SUPPORTING INFRASTRUCTURE – TRANSMISSION AND DISTRIBUTION

The goal of a sustainable, cleaner energy future depends upon sufficient infrastructure to support delivery of renewable and distributed generation resources. In particular, modernized transmission and distribution systems are critical to meet the challenges of emerging technologies, expanding renewable policies, and a holistic view of resource planning. We discuss our transmission and distribution systems in greater detail below, and address the planning considerations that may affect our long term resource planning.

I. TRANSMISSION

The NSP Companies operate an integrated transmission system (the NSP System) comprised of approximately 7,300 miles of transmission facilities operating at voltages between 23.7 kilovolts (kV) and 500 kV and approximately 553 transmission and distribution substations. The NSP Transmission 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 load serving entities (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. In this Appendix, we outline some of the transmission efforts being undertaken to ensure sufficient resources to meet resource planning requirements and other need drivers such as load and reliability.

A. System Management

The Transmission Business Unit centrally manages Xcel Energy’s transmission systems (i.e., NSPM, 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. There are approximately 2,400 total operating company employees, XES employees, and contract personnel in the Transmission business area. Of that total, more than 1,600 NSPM and XES employees and contract personnel are assigned to, or provide services to, NSPM.
Xcel Energy manages transmission planning and resource planning as inter-related functions. While transmission planning is considered separately, Xcel Energy recognizes that transmission development is an important part of the resource planning process. Transmission needs are driven by multiple factors including increased customer electric demand, new generator interconnections that adjust the flows on the existing transmission system, and generation resource choices and the availability of transmission to meet the demand for these resources. The interconnected nature of the transmission system also means that system development decisions (either transmission or generation) could have impacts on the transmission system of the NSP Companies.

B. System Planning

Consistent with the Commission’s Biennial Transmission Plan, we are constantly reviewing and studying our system to optimize operations and prepare for the future. The Company independently and in conjunction with MISO analyzes different futures to determine any necessary build-outs, in both short- and long-term planning. Based on these analyses and activities already underway, between 2010 and 2016 we will add more than $4 billion in investment to our system for all generating resources. Of that total, $2.5 billion is for new generation or major refurbishments. In addition, we are forecasting nearly $2 billion in transmission investment and another $1 billion in distribution system investment. Much of the transmission investment is in the CapX2020 and Multi-Value Projects (MVP) discussed in more detail later in this Appendix, as well as investments in upgrades to existing infrastructure to ensure the NSP System is as reliable as it can be for our customers.

This Appendix discusses many of our studies and investments in more detail, focusing on the following areas:

- CapX2020 Updates.
- FERC Order 1000.
- Competitive Readiness.
- MISO Emerging Opportunities.
- Biennial Transmission Projects Report.
- Efforts to Ensure Sufficient Transmission Resources.
- Additional Transmission Development Drivers.
- Transmission Costs.
1. **CapX2020 Updates**

In 2009, the Commission granted certificates of need for each of the four CapX2020 Group 1 Projects.\(^1\) These four projects are part of a coordinated transmission development effort by a group of regional utilities (the “CapX2020 Utilities”). The Group 1 projects include three 345 kV projects and one 230 kV project and all have completed their regulatory permitting processes and are under construction.

In 2011, MISO approved its first MVP portfolio. The portfolio of 17 projects spans the MISO footprint, and one of the projects, the Big Stone South – Brookings project is being jointly developed by Otter Tail Power Company and NSPM as a CapX2020 project. This project has completed its permitting with the state of South Dakota.

The approximate lengths, general locations, and in-service dates (ISD) of the lines are as follows:

- **Fargo Project (ISD mid-2015):** An approximately 250 mile, 345 kilovolt line between Fargo, North Dakota and Alexandria, St. Cloud and Monticello, Minnesota.

- **Brookings Project (ISD mid-2015):** An approximately 230 mile, 345 kilovolt line between Brookings, South Dakota and the southeast Twin Cities, plus a related 30-mile, 345 kilovolt line between Marshall, Minnesota and Granite Falls, Minnesota.

- **La Crosse Project (ISD late 2015):** An approximately 150 mile, 345 kilovolt line between the southeast Twin Cities and Rochester, Minnesota and La Crosse, Wisconsin.

- **Bemidji Project (completed late 2012):** An approximately 68 mile, 230 kilovolt line between Bemidji and Grand Rapids, Minnesota.

---

\(^1\) On May 22, 2009, the Commission approved certificate of need applications submitted by Xcel Energy and Great River Energy for three 345 kV projects in MPUC Docket No. ET2, E002/CN-06-1115. The Commission required that all three 345 kV lines be “double-circuit capable,” that is, constructed in a way that will facilitate a second 345 kV circuit on the same set of transmission towers. A certificate of need was granted for the 230 kV Bemidji project was granted by the Commission on July 14, 200, in MPUC Docket No. E017, E015, ET6/CN-07-1222.
2. **Big Stone South – Brookings Project (ISD late 2017):** An approximately 70 mile, 345 kilovolt line between Brookings, South Dakota and Big Stone City, South Dakota.

These projects will improve reliability in the region, address local reliability issues and provide a foundation for the interconnection of new generation resources.

2. **FERC Order 1000**

The Federal Energy Regulatory Commission (FERC) is driving significant developments in the electric transmission industry, and Xcel Energy is preparing to thrive in the emerging competitive environment. In 2011, FERC issued Order No. 1000 to address the perceived inadequacies in the regional transmission planning process and to increase competition in the electric transmission industry. In general terms, FERC Order 1000 requires: (1) that utilities continue to plan on a regional basis; (2) that transmission projects that provide regional benefits be cost allocated across the planning region (such as the MISO region); and (3) that transmission development for regional projects be opened to competitive bidding or project sponsorship models through removal of rights-of-first-refusal from federal tariffs to allow market forces to facilitate least-cost transmission development.

3. **Competitive Readiness**

As FERC Order 1000 develops, Xcel Energy has positioned itself to provide our customers the safe, clean, reliable energy services they want and value at a competitive price. Xcel Energy has taken steps to accomplish this goal in the transmission space by: assessing internal capabilities, creating organizational changes and teams to focus on and coordinate competitive readiness and execution, and by developing three transmission-only companies – Xcel Energy Transmission Development Company, LLC (XETD), Xcel Energy Southwest Transmission Company, LLC (XEST) and Xcel Energy Western Transmission Company, LLC (XEWT) – will compete and build transmission that would benefit our customers. As the Regional Transmission Organizations (RTOs) develop projects that have widespread benefits and costs allocated to all participating members, Xcel Energy will continue to ensure the regional plan studies the right scenarios, identifies the right needs, and selects the most appropriate projects to comprise the regional plan. As projects are chosen for competitive bidding, Xcel Energy will deploy its best value delivery model to ensure customers throughout the region receive the benefits of Xcel Energy’s project delivery, ownership, operations, and maintenance expertise.
MISO conducts numerous studies that review the transmission network in its territory from various perspectives and potential futures. For example, MISO studies review the transmission network for constrained interfaces for additional transmission required to meet North American Reliability Corporation (NERC) reliability standards, for potential impacts from new regulations such as EPA 111(d), and for the relationship between future transmission needs combined with future natural gas delivery needs. There are also many studies focused on transmission needs in specific areas within the MISO footprint. We participate in these processes through leadership (Vice Chair) of the MISO Planning Subcommittee, participation in the Eastern Interconnection Planning Collaborative (EIPC) Gas-Electric interdependency study, and through direct participation in ongoing MISO studies which impact our customers such as the sub-regional planning group periodic meetings, including review and coordination of proposed projects. We outline the recently completed and other studies that are underway below.

4. MISO Emerging Opportunities

MISO drives many opportunities for necessary transmission and generation as they continually balance the overall system for economic dispatch of generation. In January 2014, a large network of transmission in the southern portion of the United States joined MISO and is now called MISO South as it is integrated with MISO Classic. This new region is opening up a number of opportunities for generation dispatch from south to north in a heavily constrained area.

a. Multi-Value Projects (MVPs)

NSPW is a joint owner in an MVP located within the NSP system known as the Badger Coulee project. The project is a 345 kV project that when complete will tie the CapX2020 termination substation of Briggs Road Substation near La Crosse, Wisconsin to North Madison Substation in Madison, Wisconsin. This project has many economic and reliability benefits to the region and will help transfer clean renewable power from Western Minnesota to additional loads to the east. The project is currently seeking regulatory approval with the Public Service Commission of Wisconsin for a Certificate of Public Convenience and Necessity (CPCN), and an order is expected in April of 2015.
b. MISO Studies

The studies discussed below evaluate necessary projects to address issues in the overall MISO system including the NSP system.

- **MISO Transmission Expansion Plan (MTEP)** – MISO has an annual transmission planning process which results in identification of needed transmission facilities.

- **MISO Generation Interconnection Studies** – MISO performs generation interconnection studies to identify facilities necessary to connect new generation resources.

- **MISO Economic Planning Studies** – As part of its planning process, MISO conducts a Market Efficiency Planning Study (MEPS) whose purpose is to determine whether there are transmission projects that could remove transmission constraints and thus more efficiently use available generation resources. The MEPS results are reported as part of the annual MTEP report. During the MEPS process, projected economic and power flow models are developed which, when analyzed, determine the total production costs that are incurred to provide energy to the MISO load. Transmission constraints – the transmission elements that limit the amount of power that can be transferred between the unused, lower-cost generation and the load – are identified. Through a stakeholder discussion, transmission projects are proposed which could mitigate the constraints. The costs for these proposed transmission projects are determined and compared to the amount of production cost savings that could be realized if those projects were in service. The resultant benefit to cost (B/C) ratio of the projects indicates whether the proposed solutions should be considered for further evaluation for constructability and reliability analysis. Stakeholder review and comments are compiled and a decision on whether to recommend a MEPS project be included in the upcoming MTEP report is made.

- **MISO Unused Generation Capacity Study** – The purpose of this study is to identify opportunities to unlock generation capacity which could elect to become network resources and help alleviate MISO’s projected capacity shortfall in 2016. The system impact study was completed and revealed that 806-938 MW could be obtained with no required network upgrades, and an
additional 273-404 MW can be unlocked upon completion of transmission upgrades with an annual revenue requirement of $12-18 million. Three types or groups of generators were studied to determine what transmission would be necessary to bring Unused Generation Capacity onto the MISO system. To convert the unused generation capacity into planning capacity, the generation resources would need to go through the regular MISO Generation Interconnection Process.

- **Entergy Integration Efforts** – In December 2013, the Entergy operating companies integrated into MISO as transmission owning members. While a specific study effort is not being undertaken, MISO is conducting a number of studies to assess the Entergy transmission system. These studies will identify its overall performance and identify areas where transmission upgrades may be necessary. Particular focus has been placed on ensuring that the Entergy footprint and the traditional MISO footprint each have sufficient access to the market of the entire MISO region to fully realize the system-wide benefits. MISO has indicated a north-south transmission line spanning several states between the traditional MISO footprint and the Entergy footprint may provide market benefits, but could cost up to $3 billion. Such a project would address market access, congestion, and concerns from other transmission owners about impacts of Entergy’s integration on their systems. Projects related to Entergy’s integration would likely not be approved until 2015 at the earliest.

5. **Biennial Transmission Projects Report**

The Company, along with the other Minnesota Transmission Owners, participates every other year in the Biennial Transmission Projects Report. The report is prepared pursuant to Minn. Stat. § 216B.2425, which requires any utility that owns or operates electric transmission lines in Minnesota to report on the status of its transmission system. The Biennial Transmission Projects Report lists specific present and foreseeable future transmission inadequacies; identifies alternatives to address system inadequacies; identifies general economic, environmental, and social issues associated with the alternatives; and summarizes the input that transmission owners and operators gather from the public and local governments to assist in developing and analyzing alternatives.
The 2013 Biennial Transmission Projects Report was filed with the Minnesota Public Utilities Commission on November 1, 2013 and can be found at the Minnesota Department of Commerce’s e-filing web site or at www.minnelectrans.com. The 2013 report lists more than 100 inadequacies throughout the state, including more than 40 newly-identified inadequacies since the filing of the 2011 Biennial Transmission Projects Report. Of the inadequacies identified, 54 transmission projects are needed to address inadequacies on the Xcel Energy system or are CapX2020 projects for which Xcel Energy is one of the partners. None require a new Certificate of Need from the state of Minnesota.

With the addition of the CapX2020 projects and MISO MVPs, sufficient transmission capacity exists to meet the Company’s near-term Renewable Energy Standard (RES) requirements.

6. Efforts to Ensure Sufficient Transmission Resources

There are many planning efforts underway on an on-going basis to ensure we have sufficient transmission to support new and upgraded resources. The Company participates in all of these efforts including:

- **Minnesota Transmission Assessment and Compliance Team (MN TACT)** – The members of this group perform an annual assessment of the transmission system of participating companies to identify any deficiencies in the 1-10 year time frame which must be addressed. The annual MN TACT study tests whether our infrastructure is sufficient and assures that we are meeting any NERC requirements. Potential deficiencies – such as a line overload or voltage that is too high or too low – would be identified by this study and addressed by the appropriate MN TACT team member.

- **Minnesota Renewable Energy Integration and Transmission Study (MRITS)** – As part of the 2013 Minnesota Energy Bill (MN Laws 2013, Chapter 85- Omnibus Energy Bill, Article 12, Section 4) Minnesota utilities were required to perform a study of increased integration of renewable resources. The Department of Commerce directed the study and led a Technical Review Committee that included staff from Xcel Energy. MRITS was strictly an engineering study to determine a conceptual transmission plan needed to accommodate the integration of renewable energy at a 40 percent energy penetration level by 2030, and higher proportions thereafter, while
maintaining system reliability. The final study was completed in October of 2014. It should be noted that the study does not take into account any impact of future Environmental Protection Agency (EPA) regulations such as the proposed Clean Power Plan.

The study started with a 2028 baseline scenario which included a 28.5 percent Minnesota renewable energy penetration level and the needed transmission, including the CapX2020 projects and MISO MVPs. After the addition of 11.5 percent more renewable energy, several transmission upgrades, rebuilds, and additions were required. With the transmission additions identified in the study, the system would operate reliably. However, it did show there would be minimal curtailment of renewable energy. Since the size, location, and distribution of the new renewable generation resources is not known, the actual transmission plan may need to be modified when the resources materialize.

MRITS also identified some potential challenges. One of the challenges is the potential for increased cycling of thermal plants as the additional resources are added to the system. This increased cycling will impact the cost and maintenance of the plant. The study also determined that as more inverter-based resources are added to the system, the overall system strength should be closely monitored.

We have evaluated through our modeling what it would take to achieve 40 percent of retail sales from renewable energy on our system.

- **Eastern Interconnection Planning Collaborative (EIPC) Gas-Electric Interdependency Study** – This study is focused on understanding the interdependence between natural gas and electric infrastructure, especially increasing levels of natural gas generation that are installed in the Eastern Interconnection. The EIPC effort will result in data related to the interdependency between natural gas and electric infrastructure and may indicate some areas of the eastern U.S. where further study may be prudent. We participate in this collaborative to represent our customers’ interests and stay up-to-date on any emerging insights on this topic. This information will then be fed into regional planning processes such as MISO’s regional processes, and could lead to additional suggested gas or electric facilities in the future.
7. **Additional Transmission Development Drivers**

There are three primary drivers of new transmission need: load growth, interconnection with other companies’ generation resources, and policy requirements. Each of these issues is outlined below:

- **Load Serving:** Although load growth has slowed, the NSP companies continue to see pockets of load expansion throughout our territory requiring new transmission in order to meet the demand. Large new industrial loads like sand mines and pumping stations are a major driver for transmission projects in parts of the NSP service territory. Transmission planning is comparing this potential growth with the capabilities of the system in this area to see what expansion might be necessary and the most cost-effective way to respond to this growth. Reviewing these pockets of growth is an ongoing process as NSP learns more about the customers’ needs and the true potential for progress in this fast-changing environment.

- **Generator Interconnections from other companies’ resources:** The Company participates in the MISO Generation Interconnection Process and follows generation projects as they move through to completion. Our active participation allows transmission planning to be prepared for necessary generation requiring access to customers and markets.

- **Policy Drivers:** Transmission is sometimes required to address policies that are created around grid reliability or environmental issues. The current rule regarding Section 111(d) of the EPA’s Clean Air Act is an example of policy that may drive transmission needs. As compliance requirements related to the policy are developed, it is possible that existing generation resources could be retired and the development of new, less carbon-intensive generation may be necessary. It may not be feasible to locate the new generation in the same vicinity as the existing resources being retired. Such an outcome would require the addition of transmission infrastructure to adequately deliver the new generation to end-use customers.

8. **Transmission Costs**

Transmission costs vary significantly based on several factors. Transmission costs to interconnect and to deliver the generation to loads can vary from close to zero
incremental dollars in a case when a generator (with similar electrical characteristics and operating characteristics) is interconnected at a location where there is already transmission outlet capability (e.g., a power plant is retired and a similar generator replaces the retired generation unit), to significant transmission costs per mile multiplied by the miles of required transmission to deliver generation to loads. It is important to note that even within the same voltage level there is a range of transmission costs per mile that can vary significantly based on line location, route, type of construction, and soil conditions, among other factors. In our Modeling assumptions we assign assumed transmission delivery costs by resource type on a $/kW basis. The details of those assumed costs are included in Appendix J: Strategist Modeling and Outputs.

II. DISTRIBUTION

Distribution is the system that carries electricity at reduced voltage, five to thirty-five kilovolts, from transmission at the substation to end users via overhead lines or underground. This grid forms the backbone of our energy system that ultimately delivers electricity to our customers. This has traditionally been a one-way system, but with the introduction of increased Distributed Energy Resources (DER) or Distributed Generation (DG)\(^2\) we are working to modernize our grid to more easily integrate customer-generated electricity directly into the distribution system and function more as a two-way system. Investments to improve its operation will allow for the safe, efficient and reliable delivery of the electrical resources outlined in this plan. Current priorities for our Distribution business area include:

- Achieving operational excellent by improving reliability performance;
- Modernizing our grid system by targeting renewal of aging, unreliable or obsolete components of the system;
- Increasing the intelligence of our distribution system through the installation of key monitoring equipment and control and communications systems;

\(^2\) Distributed Energy Resources is used to refer to the various technologies—such as Demand Response, energy storage, and other decentralized devices—that supply power to the grid but are not necessarily energy generators. Distributed Generation is a type of Distributed Energy Resource, but refers specifically to those systems that generate energy in a decentralized manner,
• Maintaining the key assets on our system to improve reliability and safety – wood poles, substation transformers and breakers, vegetation management;

• Adding system capacity through the installation or reinforcement of key substations and feeders to serve new load and provide system backup for emergency conditions; and

• Integrating increasing amounts of Distributed Energy Resources from a variety of sources – including but not limited to renewable energy such as solar photovoltaic (PV) and wind, as well as battery storage, micro-generation, fuel cells and plug-in electric vehicles – into the distribution grid.

In this Appendix we provide an overview of our distribution system, discuss what informs our distribution planning process, note the impact of increasing DER on the system, and detail how our distribution system investments support a resilient and reliable grid.

A. System Overview

The NSPM-owned distribution system consists of roughly 26,700 circuit miles of line – 16,000 miles of which is overhead and 10,700 miles is underground – 262 substations and 1,155 feeders. Distribution lines operate radially, the system is sourced at the substation and lines are arranged out from there similar to a tree. The lines branch out into smaller segments as the feeder moves out from the substation to the customers. Failures, such as tree branches coming into contact with the mainline, generally cause outages to all the customers connected to that feeder and its taps. Taps are the smaller line segments that leave the mainline and fuses or reclosers are installed at those connection points, which open if a fault develops on the tap. This prevents the remainder of the system on that feeder from having their service interrupted, thus isolating the outage to just the customers beyond that fuse. At the customers’ site, service transformers feed lower voltage secondary conductors. These conductors deliver the low voltage power to the meter. The system has been developed for the efficient distribution of power, with lines routed as directly as possible. Geography, however, plays a dominant role in the ultimate design of the system; the location of lakes, road and developments dictate the siting of much of the distribution infrastructure.
Distribution substations are sized for anticipated load at a particular site, and often consist of one to three transformers. Site selection for substations is based on the availability of a transmission source, proximity to the load being served, total ownership costs and reliability considerations. Incremental transformers and feeders may be planned at substation sites to meet future load demand. Where possible, redundancy is built into the system to maintain reliability.

The Company’s distribution system employees are responsible for system design, construction, maintenance, monitoring, and operation of the distribution grid. This includes responding to trouble calls, outage restoration, coordinating emergency response, vegetation management, outdoor lighting, metering support, and facility attachments. Distribution also provides business planning, consulting, and analytical services.

To improve the delivery and reliability of the energy we provide to customers, we are making significant investments in the distribution system over the next five years. These investments will enhance customer service and choice and positively affect power quality. In order to support the wave of DER coming online in the next several years, we are embarking on a multi-year Distribution System Intelligence program. This program will include implementation of an Advanced Distribution Management System (ADMS), the installation of Supervisory Control and Data Acquisition (SCADA) at more substations on the system, utilization of Advanced Metering Infrastructure (AMI) for better data collection, and the execution of a strategy to update communications infrastructure. Investments in fault locating, isolation and restoration, and enhanced voltage and reactive power (VAr) controls will help to monitor loads and maintain system reliability. A key challenge in this process will be leveraging all the data collected from devices on the system to improve operations and integrate new technologies.

B. System Planning

Xcel Energy conducts planning for its distribution system on a continuous basis. Each year, current feeder and substation load is documented and an updated load forecast is produced. As new load growth is identified during the year, the load forecast is adjusted accordingly. We use the load forecasts to perform system-wide analysis for capacity needs in relationship to the long range plan for an area. Studies are conducted to evaluate various alternatives and determine short- and long-range plans. As capacity needs are identified, new capacity projects are prioritized and selected for inclusion in the budget. Potential new projects are weighed using a risk/reward model, considering
the probability of an outage and the consequence of that event. The new capacity is then integrated to the forecasting model and the cycle repeats. The distribution system planning process is represented below in Figure 1.

**Figure 1: Annual Distribution System Planning Process**

Load forecasting and system planning is a dynamic process that must take into account significant drivers of load changes, including new sources of demand, such as increased penetration of central air conditioning or electric vehicles, as well as proliferation of DG applications.

**C. Impact of Distributed Energy Resources (DER)**

As mentioned earlier, Distributed Energy Resources (DER) have begun to impact the distribution planning process. Our system was initially built to support one-directional flows of energy. Increased DER penetration levels pose new challenges to the distribution system to accommodate two-directional flows. As DER installations increase in an area, feeders or substations may require further analysis to ensure this equipment is adequate to continue providing sufficient power quality and reliable
service. Similarly, the Company must monitor DER contributions in relation to the system load. By identifying load and generation separately, rather than analyzing only the net result, we are able to more comprehensively evaluate whether system facilities are adequate to meet system needs under a range of likely scenarios.

While not all DER technologies are monitored on our system, we do file an annual Distributed Generation Interconnections report with the Minnesota Public Utilities Commission\(^3\), which provides information on the status of DG on our NSP system. Since 2011 we received 664 interconnection applications for DG systems with a total capacity of about 101,796 kW. Of the total applications received, about 86 percent were for solar systems (including participants in the Solar*Rewards and Minnesota Bonus programs), 3 percent were for wind, and 12 percent for other systems (diesel, gas, methane or biomass). Table 1 below summarizes the DG applications received over the past three years.

<table>
<thead>
<tr>
<th>Type</th>
<th>2011 # of Apps</th>
<th>2011 kW</th>
<th>2012 # of Apps</th>
<th>2012 kW</th>
<th>2013 # of Apps</th>
<th>2013 kW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>11</td>
<td>150</td>
<td>4</td>
<td>101</td>
<td>3</td>
<td>41</td>
</tr>
<tr>
<td>Solar</td>
<td>9</td>
<td>205</td>
<td>29</td>
<td>1,931</td>
<td>14</td>
<td>16,060</td>
</tr>
<tr>
<td>Solar*Rewards</td>
<td>140</td>
<td>1,496</td>
<td>282</td>
<td>4,180</td>
<td>94</td>
<td>1,259</td>
</tr>
<tr>
<td>Other</td>
<td>23</td>
<td>26,530</td>
<td>32</td>
<td>32,055</td>
<td>23</td>
<td>17,788</td>
</tr>
<tr>
<td>Total</td>
<td>183</td>
<td>28,381</td>
<td>347</td>
<td>38,267</td>
<td>134</td>
<td>35,148</td>
</tr>
</tbody>
</table>

Safety is a key concern with higher volumes of distributed energy. There is the potential for some DER facilities to reduce utility fault current contributions, potentially to levels that would not be detected and interrupted by existing protective equipment settings (i.e. a safety concern to the public if a downed conductor remains energized on the ground). Engineering studies are designed to review and mitigate these impacts. The interconnection study is an important tool designed to allow the Company to identify whether additional protective or regulating devices or other facilities are needed as a result of a new interconnection in order to provide for the safe and reliable operation of the distribution system. Additional operational challenges are presented by the variability of sources like solar photovoltaic and

---

\(^3\) In the Matter of North States Power Company’s Annual Report on Distributed Generation Interconnections, Docket Nos. E002/M-04-2055 & E999/PR-14-10
electric vehicles. These challenges all present opportunities for targeted safety and reliability investments in the system.

The Company is anticipating and preparing for the impact of increasing DER penetration levels on its system. We continuously evaluate new technologies, new system designs, new equipment, and new operational methods in order to continue to meet the needs of the distribution system in a changing energy environment. These new technologies include emerging smart grid tools or other advanced field devices with monitoring, controlling, and metering capabilities that better enable DER and provide for a more adaptable system. Our annual report on smart grid investments documents the investments the Company is making in improving network communications on our transmission and distribution grid.4

D. Reliability Planning

In addition to the investments required to meet the challenge of an increasingly distributed system, our system planners also must address a broader range of reliability considerations. We plan for capital projects as well as ongoing maintenance on our system. Capital plans include new build forecasting, as well as required upgrades and reinforcements to existing facilities. Maintenance planning includes budgeting for significant projects to address the aging infrastructure that supports the distribution system. Annually we file two reports on safety, reliability and service quality performance – one under our quality of service plan (QSP) tariff and one under the Minnesota rules – that document our progress in meeting reliability standards and discuss various factors impacting service quality, including reliability.5

In order to meet our obligation to provide reliable service, the Company plans extensively for restoring service after an outage. The Company’s outage restoration plans address a broad range of contingencies, restoration procedures, and prioritization requirements. The Company also invests significant resources to protect against threats to cyber or physical security at its facilities. These investments are crucial for system reliability and resiliency.

We are proud of our excellent system reliability. The average customer in Minnesota experiences less than 100 minutes of outages annually.\(^6\) Figure 2 below is a graph that shows our historic reliability data, measured by System Average Interruption Duration Index (SAIDI), from the annual QSP tariff filing.\(^7\) Our QSP tariff has a SAIDI standard of 133.23 minutes or less. If we exceed that standard, or goal, in any given year, there is an underperformance payment penalty. As the graph illustrates, our performance for the past five years has been below that 133.23 minutes standard. The challenge today is the electric distribution overhead system sustains over half of the customer outage minutes experienced by customers on only 3 percent of the days each year.

**Figure 2: Historic Reliability Data**

Minnesota Quality of Service Plan SAIDI
*(Excluding Transmission Line level, Including All Causes)*

- **Standard**: ≤ 133.23 min
- **Annual YE Actuals**

---

*IEEE Normalized by Region after excluding Transmission Line level*
*Based on sustained outages only (>5 minutes), excluding Transmission Line level, including all Causes, Meter-based customer counts*

---

\(^6\) Major storms are excluded from this average.  
To further enhance our reliability and resiliency, we are developing a Grid Resiliency Roadmap for the electric distribution overhead system. The Roadmap will work to identify ways to harden the system to prevent and minimize system damage; outage response improvement opportunities; and areas Xcel Energy can help the community move towards normalcy without complete access to the grid. The Company is also an active partner in the Electric Power Research Institute’s (EPRI) three year Grid Resiliency program and has applied program knowledge to its distribution system facilities to better withstand storm conditions. Additionally, the Company hosted a weeklong storm simulation to train and learn about outage minimization and restoration. Vegetation management, pole sizing, and automated switching are all key components of the Company’s outage prevention and restoration planning. Overall, we believe these activities will result in a stronger and more reliable grid.

III. CONCLUSION

Our transmission and distribution systems are critical to our ability to serve our customers in a reliable and safe manner, and to deliver growing choice and increasing renewable energy.

As we actively prepare our distribution system for the needs of the future, we consider the need for thoughtful investments to meet our core obligation, safely and reliably deliver energy to our customers, and adopt smarter technologies to further enable DER on our system. We recognize and will continue to respond to customer interest in increased DER. Overall, we envision building toward an integrated grid in the future, leveraging the strength of an interconnected system to make the best use of available resources.

Similarly, significant study work is underway to establish a comprehensive planning framework for new transmission that can respond to changing circumstances, including generation planning, efficiently in the years to come. The major drivers continuing to influence future transmission associated include distance from the major load centers (particularly the Twin Cities), size of proposed generation additions, proximity to other generation resources, and whether a proposed generation site is near an existing major high voltage interconnection (i.e. 345 kV). We continue to evaluate these issues as they arise in order to maintain flexibility and responsiveness for our customers.