transmission line between the Company's Couderay substation near Couderay, Wisconsin and the Company's Osprey substation south of Big Falls Flowage, Wisconsin, with a 161 kV/69 kV double circuit line to meet the NERC TPL-002 standard. Substation improvements will also be made at the Company's Radisson substation, located near Radisson, Wisconsin, the Company's Trails End substation, located north of the village of Bruce, Wisconsin, and the Osprey substation.

This project is needed to ensure adequate voltage support during certain contingencies. Load in this area of Wisconsin is growing as a result of sand mine activity, a proposed cooper mine, and increased pipeline pumping. As a result of this load growth, under certain contingencies, the existing Couderay-Osprey 69 kV line is at risk of low voltage conditions. In addition, the current line is in need of replacement due to its age and condition. The Company evaluated three other transmission alternatives to address the transmission needs in this area and selected the Couderay – Osprey project as the most cost-effective solution of those studied.

Q. WHAT, IF ANY, REGULATORY APPROVALS DID THE COMPANY OBTAIN FOR THIS PROJECT?

A. This project required a Certificate of Authority (CA) from the PSCW. The Company submitted its application on May 15, 2012, in Docket 4220-CE-178, and the PSCW issued an order granting the CA on October 15, 2012.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2016?

A. The plant addition for 2016 for this project is approximately $6.6 million with a planned in-service date of March 15, 2016. This cost estimate is an engineering estimate as all major engineering disciplines have completed their final design for this project and the project is currently being constructed.

e. T-Corners Substation Expansion

Q. PLEASE DESCRIBE THIS PROJECT.

A. This project provides for the expansion of the 115 kV section of the Company's T-Corners substation, located east of Eau Claire, Wisconsin. This project is needed to ensure compliance with NERC standard TPL-003. Under the existing 115 kV configuration at the T-Corners substation, failure of the existing 115 kV bus-tie breaker causes the loss of both 115 kV lines and both existing transformers. Expanding the 115 kV section of the substation to include the additional circuit breakers and associated equipment will resolve this problem.

Q. WHAT, IF ANY, REGULATORY APPROVALS DID THE COMPANY OBTAIN FOR THIS PROJECT?

A. The Company was not required to obtain any regulatory approvals from the PSCW for this scope of work.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2016?

A. This project has a total plant addition for 2016 of $5.4 million and it will go in-service in March 15, 2016. This cost estimate is an engineering estimate as this project has been final engineered and is currently under construction.

f. W3404 Cedar Falls-Menomonie

Q. PLEASE DESCRIBE THIS PROJECT.

A. This project will rebuild approximately 5.2 miles of 69 kV line between the Company's Cedar Falls substation, in Cedar Falls, Wisconsin and the Company's Menomonie substation, in Menomonie, Wisconsin. This project is needed to address overloading on this line that occurs under a system contingency loss of Dairyland Power Cooperative's Rock Elm to Elmwood 69 kV transmission line. When this line is out of service, the power flow models show that the existing line will experience thermal overloading of more than 10 MW above its current thermal limit rating. In addition, load is increasing in this area due to increased sand mining operations and as a result, it is anticipated that these overload conditions will worsen in the future if the line is not rebuilt. Additionally, the lower impedance and increased capacity will provide increased voltage support to the area transmission systems.

Q. WHAT, IF ANY, REGULATORY APPROVALS DID THE COMPANY OBTAIN FOR THIS PROJECT?

A. The Company was not required to obtain any regulatory approvals from the PSCW for this scope of work.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2016?

A. This project has a total plant addition for 2016 of $4.9 million and is planned to go in-service in June 2016. This cost estimate is an appropriations estimate as the project will complete its final engineering by the close of 2015 and will begin construction activities in 2016 in coordination with the region's hydroelectric generation facilities to ensure proper generation outlet.

g. W3445 Rebuild Merrillan – Jackson 69 kV Line

Q. PLEASE DESCRIBE THE PROJECT.

A. The project involves rebuilding approximately 6.1 miles of existing 69 kV line between the Company's Jackson County substation and Dairyland Power Cooperative's Merrillan substation. This line needs to be rebuilt to a higher capacity avoid line thermal overloads that occur on this line under the contingency loss of the Company's Tremval to Alma Center 69 kV transmission line. The additional capacity provided by this rebuilt line will also support the additional load growth in the area that is the result of increased sand mining operations.

Q. WHAT, IF ANY, REGULATORY APPROVALS DID THE COMPANY OBTAIN FOR THIS PROJECT?

A. The Company was not required to obtain any regulatory approvals from the PSCW for this scope of work.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2016?

A. The plant addition for 2016 for this project is approximately $3.4 million with a planned in-service date of June 1, 2016. This cost estimate is an appropriations estimate as final engineering for this project has begun and construction activities will begin in December of 2015.

3. *Asset Renewal Projects*

Q. WHAT ARE THE PRIMARY ISSUES FACING TRANSMISSION RELATED TO ASSET RENEWAL?

A. Our organization is charged with maintaining a large and aging transmission infrastructure. In fact, in Minnesota over 3,317 miles of transmission line were placed in-service in during the 1960s or the 1970s. While transmission facilities generally have long life spans– these facilities do not last forever. We examine both the condition and performance of our aging facilities to determine which facilities are in greatest need of replacement. We also prioritize replacement of aging facilities based on which facilities are most likely to fail and then which equipment will have the biggest impact to the transmission system when it does fail. Taking into account these factors helps us to prudently leverage our investment in our existing assets while still maintaining a reliable system. In addition to replacements due to age and condition, we must also make investments to replace facilities damaged by storms or other weather events.

Our Asset Renewal investments also include replacement of our fleet vehicles. We seek to maximize our investment in our fleet by making repairs when we can rather than replacing our fleet. We only replace vehicles when the cost to repair a vehicle exceeds its value.

Q. WHAT ARE THE CAPITAL ADDITIONS RELATED TO ASSET RENEWAL PROJECTS IN 2016?

A. There is one key Asset Renewal project for 2016, Transportation – NSPM. This is an annual project that relates to replacement or upgrades to the Company's fleet allocated for Transmission's use. This includes trucks, cars, trailers, cranes, semi tractors and other vehicles used to support all Transmission operations. Each year field operations and fleet managers along with the Transmission construction directors examine the condition of our existing fleet. The Company uses an "Old Fleet Strategy" where we perform continued maintenance to our fleet without regard to life expectancy or depreciation value of the assets until maintenance costs of the asset become cost prohibitive, i.e., the cost of a single repair exceeds the value of the asset. Also, as a part of this strategy the Company uses the average age of fleet assets being retired (specific to Class) to determine the baseline for which it estimates single unit replacement costs as the unit approaches the baseline for replacement within the budget. In the case of Transportation it is important to plan for the replacement or upgrade to the Company's fleet. The alternative to renewing our fleet assets is the rental of the vehicles and equipment required to complete our work which results in overall higher project costs adding to the total capital additions required to complete our projects.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2016?

A. The plant addition for 2016 for this project is approximately $5.4 million. Since the fleet assets are in-serviced when the Company takes receipt of the fleet asset this project has multiple in-service dates through the calendar year. But this annual project will close at the end of 2016 and a new budgeted project for Transportation 2017 will continue this program.

4. *Interconnection Projects*

Q. WHAT IS DRIVING TRANSMISSION'S INTERCONNECTION INVESTMENTS?

A. Under our tariff, we are required to make the necessary transmission upgrades to accommodate interconnection requests. There are three general types of Interconnection projects which drive our interconnection investments: transmission interconnections, load interconnections and generation interconnections. Transmission interconnections are where one utility is requesting to interconnect a transmission line to our transmission line. Load interconnections are where a new substation serving electric load is needed and is requesting to interconnect to our transmission system, or an existing load serving substation is being modified. Generation interconnections are where a new generator is requesting to interconnect to our transmission system.

Q. WHAT ARE THE KEY INTERCONNECTION PROJECTS WITH CAPITAL ADDITIONS IN 2016?

A. There are two key Interconnection projects for 2016. These are:

- Dean Lake Substation; and
- IA Tariff Fund.

a. Dean Lake Substation

Q. PLEASE DESCRIBE THE PROJECT.

A. The City of Shakopee requested that the Company expand its existing 115 kV Dean Lake substation to accommodate their plans to add a third 115 kV-13.8 kV transformer at the Dean Lake substation and connect that transformer to our transmission system. The Dean Lake substation is owned by NSPM, but currently contains distribution assets and transformers owned by the City of Shakopee. In this Project, the Company plans to construct a 5-position ring bus, which will involve adding two new 115 kV box structures and adding five breakers. An electrical equipment enclosure (EEE) and station auxiliary system to house our breaker controls and line relaying panels will also be required.

Q. WHAT, IF ANY, REGULATORY APPROVALS DID THE COMPANY OBTAIN FOR THE PROJECT?

A. The Company was not required to obtain any regulatory approvals from the Commission for this scope of work.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2016?

A. The plant addition for 2016 for this project is approximately $5.0 million with a planned in-service date of December 31, 2016. It is likely that this project will be placed in-service earlier than December 31, but the end of year in-service date is firm as the City has requested the facilities to be in place by year-end. The cost estimate for this project is at the scoping estimate phase and is expected to begin final engineering during the fourth quarter of 2015.

b. IA Tariff Fund

Q. PLEASE DESCRIBE THE PROJECT.

A. This program fund is for interconnection related transmission capital investments as a result of developments or requests by organizations outside the Company or by internal NSP departments, other than the Transmission Planning department. The program is for load interconnection requests which have not yet reached the specificity to be defined as specific capital projects but nonetheless are expected based on announced plans or interconnection requests in-queue to require capital funding during the five-year budget period.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2016?

A. The plant addition for 2016 for this project is approximately $3.8 million with a planned in-service date of December 31, 2016. The estimate for this project is based on the historical average cost of emerging Interconnection projects and known requests in-queue that will require capital funding in 2016.

5. Communication Infrastructure Projects

Q. WHY ARE INVESTMENTS IN COMMUNICATION INFRASTRUCTURE NECESSARY?

A. In the past, the Company has relied on third-party telecommunication providers for the infrastructure necessary for our SCADA and teleprotection circuits (i.e., communication circuits between our substations and between our substations and our control center). However, many of the telecommunication companies are phasing out their dedicated frame relay and analog wide area network (WAN) technology and replacing it with Ethernet over fiber optics or other broadband services. These new services, while capable of carrying large volumes of data, are not able to carry the small amount of data that we transmit at the speeds acceptable for the teleprotection of our transmission system. As a result, we need to invest in Company-owned and controlled communication infrastructure in optical ground wire (OPGW) that will serve our operational and system protection needs without the reliance and vulnerability exposure from a publicly available third-party network.

Similarly, cyberattacks pose a threat to the reliability of our transmission system as hackers could cause system outages by disabling telecommunications or key pieces of equipment. Every day there are coordinated attempts to infiltrate communication systems and disrupt the grid. Federal regulatory agencies have responded to these growing threats by adopting cyber security standards for transmission facilities. In April 2014, FERC adopted NERC CIP Version 5 standards for cybersecurity. The Company-owned telecommunications network we are investing in enables the Company to respond to these new NERC standards by removing our exposure to cybersecurity threats from the publicly available service provided by third-party telecommunication providers.

Q. WHAT KEY COMMUNICATION INFRASTRUCTURE PROJECTS DOES TRANSMISSION ANTICIPATE PLACING IN-SERVICE IN 2016?

A. There is one key communication infrastructure project for 2016 and 2017, the Frame Relay Project, which the Company will implement in NSPW in 2016 and NSPM in 2017.

Many substation Remote Terminal Units (RTUs) rely on Frame Relay connections to move SCADA data between substations and from substations to control centers. Telecommunication companies will discontinue frame relay by the end of 2017, as allowed by a Federal Communication Commission ruling. This project provides for the modernization of existing connections at multiple substation locations using new equipment and technologies. It also addresses the NERC CIP Version 5 standards referenced earlier in my testimony with regard to cybersecurity. The Company plans to replace the Frame Relay connections in the substations with a new leased service delivered via a new T carrier card installed in the high voltage protection unit. The Company will make these replacements in Wisconsin substations in 2016 and will make these replacements in Minnesota substations in 2017.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2016 AND 2017?

A. The plant additions for 2016 for this project are approximately $3.4 million with a planned in-service date of December 15, 2016. The plant additions for 2017 for this project are approximately $11.0 million with a planned in-service date in May 2017. There are multiple sub-projects that contribute to this program and construction has started on the first wave of substations, many others have been final engineered and are awaiting the start of construction.

E. 2017 Capital Additions

Q. WHAT CAPITAL ADDITIONS IS THE COMPANY PROPOSING TO MAKE IN 2017?

A. The total NSPM Transmission 2017 capital additions are budgeted to be approximately $167.4 million. Table 9 below provides a breakdown of these capital additions by the capital budget category.

Table 9

2017 Transmission Capital Additions	Total NSPM (Includes AFUDC) (Dollars in Millions)
Regional Expansion	$83.8
Reliability Requirement	$29.5
Asset Renewal	$15.9
Communication Infrastructure	$11.3
Interconnection	$7.0
Physical Security and Resiliency	$19.9
Total	**$167.4**

1. *Regional Expansion Projects*

Q. WHAT ARE THE KEY REGIONAL EXPANSION PROJECTS TRANSMISSION ANTICIPATES PLACING IN-SERVICE IN 2017?

A. There is one key Regional Expansion projects for 2017, the Big Stone-Brookings project. As I noted above, the Company plans to seek recovery for this project through the TCR but I am including a discussion here as this project is a major planned investment over the plan period.

Q. PLEASE DESCRIBE THE PROJECT.

A. This project is to construct 70 miles of 345 kV transmission line between Big Stone and Brookings County in eastern South Dakota. The project is a joint project between Otter Tail Power Company and Xcel Energy and was identified as one of 16 MVPs approved by MISO in December 2011. This project will serve multiple regional needs, including load-serving, generation outlet, and the improvement of energy market performance. In addition, the MVPs will help expand and enhance the region's transmission system, reduce congestion, provide improved access to affordable energy sources, and meet public policy requirements, including renewable energy mandates.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2017?

A. The Big Stone-Brookings 345 kV line is under construction and much of the major components of this project have been final engineered. This project is planned to be in-service beginning in September 2017 and all segments will be completely in-service on December 1, 2017.

2. Reliability Requirement Projects

Q. WHAT ARE THE KEY RELIABILITY REQUIREMENT PROJECTS TRANSMISSION ANTICIPATES PLACING IN-SERVICE IN 2017?

A. There are two key reliability requirement projects for 2017. These are:

- Maple River Red River 2nd 115 kV; and
- Gravel Island Substation.

a. Maple River Red River 2nd 115 kV

Q. PLEASE DESCRIBE THE PROJECT.

A. This project involves constructing five miles of new 115 kV line between the existing Maple River and Red River substations in the northwestern area of Fargo, North Dakota. The substation work required includes the conversion of the Red River substation to a three position ring bus and adding a yard structure for the new 115 kV line termination at the Maple River substation. This project is required to avoid thermal overloads on the area transmission system under several of contingency conditions and to comply with NERC standard TPL-003. The project also provides voltage support to Red River and Cass County substations. The most severe contingency identified by the Company is the loss of the single existing 115kV transmission line between Maple River and Red River. The loss of this single line causes thermal overload to both transformers at the Company's Sheyenne substation and on the two 115 kV transmission lines between the Company's Cass County substation and Sheyenne substation. When this new line is complete, it will also allow for planned maintenance outages to the 115 kV system in the Fargo area that are currently not possible without the risk of transformer and line thermal overloads even during off-peak conditions.

Q. WHAT, IF ANY, REGULATORY APPROVALS DID THE COMPANY OBTAIN FOR THIS PROJECT?

A. The Company had originally planned to file for permitting approval from the NDPSC in 2014. After consulting with the NDPSC, we were directed to seek local routing approval from all jurisdictions having authority namely the City of Fargo and the Federal Aviation Administration (FAA). The Company is currently in the process of obtaining these approvals and plans to submit its application for the CPCN permit to the NDPSC in early 2016.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2017?

A. This is a multi-year project and construction is expected to begin September 2016. The Company anticipates completing its land acquisition for new easements for this line by September 2016 and placing that portion of the project in-service by October 2016 for a total capital addition of $4.7 million in 2016. This project has a total plant addition for 2017 of $11.3 million that is planned to go in-service by June 23, 2017. The project estimate is a scoping estimate as the project team works with the City of Fargo regarding local permitting requirements prior to submitting a CPCN application to the NDPSC.

b. Gravel Island Substation

Q. PLEASE DESCRIBE THE PROJECT.

A. The project will install two additional capacitor banks and an additional 161 kV breaker at the existing Gravel Island substation north of Eau Claire, Wisconsin to meet the NERC TPL-003 standard. These substation additions are needed to address a low voltage issue on the 161 kV transmission system under certain contingency conditions and due to new load growth in the 161 kV system area. The primary contributor to system low voltages in this area is caused by the contingent loss of two 161 kV transmission lines between the Company's Wheaton to Gravel Island substations and Eau Claire substation to Presto tap.

Q. WHAT, IF ANY, REGULATORY APPROVALS DID THE COMPANY OBTAIN FOR THIS PROJECT?

A. The Company was not required to obtain any regulatory approvals from the PSCW for this scope of work.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2017?

A. This project has a total plant addition for 2017 of $3.1 million that is planned to go in-service by August 1, 2017. This cost estimate is a scoping estimate at this time and final engineering for this project will begin in early 2016.

c. Hollydale Project

Q. PLEASE DESCRIBE THE PROJECT.

A. As proposed in a CON and Route Permit applications, the Hollydale project sought to rebuild approximately eight miles of existing 69 kV transmission line to 115 kV capacity, construct approximately 0.8 miles of new 115 kV transmission line, construct a new 115 kV substation, and install associated equipment in the cities of Plymouth and Medina. The Hollydale Project was proposed to address capacity deficiencies on the existing distribution system and to alleviate low voltage conditions on the transmission system when certain facilities are out-of-service. On May 12, 2014, the Commission granted the Company's and Great River Energy's request to withdraw the pending applications for approval of the project. Since that time, the Company has been working with interested stakeholders to develop new alternatives to meet the identified needs in the area.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2017?

A. There are approximately $695,000 in capital additions in 2017 related to land acquisition for a new substation that is part of the electrical alternatives currently being evaluated by the Company and interested stakeholders. In addition, there are capital additions of approximately $2.7 million shown for 2017 that were included in the Hollydale project by mistake. This $2.7 million was already included in the plant additions for the Gleason Lake substation project, described below, and therefore should not be included in plant additions for the Hollydale project. As this item was not discovered in time to make adjustments to our initial filing, this $2.7 million in 2017 plant additions for Hollydale is shown in the capital additions included in Schedule 2. The Company will make an adjustment for this line item in rebuttal testimony and the revenue requirement impact of this line item is discussed by Company witness Ms. Heuer.

3. *Asset Renewal Projects*

Q. WHAT ARE THE KEY ASSET RENEWAL PROJECTS WITH CAPITAL ADDITIONS IN 2017?

A. There is one key routine Asset Renewal project for 2017: NSPM 0779 relocation for Redwing Bridge.

The Company's existing Line 0799 feeds the Spring Creek and Red Wing substations in Minnesota. This line is comprised of both overhead and underground segments. The underground cables, 69 kV 1250 kcmil AL with 650 mils of XLPE insulation, are installed both within segments of concrete duct bank and direct buried. As part of the Minnesota Department of Transportation's (MnDOT) project to replace the State Highway 63 bridge, approximately 1000 feet of underground Line 0799 will need to be relocated. To extend the circuit life, the Company determined that it needs to replace the cable and accessories for the entire underground segment. As part of the cable replacement, the direct buried portion of the underground segment will be replaced with concrete duct bank. The scope of this project includes the installation of approximately 3,065 feet of new duct bank to replace the direct buried portion, relocation of the segment of Line 0799 as required by MnDOT's bridge project, and installing new cable and accessories for the entire underground segment. With the re-routed duct bank, the total underground circuit length is 1.5 miles.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2017?

A. This project has a total plant addition for 2017 of $4.0 million that is planned to go in-service by September 1, 2017. This project has a scoping estimate at this time but the project team is currently working through the detailed scope while they prepare the appropriation estimate.

4. *Interconnection Projects*

Q. WHAT ARE THE KEY INTERCONNECTION PROJECTS WITH CAPITAL ADDITIONS IN 2017?

A. There is one, Quarry-GRE West St. Cloud. This project was jointly developed by Great River Energy and NSPM and was identified though the MN TACT assessment. Great River Energy will be constructing a second 115 kV transmission line from NSPM's Quarry substation near St. Cloud, Minnesota to Great River Energy's West St. Cloud substation in St. Cloud, Minnesota. The Company will expand the existing 115 kV configuration in the Quarry substation to accommodate this new line. Great River Energy submitted an interconnection request to Xcel Energy in early 2014 for this project. This project is needed to address low voltage concerns on the existing 115 kV system that arise during loss of the Company's Granite City - Cross Roads 115 kV and the Quarry - Sauk River 115 kV lines.

Q. WHAT, IF ANY, REGULATORY APPROVALS DID THE COMPANY OBTAIN FOR THIS PROJECT?

A. The Company was not required to obtain any approvals from the Commission for expansion of this existing substation.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2017?

A. The majority of the capital additions are related to construction of the new circuit termination equipment at the Quarry substation. The Quarry substation currently has a three position ring-bus. To accommodate the new 115 kV line, this will be expanded to a five position ring-bus. The ring-bus expansion, associated breakers, and other equipment are expected to be approximately $2.7 million in capital additions. To add the new 115 kV Great River Energy line, the Company will need to also reroute its own 115 kV line that runs between the Quarry substation and the St. Cloud substation so that it is routed into the Quarry substation from the south instead of from the north costing approximately $350,000 in capital additions. The costs for this project are scoping level estimates. This project will have approximately $3.1 million in capital additions with a planned in-service date of May 1, 2017.

5. Physical Security and Resiliency Projects

Q. WHAT ARE THE MAJOR ISSUES FACING TRANSMISSION WITH REGARD TO PHYSICAL SECURITY AND RESILIENCY?

A. Transmission is focused on maintaining the physical security of our assets. High voltage transformers make up less than three percent of transformers in U.S. power substations, but they carry 60 to 70 percent of the nation's electricity. Because they serve as vital nodes and carry bulk volumes of electricity, these transformers are critical elements of the nation's electric power grid. They are also the most vulnerable to intentional damage from malicious acts. In April 2013, a substation in California was subject to a coordinated military-type sniper attack that disabled 17 high voltage transformers and rendered this substation useless.

Federal regulatory agencies have responded to these growing threats by adopting physical security standards for transmission facilities. On March 7, 2014, FERC issued and Order on Reliability Standards for Physical Security Measures resulting in NERC standard CIP-014 addressing risks due to physical security threats and vulnerabilities. To address these threats and meet these new NERC standards, we are beginning to make necessary investments to make our grid more resilient so that we are able to respond quickly to physical security threats.

Resiliency projects include spare power transformers, emergency transmission line restoration structures, single point of failure – relays and DC redundancy, geomagnetic disturbances and electric magnetic pulse monitoring and testing.

Q. WHAT ARE THE KEY PHYSICAL SECURITY AND RESILIENCY PROJECTS TRANSMISSION ANTICIPATES PLACING IN-SERVICE IN 2017?

A. While the Company does not anticipate making any key capital additions in Physical Security and Resiliency projects during 2016, we will make capital additions related to the Spare Security Transformer, NSPM Physical Security, and NERC Order 754 NSPM projects in 2017.

a. Spare Security Transformer

Q. PLEASE DESCRIBE THE PROJECT.

A. This project is to purchase a spare transformer, which will be stored and then deployed for future needs in the event of a severe security incident requiring the deployment and restoration of an existing 345-115 kV 672 MVA transformer. The purchase of this transformer will provide the Company with the ability to restore service quickly in the event that one of our existing 345-

115 kV transformers are taken out of service. Without this spare security transformer, the Company is at risk for a large portion of our service territory to be exposed to a prolonged outage because these transformers can take a long time to procure.

Q. WHAT PLANT ADDITIONS ARE PLANNED IN 2017?

A. This project has a total plant addition for 2017 of about $3.7 million. This cost estimate is indicative at this time. The anticipated final in-service date is December 1, 2017.

b. NSPM Physical Security

Q. PLEASE DESCRIBE THE PROJECT.

A. The NSPM Physical Security program was developed to ensure the Company's compliance with NERC's CIP-014. The purpose of this project is to improve the physical security of the Company's substations. The Company will develop a site specific security plan for specific substations and will have a third-party verify effectiveness of these plans. These site specific security plans could include the following security measures: cameras, fencing/barrier improvements, ballistic shielding of identified key substation equipment, site access controls, ground sensory monitoring, and radar technology.

Q. WHAT PLANT ADDITIONS ARE PLANNED IN 2017?

A. This project has a total plant addition for 2017 of about $6.9 million. This cost estimate is indicative at this time. This project will have multiple in-service dates through the calendar year as multiple substations will require physical security improvements. The anticipated final in-service date for the first wave of projects in this group will be of December 31, 2017 and the program to increase physical security on our system will continue to develop and be implemented through 2020.

c. *NERC Order 754 NSPM*

Q. PLEASE DESCRIBE THE PROJECT.

A. Under FERC Order 754, the Company is required to identify single point failures at critical substations with voltages of 200 kV or above and report the results to NERC. The Company performed a study of the requisite substations and identified certain required modifications to eliminate these single point failures. This project includes separating primary and secondary relaying and adding redundant direct current circuits at several Company-owned substation facilities. This separation allows back-up battery to continue to provide protection services in the case of failure of primary battery.

Q. WHAT PLANT ADDITIONS ARE PLANNED IN 2017?

A. This project has a total plant addition for 2017 of about $6.1 million. This cost estimate is an indicative estimate. This project will have multiple in-service dates through the calendar year as multiple substations will require physical security improvements. The anticipated final in-service date for the first wave of projects in this group will be of December 31, 2017 and then will continue to develop and be implemented through 2019.

F. 2018 Capital Additions

Q. WHAT CAPITAL ADDITIONS IS THE COMPANY PROPOSING TO MAKE IN 2018?

A. The total NSPM Transmission 2018 capital additions are budgeted to be approximately $204.7 million. This capital additions budget includes a number of projects that are categorized below in Table 10 according to the capital budget groupings I described earlier.

Table 10

2018 Transmission Capital Additions	Total NSPM (Includes AFUDC) (Dollars in Millions)
Regional Expansion	$3.0
Reliability Requirement	$137.2
Asset Health	$36.7
Communication Infrastructure	$11.4
Interconnection	$5.8
Physical and Resiliency	$10.6
Total	**$204.7**

1. *Regional Expansion Projects*

Q. WHAT ARE THE KEY REGIONAL EXPANSION PROJECTS TRANSMISSION WILL PLACE IN-SERVICE IN 2018?

A. There is one key Regional Expansion project for 2018, the La Crosse – Madison project. As I stated above, the Company plans to seek recovery for this project through the TCR but I am including a discussion here as this project is a major planned investment over the plan period.

Q. PLEASE DESCRIBE THE LA CROSSE – MADISON PROJECT.

A. This project is a MVP project approved by MISO in December 2011 and jointly developed with ATC. The project involves construction of a new 345 kV transmission line beginning at NSPW's Briggs Road substation in Onalaska, Wisconsin, connecting at ATC's North Madison substation in Madison, Wisconsin, and then terminating at ATC's Cardinal substation in Middleton, Wisconsin. NSPW and ATC will share ownership of the Briggs Road to North Madison section and ATC will own and have responsibility for the North Madison to Cardinal section. The new 345 kV transmission line will be approximately 182 miles long and is expected to be in-service 2018, with construction beginning in 2016.

Q. WHAT, IF ANY, REGULATORY APPROVALS DID THE COMPANY OBTAIN FOR THIS PROJECT?

A. This project required a CPCN from the PSCW. The PSCW issued an order granting the CPCN in Docket No. 5-CE-142 on April 23, 2015.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2018?

A. The Company is currently forecasting that the new 345 kV transmission line beginning at NSPW's Briggs Road substation and ending at ATC's Cardinal substation with the improvements required for the new line at NSPW's Briggs Road substation will be completed in 2018. The capital addition in 2018 is $200.9 million. Detailed engineering was required during the preparation of the CPCN so this project has started the final engineering phase in anticipation of starting construction in early 2016.

2. *Reliability Requirement Projects*

Q. WHAT ARE THE KEY RELIABILITY REQUIREMENT PROJECTS TRANSMISSION ANTICIPATES PLACING IN-SERVICE IN 2018?

A. There are nine Reliability Requirement projects for 2018. They are:

- Minot Load Serving;
- Twin Cities Fault Current;
- Bailey Road Substation;
- Bayfield Loop;
- Blue Lake;

- Galloping Mitigation on Line 0953;
- Gleason Lake Substation;
- GIST-IV; and
- Northern Wisconsin Transmission Improvement.

a. Minot Load Serving

Q. PLEASE DESCRIBE THIS PROJECT.

A. This project involves construction of a new 230 kV substation in south eastern Minot, North Dakota and a 19-mile 230 kV transmission line between Great River Energy's McHenry substation in Velva, North Dakota the new substation in Minot, North Dakota. The existing 115 kV lines in the area will be connected to this new substation. This project is needed for reliability purposes to maintain voltage levels under contingency conditions and thus comply with NERC TPL-002 and TPL-003 standards. The load in this area is currently growing and the existing infrastructure is both aged and inadequate to serve the electrical need. Construction of the new substation will add a new 230 kV source into the area and be tied to a sister Basin Electric Power Cooperative substation, adding strength and grid resilience. The project will require approval from the NDPSC.

Q. WHAT PLANT ADDITIONS ARE PLANNED IN 2018?

A. This project has a total plant addition for 2018 of about $50.9 million. This cost estimate is a scoping estimate and has an anticipated final in-service date of October 31, 2018.

b. Twin Cities Fault Current

Q. PLEASE DESCRIBE THIS PROJECT.

A. This project is the first phase of the deployment of similar projects across the Company's 115 kV metro transmission system. It includes the installation of three single-phase Fault Current Limiters (FCL) at the Company's Terminal substation in Lauderdale, Minnesota. The FCLs are large transformer-like devices that are designed to limit fault current to protect substation equipment and limit fault current exposure to personnel in the substation should fault occur on the transmission system. The project is needed because of the high fault current availability in the Twin Cities system area from the relatively close proximity of generation which is concentrated on our tightly networked reliable transmission system. The alternate to this project would be essentially disconnecting, expanding and diversifying elements of the existing transmission system being affected which will spread the available fault current over a broader system, but consequently will also reduce our overall system reliability.

In order to make room for this FCL system at the Terminal substation, the existing substation will require extensive modifications and expansion of existing 115 kV bus sections at this substation. The existing 115 kV lines in the substation will be relocated so the existing 115kV Bus 1 and Bus 2 can be split with the new FCL devices connecting them. It will also require the addition of new 115 kV circuit breakers, disconnect switches, CCVTs and relays for system operation capability and maintenance.

Q. WHAT PLANT ADDITIONS ARE PLANNED IN 2018?

A. This project has a total plant addition for 2018 of about $17.7 million. This project is in development with a modified indicative cost estimate and has an anticipated final in-service date of January 20, 2018.

Q. WHAT IS A MODIFIED INDICATIVE ESTIMATE?

A. For this project, transmission planners are faced with several different alternatives to best mitigate fault current at the Terminal substation. To make the recommendation to include the FCL device's scope of work in our budget for this location the Company needed to better understand the physical properties of the FCL and the physical constraints within the property for the existing equipment at this substation to determine the feasibility of the scope. As a result, much more engineering detail was taken into consideration when developing the indicative estimate for this project to be included in our budget.

c. Bailey Road Substation

Q. PLEASE DESCRIBE THIS PROJECT.

A. This project involves construction of a new 345-115-34.5kV substation, preliminarily named Bailey Road substation, in Woodbury, Minnesota. This new substation is needed to address reliability issues on the area's distribution system that have resulted from increased load growth in this area. The distribution portion of this project is described in the testimony of Company witness Ms. Kelly A. Bloch. In addition, this project will also benefit the transmission system by lowering the high available fault currents on the 115 kV system at the Company's Red Rock substation, in Newport, Minnesota. This will be accomplished by removing four 115 kV lines from the Red Rock substation and terminating them in the new Bailey Road substation. This project will also require upgrades to line relaying at the remote end substations that will ultimately terminate at the new Bailey Road substation.

The planned project scope at this new substation provides for new 345 kV and 115 kV yards, two 345-115 kV, 448 MV transformers and one 115-34.5 kV, 70 MVA distribution transformer with two feeders.

Based on the scope of work and preliminary location for this substation, it is not anticipated that this project will require a CON or a Route Permit.

Q. WHAT PLANT ADDITIONS ARE PLANNED IN 2018?

A. This project has a total plant addition for 2018 of about $34.9 million. This cost estimate is a scoping level estimate and the project has an anticipated in-service date of December 31, 2018.

d. Bayfield Loop Project

Q. PLEASE DESCRIBE THIS PROJECT.

A. The Bayfield Loop project will provide voltage support on the existing 34.5 kV transmission system for the Bayfield Peninsula in northern Wisconsin. When complete, the Bayfield Loop project will allow for reliable service to all substations on the peninsula during a single contingency to the system and will allow the system to accommodate future load growth in the area. The project involves construction of approximately 20 miles of new 34.5 kV transmission line that will originate from a new 115/34.5 kV substation that will be constructed near Ashland, Wisconsin and will terminate at a newly constructed 34.5 kV switching station near the town of Bayfield, Wisconsin. The new switching station will also include capacitor banks to provide additional voltage support to the area during any potential N-1 contingency events occurring on the 34.5 kV Transmission system. This total project will require a CA from the PSCW.

Q. WHAT PLANT ADDITIONS ARE PLANNED IN 2018?

A. This project has a total plant addition for 2018 of about $26.8 million. This cost estimate is a scoping level estimate and the project has an anticipated in-service date of April 1, 2018.

e. Blue Lake Substation

Q. PLEASE DESCRIBE THIS PROJECT.

A. The Blue Lake substation project is driven by reliability concerns on the distribution system serving the Shakopee area. This project will increase reliability by providing redundant service to the distribution customers in the areas while decreasing potential thermal overloads to for loss of a distribution transformer or single distribution feeder. The potential for thermal overloads to the system is caused by distribution load growth in and around the City of Shakopee. At the Blue Lake substation, we will construct a fourth 115 kV breaker-and-a-half row to provide terminations for two new 115 kV lines to a new city of Shakopee substation. To complete this breaker-and-a-half row, we will install three new breakers, six sets of switches, and all associated bus work.

Q. WHAT PLANT ADDITIONS ARE PLANNED IN 2018?

A. This project has a total plant addition for 2018 of about $7.5 million. This cost estimate is an indicative estimate and the project has an anticipated in-service date of July 1, 2018.

f. Galloping Mitigation NSM 0953

Q. PLEASE DESCRIBE THIS PROJECT.

A. This project includes the reconductoring of two segments of Line 0953. The first phase of this project includes the reconductoring of approximately 22.4 total circuit miles of 345 kV line. Specifically, the existing conductor, a double bundle of 954kcm ACSS/TW Cardinal conductor, will be replaced with a double bundle of 795kcm (2-397.5kcm) TACSR Ibis/VR2 twisted pair conductor between Nobles County substation and Lakefield Junction substation located in southwest Minnesota. This line needs to be reconductored to mitigate galloping on the line that has caused multiple outages and damage to the existing conductor and structures.

The second phase of this scope includes the reconductoring of approximately 10.3 total circuit miles of 345 kV line from a double bundle of 954kcm ACSS/TW Cardinal to a double bundle of 795kcm (2-397.5kcm) TACSR Ibis/VR2 twisted pair conductor and install anti-galloping devices on approximately 21 circuit miles between Split Rock substation and Nobles County substation located in southwest Minnesota. The purpose is to mitigate galloping on the line that has caused multiple outages and damage to the existing conductor and structures. This line, including the segments described in both phases of the project has experienced twenty-one outages over the past five years that have been directly attributed to galloping. This project will not require a CON or Route Permit.

Q. What plant additions are planned in 2018?

A. This project has a total plant addition for 2018 of about $5.6 million. This cost estimates is an appropriation estimate and the project has an anticipated in-service date of November 30, 2018.

g. Gleason Lake Substation

Q. Please describe this project.

A. This project will require installation of a new 115 kV capacitor bank and the expansion of the existing ring bus at the Company's Gleason Lake substation, in Wayzata, Minnesota and the rebuild of the existing 115/115 kV double circuit transmission line between the Gleason Lake and Parkers Lake substations.

This project is needed to address low voltage concerns at the Gleason Lake substation during an outage to either one of the double circuit 115/115 kV lines between the Gleason Lake to Parkers Lake substations. To solve these low voltage issues, a 40 MVAR capacitor bank will be added at the Gleason Lake on the 115 kV breaker ring and share a position with the Gleason Lake to Medina 115 kV line. This project is also needed as loss of the 115 kV breaker at Gleason Lake substation causes outage to both 115 kV Gleason Lake to Parkers Lake transmission lines because both lines share this breaker. In order to solve the shared breaker issue, the Company will change the bus configuration at Gleason Lake to provide a two breaker separation for the two Gleason Lake -Parkers Lake 115 kV lines. To accommodate the new capacitor bank and provide two breaker separation of the 115 kV transmission lines, the substation's fenced area will be expanded and an extensive reconfiguration/expansion of the substation's ring bus will be required. This reconfiguration provides a bus position for the new capacitor bank, a new circuit breaker, switches, CCVT and to structural bus support structures and the associated low profile 115 kV bus.

In addition to these substation modifications, this project involves rebuilding the Gleason Lake – Parkers Lake 115/115 kV lines into two single circuit 115 kV lines. When this project is complete, a single initiating event (loss of the single breaker at Gleason Lake or loss of a common transmission line structure) that causes low voltage at Gleason Lake will be eliminated. This project does not require a CON or a Route Permit.

Q. WHAT PLANT ADDITIONS ARE PLANNED IN 2018?

A. This project has a total plant addition for 2018 of about $11.8 million. This project's cost estimates are a scoping estimate and the project has an anticipated in-service date of June 1, 2018.

h. GIST-IV

Q. PLEASE DESCRIBE THIS PROJECT.

A. This project involves implementation of a new land management software tool, LandWorks. This new software will allow us to transition from a highly manual paper system with very little ability to quickly access, analyze, share, or geographically locate the records to a modern land management system with the following key benefits:

- Landworks moves the Company from paper records in disparate location to scanned attributed records in a centralized location with ease of access and ability to performed deep analysis resulting in reduction in O&M costs.

- Landworks will for the first time geospatially locate all of the land assets held by the Company resulting in a highly intuitive interface for understanding our rights, executing new projects, and managing our valuable land assets on a daily basis. This same geospatial data will be feed by many other GIS efforts at Xcel dramatically improving the usefulness of these other efforts.
- Landworks will improve many small but important items including our ability to stay compliant and execute project competitively.

Q. WHAT PLANT ADDITIONS ARE PLANNED IN 2018?

A. This project has a total plant addition for 2018 of about $6.4 million. This project is underway with an anticipated final in-service date of December 31, 2018.

i. Northern Wisconsin Transmission Improvement

Q. PLEASE DESCRIBE THIS PROJECT.

A. This project involves the construction of a new Pershing substation, a 345-115 kV substation that will be located approximately two miles south of Sheldon, Wisconsin, at the intersection of ATC's Stone Lake to Gardner Park 345 kV line and NSPW's Holcombe to Sheldon Pump 115 kV line (W3318). The need for the project is driven by newly forecasted local increases in this area. In addition, this project is needed to ensure compliance with NERC TPL-003 standard. This project will require a CA from the PSCW.

Q. WHAT PLANT ADDITIONS ARE PLANNED IN 2018?

A. This project has a total plant addition for 2018 of about $16.9 million. This cost estimate is a scoping estimate and has an anticipated in-service date of March 1, 2018.

3. *Asset Renewal Projects*

Q. WHAT ARE THE KEY ASSET RENEWAL PROJECTS WITH CAPITAL ADDITIONS IN 2018?

A. There is only one key Asset Renewal project in 2018, the Prentice – Medford rebuild project. The Prentice to Medford transmission line rebuild project is a three phased project that rebuilds approximately 33.5 miles of 69 kV line between the Company's Prentice substation, near Prentice, Wisconsin to its Medford substation, near Medford, Wisconsin. This line requires rebuilding due to the age and condition of this existing line. The line had been identified in 2008 as an end of life replacement project based on patrolled and recorded defects that over time have contributed to the deterioration of its reliability. The existing transmission line was originally constructed in 1947 at 34.5 kV design standards and later converted to be operated at 69 kV. The first two phases of this rebuild project will be placed in-service in 2017. The last phase of this project that will be placed in-service in late 2018 requires rebuilding 16 miles of existing 69 kV line from the Rib Lake switch to the Medford substation. During this phase, the Company will remove approximately 218 wood poles and associated line assets and will replace them with new light-duty and heavy duty steel poles, conductor and line appurtenances within the existing right-of-way. This total project will require a CA from the PSCW.

Q. WHAT PLANT ADDITIONS ARE PLANNED IN 2018?

A. This project has a total plant addition for 2018 of about $4.8 million. This cost estimate is a scoping estimate and the project has an anticipated in-service date of April 30, 2018.

Q. WHAT DO YOU CONCLUDE WITH RESPECT TO THE OVERALL LEVEL OF TRANSMISSION CAPITAL COSTS THE COMPANY IS SEEKING TO RECOVER IN THIS RATE CASE?

A. The overall level of Transmission costs is reasonable, as shown by the above discussion, and is necessary to support an appropriate level of service to our customers. Finally, the costs included in our 2016 through 2018 capital budgets are representative of the types of work we must and will do year over year.

IV. O&M BUDGET

A. O&M Overview and Trends

Q. WHAT IS INCLUDED IN YOUR O&M BUDGET?

A. The Transmission O&M budget includes costs associated with the operation and maintenance of our transmission system. This includes internal and contract labor, employee expenses, fees, materials and fleet.

Q. WHAT IS THE COMPANY'S O&M BUDGET FOR THE 2016 TEST YEAR?

A. We have budgeted $43.1 million for Transmission O&M in 2016, which is a decrease of $0.8 million, or a 0.9 percent compound annual decrease, from 2014 actual expenses.

Table 11 provides our actual O&M costs for 2012-2014, the 2015 Forecast for O&M spend (half year actuals and half year forecast), and the 2016 test year O&M budget. I provide the dollar figures for both NSPM and NSPM – State of Minnesota Jurisdiction.

Table 11

Transmission O&M Budget by Category NSPM-Electric (Dollars in Millions)									
Cost Category	**2012**	**2012**	**2013**	**2013**	**2014**	**2014**	**2012 – 2014**	**2015**	**2016**
	Budget	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Average**	**Forecast**	**Budget**
Internal Labor	$22.50	$23.70	$22.70	$25.00	$24.60	$24.80	$24.50	$25.60	$24.40
Contract Labor and Consulting	$8.20	$7.80	$10.10	$11.50	$9.40	$10.50	$9.90	$10.00	$8.20
Employee Expenses	$2.30	$3.10	$2.70	$3.30	$2.80	$3.20	$3.20	$3.60	$3.10
Fees*	$3.40	$3.40	$3.50	$3.50	$3.70	$3.50	$3.50	$3.30	$3.60
Materials	$2.60	$4.20	$3.10	$3.60	$3.20	$3.40	$3.70	$3.00	$3.10
Fleet	$1.90	$2.50	$1.90	$2.50	$2.20	$2.60	$2.60	$2.10	$2.60
Other	($1.80)	($4.60)	($2.10)	($5.80)	($3.00)	($4.20)	($4.90)	($4.50)	($1.80)
Total	**$39.10**	**$40.00**	**$42.00**	**$43.50**	**$42.90**	**$43.90**	**$42.50**	**$43.20**	**$43.10**

* The "Fees" cost category includes Dues, Fees, and Licenses, which includes professional & utility association dues, as well as land and railroad permits and license fees, as well as NERC and FERC assessments.

Transmission O&M Budget by Category Minnesota Electric Jurisdiction (Net of Interchange Billings to NSPW) (Dollars in Millions)									
Cost Category	**2012**	**2012**	**2013**	**2013**	**2014**	**2014**	**2012 - 2014**	**2015**	**2016**
	Budget	**Actual**	**Budget**	**Actual**	**Budget**	**Actual**	**Average**	**Forecast**	**Budget**
Internal Labor	$16.80	$17.10	$17.10	$18.60	$18.40	$18.40	$18.10	$18.80	$18.00
Contract Labor and Consulting	$6.10	$5.80	$7.60	$8.60	$7.00	$7.80	$7.40	$7.40	$6.00
Employee Expenses	$1.70	$2.70	$2.00	$2.40	$2.00	$2.40	$2.50	$2.40	$2.70
Fees*	$2.50	$2.50	$2.60	$2.60	$2.80	$2.60	$2.60	$2.70	$2.30
Materials	$2.00	$3.10	$2.30	$2.70	$2.40	$2.50	$2.80	$2.20	$2.30
Fleet	$1.40	$1.80	$1.40	$1.90	$1.60	$2.00	$1.90	$1.60	$1.90
Other	($1.30)	($3.40)	($1.60)	($4.30)	($2.20)	($3.10)	($3.60)	($3.30)	($1.40)
Total	**$29.20**	**$29.70**	**$31.40**	**$32.40**	**$31.90**	**$32.60**	**$31.60**	**$31.80**	**$31.70**

Exhibit___(IRB), Schedule 3 provides a detailed breakdown of O&M costs by general ledger account.

Q. PLEASE DESCRIBE EACH OF THE COST CATEGORIES IN THE O&M BUDGET.

A. As can be seen from Table 11 above, the Transmission Business Unit's O&M budget consists of six main cost categories: (1) internal labor; (2) contract labor and consulting; (3) employee expenses; (4) fees; (5) materials; and (6) fleet.

B. O&M Budgeting Process

Q. HOW DOES THE COMPANY SET THE O&M BUDGET FOR THE TRANSMISSION BUSINESS UNIT?

A. As with our capital budget, the O&M budget for the Transmission business unit is built using a bottom-up approach. Each budget manager reviews their needs factoring in work plans as well as any anticipated efficiency gains for the coming years and develops budgets in accordance with those needs and anticipated efficiency improvements. As part of this bottom-up process, the Field Operations and Construction units review those facilities that need repairs to extend their asset life, addressing issues like broken insulators, loose hardware, woodpecker damage, broken or damaged guy wires, etc. In this way, Asset Renewal projects are a driver of the O&M budgeting process. The individual manager budgets are then consolidated for a total Transmission O&M budget and analyzed for reasonableness and accuracy as compared to recent actual trends. This process includes normalizing the actual spend for those expenses that are not expected to continue into the budget years due to changes in business conditions or one-time events. The total Transmission business unit budget is compared to the overall Company targets, which are discussed further in Mr. Robinson's testimony. If the budget is greater than the overall Company targets provided to Transmission, the needs are prioritized with the most critical needs funded first and the least critical needs funded last.

Q. DOES THE TRANSMISSION BUSINESS UNIT EVER NEED TO CHANGE THE ALLOCATION OF O&M FUNDS DURING THE FINANCIAL YEAR?

A. Yes, the Transmission business unit has had to change the allocation of O&M funds during the financial year. Unexpected operational or regulatory events, such as additional NERC compliance requirements, during the year can cause additional unplanned Transmission O&M costs. When this occurs, we make every effort to re-evaluate activities within the Transmission business unit to absorb the unexpected costs. In addition, the Transmission business unit will periodically receive a request from the Company to adjust O&M costs within the financial year to account for changes in business conditions in other areas of the Company. This again results in the re-evaluation of activities and the reduction of non-critical activities. While the Transmission business unit makes every effort to respond to changes in business conditions within the given targets, there are times where circumstances dictate that we will need to spend more than the targets provided by the Company in order to maintain safe, reliable service to our customers and to properly address certain items that come about during a given budget year.

Q. HOW DOES THE COMPANY DETERMINE CHANGES IN THE O&M BUDGET?

A. The Transmission business unit re-evaluates the business needs annually in development of the O&M budget. As those needs change, the budget is prioritized to fund the most critical needs first. If the funding required for critical needs is greater than the Company target provided to the Transmission business area, the critical needs that are not funded within the targets provided are brought to the Company to be prioritized along with the needs of the other business units. For example, if a new NERC compliance requirement is implemented that will cause a substantial change in O&M expenditures and was not contemplated in the targets provided by the Company, additional funding may be requested by the Transmission business area to cover that need.

During any given year, we are routinely monitoring our O&M actual expenditures versus their associated budgets and identifying any variances of significance as they materialize. As budget pressures are identified in certain areas or programs, options are reviewed to mitigate those pressures. One mitigation option would be the reallocation of funds from other areas, where budgeted work of a lower priority or more discretionary nature in the short-term may be reallocated to cover the programs experiencing the budget pressures. If the amount needing funding cannot be funded prudently within the overall Transmission business unit O&M budget, the issue is brought forward to the Company as a request to increase the overall O&M target for the Transmission business unit.

Q. PLEASE EXPLAIN HOW THE TRANSMISSION BUSINESS UNIT MONITORS O&M EXPENDITURES.

A. The Transmission business unit is supported by a dedicated Finance team. The Finance team prepares monthly reporting for the Transmission business area that includes reviews of the current month actual versus budget, year-to-date actual versus budget, and year-end forecast versus target. This reporting is provided to the individual budget managers with summaries at the Director and overall Transmission business unit level. The summarized reporting is reviewed on a monthly basis with the Transmission leadership team, where concerns or issues are also discussed.

Q. HOW DOES THE TRANSMISSION BUSINESS UNIT O&M BUDGET PROCESS AND GOVERNANCE COMPARE TO OTHER BUSINESS UNITS?

A. The process the Transmission business unit uses in the development of the O&M budget is consistent with the practices used in the other business units across the Company. As discussed above, the budget development is accomplished through a bottom-up approach where each budget manager develops their budget based on identified work plans and efficiency gains for the budget year and prioritized based on the most critical activities to ensure the Company targets are met. During the year governance is accomplished through the monthly reporting and monitoring of performance as well as formal tracking of changes to the year-end targets by Director within an Operating Company, as discussed above. Any changes to the year-end targets within the Transmission business unit are approved by the Senior Vice President of Transmission. Any changes to the overall Transmission business unit targets and brought forward to the Company for consideration. Further discussion of the overall Company budget process and governance is discussed in the testimony of Mr. Robinson.

Q. HOW ARE THE TRANSMISSION BUSINESS UNIT LONG-TERM O&M COSTS TRENDING?

A. The Transmission business unit makes efforts to hold our O&M budget relatively flat from year to year. Consequently, the NSPM long-term O&M

has risen at a compounded annual growth rate cost growth of 1.9 percent since 2012, including the impacts of changes in the business environment resulting in additional costs (e.g., increased compliance and fees). Within this average, our costs have increased slightly more or less in a given year, depending on the needs the Transmission business unit and of the overall Company.

Q. WHAT ARE THE MAJOR COST DRIVERS OF THE 2016 TRANSMISSION O&M BUDGET?

A. We have identified eight cost drivers that have contributed to the overall decrease in the O&M budget: 1) Merit Increases; 2) Fees; 3) Completed Compliance Activities; 4) Competitive Transmission Activity; 5) Employee Expenses; 6) Mutual Aid; and 7) Other. Table 12 summarizes these cost drivers.

Table 12

Transmission 2016 Budget vs. 2014 Actual O&M Expenditures NSPM-Electric (Dollars in Millions)		
Cost Drivers	**Amount**	**Total**
2014 Actual		$43.9
Merit (3% annual increase)	$1.2	
Fees: NERC, Professional and Association Dues, and License Fees	$0.1	
Completed Compliance Activities; FERC Order 754, CAPE reporting	($0.6)	
Competitive Transmission Activity	($0.3)	
Employee Expenses	($0.1)	
Mutual Aid provided to Great River Energy in 2014 - one time event	($0.7)	
Miscellaneous Other	($0.4)	
2016 Budget		**$43.1**

Q. HOW DO THESE DRIVERS RELATE TO THE COST CATEGORIES IN TABLE 11?

A. The cost drivers in Table 12 and the cost categories in Table 11 are interrelated. This means each cost driver impacts multiple cost categories, or, each cost category influences several cost drivers. I will provide examples later in my testimony of how the cost drivers are impacting changes in cost categories.

Q. IS THERE AN EXCEPTION TO THIS INTERRELATIONSHIP?

A. Yes. The one exception is the Fees cost category. The Fees cost category consists of the fees we are required to pay to the FERC, NERC, and MRO for the operation of the transmission system. Additional Fee costs are related to professional dues, license fees, and other similar fees necessary for the operation of our business. The increase in the Fees cost category for 2016 over 2014 actuals is attributable to a single driver – Regulatory Fees. The Regulatory Fees are increasing $0.15 million from 2014 to 2016, but the professional dues and license fees are slightly reduced; the off-set causing a $0.1 million variance for the Fees cost category.

Q. HOW DOES THE 2016 BUDGET COMPARE WITH 2014 ACTUAL COSTS?

A. We are expecting a decrease of $0.8 million from 2014 actuals to 2016 budget. This is due to reductions in five of the seven cost drivers for the Transmission O&M budget.

Q. HOW DOES THE 2016 BUDGET COMPARE WITH THE 2015 FORECAST?

A. The 2016 budget is $0.1 million less than the 2015 forecast. The labor increase was offset by a credit to the other category for work performed for others, as unplanned events are not forecast. The driver of the 2016 budget decrease is contract labor and consulting. A decrease of $0.2 million in consulting is due to the completion of NERC compliance requirements for transmission relay loadability (Standard PRC-023-3) and Computer Aided Protection Engineering Relay Coordination (CAPE RC). The remaining $0.3 million decrease in consulting is due to the shift of costs from NSPM to our Transco for competitive transmission activities.

C. O&M Budget Detail

1. Internal Labor

Q. WHAT INTERNAL LABOR COSTS ARE INCLUDED IN THE TRANSMISSION BUSINESS UNIT O&M BUDGET?

A. This category represents the O&M portion of salaries, straight time labor, overtime, and premium time for internal employees. An attrition factor of four percent is also applied, which reduces labor costs to account for retirements, hiring delays, and other employee transfers. These amounts include costs for both NSPM employees and the appropriate allocation of Xcel Energy Services employees. For capital construction focused positions, the vast majority of the labor costs are allocated to capital; however, some labor costs are charged to O&M activities like employee meetings, etc.

Q. WHAT CHANGES IN INTERNAL LABOR COSTS DO YOU ANTICIPATE FOR THE TEST YEAR?

A. We are expecting a decrease of $0.6 million in internal labor costs from 2014 actuals to 2016 budget.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND DECREASES IN INTERNAL LABOR COSTS?

A. The drivers that have influence this decrease in internal labor costs include:

- *Merit* – The 2016 budget includes a $1.2 million increase in labor expenses over the 2014 actual budget due to the to the annual merit increase of 3 percent. The Transmission business unit budgets for merit increases at the level determined by Human Resources for non-bargaining employees, and as set forth in collective bargaining agreements for bargaining employees. For non-bargaining employees, the 2016 test year merit increase reflects a percentage increase which is consistent with market median values. With that said, the annual merit increases for our bargaining and non-bargaining employees and the historical trends for merit increases are discussed more fully in the testimony of Company witness Ms. Ruth K. Lowenthal
- *Mutual Aid* – The Company has mutual aid agreements with several of our neighboring utility companies. In the case of a storm event or other emergency, mutual aid or mutual assistance programs are voluntary partnerships between electric utilities to help restore power safely and efficiently. In 2014, there was a tower vandalized on a segment of transmission line that was owned solely by Great River Energy. We provided the repairs, and were fully reimbursed by Great River Energy for those services. This cost driver represents a one-time event, which was reflected in 2014 actual spending, but was not budgeted for in future years as an ongoing expense. This resulted in a $0.4 million decrease in internal labor costs for 2016.
- *Overtime* – The remaining $1.4 million decrease is explained by a decrease in overtime due to less work for others.

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE INCREASES IN INTERNAL LABOR COSTS.

A. The Transmission business unit closely monitors our overall headcount numbers, ensuring that any increases in headcount above the budgeted levels are prudent and fully reviewed. In addition, we closely monitor the amount of time spent on capital activities on a monthly basis as part of the overall monthly reporting in order to manage the amount of internal labor being charged to O&M.

2. Contract Labor and Consulting

Q. WHAT COSTS ARE INCLUDED IN THE BUDGET AS CONTRACT LABOR AND CONSULTING?

A. This category represents our use of contract labor and consultants, which allows the Company to increase and decrease its staffing levels as workloads require rather than bringing on more full-time staff, and to retain the services of experts as needed for specific tasks or project efforts. We believe utilizing contractors and consultants in this way is an efficient and cost-effective way to ensure work is completed while ensuring the cost for the resources is only incurred for the time during which it is needed.

Q. WHAT CHANGES IN CONTRACT LABOR AND CONSULTING COSTS DO YOU ANTICIPATE FOR THE TEST YEAR?

A. We are expecting a decrease of $2.3 million in contract labor and consulting costs from 2014 actuals to 2016 budget.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND DECREASES IN CONTRACT LABOR AND CONSULTING COSTS?

A. The drivers that influence this decrease in external labor costs include:

- *Completed Compliance Activities* – In August 2012, NERC issued a Request for Data related to FERC Order No. 754, which requires each transmission planner, including NSPM, to conduct studies and submit data related to single points of failure on protection systems that may result in adverse reliability risks. In order to comply with this requirement, Transmission spent approximately $0.12 million for consulting services to complete the data requests and related inspections and analysis; and approximately $0.1 million for an updated Computer Aided Protection Engineering protection system model and related studies to analyze its protection system performance and identify potential misoperations. This compliance requirement should be complete in 2016. Additionally, NERC required substation maintenance that was performed by contract crews, due to internal staff performing work for Nuclear. The 2014 level of work done for Nuclear is not expected to recur, therefore, the NERC-required maintenance will be performed with internal staff, reducing the contract labor by $1.2 million.
- *Employee Expenses* – Through the use of technology and video conferencing, travel expenses are planned to decrease $0.1 million in 2016.
- *Competitive Transmission Activity* – In September 2014, the Company submitted and received approval from the Minnesota Public Utilities Commission requesting approval of Administrative Services Agreements (ASA) with Xcel Energy Transmission Development

Company, LLC (XETD) and Xcel Energy Southwest Transmission Company, LLC (XEST) in Docket No. E002/AO-14-759. These newly formed electric transmission company or "Transco" affiliates were formed to seek to construct, own, and operate transmission facilities in the MISO region outside the Company's traditional service area, and bordering on the MISO region. The approval of these Transcos allows the Company to compete on transmission projects that are proposed in the MISO region under the implementation of FERC Order 1000. The ASAs provide the terms and conditions for the Company to provide, on an as available basis, personnel, goods, and services to support XETD and XEST transmission planning, development, construction, and other activities. With the establishment of the Transcos, some external labor costs were transferred out of the NSPM budget and into XETD or XEST. This resulted in a decrease of $0.3 million in the 2016 budget, due to Competitive Transmission Activity.

- *Mutual Aid* – This cost driver, which was described above in relation to internal labor costs, represents a one-time event that resulted in a $0.1 million decrease in contract labor and consulting costs for 2016.

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE INCREASES IN CONTRACT LABOR AND CONSULTING COSTS.

A. While utilizing contractors and consultants can be a cost-effective method of managing labor costs on projects with variable workloads, the Transmission business unit has taken steps in the last few years to minimize the cost of contract labor and consulting costs. This includes increasing the reliance on workload planning to ensure the staffing levels, including both internal and external resources, are at the minimum levels required to achieve the optimal staffing levels. In addition, the Transmission business unit utilizes strategic sourcing and the competitively bid Master Service Agreement program to obtain the qualified and cost-effective contract labor. The Master Service Agreement program creates supply agreements with several preferred vendors to obtain bulk discounts and better service.

3. Fees

Q. WHAT FEES ARE INCLUDED IN THE TRANSMISSION BUSINESS UNIT BUDGET?

A. This category consists of fees we are required to pay to the FERC, NERC, and MRO for the operation of the transmission system. As a regulated utility, the Company is required to pay fees for each of those organization's operating costs. It also includes professional and utility association dues, as well as land and railroad permits and license fees, and other similar fees necessary for the operation of our business.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND INCREASES IN FEES?

A. The increase in the Fees cost category for 2016 is attributable to a single cost driver category – Regulatory Fees.

Q. WHAT CHANGES IN FEES DO YOU ANTICIPATE FOR THE TEST YEAR?

A. We are expecting an increase of $0.1 million in fees from 2014 actuals to 2016 budget.

Q. PLEASE EXPLAIN THE INCREASE IN FEES FROM 2014 ACTUALS TO THE 2016 TEST YEAR.

A. The driver of the increase is Regulatory Fees, accounting for a $0.17 million increase. This increase was offset slightly by the decrease in other fees, including $70,000 for professional association dues for the University of Minnesota Center for Electrical Engineering.

Table 13 below provides the Company's actual costs for Regulatory Fees in 2014 and 2015. We know our actual costs for fees in 2015 because we have already paid those costs for the year. The table also includes our budgeted costs for Regulatory Fees for the 2016 test year. NERC invoices the Company on behalf of itself and the MRO, so we receive one bill with a line item for our NERC fees and another line item for our MRO fees. Dollar figures are shown for both NSPM and NSPM – State of Minnesota jurisdiction.

Table 13

O&M Regulatory Fees NSPM-Electric (Dollars in Millions)						
Fee	**Assessment**	**2012**	**2013**	**2014**	**2015**	**2016**
	Basis	**Actual**	**Actual**	**Actual**	**Actual**	**Budget**
NERC	MRO	$1.39	$1.48	$1.40	$1.46	$1.55
	NERC	$0.56	$0.50	$0.54	$0.57	$0.60
*FERC	MWh	$0.04	$0.04	$0.04	$0.02	$0.00
Total		**$1.99**	**$2.03**	**$1.97**	**$2.05**	**$2.16**
* Because City of Marshall is joined MISO eff. 6/1/14, the FERC assessment will be incorporated into the NERC assessment.						

O&M Regulatory Fees Minnesota Electric Jurisdiction (Net of Interchange Billings to NSPW) (Dollars in Millions)						
Fee	**Assessment**	**2012**	**2013**	**2014**	**2015**	**2016**
	Basis	**Actual**	**Actual**	**Actual**	**Actual**	**Budget**
NERC	MRO	$1.04	$1.10	$1.04	$1.07	$1.14
	NERC	$0.42	$0.38	$0.40	$0.42	$0.44
*FERC	MWh	$0.03	$0.03	$0.03	$0.01	$0.00
Total		**$1.49**	**$1.51**	**$1.47**	**$1.50**	**$1.59**

Q. FOR NERC AND MRO, PLEASE EXPLAIN THE INCREASE FROM 2014 ACTUAL TO THE 2016 TEST YEAR BUDGET.

A. The Company forecasts its Regulatory Fees based on guidance from the regulatory bodies. Guidance from NERC and MRO suggested an 8 to 10 percent increase in 2016 for both organizations. Consistent with this guidance, the Company has budgeted approximately $2.15 million for the 2016 test year, which is an approximate eight percent increase in NERC fees over 2014.

Q. HOW DOES THE FERC ASSESS THE COMPANY ITS REGULATORY FEES?

A. We are assessed fees by the FERC in the following two ways: (1) MISO passes along a fee it is assessed by FERC for the Company's retail load; and (2) FERC charges the Transmission business unit for the fees allocated to wholesale transmission customers taking service under the Xcel Energy tariff.

Q. WHICH FERC REGULATORY FEES ARE PRESENTED IN TABLE 13 ABOVE?

A. Table 13 above depicts the assessment we pay on behalf of our wholesale transmission customers. The other FERC regulatory fees (i.e., the ones we pay for our transmission system) are paid by the Company through MISO as part of MISO's Administrative Charge in Schedule 10-FERC.

Q. WHY ARE THE FERC FEES IN TABLE 13 DROPPING TO $0 IN 2016?

A. NSPM was RESPONSIBLE for a FERC assessment related to the City of Marshall (COM) in the amount of $40,423. Effective June 1, 2014, NSPM no longer assessed COM's FERC assessment, as that responsibility transitioned to MISO once COM began taking transmission service from MISO. The final FERC assessment for COM for $15,745 was paid in 2015. Going forward, that FERC assessment will be incorporated into the NERC assessment.

4. Materials

Q. WHAT MATERIALS ARE INCLUDED IN THE TRANSMISSION BUSINESS UNIT BUDGET?

A. This category consists primarily of consumables, hardware, and refurbished materials used in substation maintenance and repair operations. Additionally, tools, small equipment and supporting supplies are included.

Q. WHAT CHANGES IN MATERIALS COSTS DO YOU ANTICIPATE FOR THE TEST YEAR?

A. We are expecting a decrease of $0.24 million in material costs from 2014 actuals to 2016 budget.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND DECREASES IN MATERIAL COSTS?

A. There is one key driver that impacts the decrease in materials costs:

- *Compliance Activities* – Expected purchases of consumable materials and small tools used to perform substation maintenance are reduced $0.2 million due to the reduction in work for Nuclear generation.

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE INCREASES IN MATERIALS COSTS.

A. Transmission O&M spending demonstrated a decrease in material costs between 2014 and 2016 due to lower anticipated substation work, resulting in a reduced need for materials. Going forward the Transmission business unit will continue to take advantage of the Master Service Agreement program, utilizing negotiated supply agreements with several preferred vendors to obtain bulk discounts and better service. In addition, we are continuing to look for opportunities to optimize the sourcing for materials through efficiencies gained within the Supply Chain organization.

5. Fleet

Q. WHAT COSTS ARE INCLUDED IN THE FLEET CATEGORY?

A. This category consists of costs for the internal fleet assets as directed to O&M accounts on an hourly basis by Transmission operations. This is an aggregate cost of all fleet equipment charged to Transmission O&M, including cars, trucks, construction equipment and trailers.

Q. WHAT CHANGES IN FLEET COSTS DO YOU ANTICIPATE FOR THE TEST YEAR?

A. We are expecting a decrease of $0.07 million in Fleet costs from 2014 actuals to 2016 budget.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND DECREASES IN FLEET COSTS?

A. The primary driver that influenced the decrease in Fleet costs is due to an adjustment in Mutual Aid. As described previously, the actual spending for our Mutual Aid agreement in 2014 was higher due to a one-time event, but was not budgeted for in future years as an ongoing expense. This resulted in a $0.1 million decrease in fleet costs for 2016.

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE INCREASES IN FLEET COSTS.

A. Since 2014, the Transmission fleet budget has decreased primarily due to efforts in the Fleet organization to reduce the per unit expense, such as rental buyouts and lower fleet fuel costs. Additionally, Transmission field operations increased focus on fleet utilization by construction personnel.

6. Other

Q. WHAT COSTS REMAIN IN THE "OTHER" CATEGORY?

A. This category is primarily a credit the Transmission organization receives for doing work for the Energy Supply organization. To explain this a bit further, from time to time the Transmission business unit will construct or maintain an asset in a substation which is "owned" by Energy Supply (i.e. classified as an Energy Supply asset). In those instances, Transmission incurs the costs within the respective cost categories. These costs are tracked within a specific work order. The costs are then transferred to Energy Supply or Nuclear by crediting the Other cost category within Transmission and debiting a defined cost category within Energy Supply or Nuclear.

Q. WHAT CHANGES IN "OTHER" DO YOU ANTICIPATE FOR THE TEST YEAR?

A. We are expecting an increase of $2.4 million in reduced credits to Other from 2014 actuals to 2016 budget.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND INCREASES IN OTHER COSTS?

A. The volume of work performed for Energy Supply and Nuclear planned for 2016 is less than the actual volume of work performed in 2014. The reduced volume of work results in lower internal labor overtime and contract services costs within Transmission, as previously discussed. Therefore, the resulting credit to Other transferring the costs to Energy Supply and Nuclear is also reduced.

D. Multi-Year Rate Plan O&M Costs

Q. WHAT IS THE LEVEL OF O&M EXPENSE THAT TRANSMISSION SEEKS TO RECOVER FOR THE 2017 AND 2018 PLAN YEARS?

A. Transmission's forecasted 2017 and 2018 increases in O&M expenses are set forth in the "budget walk forwards" in Volume 6 of the Company's initial rate case filing. Company witness Mr. Aakash H. Chandarana explains the basis of the Company's overall approach to its O&M expense requests for the 2017 and 2018 plan years and Company witnesses Mr. Charles Burdick and Mr. John Mothersole explain the basis for the Company's selection of the particular factors used in our rate requests for these years.

Q. WHILE THE COMPANY PROPOSES USING THESE FACTORS, ARE THERE SPECIFIC DRIVERS THAT YOU HAVE IDENTIFIED IN THE TRANSMISSION AREA THAT WILL IMPACT THE EXPENSE LEVELS IN 2017 AND 2018?

A. Yes. As shown in our 2017 and 2018 supporting information, provided in Volume 6 of our Initial Filing, Transmission will see the need for changes in it O&M expenses for plan year 2017 in the following areas:

- An increase of $0.6 million due to merit;
- An increase of $0.2 million due to regulatory fees; and
- A decrease of $0.3 million due to operational savings.

And for plan year 2018 in the following areas:

- An increase of $0.6 million due to merit;
- An increase of $0.1 million due to regulatory fees; and
- A decrease of $0.3 due to operational savings.

Q. PLEASE EXPLAIN THE PURPOSE AND IMPACT OF "MERIT" ON TRANSMISSION'S 2017 O&M EXPENSES.

A. The 2017 budget includes a $0.6 million increase in labor expenses over the 2016 budget due to the assumed annual merit increase of three percent. The Transmission business unit budgets for merit increases at the level determined by the Human Resources business unit for non-bargaining employees, and as set forth in collective bargaining agreements for bargaining employees.

Q. PLEASE EXPLAIN THE PURPOSE AND IMPACT OF REGULATORY FEES ON TRANSMISSION'S 2017 O&M EXPENSES.

A. The NERC fee assessment is based on NSP Companies' proportion of the MRO megawatt hours (MWh) used. The guidance from the MRO organization was to account for an 8 to 10 percent year over year increase. Due to increased activity related to FERC Order 1000 and the MRO's bid issuance and reviewing activity, NSP Companies budgeted a 10 percent increase.

Q. PLEASE EXPLAIN THE PURPOSE AND IMPACT OF "MERIT" ON TRANSMISSION'S 2018 O&M EXPENSES.

A. The 2018 budget includes a $0.6 million increase in labor expenses over the 2017 budget due to the assumed annual merit increase of three percent. The Transmission business unit budgets for merit increases at the level determined by the Human Resources business unit for non-bargaining employees, and as set forth in collective bargaining agreements for bargaining employees.

Q. PLEASE EXPLAIN THE PURPOSE AND IMPACT OF REGULATORY FEES ON TRANSMISSION'S 2018 O&M EXPENSES.

A. The NERC fee assessment is based on NSP Companies' proportion of the MRO megawatt hours used. NSP Companies budgeted a six percent increase, as the MRO's administrative expenses are becoming more stabilized as the bidding review/issuance process is practiced more frequently.

V. THIRD-PARTY TRANSMISSION EXPENSES AND WHOLESALE TRANSMISSION REVENUES

A. Overview of the Transmission System in Minnesota and the Upper Midwest

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In the past few rate cases, there has been interest in further understanding the Company's third-party transmission revenues and expenses. I am including this section of my testimony to address some of the issues we have seen in testimony and discovery from our recent electric rate cases.

Q. GENERALLY SPEAKING, WHAT ARE THIRD-PARTY TRANSMISSION EXPENSES?

A. While NSP System loads and transmission facilities are primarily located within the NSP pricing zone, the NSP Companies serve loads in five other MISO pricing zones, and a small load outside MISO. The NSP Companies also collect revenue for transmission facilities located in the Great River Energy (GRE) pricing zone, and several other utilities collect revenue for transmission facilities located in the NSP pricing zone.

As a result, the NSP System incurs third-party transmission expenses where the NSP Companies serve their native load customers in other zones, including Joint Pricing Zone (JPZ) arrangements developed to compensate other utilities for their facilities in the NSP pricing zone consistent with the MISO Transmission Owners Agreement. On the other hand, NSP System also receives revenues for transmission and ancillary services provided to other utilities with load in pricing zones where NSP owns transmission assets.

Q. WHAT IS THE RELATIONSHIP OF THIRD-PARTY TRANSMISSION EXPENSES AND WHOLESALE TRANSMISSION REVENUES TO THE COMPANY'S COST OF SERVICE?

A. Third-party transmission expenses and wholesale transmission revenues can either serve as a credit or debit to the Transmission business unit's O&M costs. We are forecasting that the net impact of third-party transmission expenses and wholesale transmission revenues will help bring down our corporate O&M costs for the 2016 test year.

Q. PLEASE DESCRIBE THE HISTORIC DEVELOPMENT OF THE TRANSMISSION FACILITIES IN MINNESOTA AND THE UPPER MIDWEST.

A. Electric utilities in Minnesota serve retail service areas that are spread throughout the state, sometimes non-contiguous to other parts of their retail service areas. The Company serves the Twin Cities, several major cities including St. Cloud, Mankato, and Winona, and about 400 other communities in Minnesota, while other utilities serve areas between the Company's territories. This is because electric utilities in Minnesota and the upper Midwest (investor-owned, cooperatives, municipal utilities) have worked together for many years to develop a transmission network that will serve our respective native load customers. As a result, electric utilities in Minnesota and the region have highly interconnected transmission facilities that do not necessarily follow the patchwork of retail service area boundaries. This cooperation benefits our customers by providing the transmission infrastructure needed to serve our loads at a lower cost than if the Company and neighboring utilities each independently constructed facilities to reach their respective service area loads.

Q. HOW DOES THE HISTORY OF COOPERATION AFFECT THE COSTS TO MINNESOTA CUSTOMERS?

A. As designed and implemented, the jointly-developed multi-owner transmission grid in Minnesota has resulted in less duplication of facilities and increased system efficiency. This has resulted in a general decrease in costs to customers throughout Minnesota.

Today, access to that multi-owner transmission grid is available under the MISO Tariff. Essentially, the Company receives revenue from other entities that use our transmission system and incurs an expense for using the transmission system of other entities.

B. Third-Party Transmission Expenses and Revenues

Q. PLEASE EXPLAIN HOW THE WHOLESALE REVENUES AND THIRD-PARTY EXPENSES ARE RECOVERED?

A. The MISO Tariff recovers the costs of transmission facilities through rates established and billed by "pricing zones," which roughly match the boundaries of the local balancing authority areas operated by individual MISO member utilities. The local balancing authority areas closely resemble the control areas from the pre-MISO operational days. Control areas were used to designate transaction schedules and system dispatch responsibilities to specific utilities. When the transmission owners first began interconnecting, control area boundaries were established to roughly encompass a utility's transmission and generation assets. The concept of control areas (now local balancing authority areas) is still used for utility energy accounting purposes.

The concept of a pricing zone is that the "network loads" within the pricing zone, including a utility's retail native load customers, will bear the Annual Transmission Revenue Requirement (ATRR) associated with the transmission facilities in the zone on a load ratio share basis. The ATRR is calculated using the transmission cost of service rate formula set forth in the MISO Tariff for each transmission owner.

Q. HOW DOES THE BILLING WORK?

A. The Company is party to JPZ agreements for both the NSP pricing zone and the GRE pricing zone. Under these agreements, the transmission-owning utilities are compensated for their facilities in the zone, and the load serving utilities are billed for their loads in the zone. Since the NSP Companies are both transmission owners and load serving entities in both pricing zones, the NSP System (1) receives revenues for its facilities in the NSP and GRE pricing zone, and (2) incurs expenses for its loads in the NSP and GRE zones.

Furthermore, as a MISO transmission owner, the NSP Companies collect third-party wholesale transmission service revenues for others' use of the NSP System under both the MISO Tariff and other wholesale transmission agreements. The NSP System also incurs transmission and/or ancillary expenses for its loads in other MISO pricing zones.

Q. PLEASE DESCRIBE THE TRANSMISSION THIRD-PARTY EXPENSES AND WHOLESALE REVENUES AFFECTING THE TEST YEAR.

A. The NSP System is operated as an integrated system and is treated as one under the relevant provisions of the MISO Tariff. Using third-party transmission is necessary to serve NSP System loads, including NSPM retail native loads in Minnesota, and thus the costs should be included in rates. However those costs are offset by various transmission service revenues, thereby reducing total costs to NSPM customers in Minnesota. Table 14 summarizes the 2016, 2017, and 2018 budgets for MISO third-party transmission revenues and expenses and administrative charges for the total NSP System, compared to 2014 actual and 2015 forecast amounts.

Table 14

NSP System Third-Party Transmission Expenses and Revenues ($000's)					
Third-Party Transmission Expenses	**2014 Actual**	**2015 Forecast**	**2016 Budget**	**2017 Budget**	**2018 Budget**
JPZ Payments (NSP and GRE Zones)	$40,053	$43,359	$47,799	$49,244	$50,722
WAPA PTP/System Integration Service	$6,817	$6,933	$ -	$ -	$ -
MISO Network Service, Point to Point, and Ancillary Services	$20,033	$19,211	$19,093	$19,874	$20,620
MISO Admin Charges (Sch. 10)	$9,571	$10,852	$10,043	$10,245	$10,550
Other (Transmission Facilities/Other Native Load Deliveries, etc.)	$1,114	$527	$389	$347	$119
Total Third-Party Expenses	**$77,589**	**$80,882**	**$ 77,323**	**$ 79,711**	**$82,011**
Wholesale Transmission Revenues	**2014 Actual**	**2015 Forecast**	**2016 Budget**	**2017 Budget**	**2018 Budget**
JPZ Revenues (NSP and GRE Zones)	$38,924	$40,745	$ 50,039	$51,547	$53,094
MISO Network Service	$19,225	$22,790	$ 31,772	$32,367	$34,413
MISO Point to Point	$9,490	$9,129	$ 9,433	$9,433	$9,433
GFAs	$18,683	$9,448	$ 399	$373	$376
Other (Ancillary Services/LBA Services, etc.)	$1,992	$2,588	$ 2,432	$2,467	$2,503
Total Third-Party Revenues	**$88,314**	**$84,700**	**$ 94,076**	**$96,187**	**$99,818**
Net Expense (Revenue)	**$(10,725)**	**$(3,818)**	**$(16,753)**	**$(16,476)**	**$(17,807)**

Since NSPM and NSPW operate the NSP System as an integrated system, the first table section above reflects NSP System revenues and expenses. The third-party transmission expenses and revenues are described in more detail later in my testimony and in Exhibit___(IRB-1), Schedules 4 and 5. The 2016 budget shows net revenue which serves to reduce the Company's overall retail cost of service.

Q. DO THE 2016 TRANSMISSION EXPENSES YOU DESCRIBE INCLUDE CHARGES UNDER MISO SCHEDULES 26 AND 26A TO RECOVER THE COSTS OF

INVESTMENTS BY MISO MEMBERS RECOVERED THROUGH THE REGIONAL EXPANSION CRITERIA AND BENEFITS (RECB) TARIFF MECHANISM?

A. No. Schedules 26 and 26A provide for cost recovery of certain transmission projects. Schedule 26 recovers from MISO loads the costs of projects determined to be eligible for partial regional cost recovery as a "reliability" or "economic" project under the RECB mechanisms. Schedule 26A recovers from MISO loads the costs of projects determined to be eligible for full regional cost recovery as a MVP. The Company includes MISO Schedules 26 and 26A charges in the TCR Rider recovery mechanism. Schedules 26 and 26A charges would thus be in addition to the third-party transmission expenses described in my testimony. The Company also includes Schedules 26 and 26A revenues in the TCR Rider as an offset to Schedules 26 and 26A expenses paid to MISO.

Q. PLEASE DESCRIBE THE 2016 NSP SYSTEM THIRD-PARTY TRANSMISSION EXPENSES.

A. There are several types of third-party costs, which are summarized in Schedule 4. These are NSP System transmission costs necessary to serve NSP System loads, including NSP retail native loads in Minnesota, pursuant to rate schedules accepted for filing by FERC. My testimony provides the NSP System costs; Ms. Heuer's test year cost of service reflects the portion allocated to the Minnesota jurisdiction.

- *JPZ Costs* – As I previously discussed, the NSP System incurs costs for serving its native loads within the NSP JPZ and in the GRE JPZ. The Company, GRE, Southern Minnesota Municipal Power Agency (SMMPA), Central Minnesota Municipal Power Agency (CMMPA), Northwestern Wisconsin Electric Company (NWEC), Minnesota

Municipal Power Agency (MMPA), and Missouri River Energy Services (MRES) each own transmission facilities and serve loads in the NSP pricing zone. The Company's payments consist of both expense and revenue components. The 2016 expense is for our use of the GRE, SMMPA, CMMPA, NWEC, MMPA, and MRES transmission facilities to serve the NSP System loads in the NSP pricing zone. The 2016 revenue reflects use of the NSP System facilities by other utilities to serve their respective loads in the NSP pricing zone. The NSP System 2016 net receipt under the NSP-JPZ arrangement is forecast to be $2.24 million, based on JPZ expense of $47.80 million and JPZ revenue of $50.04 million.

Similarly, the NSP System has both native load and transmission facilities located in the GRE pricing zone, which is also a multi-utility zone. The Company pays GRE a net payment consisting of expense and revenue components: the expense of using other parties' facilities to serve the Company's native load; and the revenue paid by other parties for their use of NSP's facilities in the GRE zone. The NSP System 2016 net payment for the GRE JPZ is forecast to be $2.37 million, based on JPZ expense of $3.48 million and JPZ revenue of $1.11 million.

Thus, the combined 2016 impact of both the NSP JPZ and GRE JPZ is a net receipt of $2.24 million, based on a total expense of $48.80 million and a total revenue of $50.04 million, as summarized in Exhibit___(IRB-1), Schedule 6.

- *WAPA Point-to-Point Transmission Service Costs* – The NSP Companies presently incur costs to deliver generation to loads over the WAPA system west of the MISO region. WAPA is not a MISO member, so service on the WAPA system is not available under the MISO Tariff. The NSP System has contracted for 190 MW of point-to-point transmission service under the WAPA Tariff, and NSP's current expense for this service is close to $7 million per year. However, service under WAPA's tariff is expected to terminate on October 1, 2015 when WAPA's system becomes integrated into the Southwest Power Pool (SPP). In light of recent NSP System investments in southwestern Minnesota and SPP transmission planning criteria, any further transmission service that the Company may need under SPP's tariff in place of the current WAPA point-to-point service is expected to be insignificant.

- *Network Integration Transmission Service (NITS) Costs* – The NSP Companies currently incur costs under the MISO Tariff for Reactive Supply and Voltage Control ancillary service needed by the NSP System to serve native load within the NSP pricing zone. The NSP Companies also incur costs under the MISO Tariff for services needed to serve other native loads that are within MISO, but located outside of the NSP pricing zone or GRE zone. These services include NITS service to serve Company loads in the Dairyland Power Cooperative, ITC Midwest, and Minnesota Power pricing zones, and charges for ancillary services for Company loads in the Otter Tail Power pricing zone. The MISO Tariff also requires the Company to use MISO PTP services to export power supply resources to the Company's native load in

Berthold, North Dakota, outside the MISO region. The NSP System 2016 payments to MISO for these services are forecasted to be $19.09 million.

- *MISO Administrative Charges* – MISO charges its transmission service customers, such as the NSP System, its Schedule 10 administrative charge to recover the costs of administering its Tariff and providing other transmission functions. The 2016 test year charges of $10.04 million are based on the MISO's forecast of its 2016 Schedule 10 rate.

- *Other Transmission Expense/Facility Charges.* The NSP Companies incur these costs to secure delivery rights for the integration of NSP System loads. This cost consists of payments to DPC, Minnkota Power Cooperative, McLeod Cooperative Power Association, Redwood Electric Cooperative, and Stearns Electric Association, and SPP (network transmission service), for use of their respective facilities to enable the Company to serve certain native loads. The NSP System 2016 test year payments to these entities are forecast to be $0.39 million.

Q. WHAT ARE THE 2016 TEST YEAR WHOLESALE TRANSMISSION REVENUES?

A. As shown in Table 14, the total NSP System 2016 test-year wholesale revenues are estimated to be $94.08 million, an increase from $88.31 million in 2014 or a 6.80 percent increase. The increase in revenues is primarily driven by the increase in ATRR, offset by an $8 million reduction in revenue due to expiration of a long-term fixed contract with United Power. Schedule 5 provides more detailed information on the various transmission service revenues by type of service (NITS, point-to-point, etc.) for 2014 and 2016. The revenues from these wholesale services are reflected as revenue credits in the Cost of Service Study supported by Ms. Heuer, thereby offsetting some of the third-party transmission expenses and reducing total costs to our Minnesota customers. The Company is willing to update these numbers as the case proceeds should other parties want us to do so.

Q. HOW ARE THE WHOLESALE TRANSMISSION REVENUES KEPT ACCURATE AND CURRENT?

A. The NSP Companies update their MISO Attachment O ATRR every year. This update is required by the MISO Tariff and coordinated with MISO Tariff Administration staff to reflect current year projected costs and the true-up of prior period costs and loads. The 2016 NSP System ATRR, which reflects our 2016 projected revenue requirement and a true-up of 2014 revenues and loads, is now under review by MISO. The preliminary 2016 ATRR is $401.6 million, an increase from approximately $303.45 million in 2014, and will result in higher MISO zonal transmission service revenues. This increase is primarily driven by increased investments in plant (26 percent increase in net plant), plus increased O&M and property taxes.

C. Pending FERC Proceeding

Q. PLEASE EXPLAIN THE RELEVANCE OF THE PENDING FERC PROCEEDINGS IN FERC DOCKETS EL14-12-000 AND EL15-45-000.

A. In November 2013, a group of customers filed a complaint at FERC against MISO transmission owners (TO), including the NSP System (Docket EL14-12-000). The complaint argued for a reduction in the return on equity (ROE) in transmission formula rates in the MISO region from 12.38 percent to 9.15

percent, a prohibition on capital structures in excess of 50 percent equity, and the removal of ROE incentive adders.

The FERC denied the portions of the complaint related to equity capital structures and ROE incentive adders but has initiated hearing procedures regarding the appropriate ROE to be used in the MISO TOs' formula rates and has established a November 12, 2013 refund effective date. Hearings were held during August 2015, an administrative law judge (ALJ) initial decision is expected to be issued by November 2015, and a FERC order is expected to be issued no earlier than 2016.

In February 2015, a separate group of customers filed an additional complaint proposing to reduce the MISO region ROE to 8.67 percent (Docket EL15-8-000). FERC has established a refund effective date of February 12, 2015 for this second complaint and has initiated hearing procedures. Hearings are scheduled to commence February 16, 2016, an initial ALJ decision is expected by June 30, 2016, and a FERC order is expected no earlier than late 2016.

In November 2014, the MISO TOs filed a request for FERC approval of a 50 basis point ROE incentive adder for participation in the MISO Regional Transmission Organization (RTO). In January 2015, the FERC approved the request, effective January 6, 2015 and subject to the outcome of the ROE complaints. This incentive adder will be added to the ROE ordered by the FERC in the outstanding complaints, with the limitation that the final ROE, including the incentive adder, cannot exceed the upper limit of the range of reasonableness to be established in the ROE complaints.

While the outcome of the ROE complaints is uncertain, it is possible that the FERC will order a rate lower than the currently authorized ROE of 12.38 percent. A reduction in the ROE used in transmission formula rates would result in decreased wholesale transmission revenues, net of third-party transmission expenses, thereby reducing the resulting revenue credit to Minnesota customers.

Q. WHAT ROE WAS ASSUMED FOR PURPOSES OF THIS CASE?

A. The 2016 test year budget for wholesale transmission revenue and third-party transmission expense was prepared based on the currently authorized FERC ROE of 12.38 percent.

Q. WHY WAS THIS ROE SELECTED?

A. Establishment of a just and reasonable ROE is not a purely mechanical process but rather requires the FERC to exercise significant judgment. Until the FERC issues its order in the ROE complaint dockets, the outcome of the cases is uncertain, and we have continued to base our assumptions on the previously authorized rate. As described in Ms. Heuer's testimony, to the extent the FERC's order in these complaints results in an adjustment to wholesale transmission revenues and third-party transmission expenses, we request the difference be trued-up through the TCR rider.

Q. WHAT WOULD BE THE IMPACT OF A LOWER FERC AUTHORIZED ROE?

A. For the 2016 test year, a 25 basis point reduction in the FERC authorized ROE is estimated to result in a reduction in wholesale transmission revenues, net of third-party transmission expenses, of approximately $1 million. This amount excludes revenues and expenses under MISO Schedules 26 and 26-A, which are included in the TCR Rider.

VI. COMPLETENESS INFORMATION

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony I discuss and present specific items required by previous Commission Orders. Specifically, pursuant to Order Points 29 and 30 from the Commission's May 8, 2015 Order in Docket No. E002/GR-13-868, I address the following:

- Present and discuss the benchmarking study the Company conducted of its Transmission O&M costs relative to appropriate peer companies;
- Present a new KPI for Transmission O&M costs;
- Propose a new cost-control KPI at the vice-presidential level for overall transmission costs; and
- Transmission's current KPIs for purposes of the Annual Incentive Program (AIP);

I also discuss the transmission studies completed by the Transmission business unit, as requested by the Commission's September 3, 2013 Order in Docket No. E002/GR-12-961.

A. 2015 O&M Benchmarking Study

Q. ORDER POINT 30(B) REQUIRES THE COMPANY TO PROVIDE A "COMPARISON STUDY OF ITS TRANSMISSION O&M COSTS BY USING APPROPRIATE PEER COMPANIES, ALONG WITH JUSTIFICATION FOR WHY CERTAIN UTILITIES WERE INCLUDED OR EXCLUDED." DID YOU COMPLY WITH THIS ORDER POINT?

A. Yes. We prepared a benchmarking study of Transmission O&M costs in compliance with this Order Point that utilizes appropriate peer companies and metrics. I explain below how these peer companies were selected for purposes of this study.

Q. PLEASE DESCRIBE THE BENCHMARKING STUDY ON TRANSMISSION O&M COSTS COMPLETED BY THE COMPANY.

A. Each year Xcel Energy performs a FERC Electric O&M Analysis study to provide additional information to senior management with respect to relative utility retail revenue and O&M cost performance. Xcel Energy's 2013 FERC Electric O&M study (2013 Corporate Benchmarking Study) was the basis for the Commission's Order Point 30(b) from the last rate case. To comply with this Order Point, we developed a similar study utilizing publicly available information to create the 2015 MISO Transmission Owner O&M Benchmark Report (2015 Transmission Benchmarking Study). A copy of the 2015 Transmission Benchmarking Study is provided as Exhibit____(IRB-1), Schedule 7.

Q. WHAT ARE THE SIMILARITIES OF THE 2015 TRANSMISSION BENCHMARKING STUDY COMPARED TO THE 2013 CORPORATE BENCHMARKING STUDY?

A. The data used in both studies comes from the SNL Energy database of FERC Form 1 filings. Both studies examined expenses for transmission overhead, underground, and substation O&M expenses, including reliability planning and load dispatch expenses utilizing transmission FERC expense accounts 560–573, excluding FERC expense account 565, Transmission of Electricity by Others and Interchange Agreement billings recorded in FERC expense account 566, Miscellaneous Transmission Expenses. The Interchange Agreement billing amounts were determined from footnotes in the FERC Form 1 filings of NSPM and NSPW.

Q. WHY IS FERC EXPENSE ACCOUNT 565, TRANSMISSION OF ELECTRICITY BY OTHERS, EXCLUDED FROM THE STUDY?

A. The purpose of this benchmarking study is to evaluate and compare retained revenue and O&M cost performance of the transmission assets owned by the Company. FERC expense account 565, Transmission of Electricity by Others, captures the costs payable to other transmission owners for the transmission of the Company's electricity over transmission facilities owned by others. These costs are excluded from the benchmarking study as they are not associated with the operation and maintenance of the Company's transmission assets.

Q. WHY ARE INTERCHANGE AGREEMENT BILLINGS RECORDED IN FERC EXPENSE ACCOUNT 566, MISCELLANEOUS TRANSMISSION EXPENSES, EXCLUDED FROM THE STUDY?

A. NSPM and NSPW plan and operate their integrated production and transmission system under the terms of the "Restated Agreement to Coordinate Planning and Operations and Interchange Power and Energy between Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin)" (Interchange Agreement). The Interchange

Agreement is a FERC formula rate which provides for the NSP Companies to charge each other for production and transmission costs associated with the integrated NSP System on an equalized basis. The billings between the NSP Companies are the revenue requirements associated with the ownership, operation, and maintenance of each Company's production and transmission assets calculated under the terms of the FERC formula rate.

It is appropriate to exclude the Interchange Agreement billings as they do not represent new incremental costs for the NSP System. Rather the billings from NSPM and NSPW represent the charges to each other such that costs for the integrated NSP System are shared on an equalized basis. The Company records the billings from NSPW to NSPM for NSPM's use of NSPW's transmission system on NSPM's financial statements in FERC account number 566. Likewise, NSPW records the billings from NSPM to NSPW for NSPW's use of NSPM's transmission system on NSPW's financial statements in FERC account 566. In order to eliminate the billings between the NSP Companies, these costs are excluded from the 2015 Transmission Benchmarking Study. Not excluding the Interchange Agreement billing would result in a mark-up of the actual costs incurred for the integrated NSP System.

Q. WHAT ARE THE MAJOR DIFFERENCES IN THE 2015 TRANSMISSION BENCHMARKING STUDY AS COMPARED TO THE 2013 CORPORATE BENCHMARKING STUDY?

A. There were four changes that were made as part of the 2015 Transmission Benchmarking Study to better reflect Transmission's actual O&M cost performance and to identify similarly situated peer companies. These changes include:

- Revisions to the peer companies analyzed;
- Replacement of the O&M per MWh metric with two new metrics: 1) O&M per Gross Plant metric;Z and 2) O&M per Net Plant;
- Analysis of the Company's performance by utilizing the performance of the combined NSP System rather than separate NSPM and NSPW systems; and
- Increased the view of the study from a three-year look to a five-year look.

Q. WHAT CONCERNS DID YOU HAVE WITH THE PEER GROUP UTILIZED IN THE 2013 CORPORATE BENCHMARKING STUDY?

A. The peer group in the 2013 Corporate Benchmarking Study was selected based on the similarities of utilities to Xcel Energy as a whole but the peers used were not similarly situated for comparison purposes to the NSP Transmission organization. For instance, the peers were not filtered based on those factors that can impact transmission O&M costs such as RTO membership or location of their transmission system. As a result, the peers used in the 2013 Corporate Benchmarking Study included several companies who had sold the vast majority of their transmission assets to a transmission-only company and thus had very little transmission O&M costs.

Q. WHY IS IT IMPORTANT TO HAVE SIMILAR PEER COMPANIES WHEN CONDUCTING A BENCHMARKING STUDY?

A. The relevance of any particular benchmarking study is largely dependent on the characteristics or similarities of the companies included in the comparison peer group. When conducting a benchmarking analysis, one wants the peer groups populated with companies with similar characteristics to ensure reliable results. In other words, to appropriately benchmark performance relative to other utilities, it is necessary to compare the NSP System and our performance to similar utilities. If dissimilar utilities are used as a peer group for comparison, the data can be skewed for reasons unrelated to our actual performance.

Q. WHAT PROCESS DID YOU USE TO REVISE THE PEER COMPANIES FOR PURPOSES OF THE 2015 TRANSMISSION BENCHMARKING STUDY?

A. The 2013 Corporate Benchmarking Study included all operating companies on the Edison Electric Institute (EEI) Index of Investor-Owned Utilities. For the 2015 Transmission Benchmarking Study, we examined all MISO TOs that file a FERC Form 1 report. The list of 25 peer utilities are all MISO RTO members which creates a more comparable group of peers when comparing O&M transmission expenses.

Q. WHY IS THE MISO TO GROUP THE RIGHT SET OF PEERS TO USE FOR THIS STUDY?

A. All of the TOs in MISO own transmission facilities throughout the mid-continental United States; this puts their assets in a fairly similar geography. Also, the fact that all of the peers in the study are a member of the same RTO/ISO helps to create a group that has the same fees and tariffs required of membership.

Q. WHY IS SIMILAR GEOGRAPHY IMPORTANT WHEN SELECTING PEERS FOR TRANSMISSION O&M COSTS?

A. Where transmission facilities are located can play a significant role in transmission O&M costs per mile. For instance, transmission facilities located in mountainous, woody, and hilly areas are often difficult to access for maintenance and result in higher O&M per line mile costs compared to facilities located in flat agricultural areas. Similarly, transmission lines in very large cities tend to be underground or in areas that are not easily accessible. Customer density (number of customers per mile) is also higher. Both of these factors will increase transmission O&M costs per mile.

Q. WHY IS IT IMPORTANT TO USE PEERS THAT BELONG TO MISO?

A. Using MISO based peers provides comparability in analyzing O&M costs related to fees and tariffs. If you were to look at peers that either are not part of a RTO, or even in another RTO, the RTO fees and tariffs could be either nonexistent or charged differently. First, if a utility is not a member of an RTO/ISO they would not have an expenses related to this membership. Second, the fact that all of the peers are members of the same RTO/ISO means that all fees and tariffs are allocated in a similar way. For example, charges in FERC expense account 561.4, Scheduling, System Control and Dispatch Services will have the same allocator for overhead charges.

Q. WHAT PEER COMPANIES WERE INCLUDED IN THE 2015 TRANSMISSION BENCHMARKING STUDY?

A. A summary of the 25 peer utilities selected for the 2015 Transmission Benchmarking Study is shown in Table 15 below.

Table 15

Transmission 2015 Benchmarking Study Peer Companies						
Company	**States of Operations**	**Net Sales of Electricity Revenue ($000)**	**Gross Utility Plant ($000)**	**Net Utility Plant ($000)**	**Annual O&M Expense ($000)**	**Transmission Line Miles**
NSP Combined System	MN, ND, SD, WI, MI	4,224,552	3,532,036	2,593,765	61,719	7,706
Northern States Power Company - MN	MN, ND, SD	3,544,878	2,813,906	2,092,108	50,805	5,296
Northern States Power Company - WI	WI, MI	679,674	718,130	501,657	10,914	2,410
Ameren Transmission Company of Illinois	Wholesale	35,449	72,762	68,595	294	28
NorthwesternWisconsin Electric Company	MN, WI	22,324	17,946	11,646	184	152
Cleco Power LLC	LA	1,194,718	625,825	425,206	10,769	1,320
Entergy Texas, Inc.	LA, TX	1,733,401	976,997	681,984	19,480	2,502
Entergy Arkansas, Inc.	AR, LA, TN	2,057,097	1,622,597	1,171,199	36,160	4,859
American Transmission Company LLC	Wholesale	635,034	4,358,716	3,249,131	118,677	9,569
Entergy Mississippi, Inc.	AR, MS	1,454,073	947,921	647,409	21,976	2,913
MidAmerican Energy Company	IA, IL, NE, SD, TX	1,761,053	1,138,403	700,406	20,149	3,889
ITC Midwest LLC	Wholesale	332,255	2,082,448	1,754,601	37,738	6,623
International Transmission Company	Wholesale	350,516	1,948,480	1,329,956	32,996	2,920
Duke Energy Indiana, Inc.	IN, OH	3,048,984	1,330,327	850,951	27,908	5,297
Ameren Illinois Company	IL	1,387,981	1,451,744	995,830	32,496	4,414
Southern Indiana Gas and Electric Company, Inc.	IN, OH	591,316	460,047	343,539	15,566	1,026
Entergy Louisiana, LLC	LA	2,727,614	1,369,047	818,182	31,320	2,694

Transmission 2015 Benchmarking Study Peer Companies						
Company	**States of Operations**	**Net Sales of Electricity Revenue ($000)**	**Gross Utility Plant ($000)**	**Net Utility Plant ($000)**	**Annual O&M Expense ($000)**	**Transmission Line Miles**
Northern Indiana Public Service Company	IN	1,660,857	894,705	445,878	31,375	1,106
Union Electric Company	IA, IL, MO	3,312,365	954,634	665,462	30,849	2,626
Entergy Gulf States Louisiana, L.L.C.	LA	2,029,794	1,147,713	695,156	30,366	2,408
Otter Tail Power Company	MN, ND, SD	369,607	323,429	220,121	10,388	5,622
ALLETE (Minnesota Power)	MN, ND	810,872	614,608	421,385	22,064	2,747
Entergy New Orleans, Inc.	LA	5,656,423	104,724	43,625	4,027	142
Indianapolis Power & Light Company	IN	1,300,730	268,594	110,283	8,184	838
Michigan Electric Transmission Company LLC	Wholesale	290,653	1,490,761	1,127,809	48,447	5,500

Q. YOU MENTIONED THAT THE METRICS USED IN THE 2013 CORPORATE BENCHMARKING STUDY HAVE BEEN ADJUSTED, WHAT WERE THESE METRICS?

A. The 2013 Corporate Benchmarking Study included two metrics: (1) O&M per MWh transmitted and (2) O&M per line mile.

Q. HOW WAS O&M PER MWH CALCULATED?

A. The O&M per MWh transmitted metric was calculated by dividing the total transmission O&M expense by the MWh transmitted across the Company's transmission system. For purposes of the study, the MWh throughput was calculated by utilizing the Total Sources of Energy for each utility in the EEI Index as provided on page 401a of their respective FERC Form 1 reports.

The Total Transmission O&M expense was calculated by summing all expenses charged to the FERC Accounts described above.

Q. HOW IS O&M PER LINE MILE CALCULATED?

A. The Transmission O&M per line mile was calculated by dividing total Transmission O&M expenses by total overhead and underground circuit miles as found on page 422 Line 36 column "f" plus column "g" of the FERC Form 1.

Q. WHY WAS THE O&M PER MWH TRANSMITTED METRIC ADJUSTED?

A. The O&M per MWh transmitted metric was removed because this metric can be misleading given that is difficult to accurately measure the MWh transmitted on a utilities' transmission system. For example, as a part of an RTO, the Company benefits from the RTO's ability to dispatch least cost generating resources to meet native load. This may mean that the Company's own generating units will be utilized to meet load requirements, or that generating units in other parts of the RTO market will be dispatched instead. The energy received and delivered to serve other members of the RTO is not necessarily captured by the MWh transmitted values reported in the FERC Form 1 reports.

Q. DID YOU REPLACE THE O&M PER MWH WITH ANY OTHER METRICS?

A. Yes. We replaced this metric with two new metrics: (1) O&M per Gross Plant and (2) O&M per Net Plant. Both metrics are calculated by taking the total O&M as described above and dividing by the FERC Form 1 reported Gross Plant and Net Plant, respectively.

Q. WHY DO THESE TWO NEW METRICS PROVIDE A GOOD COMPARISON OF O&M COSTS ACROSS PEER UTILITIES?

A. These two metrics provide a good comparison of O&M costs because the accounting behind Gross Plant and Net Plant do not allow for any ambiguity in the reported figure and all peers report these numbers in the same manner. A major driver of O&M cost for transmission comes from the amount of assets that need to remain in compliance and require maintenance, which makes a O&M costs per asset owned metrics a very good indicator of O&M cost control performance as compared to peers.

Q. WHY DO YOU NEED TO EXAMINE BOTH NET PLANT AND GROSS PLANT?

A. Gross Plant is the total value of all the utility's transmission assets, while Net Plant is the current value of the utility's transmission assets, less accumulated depreciation. It is important to look at both of these metrics because they help to tell the story of the age of the assets when understanding O&M cost performance as compared to the peers. If a company has high O&M expenses per Net Plant, they may either have very few new transmission assets or they have high O&M costs. To determine which is the case, you must also examine O&M per Gross Plant. If a company's O&M per Gross Plant is also high, one can assume that company has high O&M costs because this metric does not take age of facilities into account.

Q. WHY IS IT IMPORTANT TO EXAMINE BOTH O&M PER LINE MILE AS WELL AS O&M PER NET PLANT AND GROSS PLANT?

A. When performing a benchmarking study it is important to look at performance in as many ways as possible. For example per Table 15 above, Ottertail Power Company (Ottertail) has more transmission line miles than all but four companies in the peer group with very small Net and Gross Plant amounts (only four peers with less). If you use this information to calculate the metrics used in the study it could appear that Ottertail has lower O&M per Line Mile performance than the NSP System. However, if you look at O&M per Net Plant you now see that the NSP System is lower than Ottertail. The reason for this disparity is because while Ottertail has many miles of transmission lines, they do not own much Net Plant. Furthermore, if you look at Gross Plant, this is confirmed as the O&M per Gross Plant number is similar to the O&M per Net Plant which shows that Ottertail's system is a relatively new system so O&M costs associated with aging facilities is not the driver of their cost, but the vast distance their system covers with lower voltage lines appears to be. This is why a holistic look at all three metrics should be examined to draw overall conclusions on the Company's transmission O&M cost performance.

Q. DID YOU MAKE ANY OTHER ADJUSTMENTS FROM THE 2013 CORPORATE BENCHMARKING STUDY?

A. Yes. The 2013 Corporate Benchmarking Study compared O&M costs based on the two separate operating companies, NSPM and NSPW, rather than looking at the NSP System as whole.

Q. WHY SHOULD O&M COSTS BE COMPARED ON A NSP SYSTEM BASIS RATHER THAN ON AN OPERATING COMPANY BASIS?

A. Under the FERC approved Interchange Agreement, the NSP Companies coordinate in the development and operation of their generation and transmission facilities as an integrated system. In fact, due to this integration the NSP Companies are considered a single member of MISO. As a result, O&M costs may be incurred by one company that benefit or support the integrated NSP System, which are then subsequently allocated to the other company through the monthly Interchange Agreement billing. One example of this is FERC expense account 561.4, Scheduling, System Control and Dispatch Services, in which NSPM is invoiced from MISO all services it provides to operate and schedule the integrated NSP System. MISO does not send any invoice to NSPW for these services. NSPM subsequently bills NSPW through the Interchange Agreement for its allocated share of such charges. NSPM records its Interchange Agreement billings to NSPW within FERC revenue account 456, Other Electric Revenues and NSPW records the Interchange Agreement billing from NSPM in FERC expense account 566, Miscellaneous Transmission Expenses. As a result, an individual review of the separate operating companies would appear as if both had incurred the same expense.

Combining the transmission O&M expense for both NSPM and NSPW and then eliminating the intercompany Interchange Agreement transactions results in quantifying the total net cost of operating and maintaining the NSP System transmission assets. The Company's overall transmission O&M cost performance can then be appropriately measured across the NSP System transmission assets. Therefore, the proposed transmission O&M cost performance metrics will then result in comparable analyses with peer companies.

Q. WHY IS IT NECESSARY TO COMBINE THE NSPM AND NSPW TRANSMISSION COSTS AND ELIMINATE THESE INTERCOMPANY INTERCHANGE AGREEMENT TRANSACTIONS TO MEASURE THE NSP SYSTEM O&M EXPENSE?

A. By combining the two companies into the NSP System and eliminating the intercompany Interchange Agreement transactions the resulting analysis will be comparable to peer utilities that do not have an arrangement similar to the Interchange Agreement. This is true for two primary reasons. First, all NSP System customers pay the same cost per MWh. Through Interchange Agreement billings, transmission O&M expenses are allocated to the NSP Companies on their prorated share of total NSP System demand. NSPM is approximately 85 percent of total NSP System demand while NSPW is approximately 15 percent. In comparison, NSPM owns approximately 80 percent of the total NSP System transmission assets while NSPW owns approximately 20 percent. In other words, although NSPM owns a smaller percentage of transmission assets, because their demand (or use) of the total NSP System is larger, they pay a larger percentage of the total transmission system cost. In the end, because NSPM customers pay the same cost per MWh as do NSPW customers, including the NSP System in the study results in the only fair comparison to peer companies.

Second, the Interchange Agreement billing is a revenue requirement calculation of one company's use of the other company's transmission system. Therefore, the billing includes such costs as depreciation expense and return on rate base, in addition to O&M expense. Therefore, because the intention is quantifying the total transmission O&M costs, combining the NSPM and NSPW expense and eliminating the intercompany Interchange Agreement transactions is the most straight forward and most accurate approach to quantifying the total NSP System transmission O&M expense.

Q. WHAT CHANGE DID YOU MAKE IN THE 2015 TRANSMISSION BENCHMARKING STUDY TO EXAMINE THE NSP SYSTEM?

A. To examine the NSP System as opposed to the individual operating companies, we added all the O&M expenses from FERC expense accounts 560 – 573 and excluding any amounts in FERC expense account 565 and the transmission Interchange Agreement billings in FERC expense account 566. These amounts were then divided by the total line miles for both NSPW and NSPM to derive the Transmission O&M per Line Mile. The same process was also followed for both O&M per Net Plant and O&M per Gross Plant.

Q. PLEASE DESCRIBE THE RESULTS OF THE 2015 TRANSMISSION BENCHMARKING STUDY.

A. Overall NSP System's O&M costs are trending downward and our cost performance is better than average under all three metrics. For Transmission O&M costs per Gross Plant, the NSP System ranked sixth among our 25 peer companies or in the first quartile. For O&M per Net Plant, the NSP System ranked fifth among our 25 peer companies, or in the first quartile. For Transmission O&M per Line Mile, we ranked eleventh out of 25 companies or in the second quartile.

Q. IF YOU EXAMINED THE O&M EXPENSES FROM THE 2013 CORPORATE BENCHMARKING STUDY BUT COMPARED THESE EXPENSES TO THE 25 PEERS IN THE 2015 BENCHMARKING STUDY, WHAT ARE THESE RESULTS?

A. This analysis shows that our O&M cost performance has improved since 2013. Using the O&M costs from the 2013 Corporate Benchmarking Study, the NSP System ranks eighth as compared to the 25 MISO peer companies or in the second quartile for Transmission O&M per Gross Plant. For O&M per Net Plant, the NSP System ranked seventh among our 25 peer companies or in the second quartile. For O&M per Line Mile, the NSP System ranks 14th as compared to 25 MISO peer companies or third quartile.

In summary, we have moved from the second quartile to the first for Net Plant and Gross Plant and have moved from the third to the second quartile for O&M per Line Mile. In addition, the NSP System is performing better than its 25 MISO peers on a five-year look, which is highlighted on the graphs provided in the study.

Q. YOU MENTION A FIVE-YEAR LOOK FOR THE 2015 TRANSMISSION BENCHMARKING STUDY, WHY WAS THIS CHANGE MADE?

A. By going back five years it allows the Transmission organization to see more of a trend in performance. O&M costs can be greatly impacted by weather and storms, so using more years to develop a trend allows the opportunity to smooth out any spikes or valleys in performance that are attributed to severe weather.

Q. IF YOU USED THE SAME PEERS FROM THE 2013 CORPORATE BENCHMARKING STUDY AND ANALYZED THE DATA FROM 2013 AND 2015 BASED ON THE NEW METRICS, HOW DOES THE NSP SYSTEM PERFORM?

A. The trend is very similar to the one shown for the five years in the 2015 Transmission Benchmark Study, which is the NSP System is trending better than the EEI Index of peers on a year over year basis. Graphs showing these trends are provided as Exhibit____(IRB-1), Schedule 8.

Q. SHOULD ANY OF THE METRICS USED IN THE 2015 BENCHMARKING STUDY BE USED AS KPIS TO IMPROVE TRANSMISSION'S O&M COST CONTROLS?

A. Yes. As I discuss below, Transmission's performance in the O&M per Gross Plant metric as compared to its peers will be used as the basis for a new O&M KPI.

B. New Transmission O&M KPI

Q. ORDER POINT 30(A) REQUIRES THE COMPANY TO "PRESENT A NEW KEY PERFORMANCE INDICATOR (KPI) FOR TRANSMISSION O&M COSTS." DID TRANSMISSION DEVELOP SUCH A KPI?

A. Yes. We propose to institute a new KPI to monitor our O&M performance against peers utilizing the Transmission O&M per Gross Plant metric presented in the 2015 Transmission Benchmarking Study.

Q. WHAT IS THE NEW KPI GOAL IN 2016 WITH RESPECT TO O&M PER GROSS PLANT?

A. For 2016, the KPI will target achievement in the top half as compared to the peer group of 25 MISO TOs who file a FERC Form 1.

Q. WHY DID YOU SELECT O&M PER GROSS PLANT AS THE APPROPRIATE METRIC?

A. We selected Transmission O&M per Gross Plant because O&M costs per asset is a good indicator of how we are managing our O&M costs based on the amount and type of assets we have in-service. In addition, this information can be verified and it is easy to calculate. O&M per Gross Plant is also a metric that is being discussed by the North American Transmission Forum as an appropriate metric for comparing O&M costs amongst utilities.

Q. WHAT DOES THIS NEW KPI GOAL SEEK TO ACHIEVE?

A. This new KPI seeks to ensure that the Transmission organization is controlling its O&M costs in a year-over-year basis comparative to the identified peer group.

Q. HOW DID YOU DETERMINE THE PERFORMANCE TARGET FOR THIS NEW KPI?

A. We examined historical information from 2010 to 2014 and determined that based on past performance that the top half goal would provide a sufficiently challenging target to meet. From 2010 to 2014, the NSP System has performed consistently within the second quartile range. In 2014, the NSP System performed for the first time in the first quartile. Given our focus on customer satisfaction, meeting reliability requirements, and providing storm response including mutual aid we believe performance better than half of our peers is reasonable. This is because our O&M spend could fluctuate during a given year based on these objectives and thus performance in the first two quartiles provides the necessary flexibility to meet these objectives while also maintaining our O&M cost performance.

Q. WILL THIS KPI TARGET BE ADJUSTED IN THE FUTURE?

A. Yes. Our intent is to reassess this target each year to make sure that it is sufficiently aggressive such that we continue to improve our performance related to controlling Transmission O&M costs.

C. New Transmission Cost Control KPI

Q. ORDER POINT 30(C) REQUIRES THE COMPANY TO "PROPOSE A NEW COST CONTROL KPI AT THE VICE-PRESIDENTIAL LEVEL FOR OVERALL TRANSMISSION COSTS." DID TRANSMISSION DEVELOP SUCH A KPI?

A. Yes. In combination with the O&M cost control discussed above, we are proposing a new KPI on the capital side to measure Transmission's cost performance for non-routine capital projects with approximately $3 million of capital additions in the year. A non-routine project is one that is unique in scope and planning and is not part of a yearly reoccurring program such as the switch replacement program. Specifically, this KPI will measure whether these non-routine capital projects that are in-serviced in a particular year are implemented within their budgeted amount. As I describe later in my testimony, Transmission already has a KPI that measures the on-schedule performance for major capital projects.

Q. WHAT TYPE OF CAPITAL PROJECTS WILL BE TRACKED AS PART OF THIS NEW KPI?

A. This new KPI will track all non-routine capital projects with capital additions greater than $3 million in the performance year. This KPI is targeted at projects greater than $3 million to capture a majority of our capital projects. Transmission's goal is to capture over 65 percent of our annual capital additions with this KPI.

Q. WHAT IS THE PERFORMANCE TARGET FOR THIS NEW KPI?

A. The performance target for this new KPI requires that the actual capital addition fall within a 90-day window of the planned in-service date set during the budget process. Also, if the capital addition budget in-service date is at or near year-end, the KPI requires the addition to be completed prior to December 31. The KPI seeks to promote rigorous cost controls and monitoring within our organization such that the actual capital costs for projects are within the established budget. The KPI requires that the project be within 25 percent of the budget for the project established in the planning year prior to any material capital expenditures occurring. For instance, if a project has capital expenditures in 2016 and 2017 with an in-service date of November 1, 2017, we will compare that actual capital addition to the budget created in 2015.

Q. WHAT IS GOAL TO BE ACHIEVED BY UTILIZING THE PERFORMANCE TARGET FOR THE KPI?

A. Transmission will target a score of 70 points on a 100 point scale for the performance target of this KPI.

Q. IS THIS A STRETCH GOAL?

A. This is a measurement we have not tracked in this way before; looking at historical information derived from 2014 actuals, we believe this is a stretch. As I have discussed previously in my testimony, Transmission manages to overall budget performance. In doing this a variance in one project can have a ripple effect into a multiple number of other projects as we make intentional and calculated adjustments to these other projects which allow us to smooth out the unplanned and sometimes uncontrollable variances in other projects. If we had used this performance target in 2014 we would have achieved a score of 70 percent. This was calculated by taking the June 2013 Board approved budget and comparing it to 2014 assumed plant additions. As Transmission gains more information on this measurement in the future we will examine our past performance and adjust the target as needed. Our intent is to reassess this target each year to make sure that we continue to improve our performance related to controlling Transmission capital spend for non-routine major projects.

Q. HOW WILL THIS KPI HELP CONTROL OVERALL TRANSMISSION COSTS?

A. This new KPI will provide an equal weight to schedule and budget to ensure that non-routine major capital projects are implemented on schedule within the budget as proposed.

Q. WHEN WILL THIS NEW KPI BE IMPLEMENTED?

A. This KPI will be implemented in 2016.

D. Other KPIs

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony I discuss and present the Transmission KPIs for purposes of the AIP, in compliance with Order Point 29 in the Commission's May 5, 2014 Order in Docket No. E002/GR-13-868. Ms. Lowenthal discusses the AIP more broadly.

Q. PLEASE EXPLAIN HOW THE TRANSMISSION BUSINESS UNIT FITS WITHIN THE COMPANY'S OVERALL AIP.

A. As explained by Ms. Lowenthal, the Company's AIP has three components: individual, business area, and corporate. For the individual component, employees have performance goals tied to job functions. The business area and corporate components use KPIs to measure goals. Each business area, including Transmission, uses a scorecard that identifies priorities, KPIs, and target goals.

Q. WHAT ARE THE 2015 AIP GOALS FOR THE TRANSMISSION BUSINESS UNIT SCORECARD?

A. The 2015 Transmission business unit scorecard is focused on safety, reliability, on schedule performance, and meeting compliance obligations. Each of these priorities is measured by one or more weighted KPIs. In 2015, we had seven KPIs are as listed in Exhibit___(IRB-1), Schedule 9.

Q. PLEASE IDENTIFY AND EXPLAIN THE KPI MEASUREMENTS FOR THE TRANSMISSION BUSINESS UNIT IN 2015.

A. Schedule 9 lists the nature and metrics associated with each of our KPIs for 2015. The following summarizes these seven KPIs for the year:

- Safety
    - *OSHA Recordable Incident Rate* – Measures workplace safety incidents for employees.
- Reliability
    - *Transmission & Substations SAIDI* – Measures the average time in minutes a customer would be without power for a 12-month period due to transmission line or substation outages.

- *Distribution Substation Maintenance Execution* – Measures the execution performance for substation equipment maintenance activities that are important to sustain or improve customer service reliability. This KPI was added in 2014.

- <u>On-Schedule Performance</u>
  - *Major Capital Project On-Schedule Performance* – Measures the ability to manage significant milestones for major capital projects on schedule.
- <u>Compliance Obligations</u>
  - *NERC Monitoring Index* – Measures the ability to meet all NERC transmission-related compliance requirements of the Company for a given year. The NERC Monitoring Index is a new results-based KPI that was instituted for 2015 that replaced a previous compliance KPI that focused on performing compliance activities.
- <u>Operational Effectiveness</u>
  - *Productivity Through Technology Index* – Measures the ability to plan and execute major enterprise process re-design and ERP system implementation projects to improve operational effectiveness and control costs.
  - *Operational Excellence Benefits Savings* – Measures the amount of cost savings achieved through strategic sourcing, better material management, fleet management and other operational improvement initiatives. Previously, this KPI was titled Supply Chain Savings and only included strategic sourcing savings.

Q. WHAT KPIs FOR 2015 ARE DIFFERENT FROM PAST KPI LEVELS?

A. Several new goals have been added in 2015 to replace 2014 goals. These new KPIs in 2015 reflect our ongoing monitoring and adjustment of goals to where we need focus and improvement.

In addition, Transmission replaced our "Compliance Plan Milestone" KPI with a new "NERC Monitoring Index" KPI. This new metric is aimed at measuring compliance performance achievement instead of measuring the number of compliance activities performed. The NERC Monitoring Index will measure NERC standards compliance achievement over any given rolling 12-month period of time. To determine the target for this new KPI, historical data was compiled to assess past compliance performance. Additionally, forecasts of future potential compliance incident rates were prepared considering past trends, mitigation plan execution timeframes and expected new requirements. The 2015 KPI target was set to challenge employees to prevent potential violations from occurring and to improve upon timely completion of mitigation plans to address identified compliance violations.

Q. HAS TRANSMISSION EVER NOT ACHIEVED ITS SCORECARD/KPI GOALS?

A. Yes. In 2012, the OSHA Recordable Incident Rate performance was 1.68 versus a target of 1.63, which represented less than 1 OSHA Recordable incident for the year across a population of approximately 1,500 full-time-employee equivalents. During this timeframe, Transmission saw dramatic increase in total hours worked by "at-risk" departments due to a large ramp-up in construction projects. Much of the ramp-up of additional hours were worked by construction employees new to Xcel Energy or new to the industry. Since that time, Transmission has been successful at improving the trend in OSHA Recordable Rate while managing the influx of newer employees through improved safety "on-boarding" and various new-employee oriented initiatives.

Also, in 2013, Transmission & Substations System Average Interruption Duration Index (SAIDI) performance was 9.70 minutes, versus a target of 8.00 minutes. Transmission & Substations SAIDI performance differences from year-to-year are generally driven by a relatively few large consequence (high customer impact) events. During 2013, major equipment failures causing whole substation outages, along with galloping transmission line conductors during high-wind days drove the reliability KPI off target. To address some chief causes of the large consequence events, Transmission has implemented strategies to improve their SAIDI performance. Specifically, we implemented more focused substation equipment maintenance programs to proactively identify and correct equipment reliability problems before they result in outages. We also installed devices that reduce galloping on transmission lines susceptible to high wind/galloping conditions. This measurement is focused on the reliability of our system, so these initiatives were created to provide a more reliable system for our customers.

Q. BASED ON YOUR REVIEW, WHAT DO YOU CONCLUDE ABOUT THE INCENTIVE METRICS USED BY THE TRANSMISSION BUSINESS UNIT?

A. The goals for Transmission are based on protecting employee safety, improving on past reliability performance, in-servicing major projects on time, and meeting compliance obligations. As Ms. Lowenthal explains, in order to serve as true incentives, KPIs must be set at levels that require outstanding performance, but not so high that they are unattainable. I believe the

Transmission KPI levels are set appropriately and sufficiently challenge the Transmission organization.

E. Expensing Transmission Studies

Q. PLEASE EXPLAIN THE TYPES OF STUDIES COMPLETED BY THE TRANSMISSION BUSINESS UNIT.

A. Studies completed by the Transmission organization fall into two very broad categories: planning studies and project design studies. Planning studies are broad surveys of the entire NSP System intended to identify future points of weakness on the system – such as overloaded elements or areas that may be prone to voltage problems. Project design studies, conducted in the process of designing and constructing transmission projects, are very specifically focused on ensuring the successful completion of a particular asset or project and within the appropriate scope of work.

Q. ARE THERE ANY TRANSMISSION STUDIES THAT WILL BE EXPENSED DURING THE 2016 TEST YEAR?

A. Yes. Exhibit ___ (IRB), Schedule 10 provides a list of the Transmission planning studies the Company plans to undertake in 2016 and these relate to various planning related issues associated with the NSP System and in the MISO area.

Q. DOES THE COMPANY HAVE A LIST OF THE TRANSMISSION STUDIES THAT WILL BE CAPITALIZED?

A. No, the Company does not forecast studies which will be capitalized. Here are some examples of the type of studies which are performed in support of capital projects and are capitalized:

- Electro Magnetic Transient Program studies when they are used to perform the engineering and design of a capital substation project;
- Coordination and Operating studies required to implement capital projects; and
- Transient Voltage studies associated with capital projects.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Transmission business unit provides for the safe and reliable delivery of energy from generating resources to the distribution systems serving our customers and the customers of other load serving entities connected to the NSP System. We anticipate adding $137.4 million of capital additions in 2016, $167.4 million in 2017 and $204.7 million of capital additions in 2018 for NSPM. These capital additions include transmission projects for which the Company will seek rate recovery through the TCR Rider. These investments are focused on meeting reliability requirements, ensuring the health of our existing assets, enabling communication between our facilities, and addressing emerging physical and cybersecurity threats.

We have budgeted $43.1 million for transmission O&M in 2016, which is a decrease of $0.8 million or 0.9 percent over 2014 actual expenses.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications
Ian R. Benson

Current Responsibilities

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

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 – 2013)
Director, Transmission Planning and Business Relations - XES (2013 – present)

U.S. Navy

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

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

Capital Budget Groupings	Project Name	Parent #	Description	Addition Amount ($000s) 2016 NSPM	2016 MN Jur	2017 NSPM	2017 MN Jur	2018 NSPM	2018 MN Jur	In-Service Date
NSPM Additions										
Asset Renewal	ELR - Breakers - NSPM	11644879	St Cloud-Rpl Breakers 5N31 5N3	0	0	0	0	401	295	02/13/2018
Asset Renewal	ELR - Breakers - NSPM	11776886	Coon Creek - Replace Bkrs 5M11	817	600	0	0	0	-	12/20/2016
Asset Renewal	ELR - Breakers - NSPM	11776889	Medicine Lake - Replace Breake	0	0	0	0	317	233	10/15/2018
Asset Renewal	ELR - Breakers - NSPM	11776938	Shepard - Replace Breaker 5P24	0	0	0	0	348	256	10/15/2018
Asset Renewal	ELR - NSPM Relays RT	11644924	Westgate Relaying-EDP2MRR-EESu	0	0	0	0	502	369	11/15/2018
Asset Renewal	ELR - NSPM Relays RT	11958666	Black Dog-Replace Relaying PKN	0	0	0	0	420	309	10/15/2018
Asset Renewal	ELR - Relay - NSPM	11644800	Fifth St. Relaying - MST-BB Su	0	0	0	0	310	228	11/15/2018
Asset Renewal	ELR - Relay - NSPM	11644803	King Relaying - OPK - DD Sub	0	0	0	0	364	267	11/15/2018
Asset Renewal	ELR - Relay - NSPM	11644851	Terminal Relaying - GPH - BB S	0	0	0	0	512	376	11/15/2018
Asset Renewal	ELR - Relay - NSPM	11644858	Afton Relaying - OPK - DD Sub	0	0	0	0	403	296	11/15/2018
Asset Renewal	ELR - Relay - NSPM	11644882	Gopher Relaying - MSTTER-BBSub	0	0	0	0	512	376	11/15/2018
Asset Renewal	ELR - Relay - NSPM	11644885	Main St Relaying - GPH FST - B	0	0	0	0	512	376	11/15/2018
Asset Renewal	ELR - Relay - NSPM	11644911	Oak Park Relaying-AFTASK-DD Su	0	0	0	0	418	307	11/15/2018
Asset Renewal	ELR - Relay - NSPM	11776940	Eden Prairie Relaying - WSG1WS	0	0	0	0	502	369	11/15/2018
Asset Renewal	ELR - Relay - NSPM	11776963	NSPM 2017 ELR Relays Sub	0	0	0	0	39	29	10/15/2019
Asset Renewal	ELR - Relay - NSPM	11962684	King Relaying - OPK Comm	0	0	0	0	149	109	11/15/2018
Asset Renewal	ELR - Relay - NSPM	11979497	Granite City Relaying - BENWSC	0	0	0	0	441	324	03/15/2018
Asset Renewal	General Tools and Equipment	10378892	NSP Trans Line Tool Blanket	0	0	50	37	0	-	02/28/2017
Asset Renewal	General Tools and Equipment	10941941	Civil Dept Tool Blanket	0	0	30	22	0	-	01/31/2017
Asset Renewal	General Tools and Equipment	11492310	2016 Civil Dept Tool B Line	250	184	0	0	0	-	12/31/2016
Asset Renewal	General Tools and Equipment	11492315	2016 Survey Group Tool B Line	25	18	0	0	0	-	12/31/2016
Asset Renewal	General Tools and Equipment	11492319	2016 Tool Blanket MN Line	40	29	0	0	0	-	12/31/2016
Asset Renewal	General Tools and Equipment	11492330	NSP COM Tool 2016 Sub	595	437	0	0	0	-	12/31/2016
Asset Renewal	General Transportation	11492684	Fleet New Units 2016 El Trans	5,400	3,968	0	0	0	-	12/31/2016
Asset Renewal	HPFF Minneapolis DT	11962442	Chestnut Pressure Control Unit	0	0	1,013	744	0	-	01/15/2017
Asset Renewal	HPFF Minneapolis DT	11971483	5th St Pressure Control UnitLi	0	0	950	698	0	-	01/15/2017
Asset Renewal	Line ELR - NSPM	11490329	ND T-Line ELR 2016, Line	98	72	0	0	0	-	12/31/2016
Asset Renewal	Line ELR - NSPM	11490350	NSPM T-Line ELR 2016 Line	491	361	0	0	0	-	12/31/2016
Asset Renewal	Line ELR - NSPM	11490388	SD T-Line ELR 2016,Line	98	72	0	0	0	-	12/31/2016
Asset Renewal	Line ELR - NSPM	11643540	SD T-Line ELR 2017 Line	0	0	98	72	0	-	12/31/2017
Asset Renewal	Line ELR - NSPM	11643543	ND T-Line ELR 2017 Line	0	0	98	72	0	-	12/31/2017
Asset Renewal	Line ELR - NSPM	11643544	NSPM T-Line ELR 2017 Line	0	0	785	577	0	-	12/31/2017
Asset Renewal	Line ELR - NSPM	11776489	NSPM T-Line ELR 2018 Line	0	0	0	0	1,001	736	12/31/2018
Asset Renewal	Line ELR - NSPM	11776491	ND T-Line ELR 2018 Line	0	0	0	0	100	73	12/31/2018
Asset Renewal	Line ELR - NSPM	11776493	SD T-Line ELR 2018 Line	0	0	0	0	100	73	12/31/2018
Asset Renewal	NSP Reloc B	11490449	ND 2016 Reloc B Line	49	36	0	0	0	-	12/31/2016
Asset Renewal	NSP Reloc B	11490522	NSPM 2016 Reloc B Line	1,472	1,082	0	0	0	-	12/31/2016
Asset Renewal	NSP Reloc B	11490537	SD 2016 Reloc B Line	49	36	0	0	0	-	12/31/2016
Asset Renewal	NSP Reloc B	11643571	SD 2017 Reloc B Line	0	0	49	36	0	-	12/31/2017
Asset Renewal	NSP Reloc B	11643577	ND 2017 Reloc B Line	0	0	49	36	0	-	12/31/2017

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

Capital Budget Groupings	Project Name	Parent #	Description	Addition Amount ($000s) 2016 NSPM	2016 MN Jur	2017 NSPM	2017 MN Jur	2018 NSPM	2018 MN Jur	In-Service Date
Asset Renewal	NSP Reloc B	11643580	NSPM 2017 Reloc B Line	0	0	1,472	1,082	0	-	12/31/2017
Asset Renewal	NSP Reloc B	11776624	ND 2018 Reloc B Line	0	0	0	0	49	36	12/31/2018
Asset Renewal	NSP Reloc B	11776641	SD 2018 Reloc B Line	0	0	0	0	49	36	12/31/2018
Asset Renewal	NSP Reloc B	12068864	NSPM0799 UG Reloc Redwing Brid	0	0	3,969	2,917	0	-	09/01/2017
Asset Renewal	NSPM - Major Line Refurbishment	11962216	NSM0752 Brooten - Paynesville	0	0	0	0	2,853	2,097	12/15/2018
Asset Renewal	NSPM Group 1 Switch Replacements	11776395	Fairfax Muni Tap 450 453 Line	0	0	0	0	431	317	12/31/2018
Asset Renewal	NSPM Group 1 Switch Replacements	11776407	Bush Park Munni 4N41 4N42 & 4N	0	0	0	0	417	306	12/31/2018
Asset Renewal	NSPM Group 1 Switch Replacements	11776474	NSPM 2018 Switch Replacements	0	0	0	0	0	-	12/31/2018
Asset Renewal	NSPM Group 1 Switch Replacements	11782166	NSM0732 AvonRpl SW 4N64&4N65Li	33	24	0	0	0	-	12/31/2016
Asset Renewal	NSPM Group 1 Switch Replacements	11957990	NSM0789 Wells Ck 4H21, 4H22, 4	0	0	0	0	20	15	12/15/2018
Asset Renewal	NSPM Group 1 Switch Replacements	11958000	NSM0789 Wells Ck 4H21 4H22 4H2	0	0	0	0	384	282	12/15/2018
Asset Renewal	NSPM Group 1 Switch Replacements	12172670	Belle Plaine 4S4 4S5 Line	0	0	0	0	348	256	12/15/2018
Asset Renewal	NSPM Group 1 Switch Replacements	12172672	Hader C55 C56 Line	0	0	49	36	0	-	12/15/2017
Asset Renewal	NSPM Group 1 Switch Replacements	12172674	Lafayette C26 Line	0	0	49	36	0	-	12/15/2017
Asset Renewal	NSPM Group 1 Switch Replacements	12172677	NSM0719 Sleepy Eye switch	0	0	0	0	348	256	12/15/2018
Asset Renewal	NSPM Major Line Rebuild	11776427	760 - Red Wing to Wabasha Lin	294	216	0	0	0	-	12/31/2015
Asset Renewal	NSPM Major Line Rebuild	11776482	NSPM 2018 Major Line RebuildLi	0	0	0	0	0	-	12/31/2018
Asset Renewal	NSPM Major Line Rebuild	12172679	NSM0734 W gate - ExcelsorLine	0	0	0	0	4,972	3,654	10/15/2018
Asset Renewal	NSPM Major Line Rebuild	12172700	NSM0523 Chanarambie RbldLine	0	0	0	0	1,240	911	09/15/2018
Asset Renewal	NSPM Metro Steel pole Rplmnt	11978946	NSPM Triple Ckt Pole Repl 2018	0	0	0	0	0	-	12/15/2018
Asset Renewal	RTU - EMS Upgrade - NSPM	11807743	NSPM - 2018 - ELR - RTUComm	0	0	0	0	981	721	12/31/2018
Asset Renewal	S&E - NSP Line	11491731	ND 2016 S&E B Line	98	72	0	0	0	-	12/31/2016
Asset Renewal	S&E - NSP Line	11491741	NSPM 2016 S&E B Line	1,472	1,082	0	0	0	-	12/31/2016
Asset Renewal	S&E - NSP Line	11491772	SD 2016 S&E B Line	98	72	0	0	0	-	12/31/2016
Asset Renewal	S&E - NSP Line	11643557	SD 2017 S&E B Line	0	0	98	72	0	-	12/31/2017
Asset Renewal	S&E - NSP Line	11643561	ND 2017 S&E B Line	0	0	98	72	0	-	12/31/2017
Asset Renewal	S&E - NSP Line	11643564	NSPM 2017 S&E B Line	0	0	1,374	1,010	0	-	12/31/2017
Asset Renewal	S&E - NSP Line	11776611	NSPM 2018 S&E B Line	0	0	0	0	1,472	1,082	12/31/2018
Asset Renewal	S&E - NSP Line	11807711	ND 2018 S&E B Line	0	0	0	0	100	73	12/31/2018
Asset Renewal	S&E - NSP Line	11807748	NSPM 2018 S&E B Line	0	0	0	0	2,453	1,803	12/31/2018
Asset Renewal	S&E - NSP Line	11807755	SD 2018 S&E B Line	0	0	0	0	98	72	12/31/2018
Asset Renewal	S&E - NSP Sub	11491929	ND 2016 S&E Sub	118	87	0	0	0	-	12/31/2016
Asset Renewal	S&E - NSP Sub	11491934	NSPM 2016 S&E Sub	599	440	0	0	0	-	12/31/2016
Asset Renewal	S&E - NSP Sub	11491983	SD 2016 S&E Sub	118	87	0	0	0	-	12/31/2016
Asset Renewal	S&E - NSP Sub	11644284	MN 2017 S&E Sub	0	0	707	520	0	-	12/31/2017
Asset Renewal	S&E - NSP Sub	11644287	ND 2017 S&E Sub	0	0	64	47	0	-	12/31/2017
Asset Renewal	S&E - NSP Sub	11644290	SD 2017 S&E Sub	0	0	64	47	0	-	12/31/2017
Asset Renewal	S&E - NSP Sub	11807695	MN - 2018 S&E Sub	0	0	0	0	707	520	12/31/2018
Asset Renewal	S&E - NSP Sub	11807720	ND 2018 S&E Sub	0	0	0	0	64	47	12/31/2018
Asset Renewal	S&E - NSP Sub	11807766	SD 2018 S&E Sub	0	0	0	0	64	47	12/31/2018
Asset Renewal	Tool	11644788	2017 Civil Dept Tool B Line	0	0	250	184	0	-	12/31/2017

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Addition Amounts Represent Total Project Costs Including AFUDC

Capital Budget Groupings	Project Name	Parent #	Description	Addition Amount ($000s) 2016 NSPM	2016 MN Jur	2017 NSPM	2017 MN Jur	2018 NSPM	2018 MN Jur	In-Service Date
Asset Renewal	Tool	11644789	2017 Tool Blanket MN Line	0	0	34	25	0	-	12/31/2017
Asset Renewal	Tool	11644792	2017 survey Group Tool B Line	0	0	25	18	0	-	12/31/2017
Asset Renewal	Tool	11957920	2018 Civil Dept Tool Blanket	0	0	0	0	2,850	2,094	12/31/2018
Asset Renewal	Tools COM Substation	11644932	NSP COM tool 2017sub	0	0	739	543	0	-	12/31/2017
Asset Renewal	Tools COM Substation	11787157	NSP Ops Engineering Tools 2016	60	44	0	0	0	-	12/31/2016
Asset Renewal	Tools COM Substation	11787159	NSP Ops Engineering Tools 2017	0	0	60	44	0	-	12/31/2017
Asset Renewal	Tools COM Substation	11787161	NSP Ops Engineering Tools 2018	0	0	0	0	145	107	12/31/2018
Asset Renewal	Tools COM Substation	11787193	NSPM COM Tools 2018	0	0	0	0	1,665	1,224	12/31/2018
Asset Renewal	Tools COM Substation	11787206	NSPM COM Tools 2016 (BU 8640)	60	44	0	0	0	-	12/31/2016
Asset Renewal	Tools COM Substation	11787214	NSPM COM Tools 2017 (BU 8640)	0	0	60	44	0	-	12/31/2017
Asset Renewal	Tools COM Substation	11787218	NSPM COM Tools 2018 (BU 8640)	0	0	0	0	137	101	12/31/2018
Asset Renewal	Tools Line Field Ops	11971524	2018 MN Tool Blanket Line	0	0	0	0	220	162	12/31/2018
Asset Renewal	Tools Line Field Ops	11971543	2018 Survey Group Tool Blanket	0	0	0	0	60	44	12/31/2018
Asset Renewal	Tools System Protection Comm Eng	12172711	NSPM Sys Protect Comm Eng 2018	0	0	0	0	150	110	12/31/2018
Asset Renewal	Tools, Training Center	11782743	Tools 2016 Training Center NSP	16	12	0	0	0	-	06/30/2016
Asset Renewal	Tools, Training Center	11782747	Tools 2017 Training Center NSP	0	0	6	4	0	-	04/30/2017
Asset Renewal	Tools, Training Center	11782749	Tools 2018 Training Center NSP	0	0	0	0	103	76	12/31/2018
Asset Renewal	Tools, Training Center	11960506	NSPM Training Center Equipment	0	0	36	26	0	-	12/31/2017
Asset Renewal	Tools, Training Center	11960511	NSPM Training Center Equipment	35	26	0	0	0	-	12/31/2016
Asset Renewal	Tools, Training Center	11960513	NSPM Training Center Equipment	0	0	0	0	138	101	12/31/2018
Asset Renewal	Transportation - NSPM	11644959	Fleet New Units 2017 El TransM	0	0	2,527	1,857	0	-	12/31/2017
Asset Renewal	Transportation - NSPM	11806211	Fleet New Units 2018 EL TransM	0	0	0	0	5,746	4,223	12/31/2018
Asset Renewal	Unserviceable - Breakers - NSPM	11644292	MN 2017 Unserviceable Brkr Rep	0	0	564	414	0	-	12/31/2017
Asset Renewal	Unserviceable - Breakers - NSPM	11807698	MN 2018 Unserviceable Breaker	0	0	0	0	564	414	12/31/2018
Asset Renewal	Unserviceable - Breakers - NSPM	11940405	King-Rpl Breaker 8P2 Sub	501	368	0	0	0	-	05/15/2016
Asset Renewal	Unserviceable - Relays - NSPM	11644905	MN 2016 Unserviceable Relay Su	491	361	0	0	0	-	12/31/2016
Asset Renewal	Unserviceable - Relays - NSPM	11644907	MN 2017 Unserviceable Relay Su	0	0	491	361	0	-	12/31/2017
Asset Renewal	Unserviceable - Relays - NSPM	11807665	MN - 2018 - Unserviceable Rela	0	0	0	0	491	361	12/31/2018
Asset Renewal	Unserviceable Brkr Rplmt Program	11492708	MN 2016 Unserviceable Breaker	535	393	0	0	0	-	12/31/2016
Asset Renewal Total				**13,911**	**10,223**	**15,858**	**11,654**	**36,672**	**26,950**	
Regional Expansion	Big Stone-Brookings 345 kV Line*	11683797	BSSB-345kV Line Non-ShareROW	390	287	0	0	0	-	12/01/2015
Regional Expansion	Big Stone-Brookings 345 kV Line*	11683802	BSSB-Brooking Non Shared Sub	0	0	6,918	5,084	0	-	09/30/2017
Regional Expansion	Big Stone-Brookings 345 kV Line*	11683806	BSSB-345kV Non Shared Line	0	0	77,903	57,250	2,500	1,837	12/01/2017
Regional Expansion	CAPX La Crosse*	11410668	CAPX Hampton-N.Rochester 345kV	55,790	40,999	0	0	0	-	09/30/2016
Regional Expansion	CAPX La Crosse*	11410677	CAPX Hampton-N.Rochester 345kV	180	132	0	0	0	-	09/30/2016
Regional Expansion	CAPX La Crosse*	11944488	#0739 69kV Zumbrota-Dodge CtrN	1,063	781	0	0	0	-	07/30/2016
Regional Expansion	CAPX La Crosse*	11944489	0712 69KVZumbrota-Cannon Falls	4,112	3,022	0	0	0	-	09/30/2016
Regional Expansion	CAPX2020 Brookings MN*	11488848	CAPX Brookings Helena-Lk Mario	1,392	1,023	(451)	(331)	0	-	06/15/2017
Regional Expansion	CAPX2020 Brookings MN*	11488853	CapX Brookings Lk Marion-Hampt	1,048	770	(113)	(83)	0	-	06/15/2017
Regional Expansion	CAPX2020 Brookings MN*	11618931	0956 Lyon Cty to Cedar Mountai	756	556	(422)	(310)	0	-	12/30/2016

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

Capital Budget Groupings	Project Name	Parent #	Description	2016 NSPM	2016 MN Jur	2017 NSPM	2017 MN Jur	2018 NSPM	2018 MN Jur	In-Service Date
				Addition Amount ($000s)						
Regional Expansion	CAPX2020 Brookings MN*	11618937	0958 Cedar Mountain to Helena	329	242	0	0	0	-	12/30/2016
Regional Expansion	NSPM System Load Growth	11985624	NSP System Load Growth 2018	0	0	0	0	501	368	12/31/2018
Regional Expansion Total				**65,060**	**47,812**	**83,835**	**61,609**	**3,001**	**2,205**	
Reliability Requirement	0794:DGC-WSU Rebuild	11806206	Line 0794 69kV DGC-WSU line	2,610	1,918	276	203	0	-	12/23/2016
Reliability Requirement	Bailey Road New 345 kV Sub	12172613	Bailey Road New 345kV Sub	0	0	0	0	28,556	20,985	06/01/2018
Reliability Requirement	Bailey Road New 345 kV Sub	12172619	Line 0975 345kV RRK-AFT Line	0	0	0	0	6,349	4,666	12/31/2018
Reliability Requirement	Baytown Sub - DCP	12076440	Baytown115kV BKR Sub	0	0	1,363	1,002	0	-	06/01/2017
Reliability Requirement	Baytown Sub - DCP	12076442	0801 BYT 115kV In/Out Line	0	0	610	448	0	-	06/01/2017
Reliability Requirement	Blue Lake Substation	12173756	Blue Lake Substation	0	0	0	0	7,460	5,482	07/01/2018
Reliability Requirement	Bluff Creek 115 kV SWTC	11951789	Bluff Creek 115kV Expansion Su	12,769	9,384	0	0	0	-	06/30/2016
Reliability Requirement	Bluff Creek 115 kV SWTC	12016668	Bluff Creek Sub Comm	108	79	0	0	0	-	08/01/2016
Reliability Requirement	Cannon Falls Retaining Wall	11971501	(TBD)Cannon Falls Site Imprvmn	0	0	0	0	330	243	01/15/2018
Reliability Requirement	Eastwood Sub	11962379	Eastwood 115kV BKR Sub	1,861	1,368	20	15	0	-	12/31/2016
Reliability Requirement	Fiesta City - DCP	12076437	0756 - In/Out to Fiesta City,L	792	582	0	0	0	-	06/01/2016
Reliability Requirement	Fiesta City - DCP	12076438	Fiesta City 69kV Sub SW,Sub	572	420	0	0	0	-	06/01/2016
Reliability Requirement	First Lake Sub	11489961	First Lake Sub	15	11	0	0	0	-	12/01/2015
Reliability Requirement	First Lake Sub	11592427	Line 0883 to First Lake Sub Li	25	18	0	0	0	-	12/01/2015
Reliability Requirement	Galloping Mitigation NSM 0953	12051340	NSM0953 Galloping Mitigate SPK	0	0	0	0	5,590	4,108	11/30/2018
Reliability Requirement	GIST-IV TLine Computer Software	11808707	GIST-IV Computer Software, NSP	0	0	0	0	6,400	4,703	12/31/2018
Reliability Requirement	Gleason Lake Sub	12172607	0814/0894 Rebuild Line	0	0	0	0	5,922	4,352	06/01/2018
Reliability Requirement	Gleason Lake Sub	12172612	0894 Rebuild Line	0	0	0	0	5,825	4,281	06/01/2018
Reliability Requirement	Gleason Lake Sub	12172617	Gleason Lake Cap Bank Sub	0	0	2,774	2,039	54	40	12/31/2017
Reliability Requirement	Hatton Sub	11978972	DCP - Hatton TR Line	0	0	0	0	81	60	06/30/2018
Reliability Requirement	Hollydale Dist.115 kV	11353296	Pomerleau Lake Land	0	0	695	511	0	-	06/01/2017
Reliability Requirement	Hollydale Dist.115 kV	11353556	Hollydale - Pomerleau Lake 115	0	0	2,717	1,997	0	-	06/30/2017
Reliability Requirement	Hollydale Dist.115 kV	11712161	Hollydale to Medina, ROW	0	0	0	0	505	371	12/31/2018
Reliability Requirement	Larimore Substation Conversion	12172606	0776 Reterm LAR Line	0	0	207	152	0	-	06/30/2017
Reliability Requirement	Maple River Red River 2nd 115kV	11642703	Maple River-Red River 2nd 115k	0	0	1,528	1,123	0	-	06/23/2017
Reliability Requirement	Maple River Red River 2nd 115kV	11643331	Red River-Maple River Sub	0	0	2,378	1,748	0	-	06/23/2017
Reliability Requirement	Maple River Red River 2nd 115kV	11643334	Maple River-Red River ROW	4,658	3,423	224	165	0	-	01/01/2017
Reliability Requirement	Maple River Red River 2nd 115kV	11643335	Maple River-Red River Line	0	0	6,197	4,554	0	-	06/23/2017
Reliability Requirement	Maple River Red River 2nd 115kV	11643337	Line 0839 MPR-CAS Circuit Relo	0	0	930	683	0	-	06/23/2017
Reliability Requirement	Medford Junction Sub	11962385	Medford Junction Rpl Switch St	551	405	0	0	0	-	06/01/2016
Reliability Requirement	Medford Junction Sub	12076433	Medford Jct 69kV Sw,Line	4	3	0	0	0	-	12/15/2015
Reliability Requirement	Minot Load Serving	12046364	Minot Load Serving Line Permit	130	96	0	0	0	-	11/01/2016
Reliability Requirement	Minot Load Serving	12172608	0850 Rebuild Ward - MGCLine	0	0	0	0	1,160	852	05/31/2019
Reliability Requirement	Minot Load Serving	12172609	0850 Rebuild Ward - MGCROW	0	0	54	40	93	68	10/01/2018
Reliability Requirement	Minot Load Serving	12172610	0860 Rebuild Ward-MGCLine	0	0	0	0	1,656	1,217	10/31/2018
Reliability Requirement	Minot Load Serving	12172611	0860 Rebuild Ward-MGCROW	0	0	54	40	104	76	05/01/2018
Reliability Requirement	Minot Load Serving	12172626	New 230kV Line ROW	0	0	2,544	1,870	12	9	06/01/2018

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2016		2017		2018		In-Service
Capital Budget Groupings	Project Name	Parent #	Description	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	Date
Reliability Requirement	Minot Load Serving	12172627	New 230kV Ward - MCH	0	0	0	0	24,511	18,013	05/01/2018
Reliability Requirement	Minot Load Serving	12172633	Ward County 230 kV	0	0	0	0	23,206	17,054	05/31/2019
Reliability Requirement	Minot Load Serving	12172634	Ward County Sub 230 kVLand	0	0	553	406	0	-	06/01/2017
Reliability Requirement	Minot Load Serving	12172690	New115kV Ward to Ward BECLine	0	0	0	0	180	132	10/01/2018
Reliability Requirement	MnTACT	11808750	MnTACT 2016 Sub	501	368	0	0	0	-	12/31/2016
Reliability Requirement	MnTACT	11808765	MnTACT 2017Sub	0	0	501	368	0	-	12/31/2017
Reliability Requirement	MnTACT	11808777	MnTACT 2018Sub	0	0	0	0	501	368	12/31/2018
Reliability Requirement	MnTACT	12076098	Rogers Lake - Repl breakers 5P	939	690	0	0	0	-	04/30/2016
Reliability Requirement	No Group	12172675	Lincoln Cty Reverse Pwr Relay	225	165	0	0	0	-	01/01/2016
Reliability Requirement	NSPM CIP 5 Sub Networking	12076425	NSPM CIP 5 Fieldon Comm	2	1	0	0	0	-	12/01/2015
Reliability Requirement	NSPM CIP 5 Sub Networking	12076426	NSPM CIP 5 Quarry Comm	2	1	0	0	0	-	12/01/2015
Reliability Requirement	NSPM CIP 5 Sub Networking	12076427	NSPM CIP 5 RoseauComm	203	149	0	0	0	-	02/14/2016
Reliability Requirement	Park Sub Retire	12172712	Park Substation Removal	154	113	0	0	0	-	06/01/2016
Reliability Requirement	Prairie Island Diesel	12172713	Prairie Island-Inst STA AUXGen	0	0	883	649	0	-	03/31/2017
Reliability Requirement	Prairie Sub Expansion	11491534	Prairie 3rd 230/115 kv transfo	11,466	8,426	0	0	0	-	06/01/2016
Reliability Requirement	Red Rock 345kV BusDiffRly	11971516	Red Rock Bus Differential Rela	0	0	0	0	659	484	06/01/2018
Reliability Requirement	Renner Sub	11975330	Line 5527 Tap Line	478	351	0	0	0	-	06/01/2016
Reliability Requirement	Renner Sub	11975342	Renner Substation	1,280	941	0	0	0	-	06/01/2016
Reliability Requirement	Riverside - Apache Upgrade	11491586	Apache Switch 5M179 to 2000ASu	12	9	0	0	0	-	12/31/2015
Reliability Requirement	Riverside Sub - Upgrade	11808313	Arden Hills 115kV Relay Sub	9	7	0	0	0	-	12/31/2015
Reliability Requirement	Riverside Sub - Upgrade	11808317	Riverside Sub-Rpl Wave Trap Su	0	0	0	0	0	-	12/31/2015
Reliability Requirement	Riverside Sub - Upgrade	11808324	Termainl 115kv Relay Sub	26	19	0	0	0	-	12/31/2015
Reliability Requirement	Rosemount Sub	11962232	Rosemount TR2 Sub	0	0	1,099	808	0	-	06/01/2017
Reliability Requirement	Salem Sub - Metering	11978977	DCP - Salem TR Sub	92	68	0	0	0	-	06/01/2016
Reliability Requirement	Sioux Falls Northern 115kV Loop	11492195	Sioux Falls Substation Demolit	210	154	0	0	0	-	03/15/2016
Reliability Requirement	Sioux Falls Northern 115kV Loop	11721994	5568 Split Rock to Falls Line	1,712	1,258	0	0	0	-	12/30/2015
Reliability Requirement	Sioux Falls Northern 115kV Loop	11722007	0730 Morrell to W Sioux Falls	559	411	0	0	0	-	11/15/2015
Reliability Requirement	Sioux Falls Northern 115kV Loop	11722008	5559 Falls to W Sious FallsLin	0	0	0	0	0	-	03/30/2016
Reliability Requirement	Sioux Falls Northern 115kV Loop	11749574	Cliff Sub Relay Replacement Su	30	22	0	0	0	-	03/15/2016
Reliability Requirement	Souris 115kV Cap Bank	11972841	Souris 115 kV Capacitor BankSu	0	0	0	0	0	-	05/01/2016
Reliability Requirement	Souris 115kV Cap Bank	11972845	Souris 115 kV Capacitor BankLi	0	0	0	0	0	-	05/01/2016
Reliability Requirement	Souris 115kV Cap Bank	11987041	Souris 115 kV Capacitor Bank C	0	0	0	0	0	-	12/01/2016
Reliability Requirement	Southtown Area Upgrades	12172719	Southtown Area capacity Sub	2,196	1,614	0	0	0	-	06/01/2016
Reliability Requirement	Southtown Area Upgrades	12172720	Southtown Line Upgrades	0	0	2,263	1,663	0	-	06/01/2017
Reliability Requirement	SWTC	11394185	SWTC PHASE 2 CON & Route Permi	0	0	1,175	863	0	-	06/30/2017
Reliability Requirement	SWTC	11600720	Scott County 115kV Sub	129	95	0	0	0	-	12/30/2015
Reliability Requirement	SWTC	11600760	Westgate 115kV Sub Termination	147	108	0	0	0	-	12/30/2015
Reliability Requirement	SWTC	11956007	5569 Westgate-Bluff Crk 115kV	377	277	0	0	0	-	06/30/2016
Reliability Requirement	SWTC	11956012	5516Bluff Crk-Chanhasen 115kVS	576	423	0	0	0	-	06/30/2016
Reliability Requirement	SWTC	11956019	5570Bluff Crk-Scott Cty 115kV	288	212	0	0	0	-	06/30/2016
Reliability Requirement	SWTC	11956037	0740 Exce-Scott Cty-BLC 69kV	701	515	0	0	0	-	06/30/2016

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2016		2017		2018		In-Service
Capital Budget Groupings	Project Name	Parent #	Description	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	Date
Reliability Requirement	SWTC	11956040	5516 Westgate-Bluff Crk 115kV	444	326	0	0	0	-	06/30/2016
Reliability Requirement	Transmission Technical Compliance T	12173165	NSPM Heavy Const Simulator Net	0	0	0	0	328	241	12/31/2018
Reliability Requirement	Transmission Technical Compliance T	12173166	NSPM Heavy Const Simulator fur	0	0	0	0	100	73	12/31/2018
Reliability Requirement	Twin Cities Fault Current	12174352	(blank)	0	0	0	0	17,658	12,977	01/20/2018
Reliability Requirement	Victoria Sub	11962422	Victoria Distribution Sub	1,171	861	0	0	0	-	06/01/2016
Reliability Requirement	Waconia Distribution TR	12172722	0735 Re-term Line	0	0	129	95	0	-	06/01/2017
Reliability Requirement	Waconia Distribution TR	12172747	Waconia Substation TAM Sub	0	0	323	237	0	-	06/01/2017
Reliability Requirement Total				**48,022**	**35,291**	**29,494**	**21,675**	**137,239**	**100,855**	
Communications Infrastructure	NSPM Frame Relay	12076295	SD Frame Relay Comm	0	0	530	389	0	-	05/01/2017
Communications Infrastructure	NSPM Frame Relay	12076296	ND Frame Relay Comm	68	50	0	0	0	-	4/15/2016
Communications Infrastructure	NSPM Frame Relay	12076297	MN Frame Relay Comm	0	0	10,519	7,730	0	-	05/31/2017
Communications Infrastructure	NSPM Sub Communication Network Grou	11987052	NSPM Sub Comm Network Group 2	0	0	0	0	205	151	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987055	NSPM Sub Comm Network Group 2	0	0	0	0	125	92	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987058	NSPM Sub Comm Network Group 2	0	0	39	29	754	554	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987060	NSPM Sub Comm Network Group 3	0	0	0	0	308	226	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987064	NSPM Sub Comm Network Group 3	0	0	0	0	188	138	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987068	NSPM Sub Comm Network Group 3	0	0	49	36	1,033	759	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987072	NSPM Sub Comm Network Group 4	0	0	0	0	410	301	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987074	NSPM Sub Comm Network Group 4	0	0	0	0	250	184	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987079	NSPM Sub Comm Network Group 4	0	0	29	21	579	425	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987080	NSPM Sub Comm Network Group 5	0	0	0	0	308	226	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987083	NSPM Sub Comm Network Group 5	0	0	0	0	188	138	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987085	NSPM Sub Comm Network Group 5	0	0	49	36	1,631	1,199	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987105	NSPM Sub Comm Network Group 7	0	0	0	0	294	216	12/15/2019
Communications Infrastructure	NSPM Sub Communication Network Grou	11987115	NSPM Sub Comm Network Group 8	0	0	0	0	343	252	12/15/2019
Communications Infrastructure	NSPM Sub Communication Network Grou	11987123	NSPM Sub Comm Network Group 9	0	0	0	0	270	198	12/15/2019
Communications Infrastructure	NSPM Sub Communication Network Grou	11987126	NSPM Sub Comm Network Group 10	0	0	0	0	308	226	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987130	NSPM Sub Comm Network Group 10	0	0	0	0	188	138	12/15/2018
Communications Infrastructure	NSPM Sub Communication Network Grou	11987133	NSPM Sub Comm Network Group10	0	0	49	36	3,805	2,796	12/15/2018
Communications Infrastructure	NSPM Substation Communication Netwo	11987139	NSPM Sub Comm Network Group11	0	0	0	0	206	151	12/15/2019
Communications Infrastructure Total				**68**	**50**	**11,265**	**8,278**	**11,392**	**8,372**	
Interconnection	Chaska In and Out	12172615	Chaska In-and-Out	1,222	898	0	0	0	-	6/1/2016
Interconnection	Dean Lake Substation	12173757	Dean Lake Substation	5,010	3,682	0	0	0	-	12/31/2016
Interconnection	G858/H071 Black Oak Interconnection	12076097	Line 0795 rebuild for G858/H07	(84)	(62)	0	0	0	-	4/15/2016
Interconnection	GRE Barnes Grove Interconnection	11489991	Barnes Grove-Instl 69kV 3 way	0	0	260	191	0	-	9/1/2017
Interconnection	IA Tariff Fund	10615153	IA Tariff Fund NSP	3,804	2,796	3,720	2,734	4,206	3,091	12/31/2020
Interconnection	Maple River 115kV MPC Interconnecti	12172620	Maple River 115kV MPC IA	0	0	0	0	1,575	1,157	2/1/2018
Interconnection	Quarry-GRE West St. Cloud	12172714	QRY-New 115kV Line TermSub	0	0	2,694	1,980	0	-	5/1/2017
Interconnection	Quarry-GRE West St. Cloud	12172715	Quarry-West St Cloud 2nd Ckt	0	0	358	263	0	-	5/1/2017

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

Capital Budget Groupings	Project Name	Parent #	Description	2016 NSPM	2016 MN Jur	2017 NSPM	2017 MN Jur	2018 NSPM	2018 MN Jur	In-Service Date
				Addition Amount ($000s)						
Interconnection	Tyrone Tap MVEC	12172743	Tyrone Tap	376	276	0	0	0	-	1/1/2016
Interconnection Total				**10,328**	**7,590**	**7,032**	**5,168**	**5,781**	**4,248**	
Physical Security and Resiliency	NERC Order 754 NSPM	11975755	NERC 754 Protection Sys MNSub	0	0	6,105	4,486	6,000	4,409	12/31/2019
Physical Security and Resiliency	NSPM Bulk Trans Str	11985464	NSPM Bulk Trans Emr Restor Str	0	0	1,001	736	0	-	12/31/2017
Physical Security and Resiliency	NSPM Geomagnetic Disturbances (GMD)	12076652	NSPM Geo Mag Dist (GMD)	0	0	851	625	750	551	12/31/2019
Physical Security and Resiliency	NSPM GIC Monitoring Device	12076650	NSPM GIC Monitoring Device	0	0	1,349	991	0	-	12/30/2017
Physical Security and Resiliency	NSPM Physical Security and Resiliency	12076306	NSPM Physical Security	0	0	6,870	5,049	3,838	2,820	12/31/2020
Physical Security and Resiliency	Xfmr Spare Security NSPM	11979382	Xfmr Spare Security NSPM	0	0	3,698	2,718	5	4	12/1/2017
Physical Security and Resiliency Total				**0**	**0**	**19,875**	**14,606**	**10,593**	**7,785**	
NSPM Total				**137,389**	**100,965**	**167,359**	**122,990**	**204,678**	**150,415**	

**Those projects that will be recovered through the Transmission Cost Recovery Rider*

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

Capital Budget Groupings	Project Name	Parent #	Description	2016 NSPW	2016 MN Jur	2017 NSPW	2017 MN Jur	2018 NSPW	2018 MN Jur	In-Service Date
				Addition Amount ($000s)						
NSPW Additions										
Asset Renewal	ELR - Breakers - NSPW	11645211	Park Falls - Rpl Breaker 5R72	0	0	0	0	362	266	08/15/2018
Asset Renewal	ELR - Breakers - NSPW	11645221	Crystal Cave -Rpl Breakers 6A1	0	0	0	0	644	473	03/15/2018
Asset Renewal	ELR - Breakers - NSPW	11645255	Stone Lake-Rpl Breakers 4R7 4R	0	0	0	0	612	450	02/15/2018
Asset Renewal	ELR - Breakers - NSPW	11778067	Prentice- Replace Breakers 5R2	0	0	0	0	587	432	08/15/2018
Asset Renewal	ELR - Breakers - NSPW	11778081	ELR - Breakers - NSPW-2018 Sub	0	0	0	0	981	721	12/31/2018
Asset Renewal	ELR - Breakers - NSPW	11799404	Park Falls-Upgrade RTU Comm	0	0	0	0	26	19	08/15/2018
Asset Renewal	ELR - NSPW Relays RT	11636660	NSPW - 2017 - ELR B Sub	0	0	871	640	0	0	12/31/2017
Asset Renewal	ELR - Relay - NSPW	11772351	Osprey Relaying-HLC PFA PRN -	0	0	0	0	874	642	08/15/2018
Asset Renewal	ELR - Relay - NSPW	11772353	Park Falls Relaying - OPY & PR	0	0	0	0	442	325	08/15/2018
Asset Renewal	ELR - Relay - NSPW	11772366	River Falls Relaying - CRY-RRK	0	0	0	0	647	475	06/01/2018
Asset Renewal	ELR - Relay - NSPW	11772368	Prentice Relaying - OPY & PFA	0	0	0	0	371	273	08/15/2018
Asset Renewal	ELR - Relay - NSPW	11772375	Tremval Relaying - AMA & SEV -	318	234	0	0	0	0	12/20/2016
Asset Renewal	ELR - Relay - NSPW	11772380	La Crosse Relaying - COU - QQ	0	0	0	0	301	222	06/15/2018
Asset Renewal	ELR - Relay - NSPW	11772384	Holcombe Relaying - OPY - PP S	0	0	0	0	371	272	08/15/2018
Asset Renewal	ELR - Relay - NSPW	11772385	Crystal Cave Rly RCDRLMRFS-RRK	0	0	0	0	514	378	03/15/2018
Asset Renewal	Fault Recorders - NSPW	11645248	Stone Lake-Inst Fault recorder	377	277	0	0	0	0	12/31/2016
Asset Renewal	General Tools and Equipment	11490088	2016 Tool Blanket WI Line	25	18	0	0	0	0	12/31/2016
Asset Renewal	General Tools and Equipment	11490177	NSPW COM Tool 2016	155	114	0	0	0	0	12/31/2016
Asset Renewal	General Tools and Equipment	10378839	WI Tran Line Tool Blanket	0	0	9	7	0	0	12/01/2017
Asset Renewal	General Transportation	11490179	Fleet New Units 2016 El Trans	152	112	0	0	0	0	12/31/2016
Asset Renewal	Line ELR - NSPW	11493023	MI T-Line ELR 2016Line	50	37	0	0	0	0	12/31/2016
Asset Renewal	Line ELR - NSPW	11493041	NSPW T-Line ELR 2016Line	491	360	0	0	0	0	12/31/2016
Asset Renewal	Line ELR - NSPW	11636556	MI T-Line ELR 2017 Line	0	0	49	36	0	0	12/31/2017
Asset Renewal	Line ELR - NSPW	11636564	NSPW T-Line ELR 2017 Line	0	0	491	361	0	0	12/31/2017
Asset Renewal	Line ELR - NSPW	11766343	NSPW T-Line ELR 2018 Line	0	0	0	0	3,435	2,524	12/31/2018
Asset Renewal	Line ELR - NSPW	11766346	MI T-Line ELR 2018 Line	0	0	0	0	49	36	12/31/2018
Asset Renewal	NSPW Group 1 Switch Replacements	11766062	NSPW 2018 Switch Rplmts Line	0	0	49	36	1,472	1,082	12/31/2018
Asset Renewal	NSPW Major Line Rebuild	11766330	NSPW 2018 Major Line RebuildLi	0	0	44	32	3,435	2,524	12/15/2018
Asset Renewal	NSPW Major Line Rebuild	12172833	W3503 Barron Rice Lk Rlbd Line	0	0	0	0	2,687	1,975	12/15/2018
Asset Renewal	NSPW Major Line Refurbishment	11766332	NSPW 2018 Major Line Refurbish	0	0	49	36	10,305	7,573	12/31/2018
Asset Renewal	NSPW Major Line Refurbishment	12172828	W3351 BFT IRW RefurbLine	1,979	1,454	0	0	0	0	12/31/2016
Asset Renewal	NSPW Reloc B	11488613	MI 2016 Reloc B Line	49	36	0	0	0	0	12/31/2016
Asset Renewal	NSPW Reloc B	11488712	NSPW 2016 Reloc B Line	383	281	0	0	0	0	12/31/2016
Asset Renewal	NSPW Reloc B	11636623	MI 2017 Reloc B Line	0	0	49	36	0	0	12/31/2017
Asset Renewal	NSPW Reloc B	11636631	NSPW 2017 Reloc B Line	0	0	383	281	0	0	12/31/2017
Asset Renewal	NSPW Reloc B	11769205	NSPW 2018 Reloc B Line	0	0	0	0	383	281	12/31/2018
Asset Renewal	NSPW Reloc B	11769207	MI 2018 Reloc B Line	0	0	0	0	49	36	12/31/2018
Asset Renewal	Prentice to Medford Rebuild	11778095	Prentice to Medford 3477 Line	0	0	0	0	3,983	2,927	04/30/2018
Asset Renewal	Prentice to Medford Rebuild	11778101	Prentice to Medford 3477 ROW	265	194	20	14	49	36	02/28/2018
Asset Renewal	Prentice to Medford Rebuild	11804123	W3477 RBL Tap- MFD 69kV Rebui	0	0	0	0	657	483	03/31/2019

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

Capital Budget Groupings	Project Name	Parent #	Description	Addition Amount ($000s) 2016 NSPW	2016 MN Jur	2017 NSPW	2017 MN Jur	2018 NSPW	2018 MN Jur	In-Service Date
Asset Renewal	Prentice to Medford Rebuild	11804134	W3477 OGE-RBL Tap 69kV ROW	0	0	436	320	127	94	04/30/2018
Asset Renewal	Prentice to Medford Rebuild	11951314	Prentice to Medford Rlbd Permi	0	0	25	18	0	0	04/15/2017
Asset Renewal	RTU - EMS Upgrade - NSPW	11807384	NSPW - 2018 - ELR - RTUComm	0	0	0	0	491	361	12/31/2018
Asset Renewal	S&E - NSPW Line	11489798	MI 2016 S&E B Line	49	36	0	0	0	0	12/31/2016
Asset Renewal	S&E - NSPW Line	11489814	NSPW 2016 S&E B Line	736	541	0	0	0	0	12/31/2016
Asset Renewal	S&E - NSPW Line	11636613	MI 2017 S&E B Line	0	0	49	36	0	0	12/31/2017
Asset Renewal	S&E - NSPW Line	11636616	NSPW 2017 S&E B Line	0	0	736	541	0	0	12/31/2017
Asset Renewal	S&E - NSPW Line	11769190	MI 2018 S&E B Line	0	0	0	0	49	36	12/31/2018
Asset Renewal	S&E - NSPW Line	11769202	NSPW 2018 S&E B Line	0	0	0	0	736	541	12/31/2018
Asset Renewal	S&E - NSPW Sub	11489962	MI 2016 S&E Sub	49	36	0	0	0	0	12/31/2016
Asset Renewal	S&E - NSPW Sub	11489965	NSPW 2016 S&E Sub	687	505	0	0	0	0	12/31/2016
Asset Renewal	S&E - NSPW Sub	11638794	MI 2017 S&E Sub	0	0	49	36	0	0	12/31/2017
Asset Renewal	S&E - NSPW Sub	11638795	WI 2017 S&E Sub	0	0	687	505	0	0	12/31/2017
Asset Renewal	S&E - NSPW Sub	11769366	MI 2018 S&E Sub	0	0	0	0	49	36	12/31/2018
Asset Renewal	S&E - NSPW Sub	11769367	WI 2018 S&E Sub	0	0	0	0	687	505	12/31/2018
Asset Renewal	Tool	11645178	2017 Tool Blanket WI Line	0	0	50	37	0	0	12/31/2017
Asset Renewal	Tools COM Substation	11652095	NSPW COM Tools 2017	0	0	155	114	0	0	12/31/2017
Asset Renewal	Tools COM Substation	11980539	NSPW COM Tool 2018	0	0	0	0	317	233	12/31/2018
Asset Renewal	Tools Line Field Ops	11980529	2018 WI Tool Blanket Line	0	0	0	0	50	37	12/31/2018
Asset Renewal	Transportation - NSPW	11645301	Fleet New Units 2017 El Trans	0	0	155	114	0	0	12/31/2017
Asset Renewal	Transportation - NSPW	11806821	Fleet New Units 2018 El Trans	0	0	0	0	457	336	12/31/2018
Asset Renewal	Unserviceable - Breakers - NSPW	11638836	WI 2017 Unserviceable Bkr Repl	0	0	466	343	0	0	12/31/2017
Asset Renewal	Unserviceable - Breakers - NSPW	11808824	WI 2018 Unserviceable Breaker	0	0	0	0	466	343	12/31/2018
Asset Renewal	Unserviceable - Relays - NSPW	11645293	WI 2016 - Unserviceable Relay	491	360	0	0	0	0	12/31/2016
Asset Renewal	Unserviceable - Relays - NSPW	11645296	WI 2017 Unserviceable Relay Su	0	0	491	361	0	0	12/31/2017
Asset Renewal	Unserviceable - Relays - NSPW	11807405	WI - 2018 - Unserviceable Rela	0	0	0	0	491	361	12/31/2018
Asset Renewal	Unserviceable Brkr Rplmt Program	11490199	WI 2016 Unserviceable Brkr Rep	235	173	0	0	0	0	12/31/2016
Asset Renewal Total				**6,489**	**4,769**	**5,313**	**3,904**	**37,157**	**27,306**	
Regional Expansion	CAPX La Crosse*	11492928	Capx River-Briggs Road line	500	367	0	0	0	0	09/30/2015
Regional Expansion	LaCrosse - Madison 345kv*	11939198	LAX-MAD New 345kV Non Shared L	0	0	0	0	190,098	139,700	12/31/2018
Regional Expansion	LaCrosse - Madison 345kv*	11939203	LAX-MAD New 345kV Non Shared R	7,150	5,254	8,180	6,011	2,830	2,080	09/30/2018
Regional Expansion	LaCrosse - Madison 345kv*	11939206	Briggs Road Sub 345kV Term. Su	0	0	0	0	8,006	5,884	12/31/2018
Regional Expansion Total				**7,650**	**5,622**	**8,180**	**6,011**	**200,934**	**147,663**	
Reliability Requirement	Bayfield Loop	11348608	Bayfield Loop Sub	0	0	0	0	26,779	19,679	04/01/2018
Reliability Requirement	Bayfront to Ironwood 88 kV	11804167	BFT - IRW - PERMIT LINE	0	0	0	0	198	145	12/31/2018
Reliability Requirement	Bayfront to Ironwood 88 kV	11804383	W3351 BFT - IRW ROW	0	0	100	73	1,590	1,168	09/30/2019
Reliability Requirement	Chippewa County Improvements	11804914	Gravel Island substation expan	0	0	3,115	2,289	0	0	08/01/2017
Reliability Requirement	Chisago-Apple River High Voltage	11947319	Poplar Lake Reactor Sub	2,421	1,779	0	0	0	0	12/31/2016
Reliability Requirement	Cooperwood Mine	12172723	Copperwood Sub - New Sub	0	0	0	0	80	59	04/01/2018

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

Capital Budget Groupings	Project Name	Parent #	Description	Addition Amount ($000s) 2016 NSPW	2016 MN Jur	2017 NSPW	2017 MN Jur	2018 NSPW	2018 MN Jur	In-Service Date
Reliability Requirement	Cooperwood Mine	12172740	Norrie Sub Termination Sub	0	0	0	0	21	15	04/01/2018
Reliability Requirement	Cooperwood Mine	12172744	W33XX NRR - COP 115kV Line	0	0	0	0	1,456	1,070	04/01/2018
Reliability Requirement	Cooperwood Mine	12172745	W33XX NRR - COP ROW	0	0	0	0	0	0	09/30/2017
Reliability Requirement	Couderay-Osprey 161kv	11348484	Osprey(OPY) Substation	6,305	4,634	0	0	0	0	03/15/2016
Reliability Requirement	Couderay-Osprey 161kv	11348989	Wxxxx CDY to OPY 161kV Line	150	110	0	0	0	0	12/18/2015
Reliability Requirement	Couderay-Osprey 161kv	11863631	W3474 WTL - BFS Rebuild 69kV L	5	4	0	0	0	0	12/18/2015
Reliability Requirement	Couderay-Osprey 161kv	12052096	Osprey Sub COMM	134	98	0	0	0	0	03/15/2016
Reliability Requirement	Curran Substation	12172724	Curran Sub TAM Sub	410	301	0	0	0	0	11/01/2016
Reliability Requirement	Curran Substation	12172746	W3401 Curran In/Out Line	393	289	2	1	0	0	11/01/2016
Reliability Requirement	GIST-IV TLine Computer Software	11808820	GIST-IV Computer Software NSPW	0	0	0	0	6,678	4,907	12/31/2018
Reliability Requirement	Harstad County Park Substation	11838388	W3409 Harstad County Park TapL	5	4	0	0	0	0	10/16/2015
Reliability Requirement	N WI Transm Improvement	11941346	Pershing Substation Add Transf	210	154	0	0	0	0	05/31/2016
Reliability Requirement	N WI Transm Improvement	11941353	Pershing Substation 115/345 Tr	0	0	0	0	15,390	11,310	03/01/2018
Reliability Requirement	N WI Transm Improvement	11944583	Line 3318 Tap to Pershing sub	0	0	0	0	1,542	1,133	03/01/2018
Reliability Requirement	N WI Transm Improvement	11944585	Line 3318 Tap to Pershing sub	10	7	40	29	0	0	02/28/2017
Reliability Requirement	N WI Transm Improvement	12075482	Pershing Sub Line Permitting	14	11	0	0	0	0	12/30/2016
Reliability Requirement	N2 WI Upgrade	11980365	Gravel Island TR 1 Sub	12	9	0	0	0	0	12/04/2015
Reliability Requirement	New Rockland Sub	11980475	W3411 Tap to New Rockland SubL	0	0	829	609	0	0	08/01/2017
Reliability Requirement	New Rockland Sub	11980481	New Rockland Area Substation	0	0	484	356	0	0	08/01/2017
Reliability Requirement	No Group	12172741	Prescott add 2nd Transformer	194	142	0	0	0	0	09/30/2016
Reliability Requirement	NSPW Galloping Conductors	11980515	NSPW 2018 Galloping Mitigation	0	0	0	0	2,944	2,164	09/15/2018
Reliability Requirement	NSPW NERC TPL (MnTACT)	11980388	2018 NSPW NERC TPL (MN-TACT)	0	0	0	0	3,004	2,208	12/31/2018
Reliability Requirement	Osceola Cap	12172852	NSPW3438Osceola ClearanceLine	79	58	0	0	0	0	12/15/2016
Reliability Requirement	Osprey 69 kV Sub Expansion	12172835	BFS-OPY 69kV Yard CrossingLine	0	0	0	0	65	48	11/15/2018
Reliability Requirement	Osprey 69 kV Sub Expansion	12172836	Big Falls Sub Remove Line Term	0	0	0	0	222	163	06/01/2018
Reliability Requirement	Osprey 69 kV Sub Expansion	12172853	Osprey 69 kV Sub Expansion	0	0	0	0	1,912	1,405	08/31/2018
Reliability Requirement	Osprey 69 kV Sub Expansion	12172857	W3474 R BFS Term Reroute OPY L	0	0	0	0	704	517	11/15/2018
Reliability Requirement	Osprey 69 kV Sub Expansion	12172858	W3476 RBFS TermReroute OPYLin	0	0	0	0	318	233	11/15/2018
Reliability Requirement	Prescott Second TR	12172855	Prescott Cap Bank TAM Sub	427	314	0	0	0	0	09/30/2016
Reliability Requirement	Prescott Second TR	12172856	W3410 Tap Line	412	303	0	0	0	0	09/30/2016
Reliability Requirement	River Falls Municipality	11981358	River Falls - Muni EEE Sub	0	0	1,503	1,105	0	0	02/01/2017
Reliability Requirement	River Falls Municipality	11981361	River Falls Muni Ctrl Eq ReloC	0	0	50	37	0	0	02/01/2017
Reliability Requirement	Stone Lake Pump Interconnection	11805023	Stone Lake sub transformer Sub	0	0	2,302	1,691	25	18	12/01/2017
Reliability Requirement	T-Corners Brkr and a Half	11804378	T-Corners Breaker and a HalfSu	5,118	3,761	0	0	0	0	03/15/2016
Reliability Requirement	T-Corners Brkr and a Half	11804379	W3305 Hyd - TCN 115kV Line	232	171	0	0	0	0	03/15/2016
Reliability Requirement	T-Corners Brkr and a Half	12042394	T-Corners Sub Comm	41	30	0	0	0	0	03/15/2016
Reliability Requirement	Tremval	11765023	Tremval 2nd 161/69 kV Transfor	6,744	4,956	49	36	0	0	12/15/2016
Reliability Requirement	Tremval	11804269	Tremval 2nd 161/69 kV Line	15	11	0	0	0	0	12/15/2016
Reliability Requirement	W3404 Cedar Falls-Menomonie	11804392	CEF-Upgrade Bus Sub	236	174	0	0	0	0	05/20/2016
Reliability Requirement	W3404 Cedar Falls-Menomonie	11804394	MEN-Re-Tap CTs Sub	366	269	0	0	0	0	05/01/2016
Reliability Requirement	W3404 Cedar Falls-Menomonie	11804398	W3404 69kV CEF-MEN Line	4,260	3,130	0	0	0	0	06/01/2016

Northern States Power Company

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

Capital Budget Groupings	Project Name	Parent #	Description	Addition Amount ($000s) 2016 NSPW	2016 MN Jur	2017 NSPW	2017 MN Jur	2018 NSPW	2018 MN Jur	In-Service Date
Reliability Requirement	W3445 Rbld Merrillan Jackson	12173557	W3445 Rbld Merrillan Jackson	3,367	2,475	0	0	0	0	06/01/2016
Reliability Requirement Total				**31,562**	**23,194**	**8,474**	**6,227**	**62,928**	**46,245**	
Comm Infrastructure	NSPW Frame Relay	12076293	MI Frame Relay Comm	0	0	281	206	0	0	03/15/2017
Comm Infrastructure	NSPW Frame Relay	12076294	NSPW Frame Relay Comm	3,175	2,333	0	0	0	0	12/15/2016
Comm Infrastructure Total				**3,175**	**2,333**	**281**	**206**	**0**	**0**	
Interconnection	IA Tariff Fund	10615256	IA Tariff Fund NSPW	3,379	2,483	4,106	3,017	4,607	3,385	12/31/2020
	WI Muni Meter Replacement	11981375	Medford Muni - WhelenComm	20	15	0	0	0	0	12/15/2016
Interconnection Total				**3,399**	**2,498**	**4,106**	**3,017**	**4,607**	**3,385**	
Security\Resiliancy	NSPW GIC Monitoring Device	12076654	NSPW GIC Monitoring Device	0	0	426	313	0	0	12/31/2017
Security\Resiliancy Total				**0**	**0**	**426**	**313**	**0**	**0**	
NSPW Total				**52,275**	**38,416**	**26,779**	**19,679**	**305,626**	**224,600**	

**Those projects that will be recovered through the Transmission Cost Recovery Rider*

NSPM-Electric

General Ledger Account	2012 Actual	2013 Budget	2013 Actual	2014 Budget	2014 Actual	2015 July Forecast	2016 Budget
711142 Productive Labor	15,890,773	16,572,280	16,084,610	17,978,311	16,525,001	17,678,085	17,520,123
711142.90 Productive Labor-S3	(26,299)		(87,152)		(79,088)	(28,797)	-
711143 Reg Labor Loading-NonProductiv	2,939,586	3,167,884	3,029,057	3,397,553	3,220,908	3,612,123	3,801,946
711143.90 Reg Labor Loading-NonP	(4,380)		(17,094)		(16,917)	(6,452)	-
711146 Prod Lab-Attrit (frmly taxes)	-	(662,891)	-	(719,133)	-	(353,628)	(700,805)
711150 Premium Time	303,838	338,250	312,945	352,587	350,611	346,740	335,019
711150.90 Premium Time-S3	-		(606)		-	-	-
711155 Labor Budget Adjustment		210,323					
711190 Overtime	4,279,450	2,800,113	5,390,786	3,339,316	4,398,160	4,009,382	3,150,441
711190.90 Overtime-S3	(7,802)		(38,565)		(90,150)	(39,578)	-
711230 Incentive	-		7,002		2,316	-	-
711270 Other Compensation	44,657	32,877	23,443	33,660	66,549	33,231	20,310
711275 Other Comp- Welfare Fund	325,590	265,274	301,051	265,274	459,936	311,947	272,141
711275.90 Other Comp- Welfare Fund S3	(2,597)		(139)		-	-	-
712110 Contract Labor	775,565	618,187	782,083	527,900	1,022,193	2,119,942	898,549
712110.90 Contract Labor-S3	(352)		(1,025)		(104)	-	-
713000 Consulting/Prof Svcs-Other	2,066,331	4,064,351	4,046,256	4,370,981	4,066,155	4,825,187	2,371,726
713000.90 Consulting/Prof Svcs-Other	(1,452)		(2,952)		(6,843)	(1,140)	-
713050 Contract LT Outside Vendor	3,620,660	5,452,536	6,244,199	4,530,615	5,331,876	2,963,364	4,731,008
713050.90 Contract LT Outside Vendor	(6,167)		-		-	-	-
713055 Outside Srvcs-Cust Care	-		199		-	29,248	-
713100 Consulting/Prof Svcs-Legal	804,250		205,259		55,596	52,898	-
713101 Partner Invoicing - CapX-O&M	484,749		202,559		53,180	87,423	180,000
713150 Consulting/Prof Svcs-Acctg	7,124		-		-	-	-
714000 Materials	4,091,962	3,048,755	3,559,739	3,082,289	3,359,468	2,877,776	2,962,515
714000.90 Materials-S3	(21,082)		(6,039)		(3,783)	(8)	-
714050 M&S Inventory Adj-Obsolete Mat	163,254	54,000	24,250	150,000	-	113,519	150,000
714100 Print/Copy-Other	34,717	38,753	45,569	35,552	37,245	72,060	39,278
714500 Equipment Maintenance	-		-		6,508	-	-
715200 IT Hardware Purchases	-		-		101	-	-
715400 Software - term lic purch	-		-		77,944	-	-
715600 Personal Communication Devices	239,840	345,954	296,795	315,303	280,254	274,504	307,665
715810 Distributed Systems Services	-		-		-	9	-
721005 EE Exp Airfare	181,086	207,330	232,646	217,687	271,809	336,322	231,189

721005.90 EE Exp Airfare	(3)		-		-	-	-
721010 EE Exp Car Rental	28,703	35,993	40,454	38,371	45,465	52,712	53,444
721015 EE Exp Taxi/Bus	12,640	17,451	13,745	18,935	18,123	22,367	17,313
721020 EE Exp Mileage	397,955	420,990	484,853	417,170	468,114	478,519	446,161
721020.90 EE Exp Mileage	(510)		(1,843)		(740)	(770)	-
721025 EE Exp Conf/Semnrs/Trng	309,587	151,417	201,477	229,897	210,856	344,253	217,761
721030 EE Exp Hotel	176,572	183,869	247,568	187,911	262,225	265,329	235,172
721030.90 EE Exp Hotel	-		(3)		-	-	-
721035 EE Exp Meals/EE's	265,180	232,773	329,270	240,374	321,579	311,094	310,637
721035.90 EE Exp Meals/EE's	(348)		(1,498)		(1,636)	(768)	-
721040 EE Exp Meals/Incl.Non-EE's	21,102	14,978	48,825	14,944	30,816	52,694	18,238
721045 EE Exp Parking	41,431	41,170	61,893	41,151	65,238	62,841	64,543
721050 EE Exp Per Diem	1,405,338	990,369	1,217,837	1,147,964	1,161,348	1,367,765	1,132,952
721050.90 EE Exp Per Diem	(5,076)		(27,470)		(34,493)	(12,726)	-
721055 EE Exp Safety Equip	186,608	157,133	370,331	177,759	314,782	273,600	329,630
721060 EE Exp Other	57,704	232,282	51,114	49,063	81,691	81,953	28,661
721060.90 EE Exp Other	(205)		(21)		-	-	-
721500 Office Supplies	152,829	176,339	149,767	159,695	132,080	120,914	150,533
721700 Workforce Admin Expense	31		400		217	-	-
721750 Recog - Employee Engagement	-		-		-	2,209	-
721800 Safety Recognition	95,346	76,164	104,724	85,520	122,634	113,536	147,342
721810 Life Events		9,897		4,739			
721810 Life Events/Career Events	1,954		3,380		2,644	7,304	2,291
722000 Transportation Fleet Cost	2,499,599	1,933,221	2,551,102	2,158,404	2,645,145	2,142,187	2,562,078
722000.90 Transportation Fleet Cost	(6,397)		(13,154)		(17,786)	(7,292)	-
723031 Electric Use Costs	116,699	134,980	139,547	127,713	114,254	141,551	140,002
723032 Gas Use Costs	935	144	(273)	144	(906)	148	65
723035 Snow Removal Costs	12,030	70,000	88,664	50,000	94,653	25,465	50,530
723036 Trash Removal Costs	174	16,000	-	16,000	-	8,124	16,476
723037 Water Use Costs	161,760	169,531	254,478	163,914	167,704	176,413	162,624
723040 Moves/Adds/Changes	25,445		11,347	234	37,348	6,263	-
723060 Non-Energy	38,000		(26,675)	21,029	-	-	-
723110 Space	-		-	939	113	(2,240)	991
723130 Equipment Rental	439,833	399,928	539,949	405,485	446,409	358,451	431,822
723130.90 Equipment Rental-S3	(4,848)		-		-	-	-
723131 Steam Gen Rents	58		-		-	-	-
723135 Elec Transmission Rents	15,724		6,579		11,886	-	-

723136 Elec Distribution Rents	(51)		-		-	-	-
723144 Equip Rental-Cust Care	13		51		567	-	-
723300 Lease Costs	11,506		-		192	-	-
723400 Postage	23,351	24,635	31,443	27,619	26,052	42,218	29,720
723480 Injuries & Damages	-		16,674		(16,674)	-	-
723480.1000 Injuries & Damages FERC 426.5	-		-		24,778	-	-
723720 Advertising - General	2,524		-		1,262	-	-
723745 Conservation OM Communication	-		-		74	-	-
723750 Customer Program Advertising	-		-		-	-	-
723775 Safety Information	-		-		12	-	-
723780 Mandated Regulatory Notices	-		-		-	-	-
723785 Mandated Inserts/Communication	-		-		77	-	-
723810 Professional Association Dues	39,707	43,859	109,386	54,796	170,628	46,794	43,620
723820 Utility Association Dues	1,307	1,000	4,386	1,000	1,450	2,019	66,200
723821 Electric Util Assoc Dues	160,056	83,042	122,214	189,451	198,267	23,647	77,916
723823 Dues - Lobbying	-		-		107	-	-
723833 Charitable Contributions	(74)		467		32	-	-
723834 Community Sponsorships	115		1,813		645	357	-
723836 Chamber of Commerce Dues	-		-		-	122	-
723840 Regulatory Fees	40,423	2,160,892	40,019		-	-	97,289
723841 NERC only Regulatory Fees	1,948,101		1,988,578	2,153,197	1,974,994	2,020,038	2,159,160
723850 Social Service Dues	868	733	828	831	1,311	738	289
723854 Deductions-Corp Tickets	1,139		1,584		9,495	1,830	-
723855 Other Deductions	958		1,636	8,836	2,504	9,742	-
723860 Bank Charges	-		-		8,794	-	-
723875 Regulatory Fees-Direct	-		-		-	-	-
723890 Environmental Permits & Fees	25		25		118	45,090	90,000
723895 License Fees & Permits	1,194,288	1,222,656	1,181,025	1,331,193	1,166,684	1,152,615	1,094,093
723897 Penalties	186,486		70,546		(96,305)	-	-
724100 Misc O&M Credits	(736,265)	(780,000)	(321,992)	(1,568,724)	(30,260)	(275,880)	(13,945)
724185 Relocate Non-Grat E&G Distr	(27,000)		-		-	-	-
725000 Other	(5,548,519)	(2,768,384)	(7,403,720)	(2,955,667)	(5,882,194)	(5,734,310)	(3,346,600)
725000.90 Other - Sherco	86,271		197,095		251,028	108,591	-
725005 Online Information Services	29,051		9,189	37,425	16,860	47,818	38,139
Grand Total	**40,043,431**	**42,007,038**	**43,532,490**	**42,915,207**	**43,919,186**	**43,197,482**	**43,126,252**

NSP System Transmission Expenses ($000's)

Description	2014 ACTUALS (000's)	2016 BUDGET (000's)	2017 BUDGET (000's)	2018 BUDGET (000's)
NSP JPZ payments and GRE JPZ charges	$ 40,053	$ 47,799	$ 49,244	$ 50,722
MISO Network Service	$ 10,579	$ 9,399	$ 9,784	$ 10,151
MISO Transmission Expansion Plan (RECB)	$ 73,838	$ 121,271	$ 135,833	$ 144,412
Schedule 2 (Reactive Supply)	$ 8,788	$ 9,273	$ 9,653	$ 10,015
MISO Schedules 10, 10-FERC	$ 9,785	$ 10,263	$ 10,468	$ 10,779
MISO Schedules 16 and 17	$ 6,754	$ 5,943	$ 6,044	$ 6,165
WAPA Point-to-Point	$ 6,817	$ -		$ -
MISO Schedule 24	$ 906	$ 885	$ 911	$ 939
Schedule 1 (Sch, Sys Ctrl & Disp)	$ 563	$ 308	$ 320	$ 332
Sch 33 - Blackstart	$ 35	$ 36	$ 38	$ 39
Sch 45 - NREAC Recovery	$ 3	$ 6	$ 6	$ 7
Transmission Facilities	$ 650	$ -	$ -	$ -
Other native load deliveries	$ 370	$ 344	$ 301	$ 72
MISO Point-to-Point	$ 66	$ 71	$ 73	$ 75
MISO System Studies and Interconnection Upgrades	$ 94	$ 45	$ 46	$ 47
Courtenay Wind Project - Point-to-Point and Interconnection Upgrades	$ -	$ 273	$ 2,186	$ 2,186
Total Expense	**$ 159,300**	**$ 205,916**	**$ 224,909**	**$ 235,941**
Less:				
MISO Schedules 10, 10-FERC - Regional Markets portion	$ 214	$ 220	$ 223	$ 229
MISO Schedules 16 and 17	$ 6,754	$ 5,943	$ 6,044	$ 6,165
MISO Schedule 24	$ 906	$ 885	$ 911	$ 939
Note: Regional Markets Items [See Note #1]	**$ 7,873**	**$ 7,049**	**$ 7,179**	**$ 7,332**
MISO Transmission Expansion Plan (RECB)	$ 73,838	$ 121,271	$ 135,833	$ 144,412
Note: Items Collected through TCR	**$ 73,838**	**$ 121,271**	**$ 135,833**	**$ 144,412**
Courtenay Wind Project - Point-to-Point and Interconnection Upgrades	$ -	$ 273	$ 2,186	$ 2,186
Note: Items Collected through RES	**$ -**	**$ 273**	**$ 2,186**	**$ 2,186**
Net Base Rate Transmission Expense	**$ 77,589**	**$ 77,323**	**$ 79,711**	**$ 82,011**

Note #1
MISO energy and ancillary services market administration charges are reflected in Commercial Operations portion of Energy Supply budget and included in base rates.

NSP System Transmission Revenues ($000's)

Description	2014 ACTUALS (000's)	2016 BUDGET (000's)	2017 BUDGET (000's)	2018 BUDGET (000's)
Network JPZ - GRE/SMMPA	$ 38,924	$ 50,039	$ 51,547	$ 53,094
Network Service - Midwest ISO Tariff	$ 19,225	$ 31,772	$ 32,367	$ 34,413
MISO Transmission Expansion Plan (RECB)	$ 109,795	$ 148,317	$ 148,279	$ 158,736
Point-to-Point Firm, Point-to-Point Non Firm	$ 9,490	$ 9,433	$ 9,433	$ 9,433
Schedule 2 (Reactive Supply)	$ 8,518	$ 8,535	$ 8,535	$ 8,535
Tm-1 GFAs	$ 10,250	$ -	$ -	$ -
Fixed GFA Contracts	$ 8,433	$ 399	$ 373	$ 376
MISO Schedule 24 - Balancing Authority	$ 1,061	$ 1,278	$ 1,312	$ 1,348
Schedule 1 (Sch, Sys Ctrl & Disp)	$ 931	$ 1,154	$ 1,154	$ 1,154
GRE O&M service	$ 266	$ 267	$ 267	$ 267
Marshall TOPS Agreement	$ 145	$ 127	$ 130	$ 134
Total Revenue Collected	**$ 207,037**	**$ 251,322**	**$ 253,399**	**$ 267,490**
Less:				
Schedule 2 (Reactive Supply)	$ 8,518	$ 8,535	$ 8,535	$ 8,535
Note: Revenues transfer to Energy Supply	**$ 8,518**	**$ 8,535**	**$ 8,535**	**$ 8,535**
MISO Transmission Expansion Plan (RECB)	$ 109,795	$ 148,317	$ 148,279	$ 158,736
Note: Included as credit in TCR Rider	**$ 109,795**	**$ 148,317**	**$ 148,279**	**$ 158,736**
GRE O&M service	$ 266	$ 267	$ 267	$ 267
Marshall TOPS Agreement	$ 145	$ 127	$ 130	$ 134
Note: Revenues transfer to Distribution	**$ 410**	**$ 394**	**$ 397**	**$ 401**
Net Base Rate Transmission Revenue	**$ 88,314**	**$ 94,076**	**$ 96,187**	**$ 99,818**

Joint Zonal Revenues and Expenses - 2016 Test Year

Revenue

NSP JPZ	GRE	SMMPA	MRES	Total
Jan-14	$ 3,176,785	$ 562,682	$ 369,156	$ 4,108,622
Feb-14	$ 2,849,334	$ 500,369	$ 318,186	$ 3,667,890
Mar-14	$ 2,929,589	$ 511,315	$ 351,694	$ 3,792,597
Apr-14	$ 2,280,489	$ 474,298	$ 334,088	$ 3,088,875
May-14	$ 3,145,696	$ 574,935	$ 341,582	$ 4,062,213
Jun-14	$ 3,596,540	$ 652,920	$ 367,448	$ 4,616,908
Jul-14	$ 3,776,391	$ 725,737	$ 388,911	$ 4,891,039
Aug-14	$ 3,621,642	$ 737,990	$ 387,417	$ 4,747,048
Sep-14	$ 3,413,208	$ 621,148	$ 359,349	$ 4,393,704
Oct-14	$ 2,705,124	$ 517,441	$ 346,085	$ 3,568,650
Nov-14	$ 2,977,265	$ 514,431	$ 343,056	$ 3,834,752
Dec-14	$ 3,229,069	$ 563,624	$ 366,092	$ 4,158,786
Total	**$ 37,701,132**	**$ 6,956,890**	**$ 4,273,063**	**$ 48,931,085**

GRE JPZ	GRE
Jan-14	$ 118,609
Feb-14	$ 110,959
Mar-14	$ 118,499
Apr-14	$ 87,293
May-14	$ 96,836
Jun-14	$ 77,557
Jul-14	$ 98,992
Aug-14	$ 89,624
Sep-14	$ 76,255
Oct-14	$ 67,744
Nov-14	$ 77,993
Dec-14	$ 87,101
Total	**$ 1,107,463**
Total GRE Revenue	**$ 38,808,594.90**

Total Transmission Joint Zonal Revenue $50,038,548

Expense

NSP JPZ	GRE	SMMPA	CMMPA	NWEC	MMPA	MRES	Total
Jan-14	$ 2,214,719	$ 973,540	$ 86,983	$ 56,873	$ 63,564	$ 173,966	$ 3,569,646
Feb-14	$ 1,978,042	$ 869,502	$ 77,687	$ 50,796	$ 56,772	$ 155,375	$ 3,188,174
Mar-14	$ 2,021,925	$ 888,792	$ 79,411	$ 51,923	$ 58,031	$ 158,822	$ 3,258,903
Apr-14	$ 1,809,668	$ 795,488	$ 71,075	$ 46,472	$ 51,939	$ 142,149	$ 2,916,791
May-14	$ 2,304,345	$ 1,012,937	$ 90,503	$ 59,175	$ 66,137	$ 181,006	$ 3,714,103
Jun-14	$ 2,689,167	$ 1,182,096	$ 105,617	$ 69,057	$ 77,182	$ 211,234	$ 4,334,352
Jul-14	$ 2,949,913	$ 1,296,714	$ 115,858	$ 75,753	$ 84,665	$ 231,715	$ 4,754,618
Aug-14	$ 2,833,859	$ 1,245,699	$ 111,300	$ 72,773	$ 81,334	$ 222,599	$ 4,567,564
Sep-14	$ 2,431,308	$ 1,068,747	$ 95,489	$ 62,435	$ 69,781	$ 190,979	$ 3,918,740
Oct-14	$ 2,032,194	$ 893,306	$ 79,814	$ 52,186	$ 58,326	$ 159,629	$ 3,275,455
Nov-14	$ 2,034,749	$ 894,429	$ 79,915	$ 52,252	$ 58,399	$ 159,829	$ 3,279,573
Dec-14	$ 2,198,843	$ 966,561	$ 86,359	$ 56,466	$ 63,109	$ 172,719	$ 3,544,056
Total	**$ 27,498,733**	**$ 12,087,811**	**$ 1,080,011**	**$ 706,161**	**$ 789,239**	**$ 2,160,021**	**$ 44,321,975**

GRE JPZ	GRE
Jan-14	$ 362,466
Feb-14	$ 293,499
Mar-14	$ 332,375
Apr-14	$ 228,492
May-14	$ 280,820
Jun-14	$ 224,529
Jul-14	$ 306,757
Aug-14	$ 349,572
Sep-14	$ 206,232
Oct-14	$ 258,660
Nov-14	$ 314,470
Dec-14	$ 318,941
Total	**$ 3,476,814**
Total GRE Expense	**$ 30,975,546.19**

Total Transmission Joint Zonal Expense $ 47,798,789

Net Transmission Joint Zonal $2,239,759

Net Transmission Joint Zonal Payment for NSP Pricing Zone $ 4,609,110
Net Transmission Joint Zonal Payment for GRE Pricing Zone $ (2,369,351)

MISO Regional Peer Analysis of Transmission O&M Costs

August 2015

Study Inputs

- Utilized FERC Form 1 O&M data for 25 peer companies, included all MISO Transmission Owners who file FERC Form 1.
- Utilized data in FERC accounts 560 – 573 (excluding 565, transmission charges by others, and a footnoted portion of Xcel's 566 (Capital Project charges from the other operating company per the NSP System Interchange Agreement) .
- Compared O&M costs based on three metrics: (1) O&M per Line Mile; (2) O&M per Net Plant, and (3) O&M per Gross Plant.
- Looked at five years of data compared to quartile performance and average performance of peers.
- Compared peers to NSP System as NSPM and NSPW operate as one transmission system and NSP System comparison incorporates the Interchange Agreement.

Peer Group Summary (1 of 2)

The peer group used for comparison was all the MISO transmission owners that file a FERC Form 1.

Company	States of Operations	Net Sales of Electricity Revenue ($000)	Gross Utility Plant ($000)	Net Utility Plant ($000)	Annual O&M Expense ($000)	Line Miles
NSP Combined System	MN, ND, SD, WI, MI	4,224,552	3,532,036	2,593,765	61,719	7,706
Northern States Power Company - MN	MN, ND, SD	3,544,878	2,813,906	2,092,108	50,805	5,296
Northern States Power Company - WI	WI, MI	679,674	718,130	501,657	10,914	2,410
Ameren Transmission Company of Illinois	Wholesale	35,449	72,762	68,595	294	28
Northwestern Wisconsin Electric Company	MN, WI	22,324	17,946	11,646	184	152
Cleco Power LLC	LA	1,194,718	625,825	425,206	10,769	1,320
Entergy Texas, Inc.	LA, TX	1,733,401	976,997	681,984	19,480	2,502
Entergy Arkansas, Inc.	AR,LA,TN	2,057,097	1,622,597	1,171,199	36,160	4,859
American Transmission Company LLC	Wholesale	635,034	4,358,716	3,249,131	118,677	9,569
Entergy Mississippi, Inc.	AR,MS	1,454,073	947,921	647,409	21,976	2,913
MidAmerican Energy Company	IA,IL,NE,SD,TX	1,761,053	1,138,403	700,406	20,149	3,889
ITC Midwest LLC	Wholesale	332,255	2,082,448	1,754,601	37,738	6,623

*Note: States of operation include any state with electric generation, transmission, or distribution facilities.
Source: SNL Financial
Net Sales of Electricity Revenue: FERC Form 1: Page 300, Line 14, Column b
Gross Utility Plant: FERC Form1: Page 207, Line 58, Column g
Net Utility Plant: Gross Utility Plant less accumulated depreciation (FERC Form 1: Page 219, Line 25, Column b)
Line Miles: FERC Form 1: Page 422, Line 36, Column f + Column g
Net Plant vs Gross Plant: Gross Utility Plant is the total value of all the utility's transmission assets. Net Plant is the current value of the utility's transmission assets, less accumulated depreciation.

Peer Group Summary (2 of 2)

The peer group used for comparison was all the MISO transmission owners that file a FERC Form 1.

Company	States of Operations	Net Sales of Electricity Revenue ($000)	Gross Utility Plant ($000)	Net Utility Plant ($000)	Annual O&M Expense ($000)	Line Miles
International Transmission Company	Wholesale	350,516	1,948,480	1,329,956	32,996	2,920
Duke Energy Indiana, Inc.	IN,OH	3,048,984	1,330,327	850,951	27,908	5,297
Ameren Illinois Company	IL	1,387,981	1,451,744	995,830	32,496	4,414
Southern Indiana Gas and Electric Company, Inc.	IN,OH	591,316	460,047	343,539	15,566	1,026
Entergy Louisiana, LLC	LA	2,727,614	1,369,047	818,182	31,320	2,694
Northern Indiana Public Service Company	IN	1,660,857	894,705	445,878	31,375	1,106
Union Electric Company	IA,IL,MO	3,312,365	954,634	665,462	30,849	2,626
Entergy Gulf States Louisiana, L.L.C.	LA	2,029,794	1,147,713	695,156	30,366	2,408
Otter Tail Power Company	MN,ND,SD	369,607	323,429	220,121	10,388	5,622
ALLETE (Minnesota Power)	MN,ND	810,872	614,608	421,385	22,064	2,747
Entergy New Orleans, Inc.	LA	5,656,423	104,724	43,625	4,027	142
Indianapolis Power & Light Company	IN	1,300,730	268,594	110,283	8,184	838
Michigan Electric Transmission Company LLC	Wholesale	290,653	1,490,761	1,127,809	48,447	5,500

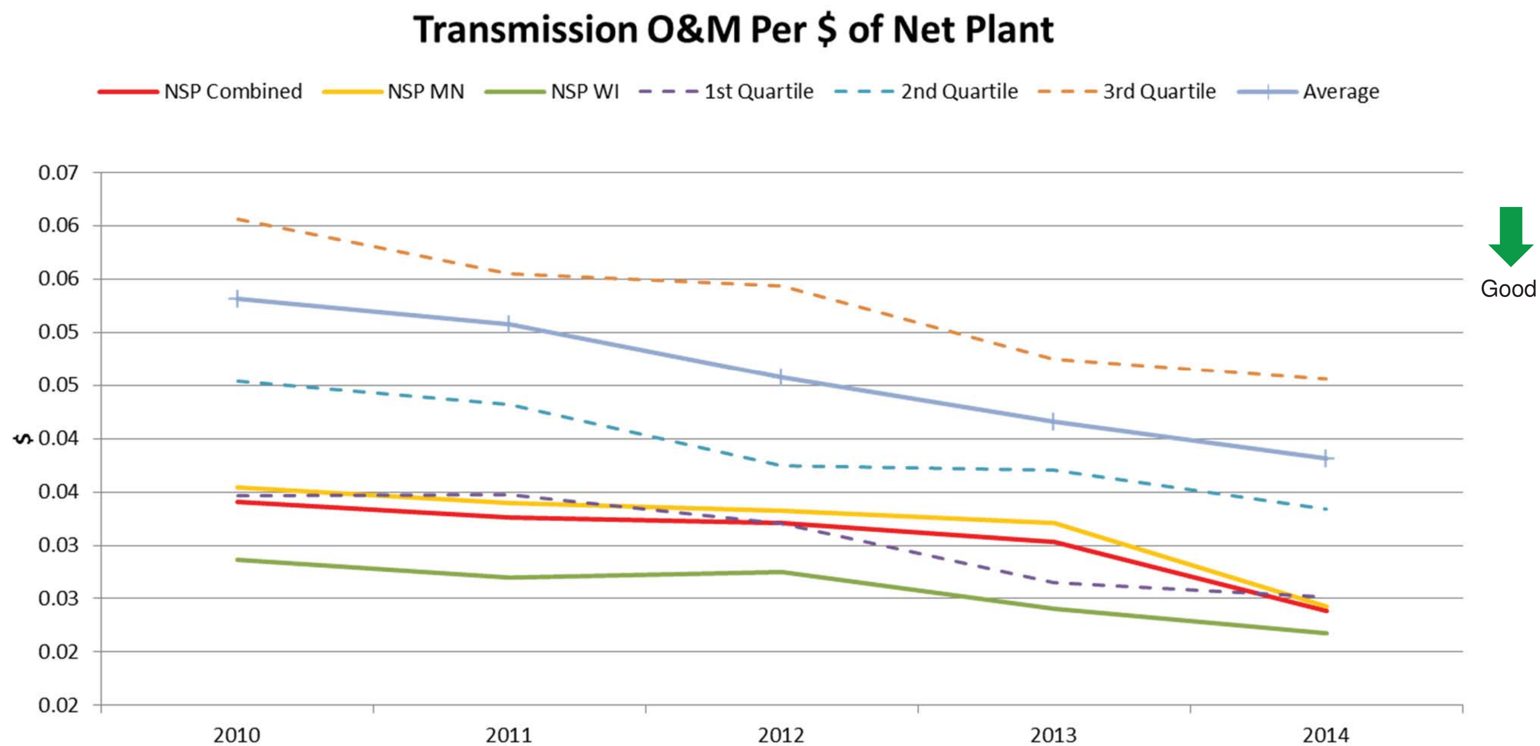
*Note: States of operation include any state with electric generation, transmission, or distribution facilities.
Source: SNL Financial
Net Sales of Electricity Revenue: FERC Form 1: Page 300, Line 14, Column b
Gross Utility Plant: FERC Form1: Page 207, Line 58, Column g
Net Utility Plant: Gross Utility Plant less accumulated depreciation (FERC Form 1: Page 219, Line 25, Column b)
Line Miles: FERC Form 1: Page 422, Line 36, Column f + Column g
Net Plant vs Gross Plant: Gross Utility Plant is the total value of all the utility’s transmission assets. Net Plant is the current value of the utility’s transmission assets, less accumulated depreciation. If a utility has a large system made up of old assets, it could have a high gross plant but a low net plant. This has implications for O&M analysis because a utility with high O&M per net plant might be high-cost, but might just have an old system, making the denominator in that ratio (Net Plant) low.

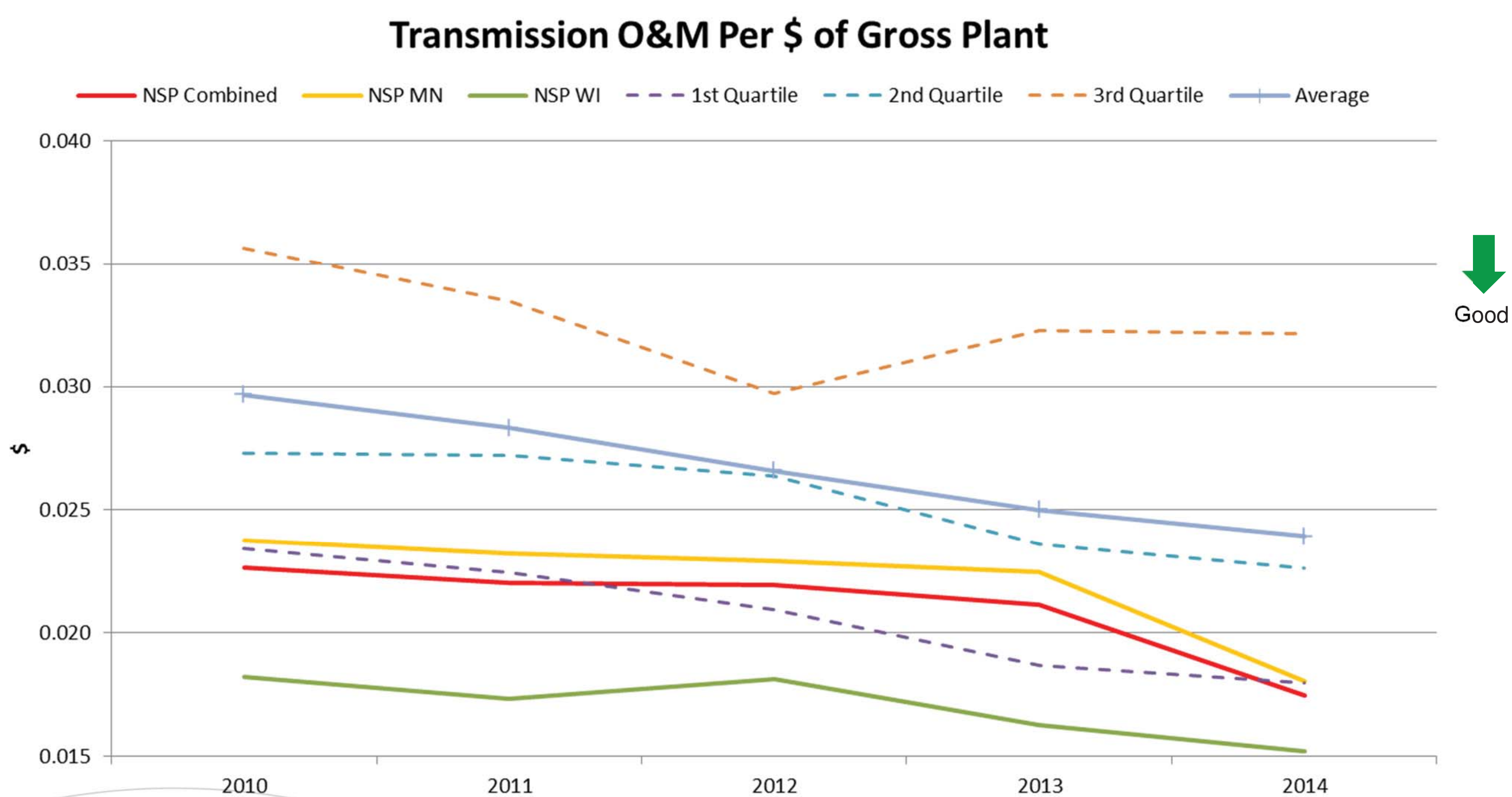
Summary of Results

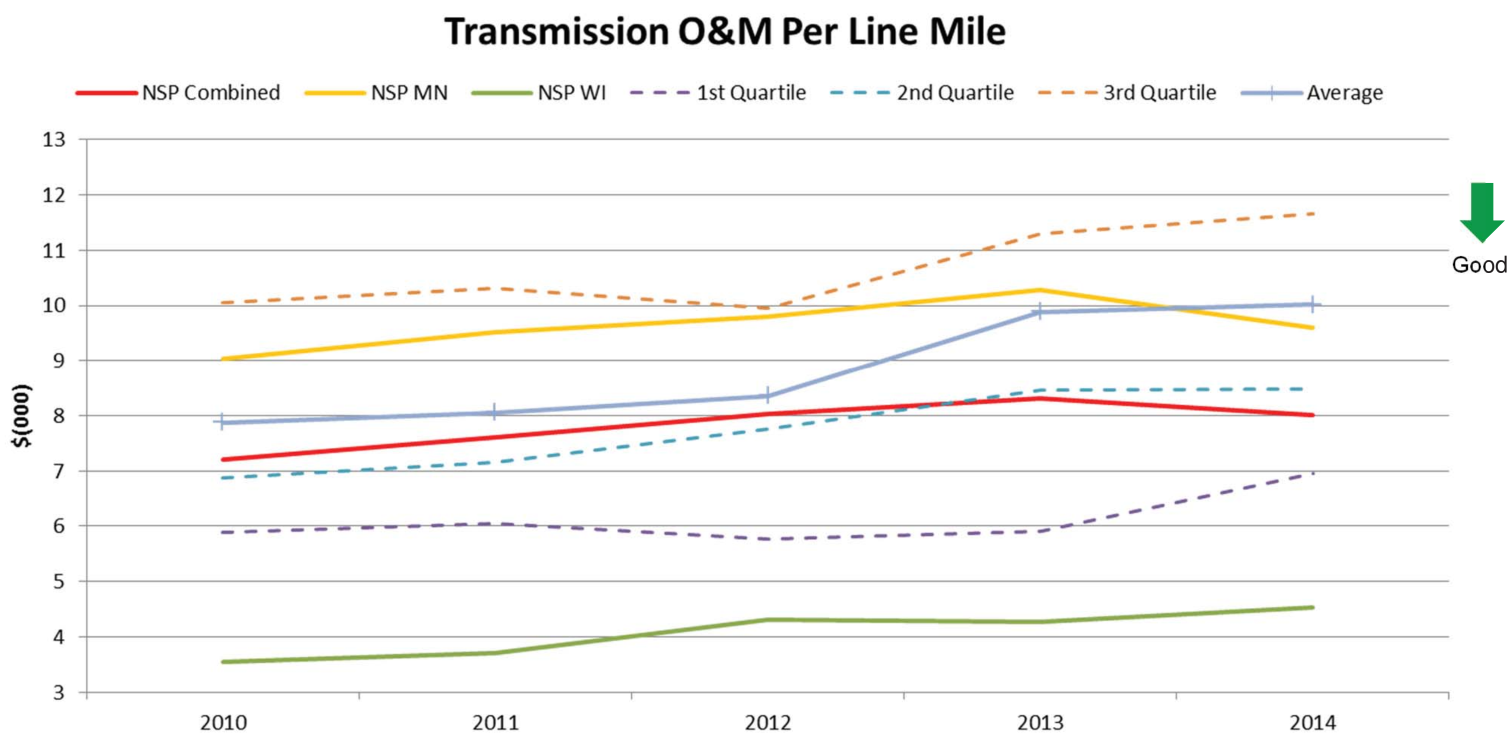
- **Overall NSP System's O&M cost performance is trending downward and is better than average under all three comparison metrics.**
- **NSP System ranks in the first quartile in O&M per Net Plant (#5 overall) and O&M per Gross Plant (#6 overall).**
- **NSP System ranks in the second quartile in O&M per Line Mile (#11 overall) but O&M costs are trending downward while peer company O&M costs per Line mile are trending upward.**

Summary of Results

	2014 NSP System Rank	2014 NSPM Rank	2014 NSPW Rank
O&M Per Net Plant	5	6	4
O&M Per Gross Plant	6	8	3
O&M Per Line Mile	11	15	3
1st Quartile	1-6	1-6	1-6
2nd Quartile	7-12	7-12	7-12
3rd Quartile	13-18	13-18	13-18
4th Quartile	19-25	19-25	19-25

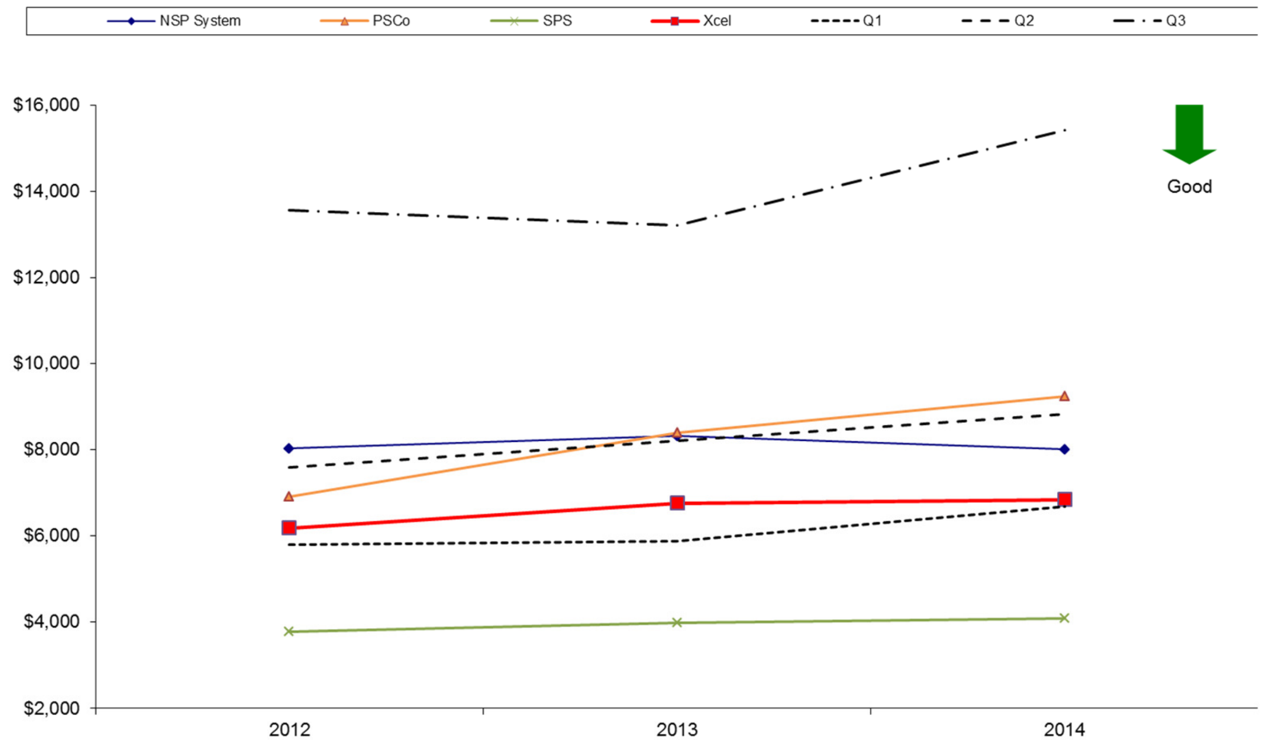

Transmission O&M Per $ of Net Plant
NSP Combined
NSP MN
NSP WI
1st Quartile
2nd Quartile
3rd Quartile
Average
$
0.07
0.06
0.06
0.05
0.05
0.04
0.04
0.03
0.03
0.02
0.02
2010
2011
2012
2013
2014
Good


Transmission O&M Per $ of Gross Plant
NSP Combined
NSP MN
NSP WI
1st Quartile
2nd Quartile
3rd Quartile
Average
0.040
0.035
0.030
0.025
0.020
0.015
$
2010
2011
2012
2013
2014
Good


Transmission O&M Per Line Mile
NSP Combined
NSP MN
NSP WI
1st Quartile
2nd Quartile
3rd Quartile
Average
$(000)
13
12
11
10
9
8
7
6
5
4
3
2010
2011
2012
2013
2014
Good

Transmission O&M per Line Mile

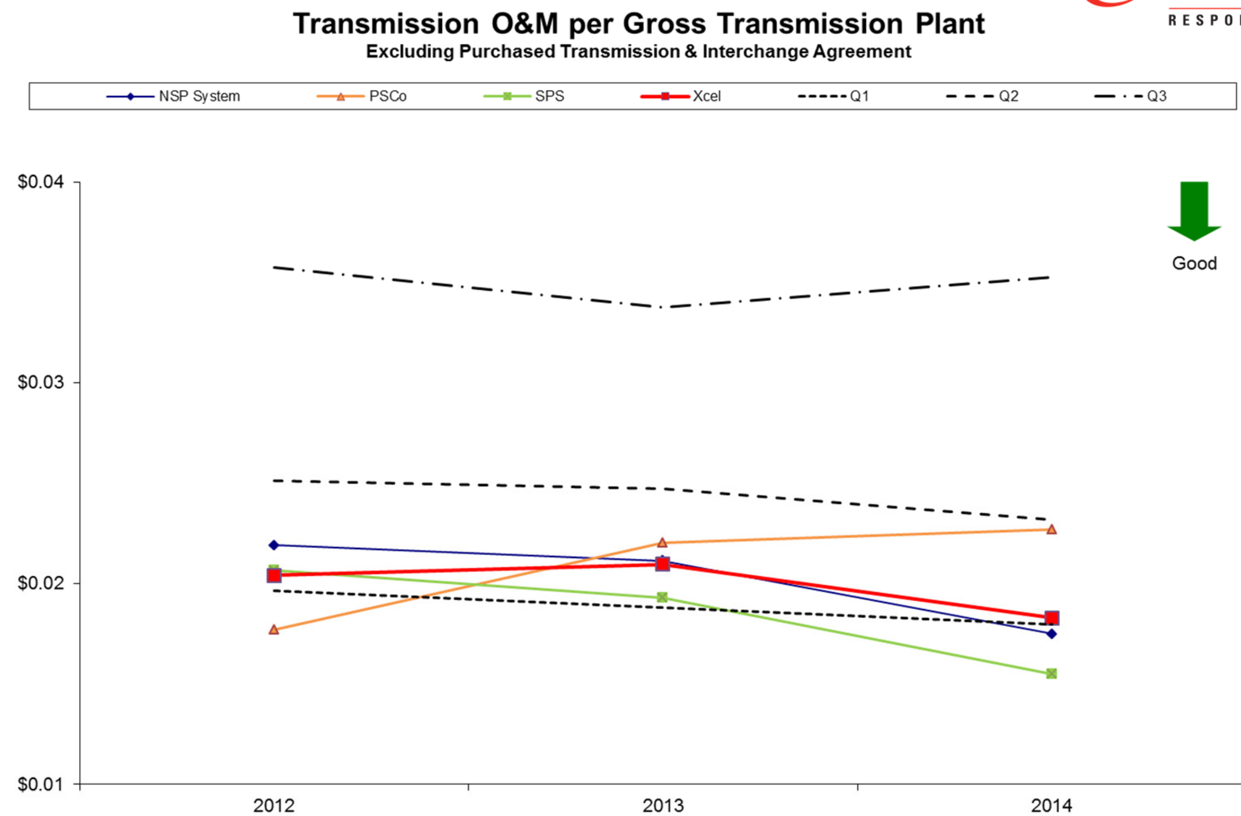
Excluding Purchased Transmission & Interchange Agreement



Transmission O&M 3-year CAGR Excluding Purchased Transmission & Interchange Agreement			
	NSP System	PSCo	SPS
O&M	4.1%	11.7%	8.9%
Line Miles	2.3%	-0.9%	2.5%
Gross Transmission Plant	12.3%	7.8%	19.5%
Net Transmission Plant	15.4%	8.4%	23.8%

- NSPM and NSPW O&M and line miles are combined for the NSP System to better reflect the transmission costs the retail customer pays.
- Growth in transmission O&M is outpacing growth of line miles.

Quartiles are set using EEI Index of Companies



Transmission O&M 3-year CAGR Excluding Purchased Transmission & Interchange Agreement			
	NSP System	PSCo	SPS
O&M	4.1%	11.7%	8.9%
Line Miles	2.3%	-0.9%	2.5%
Gross Transmission Plant	12.3%	7.8%	19.5%
Net Transmission Plant	15.4%	8.4%	23.8%

- NSPM and NSPW O&M and gross transmission plant are combined for the NSP System to better reflect the transmission costs the retail customer pays.
- PSCo O&M growth is more than the growth in gross transmission plant.

Quartiles are set using EEI Index of Companies

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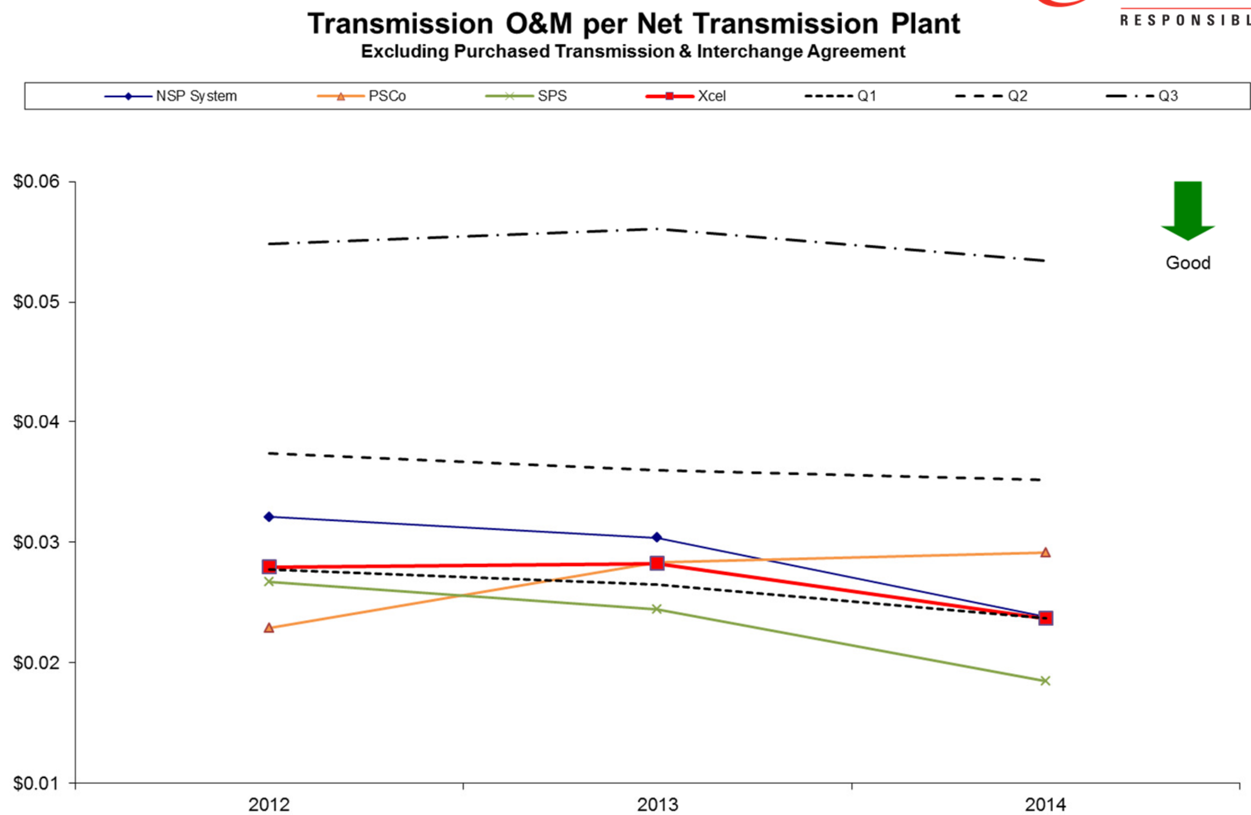

Transmission O&M 3-year CAGR Excluding Purchased Transmission & Interchange Agreement			
	NSP System	PSCo	SPS
O&M	4.1%	11.7%	8.9%
Line Miles	2.3%	-0.9%	2.5%
Gross Transmission Plant	12.3%	7.8%	19.5%
Net Transmission Plant	15.4%	8.4%	23.8%

- NSPM and NSPW O&M and net transmission plant are combined for the NSP System to better reflect the transmission costs the retail customer pays.
- Growth in transmission O&M for the NSP System and SPS is less than the growth in net transmission plant

Quartiles are set using EEI Index of Companies

Transmission Key Performance Indicators (KPI)

Metric	2012		2013		2014		2015
	100% Target Level	Actual Results	100% Target Level	Actual Results	100% Target Level	Actual Results	100% YE Target Level
OSHA Recordable Incident Rate	1.63	1.68	1.63	1.45	1.42	1.33	1.24
Trans & Subs SAIDI	8.90	7.20	8.00	9.70	9.00	8.30	8.73
Distribution Substation Maintenance	NA	NA	1000	1048	1100	1289	1300
Major Capital Project On-schedule Performance	99%	104%	100%	104%	101%	106%	105%
Compliance Plan Milestones Met / NERC Monitoring Index	547	547	578	577 93.4%	689	689 96.6%	97%
Supply Chain / Operational Excellence Savings	$19.2 Mil	$21.1 Mil	$22.0 Mil	$33.6 Mil	$33.1 Mil	$33.2 Mil	$30.5 Mil

Notes:
Trans & Subs SAIDI defined as T-SAIDI plus 1/2 Distribution Substations SAIDI
Distribution Substation Maintenance KPI added in 2013 to target execution of maintenance activities within distribution substations to improve customer reliability.
NERC Monitoring Index was developed in 2014 to replace the Compliance Plan Milestones Met KPI beginning in 2015. Historical results for 2013 and 2014 were calculated based upon the new KPI definition utilizing historical data.
Supply Chain Savings KPI was expanded and re-named beginning in 2015 to Operational Excellence Savings to encompass additional cost savings beyond strategic sourcing savings from material purchases - which was the sole focus for prior years.

Transmission Studies Planned for 2016

Description	Forecast Amount	Not Capitalized	Support	Allocation/Sharing
Future Business Planning - regional projects	$50,000	Survey level study, not tied to specific capital asset	Estimate based on engineering judgement of consulting engineer time to complete study.	All NSPM
CapX joint planning/Greenhouse Gas/Increased Renewables	$500,000	Survey level study, not tied to specific capital asset	Amount shared with CapX Parties	All NSPM, Amont shared among CapX owners
MISO Studies - Interconnection (Reimbursable)	$250,000	Development phase only	Historical trends	All NSPM
Generation Retirement/Replacement Studies	$267,000	Survey level study, not tied to specific capital asset	Estimate based on engineering judgement of consulting engineer time to complete study.	All NSPM
Less than 100 kV transmission study - Northern WI	$20,000	Survey level study, not tied to specific capital asset	Estimate based on engineering judgement of consulting engineer time to complete study.	All NSPM
Less than 100 kV transmission study - Mankato MN	$20,000	Survey level study, not tied to specific capital asset	Estimate based on engineering judgement of consulting engineer time to complete study.	All NSPM
Less than 100 kV transmission study - Central MN	$20,000	Survey level study, not tied to specific capital asset	Estimate based on engineering judgement of consulting engineer time to complete study.	All NSPM
MN TACT - Required annual NERC assessment	$50,000	Survey level study, not tied to specific capital asset	Estimate based on engineering judgement of consulting engineer time to complete study.	All NSPM
Voltage Regulation studies following MISO MVP in service	$100,000	Survey level study, not tied to specific capital asset	Estimate based on engineering judgement of consulting engineer time to complete study.	All NSPM
Reliability Studies following up on issues identified in annual NERC assessment	$40,000	Survey level study, not tied to specific capital asset	Estimate based on engineering judgement of consulting engineer time to complete study.	All NSPM
Total	**$1,317,000**			

Transmission Discovery - 2016 TY Electric Rate Case
Index

Docket No.	IR No.		Question	Addressed in 2016 TY Case
12-961	DOC	192	A. Please provide capital additions for Energy Supply, Transmission, Distribution for 2012 actual, 2013 actual, 2014 actual, 2015 forecast, 2016 forecast, 2017 forecast, 2018 forecast.	Testimony p. 32
12-961	DOC	192	C. Please provide a breakout by capital project for Transmission capital additions for 2016, including brief description of each project, why project is needed, support for estimated cost of the project, impact on depreciation life of the facility and why, and support for in-service date of the project.	Testimony p. 57-99 and Schedule 2
12-961	DOC	192	D. Please break out capital projects for transmission included in rate case and capital projects included for the transmission recovery rider (TCR) and explain how these two do not overlap.	Schedule 2
12-961	DOC	1102	A. Please provide a breakout by project of the transmission plant in-service for 2016-2018. Please include a brief description of the transmission project (or segment of transmission project if part of a larger transmission project), summary of year end 2016-2018 total charges by work order matched to each transmission project, and in-service date of the project.	Testimony p. 57-99 and Schedule 2
12-961	DOC	1102	B. Please provide a breakout by project of the transmission plant in-service for 2016-2018. Please include a brief description of the transmission project (or segment of transmission project if part of a larger transmission project), summary of year end 2016-2018 total charges by work order matched to each transmission project, summary of expected in-service cost and support for why the amount is reasonable, in-service date of the project, and any information to support the reasonableness of the in-service date.	Testimony p.57-99 and Schedule 2
12-961	DOC	1103	Subject: Transmission O&M Costs Reference: Larson Direct Testimony page 38 and Table 6 and Table 7 A. Please provide the same Table 6 information for Transmission O&M costs for 2012 actual, 2013 actual, 2014 actual, 2015 forecast, and 2016 test year.	Testimony p. 100, p. 105-118.
12-961	DOC	1103	G. Please include the Company's policy for capital vs. expense for...project studies and explain how expensing this *(these)* transmission project study *(studies)* is consistent with the Company's policy.	Testimony p. 158-159, Schedule 10
12-961	DOC	1103	H. Please identify any other transmission studies that have been expensed and included in the 2016 test year. Please include the total costs of the study, support for the cost, brief description of the study, why the study is appropriately expensed rather than capitalized, and any cost sharing and/or allocation between other parties.	Testimony p. 158-159
12-961	DOC	1104	D. For Schedule 5, Transmission Expense Budget, please provide a narrative to explain why each item is included or excluded in the calculation for transmission expense, and any information to support the Company has identified all related MISO charges (not simply a picking and choosing of select MISO charges).	Testimony p. 120-133
12-961	DOC	1104	E. For Schedule 6, Transmission Revenue Budget, please provide a narrative to explain why each item is included or excluded in the calculation for transmission revenue, and any information to support the Company has identified all related MISO charges (not simply pcking and choosing select MISO charges).	Testimony p. 120-133
13-868	DOC	2120	Reference: Direct Testimony of Daniel P. Kline at Page 48, Table 7 Please update Table 7 to include 2015 Actuals to September 30, 2015.	Appendix A

Docket No. E002/GR-13-868
Information Request No. DOC-2120

Question:

Reference: Direct Testimony of Daniel P. Kline at Page 48, Table 7

Please update Table 7 through September 30, 2015.

Response:

Updated Table 7 is provided as Attachment A to this response. The updated table shows Transmission's Estimated vs. Actual cost performance for projects that have been placed in-service (excludes AFUDC). The Business Area uses this table to track its ability to accurately estimate, execute, and control project(s) costs, within the OpCo portfolio of projects, from project origination through in-service and closing.

Preparer: Chris Buboltz
Title: Manager – Transmission Project I
Department: Project Management North

Table 7 (Updated through September 30, 2015)
NSPM Performance on CPI
January 1, 2011 - May 31, 2015 Estimated vs. Actual Cost

Year	Estimates Closed	Sum of Actual Cost	Sum of Estimated Cost	Over/(Under) Percentage
2011	142	$70,894,046	$74,462,484	-4.8%
2012	131	$97,024,827	$96,196,833	0.9%
2013	225	$259,200,934	$273,321,921	-5.2%
2014	77	$92,702,297	$91,996,455	0.8%
2015	95	$379,928,970	$344,667,852	10.2%
Total	670	$899,751,074	$880,645,545	2.2%