414 Nicollet Mall
Minneapolis, MN 55401

November 1, 2017

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: 2017 BIENNIAL REPORT – DISTRIBUTION GRID MODERNIZATION
DOCKET NO. E002/M-17-776

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission the enclosed 2017 Biennial Distribution Grid Modernization Report in compliance with Minn. Stat. § 216B.2425, subd. 2(e).

Minn. Stat. § 216B.2425 contains three reporting requirements applicable to Xcel Energy. First, it requires the filing of a Biennial Transmission Report which is being filed jointly today by the Minnesota Transmission Owners in Docket No. E999/M-17-377.

The next two reporting requirements under Minn. Stat. § 216B.2425 apply to utilities operating under multiyear rate plans: (1) subd. 2(e) requires that we report certain investments necessary to modernize the transmission and distribution system (Grid Modernization report), and provides the opportunity to seek certification of certain projects; and, (2) subd. 8 requires that we conduct a distribution study (Hosting Capacity report).

Enclosed is the required Grid Modernization Report in compliance with Minn. Stat. § 216B.2425, subd. 2(e). We have separately submitted the Hosting Capacity Report today in Docket No. E002/M-17-777 because of the substantive nature of the report and the past level of stakeholder interest.

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and served copies on all parties on the attached service lists.

If you have any questions about this filing, please contact me at bria.e.shea@xcelenergy.com or (612) 330-6064.

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY & STRATEGIC ANALYSIS

Enclosure
c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF XCEL ENERGY'S 2017 GRID MODERNIZATION REPORT UNDER MINN. STAT. § 216B.2425, SUBD. 2(e)

DOCKET NO. E002/M-17-776

GRID MODERNIZATION REPORT

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this Grid Modernization Report to the Minnesota Public Utilities Commission in compliance with Minn. Stat. § 216B.2425. As a utility that owns and operates transmission lines in Minnesota – and as a utility operating under a multiyear rate plan, we are required to submit both transmission and distribution plans under the statute. As in 2015, we submit this distribution grid modernization report separate from our joint Biennial Transmission Projects Report, filed this year in Docket No. E999/M-17-377.

Minn. Stat. § 216B.2425 contains two reporting requirements for utilities operating under multiyear rate plans: (1) subd. 2(e) requires that we report certain investments necessary to modernize the transmission and distribution system (Grid Modernization Report), and provides the opportunity to seek certification of certain projects for later rider recovery; and, (2) subd. 8 requires that we conduct a distribution study (Hosting Capacity report), and include it with our biennial distribution reports. Because of the substantive nature of the Hosting Capacity report and the past level of stakeholder interest, we have separately submitted it today in Docket No. E002/M-17-777.

These distribution plan reporting requirements stem from modifications to Minn. Stat. § 216B.2425 in 2015 to reflect the growing interest in ensuring the distribution system is well-positioned to meet future system and customer needs while maintaining reliability, safety and security. The Commission is concurrently advancing this discussion through its Investigation into Grid Modernization in Docket No. E999/CI-15-556.

In this biennial Grid Modernization report we discuss the foundational investments we are making and planning to make in the distribution grid as well as our request for certification for two projects.

The first project for which we seek certification is a residential Time of Use (TOU) rate pilot that involves two-way communications Field Area Network (FAN) infrastructure and Advanced Metering Infrastructure (AMI). We summarize our TOU proposal in this report, however, due to the distinct stakeholder process surrounding the TOU pilot as well as the supporting details and required tariff changes, we have detailed and proposed the TOU Pilot in a separate November 1, 2017 Petition in Docket No. E002/M-17-775. We note that our intended implementation of the TOU Pilot is contingent on affirmative Commission actions in both this grid modernization certification request and the concurrent TOU Pilot petition. As discussed in that petition, upon certification, we would then request cost recovery through our next Transmission Cost Recovery (TCR)/Grid Mod Rider filing.

The second project for which we seek certification is a reliability improvement project – Fault Location, Isolation, and Service Restoration (FLISR), which we detail in this filing. FLISR also relies on the Advanced Distribution Management System (ADMS) and FAN infrastructure and involves installation of intelligent field devices. FLISR is a form of distribution automation that involves the deployment of automated switching devices that work to detect feeder mainline faults, isolate them, and restore power to unfaulted sections – decreasing the duration and number of customers affected by any individual outage. FLISR is expected to reduce outage durations for customers and improve overall system reliability performance metrics, such as system average interruption duration index (SAIDI) and the system average interruption frequency index (SAIFI). We propose a 10-year deployment timeline for this approximate $65 million investment, but are open to accelerating the pace of our implementation, which would accelerate the corresponding customer reliability benefits. Like the TOU Pilot, upon certification, we would request cost recovery through our next TCR filing.

Typically, we would submit our grid modernization report and request certification of projects *biennially* on November 1 as required by the guiding statute. However, with the pace of change in advanced grid technologies and our advanced grid initiative starting in earnest, we believe submitting reports annually for the next several years will help keep the Commission informed, and will better keep pace with the marketplace and industry. Further, while we have continued our work to develop our AMI and supporting FAN component proposals, they are not ripe for certification at this time. Waiting two years to return to the Commission in a scheduled biennial report to request certification of these projects would delay the implementation of these investments and thus, the expected benefits.

Technologies in the intelligent grid space are developing and evolving rather rapidly. The one-year timeframe we request for our next report specifically – and ongoing annual reports for the foreseeable future – will also allow us to continue to monitor and develop other complementary technologies that may allow us to bring even bigger benefits to our customers. Accordingly, we request the Commission allow the Company to make a filing in one year, on November 1, 2018, to provide an updated biennial report and certification request for additional grid modernization projects to include at minimum, AMI, and a substantive buildout of the FAN to support it.

We also request the Commission to establish an annual reporting cycle for our Grid Modernization reports for the next five years. We believe that while the authorizing statute mandates a filing every other year, there is nothing prohibiting more frequent filings. This request is consistent with the Commission's verbal discussion surrounding our 2015 Grid Modernization Report at their May 25, 2016 hearing as well as their permission for the Company to return to the Commission with a Belle Plaine solar/battery proposal at any time, should we choose.[1] Establishing an annual reporting cycle is also supported by the Commission's requirement for the Company to file a Hosting Capacity report every year, despite the statute specifying a biennial schedule.[2]

We are actively participating in the Commission's grid modernization efforts – and look forward to continued dialogue on bringing new capabilities, functions and technologies to the distribution grid. We support the evolution of the grid and anticipate meeting our customers' expanding energy needs at the "speed of value." We also look forward to continued discussions surrounding grid modernization with stakeholders. We appreciate the opportunity to provide this Grid Modernization Report and to continue advancing the grid modernization discussion here in Minnesota. We respectfully request the Commission to:

- Certify our residential TOU rate pilot (as proposed in Docket No. E002/M-17-775);
- Certify FLISR, a reliability improvement investment,
- Allow the Company to file a Grid Modernization Report and certification

[1] *See* ORDER CERTIFYING ADVANCED DISTRIBUTION-MANAGEMENT SYSTEM (ADMS) PROJECT UNDER MINN. STAT. § 216B.2425 AND REQUIRING DISTRIBUTION STUDY, Docket No. E002/M-15-962 (June 28, 2016).
[2] *See* ORDER SETTING ADDITIONAL REQUIREMENTS FOR XCEL'S 2017 HOSTING CAPACITY REPORT, Docket No. E002/M-15-962 (August 1, 2017).

request on November 1, 2018,

- Allow the Company to submit annual Grid Modernization and certification request reports annually through at least 2022, and
- Establish a procedural schedule for consideration of our TOU Pilot and FLISR certification request that aligns with a Commission decision no later than June 1, 2018, as provided in Minn. Stat. § 216B.2425, subd. 3.

This report is organized as follows:

- Background
- Landscape
- Foundational Elements of Grid Modernization
- Certification Request
- Impending Advanced Grid Projects
- Overall AGIS Modernization Implementation Strategy
- Other Technologies
- Distribution Study
- Conclusion

REPORT

I. BACKGROUND

The Minnesota legislature modified Minn. Stat. § 216B.2425 in 2015 to require certain distribution system information be included in the biennial reports – also allowing a path for cost recovery through the Transmission Cost Recovery rider under Minn. Stat. § 216B.16, subd. 7b. The biennial reporting requirements are as follows:

Minn. Stat. § 216B.2425, subd. 2(e) specifically requires that we report:

> *…investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.*

Minn. Stat. § 216B.2425, subd. 8 requires that the report required under subd. 2 include the results of a study to:

> *…identify interconnection points on its distribution system for small-scale distributed generation resources and shall identify necessary distribution upgrades to support the continued*

development of distributed generation resources.

We submitted our initial Grid Modernization Report required under subd. 2 of the Statute on October 30, 2015 in Docket No. E002/M-15-962, and requested certification of two projects: (1) ADMS, and (2) Belle Plaine Battery Project.

In its June 28, 2016 Order, the Commission certified ADMS and denied without prejudice the Belle Plaine project.. The Order also required that we complete and file by December 1, 2016 a distribution system study (Hosting Capacity report), which we had not included with our report due to the short amount of time between the legislative session and the report's due date. Our report had noted that it was unclear whether the notice requirement under Minn. R. 7848.1900 applied to certification for distribution projects. The Commission's Order confirmed that no notice is required under Minn. R. 7848.1900, because the rule applies only to transmission lines proposed for certification.[3]

We submitted our initial Hosting Capacity report required under subd. 8 of the statute in Docket No. E002/M-15-962 on December 1, 2016. On August 1, 2017, the Commission issued an Order setting additional requirements for our 2017 Hosting Capacity Report. We separately filed our 2017 Hosting Capacity report on November 1, 2017 in Docket No. E002/M-17-777.

We note that we will soon separately file a request for cost recovery for the previously-certified ADMS project as part of our Transmission Cost Recovery Rider. As noted previously, on November 1, 2017 we also separately submitted a detailed proposal for the TOU Pilot for which we request certification in this biennial distribution report.

II. LANDSCAPE

Enabled in large part by technological advancement, utility distribution grids are beginning to evolve from a predominantly one-way system to integrated networks of centralized and decentralized energy resources that are connected and optimized through communication systems that share information across the grid. We will manage power flows and support new generation, load and storage technologies through wide spread deployment of sensors and controls. Security protocols to protect against, detect and remedy cyber and physical threats are necessarily expanding. This future grid is expected to leverage automation and real-time monitoring to improve system efficiency and performance, prevent disruptions, and

[3] *See* footnote 12 of the Commission's June 28, 2016, Order in Docket No. E002/M-15-962.

reduce the duration and impact of outages. These new system capabilities will expand the options available to customers, who are increasingly expecting a more customized, convenient and clean energy experience that preserves the high reliability they have come to depend upon.

We have started this transition – taking a building block approach – and focusing first on foundational elements needed to support fundamental applications before enabling more advanced applications. For example, in our initial 2015 Grid Modernization Report, we discussed the importance of a secure, two-way communications network to support the full capabilities and benefits of our ADMS. This two-way, end-to-end field communications system – the FAN – will provide connectivity to our intelligent field devices, increasing our visibility into the system and allowing us to remotely operate and maintain related aspects of our system. The FAN will also enable communication and interoperability across the system between meters, distributed generation resources, energy storage, microgrids, and other technologies. More advanced applications are enabled with the fundamental applications in place. For example, with the FAN and ADMS in place, we can implement programs such as FLISR and AMI – both of which we discussed in our most recent biennial report.

FLISR will allow the Company to understand when an event occurs and reconfigure the system more quickly than we are able to today – reducing the number of customers that suffer an outage for a prolonged period of time in the event of a fault. We have limited capabilities to do this today through our present field-based automation and automated reclosers that we have selectively implemented around the system to improve customer reliability. ADMS brings important flexibility in device choices – and new capabilities due to its awareness of the real-time state of the grid. FLISR will provide us with information that calculates the probable location of the fault which will help us more effectively respond to major events on the system.

Similarly, the capabilities of today's AMI far surpass our present Automatic Meter Reading (AMR) technology, and can provide customers with near real-time information upon request – meaning customers can access usage information that is only a few minutes old. We implemented AMR in the mid-1990s – equipping each electric and natural gas meter with a radio frequency communication module that collects and transmits primarily meter reading data from the meter to distributed receivers that are part of a fixed proprietary communications network. The current system enables regular meter reads for meters that are not easily accessible, and is generally able to provide customers with daily usage information and some capability to check for line-side power before dispatching a truck. We have realized some operational efficiencies from this capability, and expect to realize even greater efficiencies from AMI – as well as greater information capabilities that will unlock our ability to deliver new products and services to our customers.

Even with our continued investments over the years that have upgraded the grid from its original configuration to provide us greater visibility and some reliability improvements, the impact has not been substantial. We are transitioning from a predominately one-way system to an integrated system that shares information across the distribution grid. The advanced grid will leverage automation, real-time monitoring, and communication to locate and isolate disruptions in the system and improve safety, efficiency, and reliability of the system. The advanced grid will enable greater customer choice by allowing customers to adopt new products, services, and technologies, including access to near real-time data regarding their electric usage. The advanced grid will also include security protocols that will protect against, detect, and remedy cyber and physical threats. Additionally, the advanced grid will provide timely and accurate information that will allow the Company to manage the increasing amount of Distributed Energy Resources (DER) entering our system. We will accomplish this through implementation of multiple programs over time that work together to improve and update our distribution system.

The need to update the grid is driven by a confluence of factors including rapid technological advances, changing customer needs and preferences, increasing industry reliability standards, emerging generation resources, and policy objectives.

- *Rapid Technological Advances*. Computer-based remote control, automation, and two-way communication technologies that have been used for decades in other industries are rapidly being deployed on the electrical grid. These technological advances are causing a phase-out of existing, older equipment. For instance, AMR meters are slowly being discontinued by manufacturers as they are replaced with AMI meters. To ensure that we have replacement parts for key elements of our system, we will need to upgrade to keep pace with these advancements.
- *Changing Customer Needs and Preferences*. The needs and expectations of our customers and stakeholders have evolved, and continue to evolve while the design and capabilities of the infrastructure has remained mostly unchanged. Today’s utility customers expect a more robust, reliable, and resilient system, which is fueled by the increasing dependency on the connectivity of digital devices. Thus, electric service interruptions, whether momentary or sustained, lead to greater dissatisfaction and negative economic impact than they did decades ago. Additionally, customers desire more insight and visibility into the energy choices that they are making, which is enabled by AMI and other advanced grid technologies.

- *Increasing Industry Reliability Standards.* The standard reliability indicator for the utility industry is SAIDI, which is the average duration of interruptions customers experience during a year – quantified in minutes. A utility's SAIDI is used to rank its reliability performance against its peers. In the 2016 performance year rankings, NSPM ranks in the second quartile for the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group (DRWG) benchmark large utility group with a SAIDI value of 93 minutes.[4] However, the industry expectations are becoming more stringent as technology for advanced grids develops. It is expected that by 2020, to achieve first quartile SAIDI status utilities will need a SAIDI of 82 minutes, and the second quartile will consist of ranking between 87 and 82 minutes. Without implementing advanced technologies such as FLISR, we will not keep pace with our peers in terms of SAIDI.
- *Emerging Generation Resources and Public Policy.* Finally, we expect that the amount of DER that we will need to integrate into the distribution system will rise in coming years. As a result, we need to have the visibility and control over the distribution system in order to control system power quality and enable increased adoption of these highly variable generation resources.

A modern grid will function as an enabler – it will allow for higher penetration levels of renewable resources, greater system efficiency and optimization, and a broader range of energy services. Some of the key benefits we expect to see from the modern electric grid and are forefront in our minds as we evaluate, strategize, and plan for our upcoming investments and next steps are as follows:

Reliability & Resiliency. The modern grid will be more reliable and disturbances will be shorter and impact fewer customers. We will have heightened awareness about the current behaviors and health of the grid due to the intelligent devices in the field that are able to sense and adjust power flow, as well as provide intelligence on the current status at local points on the grid. Automation of certain parts of the system will allow the grid to dynamically respond to adverse conditions and restore portions of the system without human intervention. Additionally, when we do have outages, the advanced grid will provide a more accurate understanding of exactly who is out of power and possible fault locations enabling quicker and more efficient outage

[4] The industry standard IEEE benchmark SAIDI calculation differs from the calculations specified under the Minnesota Rules and the Company's QSP Tariff. The IEEE benchmark includes all levels and all causes across the entire NSPM operating company. The Rules calculation excludes transmission level events and is calculated based on the four Minnesota regions. The QSP Tariff includes all levels of interruption to Minnesota customers, and major event days are excluded based on the count of sustained outages per day instead of the IEEE standard calculation of a daily SAIDI threshold.

response.

Safety. The new grid will be safer. In addition to fewer truck rolls for our crews that reduce total drive time –greater awareness of grid conditions due to more measurement points, real time data, and predictive capabilities will allow us to understand the behavior of the distribution grid when we switch or otherwise modify the system. Improved information will allow us to be more proactive in our maintenance and service work, making a safer environment for our workers and customers. The automation of the system will allow for remote switching, which is then accomplished without the employee in close proximity to the switching action. Outage isolation and fault location prediction will limit drive time to find the source of the outage. We do note that the introduction of distributed generation presents safety concerns, but believe these concerns will be met through adherence to good standards, processes, and safety codes.

Efficiency. Enhanced monitoring will enable us to know, rather than estimate, how elements of the system are loaded. This knowledge will help us make more informed decisions about when and where to improve or modify the grid ensuring we use financial and labor resources most efficiently. The modern grid will also operate more efficiently by minimizing energy losses through optimal power factor correction and potentially through optimized switching.

The timeline for actual implementation of these building blocks is fluid to allow for the pace of technological maturity, evolving system needs and customer interests, and Commission and stakeholder input regarding the desired scope and pace of implementation. Many of the grid modernization technologies and devices discussed within this report are relatively new within the industry. We are working with the industry and vendor partners to identify and implement solutions which leverage open architecture and interoperability. Solutions are maturing and we are implementing them, however, we need to balance the need for new solutions with the needs of our current grid without negatively impacting our customers. We believe it is important to take a measured, incremental approach to ensure that we balance cost and customer value with other policy objectives.

With that said, we are beginning to realize our Advanced Grid Intelligence and Security (AGIS) initiative – starting with the implementation of ADMS, which "unlocks" the capabilities of other advanced applications. We have continued development of the FLISR advanced application and other foundational and complementary technologies, including FAN and AMI that we believe will bring additional benefits to our customers. We are poised and ready to begin realizing the reliability benefits of FLISR – and while an overall AMI project is not quite ripe for certification at this time, we are prepared to implement a TOU Pilot for our customers that relies on AMI.

Depending on the Commission's certification determinations in this proceeding, we expect our implementation of FLISR to begin in earnest in early 2019 and late 2018 for the TOU Pilot. If certified, we will submit a cost recovery request for these projects – seeking recovery of all incurred and expected costs. If the Commission approves our request to submit an off-cycle, November 2018 distribution grid modernization report, we expect to request certification of full AMI and FAN deployments, which would continue and expand upon the FAN deployment and TOU Pilot-related AMI efforts presented in this report. We may also request certification of some smaller-scale related technologies that will complement our existing intelligent grid efforts at that time. Finally as we have previously noted, with the pace of change in advanced grid technologies and our AGIS initiative starting in earnest, it may be prudent to submit reports annually for the next several years to keep the Commission informed and keep pace with the marketplace and industry.

III. Foundational Elements of Grid Modernization

In order to fully realize the benefits of the modern grid, we must prepare our current grid. We discussed some of the investments we are making today and in the near-term in our recently concluded rate case (Docket No. E002/GR-15-826) that will support our longer-term grid modernization efforts.

For example, we are leveraging equipment replacement opportunities and as part of that, considering whether the functionality of a particular asset can be enhanced to promote grid modernization. One example of this is our plan to replace electro-mechanical relays with solid-state relays that are not only communication-enabled – but are also capable of providing fault data that an ADMS system can use to calculate probable fault location. This enables us to more quickly identify faults on our system and improve our response time. Additionally, the voltage regulators we are purchasing for replacements will have controls that identify reverse-power flow and react accordingly, which will facilitate integration of distributed generation onto the system. We are also continuing to deploy sensors on our system that aid our efforts to locate faults more quickly – improving our responsiveness to outage events, and thus the customer reliability experience.

We are also implementing limited aspects of the FAN, as approved in our multiyear rate case in Docket No. E002/GR-15-826. This limited deployment will support the TOU Pilot and initial FLISR implementation proposed for certification in this report.

A. Advanced Distribution Management System

ADMS is a foundational software platform for operational hardware and software applications. An ADMS is foundational because it provides situational awareness and automated capabilities that sustain and improve the performance of an increasingly complex grid. By implementing an ADMS, we are better positioned to fully realize benefits of technologies on the modern grid.

ADMS acts as a centralized decision support system that assists the control room, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. ADMS does this by utilizing the as-operated electrical model and maintaining advanced applications which provide the Company with greater visibility of an electric distribution grid that is capable of automated operations. In particular, ADMS incorporates Distribution Supervisory Control and Data Acquisition (D-SCADA) measurements and advanced application functions with an enhanced model to provide load flow calculations everywhere on the grid and accurately adjusts the calculations with changes in grid topology. This allows the Company to improve the monitoring and control of load flow from substations to the edge of the grid, which enables multiple performance objectives to be realized over the entire grid.

The key objectives of ADMS are to provide integrated grid preparedness, improve reliability, and to increase efficiency on the grid. Examples of how ADMS meets these objectives are as follows:

- *Integrated Grid Preparedness.* With the current forecasted high level penetration of DER, along with existing electric distribution grid impacts, it is essential to have a system that enables integration of grid technologies and functionalities. ADMS enables integrated grid preparedness by managing the complex interaction of DER, outage events, feeder switching operations and future advanced applications in one system.
- *Improved Reliability.* ADMS, in consort with automated grid components can improve reliability and quality of service in terms of reducing outages, minimizing outage time, and enabling advanced energy efficiency.
- *Increased Grid Efficiency.* ADMS acts as an integrated distribution control platform that provides improved grid efficiency and grid agility by enabling efficient execution of technologies on the same area of the grid through central control of automated devices.

We will be using a fully integrated ADMS D-SCADA system. An ADMS D-SCADA provides the functionalities of a D-SCADA system in addition to improving outage restoration, grid performance, and planning engineering. D-SCADA collects and stores information on the grid, such as: device status information, operating parameters, disturbance types (sustained or momentary), and other system performance information. This information improves ADMS load flow accuracy throughout feeders and taps which optimizes the grid technologies and functionalities and provides operators with an enhanced visibility and situational awareness of the distribution system. Distribution planning engineers will also use the performance information to perform load and operating analyses to establish system improvement programs that ensure we adequately meet load additions and continue to provide our customers with strong reliability.

The NSPM distribution system includes a total of 1,274 feeders, 270 substations, and 449 substation transformers.[5] Approximately 60 percent of the total NSPM substations have SCADA.[6] Approximately 85 percent of the NSPM feeders have SCADA. Combined, our SCADA-enabled substations and feeders serve approximately 90 percent of our customers. Given the importance of SCADA capabilities to reliability and load monitoring, in 2016 we have embarked on a long-term plan to install SCADA at more distribution substations. We are completing five in 2017, and have plans for an additional 25 over the next five years – with more likely in the future. In addition, we have been deploying advanced power sensors at our non-SCADA substations to get much of the data we would get from SCADA, but with no control capabilities. These solutions are a cost-effective stopgap measure to provide us data and visibility into the operation of additional substations.

B. Field Area Network

The FAN is an integral part of our intelligent grid initiative, and will be capable of simultaneously accessing diverse types of endpoints on the electric system – each with their own performance requirements. Our FAN strategy seeks to provide a two-way communication network that serves multiple "users" that include, but are not limited to ADMS, FLISR, and AMI – with potential for future applications such as natural gas regulators that are installed or upgraded with communications modules, streetlight monitoring and control, and smart inverter monitoring and control (though development in this area is not yet mature).

The FAN is a private, Company-owned wireless communications network that will

[5] NSPM Distribution System consists of three jurisdictions: Minnesota, North Dakota, and South Dakota.
[6] Approximately 45 percent have full SCADA, and the remaining 15 percent are equipped to provide partial SCADA data.

leverage our existing Wide Area Network (WAN) and substation infrastructure to securely and reliably address the need for increased communication capacity that arises from grid advancements.[7] Its primary function will be to enable secure and efficient two-way communication of information and data between our existing substation infrastructure and new or planned intelligent field devices – up to and including meters at customers' homes and businesses.[8] It is consistent with developments within the electric utility industry, and is premised on current industry standards that have been adopted by vendors, organizations, and other electric utility companies.

The FAN will use two wireless IEEE technology standards: (1) a Worldwide Interoperability for Microwave Access (WiMAX) network; and (2) a Wireless Smart Utility Network (Wi-SUN) mesh network.[9] A comprehensive communications network improves efficiency through increased standardization, monitoring and remote control of the system in a secure manner. We discussed the FAN in our most recent biennial distribution report. Company Witness Mr. David C. Harkness also discussed the FAN in our recently concluded multiyear rate case.[10]

Figure 1: WiMAX portion of the FAN on a distribution pole

Data from the FAN will be returned to the ADMS, which will act as a centralized

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[7] The current WAN is a communications network primarily composed of private optical ground wire fiber and a collection of routers, switches, and private microwave communications that are supplemented by leased circuits from a variety of carriers as well as satellite backup facilities.
[8] These endpoints will include a variety of field devices including reclosers, feeders, electric meters, capacitor banks, and virtually any other field device capable of communications now and in the future.
[9] The term "mesh" refers to the network's topology, which resembles the interlaced design of mesh material, as shown in Figure 3 below. All nodes on the network will relay data and cooperate in the distribution of that data in the network. The mesh design provides redundancy benefits.
[10] Harkness Direct at page 49, Docket No. E002/GR-15-826 (November 2, 2015).

decision support system to assist the control room, field operating personnel, and engineers with the monitoring, control, and optimization of the electric distribution system. The FAN allows the ADMS to access real-time and near real-time data to provide all information on operator console(s) at the control center in an integrated manner. This connectivity will enable the improvement of reliability, in terms of reducing outages, minimizing outage time, and maintaining acceptable voltage levels on the system. ADMS will also manage the complex interaction of distributed energy resources, outage events, feeder switching operations and advanced applications such as FLISR.

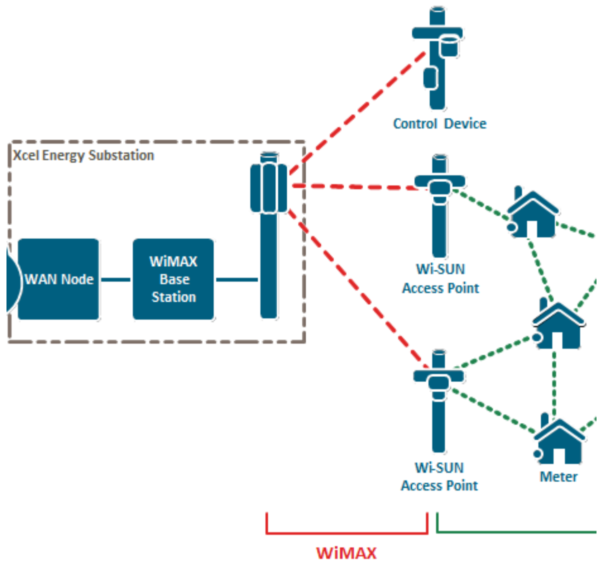
Currently, our internal communications networks serving field devices and all external network providers bypass the substations, which add delays that can make the data unusable for real time automated operations. By bringing more of the communications network in-house, we are able to improve security against cyber threats by reducing third party networks, reducing the use of public networks (*i.e.*, cellular) and reducing the reliance on external entities for communications support. The FAN will also enable the use of Quality of Service (QoS) to separate communication channels that might be more important in an emergency situation, which is not widely available today with many public communications options.

1. FAN Components – WiMAX

WiMAX is the commercialized name for the IEEE 802.16 series of standards. It will be based in our substations and will enable high-speed connectivity across the distribution system. It will connect wirelessly to devices on our distribution feeder lines and provide secure, reliable connectivity between our WAN and the Wi-SUN network component – and in some cases, directly with intelligent field devices.

We illustrate the WiMAX network in Figure 2 below

Figure 2: WiMAX Network Illustration



WiMAX base stations will connect to the WAN at the substation to enable connectivity back to the data center locations.[11] WiMAX is necessary to implement FLISR and complementary relay and sensing devices that aid fault location – and is an essential part of the overall FAN that will ultimately support AMI.

2. *FAN Components – Wi-SUN*

Wi-SUN is the common name for the IEEE 802.15.4g standard for local and metropolitan area mesh networks.[12] It operates on the unlicensed 900 MHz spectrum, and is well-accepted in the utility and communications industries. Wi-SUN can wirelessly connect meters, sensors, distribution devices, street lights, and signal repeaters to create a robust and reliable wireless network.

We illustrate the flow of communications between field devices and Wi-SUN access points through a "mesh" network in Figure 3 below.

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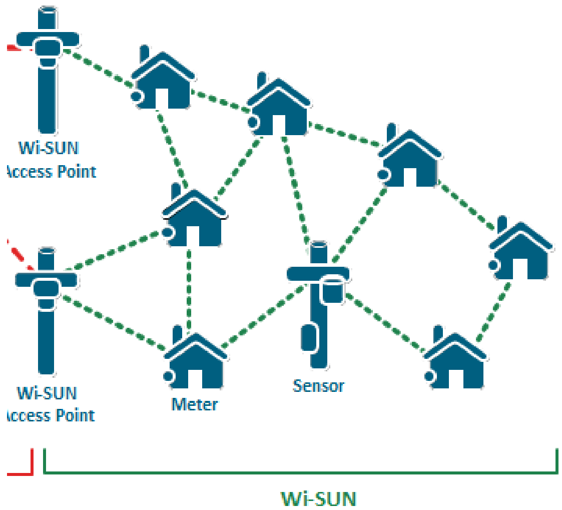
[11] In limited circumstances such as where deployment of the WiSUN mesh and WiMAX networks is not practical (such as remote locations on the edge of the Company's distribution system), we may use cellular or other wireless technologies as part of our comprehensive FAN solution. While these technologies are not adequate to support AMI as a whole, they provide alternatives in limited situations. In these instances, information such as data from AMI meters will be transmitted to the Company's WAN over an alternate technology.

[12] The Wi-SUN naming convention is similar to how "Wi-Fi" is the commercial name for IEEE's 802.11 standard, which is used throughout the general public.

Figure 3: Wi-SUN (Mesh) Communications Flow



The Wi-SUN is a mesh network, so adding more nodes to the network means that the devices have more options to communicate with their access point. For example, adding a new capacitor bank could mean that meters nearby would have a more reliable and efficient way to reach their communications destination through the network. Further, if other devices are added, such as streetlights, there would be additional nodes located at greater heights to the system, which could mean a meter may only be two communication "hops" away from an access point rather than three – increasing the speed of that communication.

In addition, the mesh network will be able to reconfigure itself to respond to any ongoing environmental change, such as radio frequency interference, outages, and traffic congestion on the network itself. In short, the network improves as more devices are brought online and within the FAN. The meters we deploy as part of our AMI implementation will become an essential and important part of the Wi-SUN network – providing important data from these points across our system, including voltage and power quality.

In addition to their metering function, AMI meters will have embedded communication modules that will allow the devices to communicate with the Wi-SUN network. Once fully deployed, we estimate that the AMI meters will make up over 90 percent of the devices that will communicate as part of the mesh network. The Wi-SUN mesh network, including the meters' communication nodes that will communicate as part of the network, will support AMI through the meters' communication function. The FAN will provide the transport for data transfer between the meters and the AMI head-end application, including interval reads, register reads, voltage information, and power quality data. It will also provide the sending and receiving of commands like power outage notifications.

We know that we will need to be prepared to obtain and process significantly more data from field devices than we have in the past. This additional data will require additional space for storage, and a data management plan to ensure we are keeping the necessary data only for as long as it is needed. We will also need to integrate this data into various back-office applications that will process it for billing or other operational purposes. The details of the interfaces will be determined in the design phase of the project, but we know that there will be requirements for the interfaces to transfer large volumes of data in a small amount of time.

3. Summary

Implementation of the FAN will provide secure and reliable communication capabilities to all participating field devices, regardless of the device's use. Our proposed standards-based solution will ensure interoperability of components and technologies; therefore, the FAN will provide the same, reliable communication to multiple business applications and devices. Furthermore, our ownership of the FAN will allow the Company to ensure that the network will consistently satisfy performance, security, and reliability needs as compared to a commercial/shared communications network approach.

In addition to supporting the advanced grid infrastructure, the FAN will support our ability to deploy computing capabilities closer to the field devices (for example, in substations) that will allow for quicker identification of potential issues and therefore quicker resolution. This approach will enable the Company to monitor and manage impacts of DER – for example, solar resources – and other events occurring on the grid in a more timely manner. Deploying solutions such as AMI without the FAN would be considerably more expensive to install and operate, and would limit our ability to gain full value from their capabilities.

We discuss our initial limited implementation of the FAN that will support our TOU Pilot and FLISR in Section IV below. We expect to seek certification of the full FAN at the time we seek certification of AMI. We have proposed to submit our next certification request in November 2018, which will likely include the FAN, AMI, and possibly some smaller scale technologies that will complement FLISR and further leverage the FAN infrastructure.

C. Energy Management System (EMS)

We use a Dynamic EMS (DEMS) to monitor automated devices and manage the health of the bulk electric system, including substations. This real-time, two-way communication system provides transmission and distribution operations the ability to remotely control the flow of electricity during outage and maintenance period, which is a key driver of our ability to maintain efficient and reliable service to our customers. ADMS will become the primary interface for monitoring and management of distribution substation devices, with EMS working in the background and continuing to serve as the Transmission EMS.

D. Field Devices

We have had a large deployment of distribution power line sensors ongoing in Minnesota since 2015. These sensors provide power quality data, fault information and other critical information for operating the distribution grid. We have placed these sensors at substations that are without SCADA as an interim measure. The installation of SCADA at all distribution substations is costly and at current funding rates, will take a number of years to complete. This new technology provides much of the benefit from SCADA and is an interim solution until SCADA has been installed. We plan for over 40 substations to have this technology installed and available in the DEMS system.

In addition to the power line sensors, we use several other modern field device technologies on the distribution system in Minnesota, including the following:

- *Capacitor controls* – these have two-way cellular modems that are used to manage power factor and reduce system losses through the SmartVAR system.
- *Automated Switch controls* – these are used with a FLISR system and automatically isolate faulted feeder sections and restore power to customers.
- *Remote Fault Indicators* – these are an inexpensive way to alert operations of a fault on the system, and also minimize field response patrol time.

E. Geospatial Information System

Our Geospatial Information System (GIS) provides a geospatial representation of our transmission and distribution physical assets to support field operations in the deployment and maintenance of these assets on behalf of customers. GIS allows us to view, understand, question, interpret, and visualize data in many ways that reveal relationships, patterns, and trends in the form of maps. GIS is a foundational tool and data repository for the grid modernization effort, but it is not a complete solution for the system data needs of the future; we will need enhanced data structures and future system upgrades.

As mentioned in our 2015 Grid Modernization Report and our impending TCR filing detailing the ADMS rollout, GIS is a critical system that will need to be integrated with ADMS. Accordingly, concurrent with the roll-out of the hardware and software components of the ADMS system, we will carry out a critical GIS data collection effort.

F. Underlying Information Technology Infrastructure

We envision an increasingly intelligent, automated, and interactive electric distribution system that utilizes advancements in sensing, controls, information, computing, communications, materials and components. This greater intelligence and automation is dependent on information technology (IT) to share and analyze information, integrate systems, and support the advanced infrastructure in a timely and efficient manner. In turn, the more advanced distribution system will be able to better meet customers' energy needs, while also integrating new sources of energy and improving grid reliability.

Our corporate IT infrastructure therefore requires attention and investment on an ongoing basis in order to continue to meet increasingly demanding cyber security, data traffic, reliability, and compliance requirements – and the service expectations of our customers. Many of the investments and projects discussed within this report involve additional data and communication needs, and a current IT infrastructure is critical to supporting those efforts.

Company Witness Harkness discussed our overall Business Systems strategy and planned investments in his Direct Testimony in our recently-concluded multiyear rate case. In the case of the advanced grid, our underlying IT infrastructure and integration of advanced grid components must allow new applications and field devices to communicate with and deliver data to our "back office applications." It is through these software applications that we fulfill our customer service needs, billing, payment remittance, service order management, outage management, meter reading, and asset inventory lifecycle management applications to utilize the customer data, outage data, and other information supplied by the advanced distribution grid.

The IT infrastructure also involves the necessary cyber security protection for the advanced grid – ensuring all components are identified and protected, both for the protection of customers and for the reliable and safe delivery of energy to customers. Additionally, cyber security validates that there are sufficient detective controls at strategic locations to provide early notification of suspicious behavior or anomalous activity. Finally, we must plan, refine and exercise appropriate levels of response, to react appropriately to all possible threats to the advanced grid.

As we move forward into the next generation of intelligent electric distribution, each and every facet of the electric network must be scrutinized and evaluated for cyber security risk. While reliable delivery of electricity is of paramount importance, protecting the integrity of the system is part of that responsibility. Therefore, all aspects of the advanced distribution system must be inventoried, securely configured, and monitored regularly and thoroughly to protect Xcel Energy and our customers from cyber security threats.

We are also changing the way that we are planning and operating the distribution grid, because an intelligent grid requires a different set of skills, processes, standards, and strategies compared to the traditional grid

IV. CERTIFICATION REQUEST

The ADMS is underway, as we discuss in more detail in our impending TCR filing. As noted previously, early aspects of the FAN are also underway. This limited FAN deployment will be largely sufficient to support the TOU Pilot and FLISR projects for which we request certification in this filing. We discuss these projects in this section – and in Part V below, we outline the AMI and full FAN projects for which we request the ability to seek certification of in November 2018.

A. TOU Pilot

1. Overview

We seek Commission certification of a pilot that provides select residential customers with variable pricing based on the time of day energy is used. Through the pilot, we will provide participants with new metering technology, increased energy usage information, education, and support to encourage shifting energy usage to daily periods where the system is experiencing low load conditions. Strategies that shift load away from peak may reduce or avoid the need for system investments in fossil fuel plants that serve peak electric load.

As described in the TOU Pilot Petition filed in conjunction with this certification request, we will deploy advanced meters to approximately 17,500 residential customers in two geographic locations: Minneapolis and Eden Prairie and its immediate surrounding area. Pilot participants will be enrolled on a new rate structure, with time periods corresponding to the system's profile at on-peak, off-peak, and "super off-peak" times.

The pilot was developed with the engagement of stakeholders and with the benefit of learnings from our recently launched pilot in our Colorado service territory. Through the pilot, we will study the impact of rigorously designed price signals and technology-enabled data on customer usage patterns for a subset of customers. We intend to operate the pilot for two years and will share learnings about the effectiveness of these techniques to generate peak demand savings. We will explore the performance of the selected technology, the impact of the price signals, and the effectiveness of customer engagement strategies, and will use the pilot experience to inform future consideration of a broader Time of Use rate deployment in Minnesota.

2. Benefits

The pilot is focused on providing benefits contemplated under the Grid Modernization statute. Namely, the pilot will increase conservation opportunities for customers, as it deploys advanced metering capabilities to facilitate communication between the utility and customer participants in service of on-peak energy efficiency and load-shifting. It also enables demand response activities through increased communication capabilities, customer information and education, and targeted price signals. In addition to energy conservation and communication benefits, the features of the pilot also modernize the grid by enhancing reliability. The AMI technology selected for this pilot acts as a voltage input, providing data to the ADMS to improve grid operations. It also includes outage reporting functionality that enhances outage response capability and improves reliability.

The pilot project will also generate beneficial learnings about the ability of Residential customers to respond to price signals and tailored educational messages by engaging in energy efficiency and shifting energy usage to non-peak periods. By limiting the TOU rate and technology implementation to a subset of customers, the Company will measure and verify key assumptions about the project in advance of a wider rollout.

3. Implementation

Customers selected for the pilot include a subset of those served out of the Westgate substation (which includes portions of Eden Prairie, Chanhassen, and Minnetonka) and the Hiawatha West and Midtown substations (located in Minneapolis). We will install new meters on a sample population of Residential customers in these areas. With the support of a third party Measurement and Verification (M&V) expert, we will divide customers who receive new meters into "treatment" and "control" groups. Customers selected for treatment will be automatically enrolled onto new TOU rates, and will retain the ability to opt out of the pilot at any time. Customers in the control group will receive new meters but experience no change to their current flat rates. The targeted areas will enable the Company to study the impact of the pilot's features on a diverse group of customers, and to deploy the required technology within an efficient footprint.

As described in the accompanying Petition, we will, upon Commission approval in 2018, implement a multi-phase customer outreach strategy and will begin to build, design and test the systems required to enable the pilot. This work will begin in 2018 and we anticipate it will be completed in mid-2019 – allowing for the installation of the meters in the pilot areas during the latter half of 2019. When the meters are in place, we will collect baseline data from customers prior to implementing new rates. Today we expect the launch of the TOU rates in late 2019 and early 2020. We will study customer response through the pilot for a two year period.

4. Costs

We summarize our estimated total TOU Pilot costs in the below tables, which comprehensively represent expected costs for equipment, implementation, and integration. For example, the TOU Pilot amounts include costs for items such as the AMI meters, software licenses and support, consulting for program development and measurement and verification, marketing communications, and various integration and customer presentment costs. The FAN line item includes both necessary WiMAX and Wi-SUN infrastructure that will also support FLISR, as discussed in Part B below – and ultimately all advanced grid technologies, including full AMI. These costs are based on the implementation timeline that we have outlined, and are subject to change if the timeline or other aspects of our proposed implementation change.

For purposes of this certification request, we have assigned a portion of supporting FAN costs to the TOU Pilot, because it requires earlier deployment of FAN infrastructure than FLISR. If the Commission does not certify both the TOU Pilot and FLISR projects we propose, we will need to provide updated cost projections for the certified project that properly reflect supporting FAN capital and O&M.

We additionally clarify, that the same FAN infrastructure that will support the TOU Pilot and FLISR as we have proposed will ultimately benefit all advanced grid projects – including AMI. In that respect, later advanced grid projects will have *lower costs than they otherwise would have* because we will be incurring significant FAN costs upfront for the earlier-proposed projects.

Table 1: Total Estimated TOU Pilot Costs – Capital
State of Minnesota
(millions)

	2018	2019	2020	2021	2022	2023-2027	Total
TOU Pilot	$0.5	$6.2	$0.6	$0.3	$0.0	$0.0	$7.6
FAN*	$2.5	$0.5	$0.0	$0.0	$0.0	$0.0	$3.0
Total	**$3.0**	**$6.7**	**$0.6**	**$0.3**	**$0.0**	**$0.0**	**$10.6**

** Note: the underlying FAN infrastructure will also support other advanced grid technologies, including AMI.*

Table 2: Total Estimated TOU Pilot Costs – O & M
State of Minnesota
(millions)

	2018	2019	2020	2021	2022	2023-2027	Total
TOU Pilot	$0.4	$1.1	$0.5	$0.5	$0.4	$0.3	$3.2
FAN	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1
Total	**$0.5**	**$1.1**	**$0.5**	**$0.5**	**$0.4**	**$0.3**	**$3.3**

** Note: the underlying FAN infrastructure will also support other advanced grid technologies, including AMI.*

As noted previously, we included limited costs for advanced grid projects in our multiyear rate case, which will serve to offset the total TOU Pilot and FLISR project costs. For example, the capital we included for the FAN is nearly sufficient to cover the WiMAX component of the infrastructure needed for FLISR and the TOU Pilot through 2019. For purposes of certification however, we believe it most important to present an estimate of the full cost of the projects.[13] We will detail the multiyear rate case impacts to the total project costs in our cost recovery request that will follow Commission certification of the proposed projects.

B. Fault Location Isolation and Service Restoration

FLISR is a form of distribution automation that involves the deployment of automated switching devices that work to detect feeder mainline faults, isolate them, and restore power to unfaulted sections – decreasing the duration and number of customers affected by any individual outage. The FLISR application relies on three primary components to operate: (1) ADMS, for the central control and logic; (2) the FAN, for wireless communications to each device; and (3) intelligent field devices

[13] The estimated costs in our TOU Pilot proposal petition filed in Docket No. E002/M-17-775 excludes the capital included for the FAN WiMAX that was approved in our multiyear rate case.

(reclosers, overhead switches and padmount switchgear), to detect faults and operate field equipment. Fault Location Prediction (FLP) is a subset application of FLISR that indirectly considers and leverages sensor data from field devices (such as sensors and relays) to locate a faulted section of a feeder line and reduce field response patrol times needed to physically locate the fault.

The FLISR system is expected to reduce outage durations for customers and improve overall system reliability performance metrics, such as SAIDI and SAIFI.

1. FLISR Operation

Distribution system faults are either temporary or permanent. A permanent fault is one where damage is done to the system, which may be the result of insulator failures, broken wires, equipment failure, or public damage (e.g., an automobile accident impacting a utility pole). Temporary faults are those where customers experience a momentary interruption from causes such as lightning, conductors slapping in the wind, and tree branches that fall across conductors and then fall or burn off. FLISR and its advanced devices benefit both types of faults, however, the majority of the value comes from addressing permanent faults.

During a fault event on a distribution circuit, the field devices operate to the extent possible to isolate the faulted section of the circuit and report back their information to ADMS via the FAN. ADMS takes the data from each device to identify the area on the circuit where the fault occurred and will execute additional steps to restore power to as many customers as possible. The sequence of this action from start to finish will take from 15-45 seconds – and by design, should restore power to two-thirds of the customers on that particular circuit, on average.[14]

We currently have small-scale automation programs across our distribution system. For example, we have been installing intelligent switches for a number of years on much of our 34.5 kV system in Minnesota. Like FLISR, these devices act to isolate the faulted section of the system and restore power to unfaulted sections of the feeder when possible. These intelligent switches have improved the reliability for over 100,000 Minnesota customers since 2013 – which with FLISR, will grow to nearly 500,000. If the device is successful at isolating the fault to one portion of the line,

[14] This is done by restoring power to all but one section of the circuit. In general, our philosophy is to design our feeders in thirds. So, a fault in one section would typically restore power to the remaining two-thirds of customers, if successful.

customers upstream of the device are spared from the outage.[15] We have also been installing sensors and replacing relays on the system that aid our ability to quickly find a fault, so we can begin restoring service to interrupted customers. We intend to continue these efforts, which fall into the category of FLP as discussed earlier.

However, without a centralized management system such as ADMS, the benefits of these devices are limited. For example, while intelligent existing devices can automatically restore customers located outside the fault zone, we do not get important data, such as the type of fault that occurred, and identification of the line sections where the fault may have occurred. While the traditional FLP-like sensing devices provide important benefits, they are not as flexible as fault location devices that are now available – and that can function within a broader strategy for advancing the distribution grid. Therefore, while these early intelligence devices have been beneficial for our customers and our operations, we intend to implement newer FLISR technologies going forward – eventually replacing some of the current devices, as appropriate.

2. *FLISR Components*

Over time, as we have needed to replace distribution equipment, we have done so with updated technology that becomes available and that is compatible with our current system. FLISR will involve implementing four principal components: (1) Reclosers, (2) Automated Overhead Switches, (3) Automated Switch Cabinets, and (4) Substation Relaying.

a. Reclosers

A recloser is a circuit breaker equipped with a mechanism that can automatically close the breaker after it has been opened due to a fault. Reclosers have evolved from hydraulic operation, which were limited in their ability to sense faults and to coordinate with other devices, to today's reclosers that are equipped with vacuum or SF_6 gas interrupting technology and digital electronic controls. Modern reclosers require less maintenance, provide enhanced operator safety, and add application flexibility that allows them to be used in numerous ways. The programmable electronic controls allow close coordination with other devices, and their enhanced sensing capabilities ensure more accurate operation and provide information that helps evaluate system performance. When connected with a communication network,

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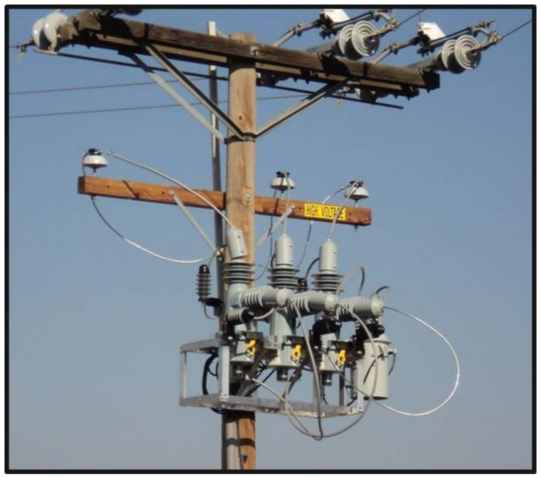
[15] This is comparable to a household ground fault circuit interrupter that opens when it detects a fault or issue, only affecting the devices downstream of the fault or issue, and not opening the breaker in a household breaker panel.

the recloser can communicate the operating information and a field crew can be dispatched to fix a fault when the reclosing operation doesn't eliminate the problem.

Figure 4: Recloser on a Distribution Pole



FLISR reclosers will be pole-mounted remote supervisory reclosing and switching devices. We currently have reclosers on the distribution system; the new devices will perform the functions of existing reclosers, will "re-close" after a fault event to determine if a fault still exists and restore service if possible, and will also be able to interrupt a fault event. They will also be able to report fault current to ADMS. If the recloser determines that there is a permanent fault after multiple attempts to reclose, the device will communicate the fault information to ADMS, which will inform the Company of the need to dispatch a crew to the fault location.

b. Automated Overhead Switches

When a fault occurs, a feeder breaker senses the fault and opens. Although the overhead switches do not communicate directly with the feeder breaker, local controllers on switches on both sides of the fault would sense the loss of voltage and open, isolating the fault. However, unlike a recloser, the overhead switches will not be able to re-close to determine whether there is a permanent fault. Instead, overhead switches rely on the feeder breakers for the reclosing functionality. Although automated overhead switches lack the reclosing capability, they are compact – making them a better choice for space-constrained locations compared to reclosers.

c. Automated switch cabinets

These pad-mounted sectionalizing and switching devices are motor-operated, remote-controlled devices used for underground feeder installations – performing functions similar to the automated overhead switches, but for underground feeders. These cabinets have multiple switches inside each unit providing versatility which is unique to the underground system.

d. Substation Relays

Substation relays provide the logic inside a substation for when and why a breaker opens. Modern relays are multi-functional and have multiple protection functions programmed into them. The primary use-case for a relay on a feeder breaker is to monitor the status of the distribution system and trigger an open command to the breaker in the event of a fault on the system. These relays can also capture important fault information which will be sent to ADMS for the Fault Location application.

In the event of a fault, the FLISR protective devices will reclose, or sectionalize the feeder, and send data to ADMS. ADMS will locate the device closest to the fault and generate a switching plan to restore service to other customers on the feeder – taking into account not only device and feeder loading – but surrounding feeder and substation loading as well. ADMS will then execute the proposed switching plan and notify the operator of the need to send a crew to the isolated section to investigate the fault event. This process is expected to take from 15-45 seconds from start to finish and by design, restore power to approximately two-thirds of the customers on that feeder. ADMS will also run the FLP algorithm and predict where within a FLISR section the fault exists, which will reduce expected patrol times by crews. FLP can also be run on its own, with only information about the fault, providing value to non-FLISR equipped feeders as well.

3. Operational and Reliability Benefits

We expect to realize benefits in the areas of reliability and operational efficiency.

a. Operational Benefits

We expect to realize operational benefits that will translate to customer benefits in the areas of: (1) Equipment interoperability and cost, (2) Increased visibility into the system that improves crew efficiency and our management of the system, and (3) improved data for system planning.

Equipment interoperability and cost. Implementing FLISR rather than continuing to rollout the existing automated devices is consistent with our strategy of selecting and implementing devices, communications systems, and control systems that are vendorneutral, non-proprietary, standards-based and interoperable. With ADMS-based FLISR, we have the ability to install devices for a significantly lower cost per device than the equipment that has been available historically – and we will have the ability to switch equipment vendors at any time, knowing that the new device will also operate in the FLISR system with less time necessary to integrate the new devices in the system that if they were proprietary and not interoperable, for example.

With our intent to automate hundreds of feeders across our operating footprint, a standards-based approach is financially responsible, provides important long-term flexibility, and aids our resilience to changes in equipment technologies and availability.

Increased visibility into the system. A primary benefit of FLISR is the ability to see the real-time load across many critical points on the distribution system – and the ability to operate those devices remotely. During the summer peak season and during normal switching operations for construction, the control center must dispatch crews to drive to switches to open and close them, moving load from one feeder to the next either to offload a piece of equipment or de-energize a section of line for planned work. The remotely controlled devices from FLISR allow much of that work to be done remotely, which is faster, safer, and allows the efforts of our crews to be more focused and thus productive.

We discuss the reliability benefits of FLISR in part b. below. However, we additionally note that in terms of operational efficiency, because FLISR and other remotely-controlled devices will allow us to identify and thus restore the root cause of an outage faster, our crews will be able to get to the next outage faster – increasing crew productivity and reducing the duration of each subsequent outage event from what it would have been without the increased system visibility. Once our system is widely automated, the cascading benefits from this will have a meaningful impact on reliability for all customers, whether they are on a FLISR feeder or not.

This increased visibility and remote control capabilities also allows distribution system operators to better manage, in real-time, the flow of electricity on the grid. In many instances during the summer peak season, operators send trouble crews to manually close and open switches to move electric load from one circuit or substation to another. This action helps us reduce the risk of overload on the system and maintain system integrity. With the FLISR program, much of this work will be done quickly and easily from the control center, with ADMS providing a high level of detail around the real-time load and capacity of the system.

Improved data for system planning and reliability. FLISR provides key data at critical points along the system, which is fed into historical systems and can be leveraged by engineering to make decisions about how to plan and design the future. System planning uses historic measured load at a single point on the feeder to allocate that load across the feeder. With multiple FLISR devices on each feeder, the granularity of these data measurements will be much finer across the feeder. The increased system visibility will also improve our reliability management efforts by increasing the richness of the information we are able to analyze. In addition, these FLISR devices can capture momentary or transient fault and disturbance information, providing the ability to proactively identify potential issues on the distribution system.

b. Reliability Benefits

Overall, implementing FLISR allows the Company to more efficiently restore power with the use of fewer resources and will improve the customer reliability experience. Specifically, FLISR will reduce the number of customers who experience a sustained outage, and will shorten the duration of certain sustained outages that affect a substantive portion of our customers.

Because of our current lack of visibility into the conditions on distribution system feeders, when a fault occurs, we generally rely on calls from customers to learn of the problem. Our systems take the call data and attempt to identify the device or portion of the system that was interrupted. However, finding a fault location can involve patrolling the length of the entire feeder with little or no knowledge of the general location. Once found, the crews isolate the fault, manually close switches, and make any needed repairs to restore service to customers affected by the fault.

During major events, we almost always prioritize switching loads at the feeder/mainline level to restore customers as quickly as possible.[16] FLISR in combination with ADMS will automate this analysis – giving us the ability to switch without having to deploy crews or engage in customer calls to gather data. Once a feeder is enabled with FLISR, the system will automatically restore service to approximately two-thirds of the customers on the feeder within minutes of the fault. The other one-third of customers will likely experience shorter outage durations, because we will be able to more specifically direct our crews to the location of the fault – facilitating quicker restoration of service. Other sensing devices at the tap level will similarly facilitate shortened outages for customers, as they too will report

[16] Major events are situations where the volume of events impacting the system overwhelms our ability to respond. As a result, we are forced to prioritize our corrective activities based on which corrective actions will restore power to the majority of the customers that are currently experiencing an outage.

information across the FAN to FLISR, ADMS and related applications – providing the general location of the faulted section of line and thus reducing the area crews need to patrol to find and repair the issue.[17]

4. *Implementation Strategy*

In general, we plan to target areas for FLISR where the electric system is predominately overhead, has high customer density, and has a history of outages that is more frequent than the rest of the distribution system. There are two key criteria that drive feeder selection, both of which are based on actual historical reliability information: (1) feeder SAIDI performance, and (2) the combination of the number of feeder mainline outages and customers impacted over a period of time. Additionally FLISR, like other advanced grid applications requires communications capabilities to each sensor and switching device. For Xcel Energy, this communications platform is the FAN. So, the implementation must be in concert with the FAN.

FLISR devices in general are among the most critical devices that will communicate via the FAN. These devices must respond quickly and reliably in an outage – and must be available when there are wide-spread power outages, in order for FLISR to respond and restore the system to the fullest extent.[18] We are designing our FLISR implementation to divide the distribution feeders into approximately thirds with each section having less than 1,000 customers – and with intelligent switches in place to tie the automated feeder to another feeder.[19] This approach is consistent with the way we plan and design our overall distribution system. We are also integrating existing reclosers and other intelligent devices into the FLISR scheme to further enhance the capabilities and customer benefits of that existing automation.[20]

Our initial FLISR rollout will overlay the TOU Pilot geographic area, providing efficiencies to both of the projects we propose for certification by leveraging the underlying FAN infrastructure. More generally, the FLISR application is most effective and can have the largest impact on reliability and operations when deployed

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[17] Ultimately, outages that occur below the tap level will benefit from AMI meters, as they too will also report via the FAN into the system helping to pinpoint the location of the issue on the system.

[18] Part of the engineering and design of FAN is to ensure that FLISR devices have Quality of Service (QoS) over other devices on the network, to ensure that the critical FLISR data can get through the network to ADMS as well as a requirement that the communications route from the FLISR device to the head-end be battery-backed.

[19] More heavily populated feeders with greater than 4,000 customers will end up with four or five feeder sections and multiple tie-points.

[20] If an existing device is in a proper location to employ FLISR functionality, in most cases, we will be able to use that existing device rather than install a new device.

on multiple distribution feeders in a geographic area. Doing so allows for normally open tie switches to be shared between two automated feeders, reducing the cost of deployment and also increasing operational flexibility. The deployment plan we therefore propose for Minnesota is focused around deploying in this geographic approach – first identifying areas where a number of feeders have experienced the lowest levels of reliability over the past several years, and building out from there. Our concentrated geographic approach also helps reduce the costs associated with the underlying FAN infrastructure. As we have noted previously, we present our proposed FLISR project based on a 10-year deployment timeline, but we are open to a more accelerated implementation if the Commission wants to realize the customer benefits more quickly.

We note that for a period of time, we will run FLISR in "advisory mode," where ADMS will take all of the inputs from the field devices and propose the optimal switching sequence for isolation and restoration. Our control center operators and grid engineers will review the sequence in real-time to verify the identified steps are accurate. We expect this review will happen very quickly (minutes), and once validated, the operator will allow ADMS to execute the switching sequence. Once we have established high confidence in the system, communications, and devices, we will enable ADMS to function automatically with little or no user interaction for FLISR.

We discuss and outline the FLISR costs and value proposition in Part 5 below, which are based on our implementation strategy. As shown in Table 3 – and visually in Figure 7 – we are planning a scaled deployment, with investment increasing each year. We learned from our Colorado FLISR project that an incremental approach that starts slower and ramps-up year-over-year is a prudent strategy. This approach affords the ability to continue to evaluate feeders for deployment, to ensure that we are identifying and installing devices where we and our customers will gain the greatest value. This approach also allows us to tightly integrate with the ADMS schedule; while we will immediately realize benefits from deploying the devices, we will realize full FLISR benefits when it is fully operational in ADMS.

5. Value Assessment

Determining the value of implementing FLISR required that we assess the value of the benefits we expect from FLISR, which are primarily related to customer reliability.[21] We did this by applying values to the primary FLISR benefits, applying those values to the feeders identified by our implementation strategy, and comparing

[21] We would expect to also realize the indicated Company efficiencies, which would increase the benefits of implementation.

deployment costs to the calculated value of implementation. Accelerating the deployment will correspondingly accelerate the value realized.

We expect the greatest benefits from FLISR to occur at the mainline feeder level. Today, feeder level outages account for approximately 2.5 percent of distribution outage events in Minnesota. While this is a low percentage of events, corresponding historical reliability statistics show that feeder level events account for over 35 percent of our distribution SAIDI.[22] Given the number of customers impacted from mainline feeder events, the value of automating the mainline system is positive when compared to other potential reliability improvement initiatives, such as burying overhead lines or hardening the system with larger wires and/or stronger poles.

a. Value of FLISR Implementation

SAIDI is the industry standard for measuring utility reliability performance, and indicates how long a typical electric customer is expected to be out of power each year. To determine the cost-benefit value proposition for FLISR, we performed studies on the historical SAIDI performance of each feeder to establish a baseline of reliability, using a rolling five-year average. We derived a cumulative customer minutes out (CMO) for each of the identified feeders, using actual reliability data over the 2010 to 2016 period.[23] Finally, we calculated an annual average CMO for each of the feeders to compare to a future state system with FLISR strategically deployed.

To quantify FLISR benefits, we established a value for each CMO, and applied this value to the numbers of customers impacted by mainline feeder events – again using actual historical data. For the comparative future state system with FLISR, we assumed that in a mainline fault event:

- All but one section of the customers on the feeder will see their power restored in less than one minute, which eliminates a sustained outage for the majority of customers on the feeder,[24]
- An improvement of at least 50 percent from historical performance,
- Efficiencies associated with sharing tie switches between two automated feeders, such that each feeder acts as the back-up for the other, and

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[22] An additional six percent of outages are at the substation or transmission levels, which in many cases will also benefit to some extent by FLISR.

[23] CMO is a primary input to SAIDI and our other reliability performance measurements.

[24] A sustained outage is defined as an outage lasting five minutes or more. In many cases, we expect that half or more of the restored customers will not even see a momentary outage due to our use of electronic reclosers across the feeders, which act to limit the number of customers interrupted in an outage event.

- A 25 percent reduction in the identified benefits, to represent a conservative but realistic estimate of the percentage of time that FLISR may not be available during an outage for some reason.[25]

We illustrate the formula we used to determine the annual CMO savings for each feeder in Figure 5 below:

Figure 5: CMO Savings Calculation

$$\text{CMO Saved} = \frac{(Average\ Annual\ CMO\ Saved) * (Number\ Of\ Equipment - 1)}{Number\ of\ Equipment} * (1 - \text{Scale Factor})$$

To determine the cost per CMO for a particular feeder, we divide the cost of the devices to automate that feeder with FLISR by the number of expected CMO saved to determine the cost per CMO saved.

b. Determining High Impact FLISR Opportunities

An important factor in deciding when automation is a good financial decision is based on the value of a CMO. In Minnesota, we calculated the value of a CMO at $0.76 per minute, which is a blended value based on the mix of residential, commercial and industrial customers. In order to determine whether a FLISR investment is worthwhile, we calculated a Net Present Value of an annual CMO over 20 years, resulting in a value of $8.04 in impact for a customer. Feeders with the lowest cost per CMO saved are prioritized first, as they provide the highest value to the customer and Company. For the initial years of FLISR, our implementation plan focuses on feeders with a cost of less than $4.00 per CMO, with many under $2.00 per CMO.

c. Deployment Costs

In the below tables, we outline the total expected project costs – splitting them between FLISR and the supporting FAN infrastructure. FLISR costs include the devices, installation, and system integration. The FAN costs comprise necessary WiMAX and Wi-SUN equipment, installation, and integration needed to support FLISR.[26] For purposes of this certification request, we have assigned a portion of supporting FAN costs to the TOU Pilot, because it requires earlier deployment of FAN infrastructure than FLISR. If the Commission does not certify both the TOU Pilot and FLISR projects we propose, we will need to provide updated cost

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[25] The system might not be available for switching for a variety of reasons including: construction, abnormal state of system, devices out of service for maintenance, system loading, communications failure and others.
[26] The FAN costs for FLISR are a primarily WiMAX-related.

projections for the certified project that properly reflect supporting FAN capital and O&M.

We additionally clarify, that the same FAN infrastructure that will support the TOU Pilot and FLISR as we have proposed will ultimately benefit all advanced grid projects – including AMI. In that respect, later advanced grid projects will have *lower costs than they otherwise would have* because we will be incurring significant FAN costs upfront for the earlier-proposed projects.

Table 3: FLISR Costs – Capital
State of Minnesota
(millions)

	2018	2019	2020	2021	2022	2023-2027	Total
FLISR	$0.0	$4.5	$5.1	$6.3	$5.7	$43.7	$65.3
FAN*	$0.0	$3.8	$8.4	$8.9	$7.4	$35.6	$64.1
Total	**$0.0**	**$8.3**	**$13.5**	**$15.2**	**$13.1**	**$79.3**	**$129.4**

** Note: the underlying FAN infrastructure will also support other advanced grid technologies, including AMI.*

Table 4: FLISR Costs – O & M
State of Minnesota
(millions)

	2018	2019	2020	2021	2022	2023-2027	Total
FLISR	$0.0	$0.4	$0.5	$0.6	$0.7	$3.2	$5.4
FAN*	$0.1	$0.2	$0.5	$0.6	$0.6	$3.2	$5.2
Total	**$0.1**	**$0.6**	**$1.0**	**$1.2**	**$1.3**	**$6.4**	**$10.6**

** Note: the underlying FAN infrastructure will also support other advanced grid technologies, including AMI.*

As noted previously, we included limited costs for advanced grid projects in our multiyear rate case. This will serve to offset the total TOU Pilot and FLISR project costs. For example, the capital we included in the multiyear case for the FAN is nearly sufficient to cover the WiMAX component of the infrastructure needed for FLISR and the TOU Pilot through 2019. For FLISR, we are additionally able to redeploy capital intended to continue our installation of intelligent switches, lowering the incremental amount we will eventually propose to recover in the rider, assuming the Commission certifies the projects. For purposes of certification however, we believe it most important to present an estimate of the full cost of the projects. We will detail the multiyear rate case impacts to the total project costs in our cost recovery request that will follow Commission certification of the proposed projects.

d. Summary – Value Proposition

In assessing the value proposition, we compared FLISR-specific costs to our calculated CMO savings for the identified high-value feeders. For purposes of this value assessment, we did not include foundational investments such as the FAN and ADMS, as they will be leveraged by several advanced grid projects. As shown above, we are proposing a FLISR implementation of approximately $65 million. We believe this level of investment will save approximately 30 million CMO and reduce our all-day SAIDI[27] by 23 minutes annually, when complete.[28]

We portray the value proposition of our proposed of FLISR for Minnesota in Figure 6 below. Our proposed FLISR deployment timeline is ten years. We are however, open to accelerating the deployment, which will correspondingly accelerate the customer reliability benefits.

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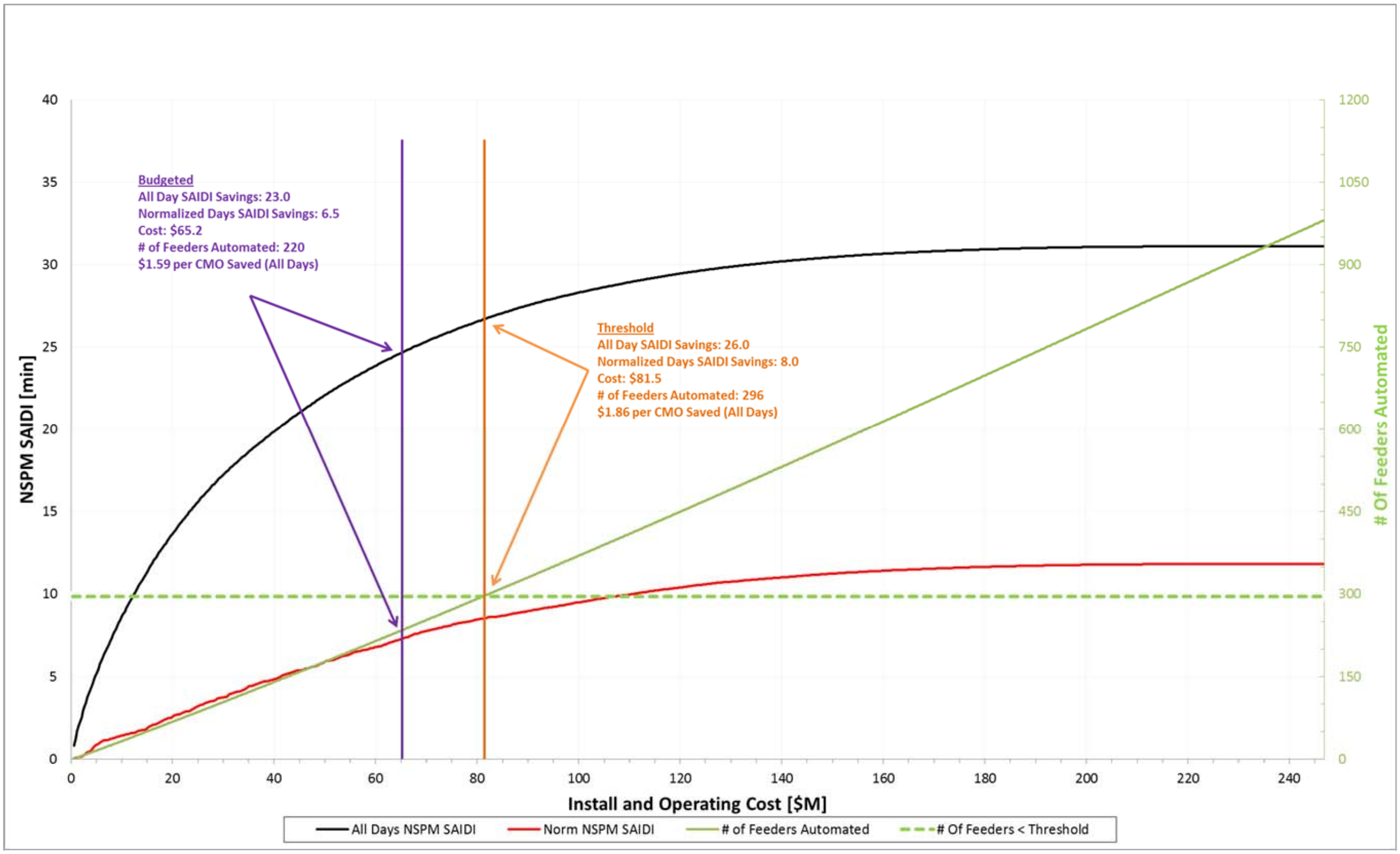
[27] All-day SAIDI is a non-storm normalized value. FLISR will provide benefits in both escalated/storm operations and normal/non-escalated operations, so an all-day SAIDI value is the appropriate benchmark.
[28] Customers will realize incremental CMO savings over the deployment period.

Figure 6: Overall FLISR Value Proposition – State of Minnesota



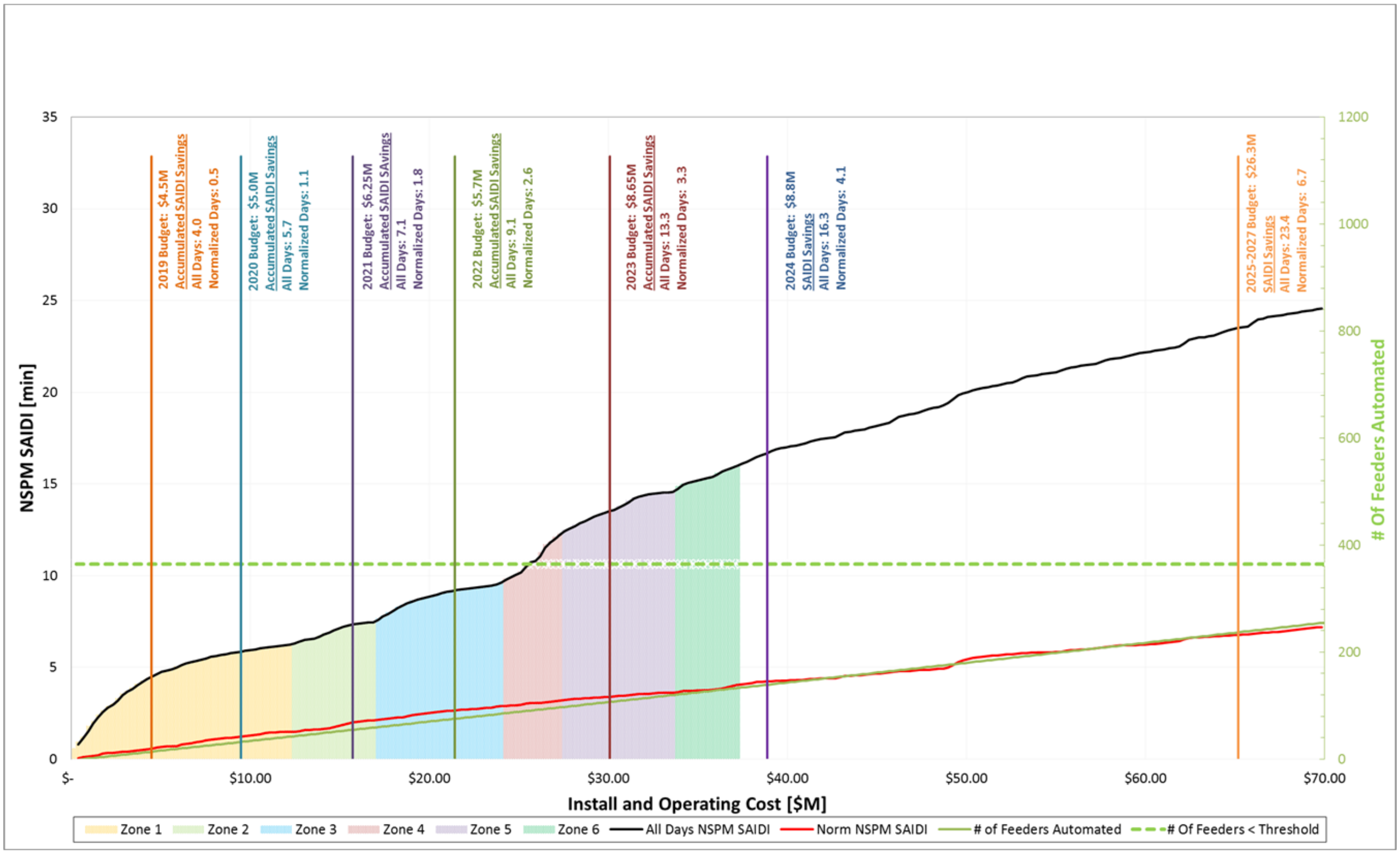
The level of investment is on the X axis and the SAIDI savings is on the Y axis – with the number of feeders automated also indicated (in green). The black arched line indicates the incremental all-day SAIDI reduction by level of investment, which begins to level-off at our proposed level of $65 million. While we could gain additional SAIDI reduction with increased investment, the benefits start to diminish to the point that there may be better reliability investment opportunities than automating the next feeder.

"Normalized" SAIDI is shown by the red arched line, which also shows improvement, but not as drastic as we expect to gain in all-day SAIDI.[29]

Figure 7 below shows the incremental value proposition of our planned deployment as we make incremental feeder automation investments. The trend of incremental reliability benefits would be realized sooner if we were to accelerate the deployment timeline, and thus our level of investment.

[29] Normalized SAIDI removes the effects of storms/escalated operations, so represents "normal" operations.

Figure 7: FLISR Value by Incremental Investment for Planned Deployments – State of Minnesota



We believe the FLISR investment level we propose in this certification request is the appropriate level to deliver the greatest reliability value to customers.[30] We are proposing a 10-year deployment timeline, but are open to accelerating the deployment if the Commission wants to accelerate the benefits.

V. IMPENDING ADVANCED GRID PROJECTS

The advanced grid initiatives that we have underway create an interactive system where the various technologies and systems have the ability to automatically update each other – creating the ability for the distribution system to essentially repair itself, or as stated within the industry, the ability to "self-heal." ADMS is underway, and we are presently proposing a FLISR deployment and a TOU Pilot that rely on a limited

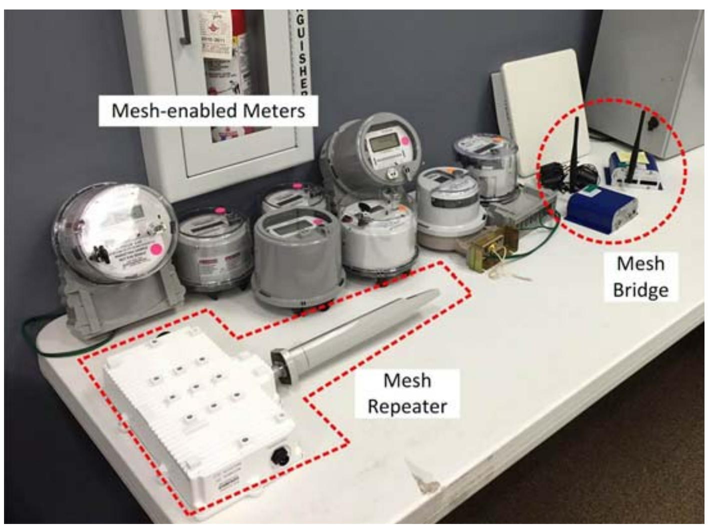
[30] Because our implementation strategy is to deploy on the feeders where we expect to gain the greatest benefits, the exact feeders where we deploy automation may change over time.

FAN deployment. We are also evaluating other complementary technologies. At this time, we believe AMI and a full FAN deployment are next on the horizon. We have requested to submit a Grid Modernization report November 1, 2018, requesting certification of these projects, at a minimum. We provide an overview of these impending projects below.

A. Advanced Metering Infrastructure

AMI can be defined as an integrated system of advanced meters, communications networks, and data management systems that enable two-way communication between the meters and utilities' business and operational data systems. These two-way communications capabilities enable added benefits for customers and utilities. AMI systems enable measurement and recording of customer energy usage, utility service status, and service quality events in detailed, time-based information formats for frequent transmittal and provision of such information to the utilities and customers.

Figure 8: AMI-Related Equipment



Our AMI strategy includes using advanced electric meters enabled with these data and communication capabilities. The communication function embedded within the advanced meters will be a component of our FAN, which enables more frequent Company communication with the meters; greater customer awareness of their consumption; and broad Company visibility into distribution grid conditions.

By leveraging the FAN, AMI creates a network among the advanced meters, our business systems, distribution automation field devices, and control centers, facilitating near real-time collection and dissemination of energy usage, customer service status, and service quality information to customers and the Company (in contrast to AMR), which is time-delayed and more limited in data capabilities) that we can use to improve our ability to monitor, operate, and maintain the distribution grid.[31] AMI will also provide enhanced capabilities to:

- Send price signals to customers, allowing for new rate structures that would allow customers to more proactively manage their energy usage with near real-time energy usage data,
- Monitor reliability and analyze system protection and operational attributes, leading to improved planning and design, outage response, and ultimately, the reduction or elimination of certain outages,
- Detect and verify outages without customer reporting,
- Detect and report meter tampering events,
- Identify and respond efficiently to potential metering equipment and customer usage issues, and
- Allow remote service disconnects and reconnects.

AMI will also provide data that will help the ADMS system control distribution-automation equipment – and the meters acting as a communications hub will support other applications, such as two-way demand response and Home Area Networks, should the need arise in the future.

While we could obtain some customer benefits through deploying advanced grid initiatives that do not include AMI, we believe the deployment of AMI meters throughout our service area maximize the benefits of the advanced grid for both our customers and the Company. In addition to the customer and operational benefits outlined above, the capabilities of today's AMI meters are a critical component of the FAN/mesh communication network described in Part _ above. These advancements allow one device, the AMI meter, to perform functions that historically required multiple standalone technologies and systems.

1. *AMI Compared to Present AMR Capabilities*

We currently have an AMR system in our Minnesota service area that we implemented in the mid-1990s. The AMR system is owned and operated by

[31] Provided the required complementary technologies (*i.e.,* communication, business software systems and data storage systems) are in place.

Landis+Gyr, who provide meter reading services for customer billing purposes. We are continuing to determine a migration strategy and metering requirements to transition to AMI from the present AMR services agreement, which expires in 2021. In the meantime, we have established a controlled AMI testing environment that we are using to test communications and features of various AMI devices and systems. Our primary testing approaches have included laboratory tests and limited field deployment to provide real-world settings for testing communication and meter functionality. We have also developed and proposed a TOU Pilot, discussed in Section IV above, which will involve deployment of approximately 17,500 AMI meters.

At the time we opted to install AMR meters, advanced meter technology was available, but was still in its infancy and not ready for large-scale deployment. We have reaped significant benefits from our present AMR in terms of operational efficiencies, which have translated to increased service to our customers. However, AMI technology is now sufficiently advanced and has matured to the point where many additional benefits are available, and the technology is well-known – reducing the risk of a full-scale deployment.

While our present AMR system has some ability to support more complex rates, such as time of use and rates requiring the collection of interval usage data, and provide non-usage data that aids our operations (such as a "last gasp" when the power goes out or a line-side power indicator), it does not have two-way communication capabilities. Two-way capability allows the meter to receive commands from the Company's systems reset demand registers, for example, or configure the meter to measure specific sets of energy parameters or time of use intervals. Today, we must dispatch a meter technician to perform these functions, which is costly and can create delays for customers wishing to change the rate they are on, for example.

We summarize the general capabilities of various meter technologies in Figure 9 below.

Figure 9: General Metering Capabilities Summary – AMR and AMI

Feature/Capability	AMR One-Way	AMR Limited Two-Way	AMR Drive-By	AMI
Consumption Data	◑	◑	◑	●
Demand Data	◑	◑	◑	●
Support for ADMS	○	○	○	●
Interval Data	◔	◑	◔	●
Time of Use	◑	◑	◔	●
Outage Notification	◔	◑	○	●
Real-Time Access to Customer Data	○	◑	○	●
Direct Customer Facing DSM Programs	○	○	○	●
Support for Advanced Rates	○	◑	○	●
Customer Direct Access to Metering Data	○	○	○	●
Diagnostic Data	◔	◑	◔	●
Energy Theft	◔	◔	○	●
Detect Unsafe Field Metering Conditions	◔	◔	○	●
Vehicle to Grid Interconnect	○	○	○	●
Remote Reconfiguration/Firmware Updates	○	○	○	●

Capabilities Legend				
Full	Most	Partial	Minimal	None
●	◕	◑	◔	○

2. *AMI as an Integrated Advanced Grid Component*

As we have outlined, the AMI meters will be an important part of the "mesh" FAN communications infrastructure that supports all advanced grid applications. Modules in the meters will not only transmit usage information for billing purposes – they will transmit voltage measurement information to assist in load flow and voltage calculations performed by the ADMS. They will also serve as "repeaters" for other

AMI meters or mesh network components, which strengthens the FAN capabilities and ensures the consistent provision of data.

B. Full FAN Deployment

We described the FAN infrastructure components in Section III above. To support FLISR and the TOU Pilot, we are deploying limited FAN infrastructure to a concentrated geographic area. To support AMI, we will need to fully deploy the FAN, which like AMI, will be a substantial operational undertaking and investment.

For any given geography, FAN availability will precede AMI meter deployment by approximately 3-6 months, in order to ensure meters will have a fully operational network to use when they are installed. To support this, we will need to begin FAN installation approximately 12-18 months ahead of AMI meter deployment to allow adequate time for permitting, material sourcing, and construction.

VI. OVERALL AGIS IMPLEMENTATION STRATEGY

Due to the integrated nature of the various components of our advanced grid initiative, certain components must be placed in-service first, as they provide the necessary foundational elements for later components. Thus, it will not be completed in a single project effort or within a single year; rather, the component facilities will be constructed and placed in-service over time – and the system will grow and layer additional capabilities and functionalities, delivering increasing value to our customers.

Following Commission certification of FLISR and the TOU Pilot as requested in this report, we will return to the Commission in late 2018 with a cost recovery request and begin deployment in 2019. In this report, we have requested to return to the Commission with a more detailed plan and to request certification for AMI and the full FAN in November 2018. Assuming Commission certification of the AMI and full FAN projects in 2019, we would return to the Commission with a cost recovery request in late 2019 and begin full AMI and full FAN deployment as soon as practicable – and as determined through the certification filing process. As the full FAN infrastructure is installed, it will enable our expansion of FLISR to additional high-value areas, providing additional reliability improvements to customers and our operations.

Table 5 below provides an overview of the current deployment timeline for the various components assuming this procedural path.

Table 5: Current AGIS Implementation Timeline

Project	Deployment Timeframe
ADMS	*Planning*: Ongoing *Implementation*: Detailed design – Complete System implementation – In progress. Expected in-service Jan 2020.
FAN (*limited to support FLISR and TOU Pilot*)	*Planning*: Ongoing *Installation*: WiMAX and backhaul infrastructure Jan 2018 – Dec 2018 Wi-SUN (mesh network) implementation Jan – Jun 2019
FLISR	*Planning*: Ongoing *Installation* – Jan 2019 – Dec 2027
AMI (*TOU Pilot*)	*Planning:* Ongoing *Vendor Selection* – Nov 2017 *Anticipated installation of first pilot meter* – Jul 2019 *Complete TOU Pilot meter installations* – Dec 2019
Full AMI and full FAN	*Planning*: Ongoing *Installation*: 2018 to 2023

In order for the Company to deploy an AMI meter at a customer's house, several things need to be in place. The FAN must have communications reach to that house and the AMI head end system must be in place to start billing. For the TOU Pilot, we plan to start design and engineering for FAN base stations around our pilot areas as soon as possible – with construction both starting and ending in 2018. We plan to in-service the WiMAX base station on January 1, 2019. This provides several months to install the mesh radio network to communicate to each meter.

For FLISR, the schedule of device installation will closely follow the WiMAX installations. After a base station has been installed, devices can be installed in that area. In 2019, this will happen in advance of the ADMS being put into service, but after that point, new devices will be deployed feeder by feeder and enabled in ADMS as soon as possible after sufficient testing to start capturing benefit.

VII. OTHER TECHNOLOGIES

In this section, we summarize other advanced grid projects and technologies that we are evaluating or have underway.

A. Storage Projects

As discussed at the Commission planning meeting on storage on October 10, 2017, Xcel Energy is conducting two pilot projects in Colorado. Both of these projects were approved in March 2016 by the Colorado Public Utilities Commission (CPUC) under the company's Innovative Clean Technology (ICT) Program. In the interest of sharing the information we learn while administering these two projects, we will file the status reports that we will be filing with the CPUC in this docket on an ongoing basis. The docket number is 15A-0847E and we will file them in this docket every 6 months (as they are made in Colorado). We anticipate the reports will begin late in 2018, depending on the testing and commissioning of the units. We summarize the two projects below.

1. *Pena Station/Panasonic Battery Demonstration Project*

Through a public/private partnership, Xcel Energy, Panasonic, and Denver International Airport are partnering on a battery demonstration project. The pilot project – located at Panasonic's Denver operations hub within the new 400-acre Peña Station NEXT development just southwest of the Denver airport – will examine how a battery storage system helps: (1) facilitate the integration of renewable energy, (2) Enhance reliability on the distribution system, (3) assist in providing voltage management and peak reduction, and (4) provide power to Panasonic in case of a grid outage by functioning as a microgrid.

The demonstration project is composed of four primary components: (1) a 1.3 MW ac carport solar installation (the carport is owned by the airport, but the solar system is owned by Xcel Energy (2) a 0.20 MW ac rooftop PV system at Panasonic's facility, owned by Panasonic, (3) a 1 MW/2 MWh lithium ion battery system supplied by Younicos, owned by Xcel Energy, and maintained by Panasonic, and (4) the switching and control systems to operate the energy storage system and microgrid functionality, owned by Xcel Energy.

Figure 10: 1.3 MW Carport Solar Installation

Figure 11: 1 MW Battery System

Note: The 1MW battery system is the white equipment and the associated switchgear is in the blue box

In the event of a grid outage, an "islanding" switch will automatically form a microgrid, allowing the battery to provide power to the Panasonic building. In microgrid mode, both the battery and the rooftop PV will provide power to Panasonic. Panasonic's building management system can prioritize and shed non-critical loads to keep critical services – such as its network operations center (NOC), which monitors and manages a nationwide network of largescale PV projects totaling hundreds of megawatts – up and running. Should power from the PV system exceed the building's needs, excess generation will be stored in the battery. Once grid power has been restored, the microgrid will seamlessly transition out of islanding mode and back to grid mode.

During a two-year demonstration period, the system will be tested under multiple scenarios to determine how it can be used to increase reliability and resiliency for both Xcel Energy's electric grid and Panasonic. After the demonstration is complete and the collected data analyzed, the battery will operate at its optimal settings. It will function at these settings for the rest of its life span – which is approximately eight additional years, or about ten years in total.

2. *Stapleton Battery Storage Project*

The Stapleton project is aimed at examining how battery storage can help integrate higher concentrations of photovoltaic (PV) solar energy on our system. As part of an energy storage demonstration project, Xcel Energy is installing six in-home batteries and six larger batteries on the distribution feeder in Denver's Stapleton neighborhood. The batteries will operate to manage solar integration and also support other areas of the grid. For the six large scale batteries, we are installing two sets of 18 kW batteries, two sets of 36 kW batteries and two sets of 54 kW batteries. The customer in-home batteries are six 6 kW batteries. Xcel Energy is particularly interested in learning about how battery storage can help: (1) increase the ability to accommodate more solar energy on our system, (2) manage grid issues such as voltage regulation and peak demand, and (3) reduce energy costs.

Figure 12: Residential and Large Scale Battery Comparison

RESIDENTIAL

LARGE-SCALE

B. Integrated Volt Var Optimization

We have a portion of Integrated Volt Var Optimization (IVVO) largely in place in Minnesota due to our SmartVAR Management pilot program, where we replaced existing capacitor bank controls with modern, two-way controls.[32] We installed a head-end system to manage capacitor banks across the distribution system to improve power factor on feeders to reduce system losses. The controls communicate with the central control system via commercial cellular transmission. We plan to replace the cellular with FAN radios to reduce operating costs. The

[32] We filed updates on our SmartVAR Management pilot program with the Commission in Docket No. E002/M-09-1488.

system, together with the local capacitor controls, ensures that distribution feeder voltage remains within ANSI C84.1 standards.

C. Substation Automation

Substation Automation involves upgrading protection relays and schemes, expanding SCADA capabilities, and installing high speed communications inside and outside the substation. Most of our substations with SCADA are well automated; so much of the automation we propose to add will be done in conjunction with SCADA additions that meet specific substation business needs.

D. Demand Response Technologies

The processes to manage a Demand Response (DR) program portfolio have grown over time due to complexity and scale. Managing these DR resources using a combination of legacy systems and manual processes is no longer a viable option. These aging DR systems are currently being replaced by a Demand Response Management System (DRMS) in order to address the Company's existing compliance and financial risks, as well as positioning the Company to grow DR in the future – increasing customer choice and aligning with changing ISO requirements. Release 1 was implemented in February 2017 allowing for the delivery of two new DR programs in PSCo. Release 2 was released in July 2017, allowing for the delivery of AC Rewards in Minnesota. Release 2 and the introduction of Smart Thermostats in Minnesota are allowing the Company to begin leveraging modern DR program designs.

E. Other Substation Upgrades

There are also two other existing projects underway that are to upgrade or enhance components in the substation. We are updating obsolete substation communications circuits and metering capabilities. Many older substations only have single-phase amp readings or just a basic megawatt value. With these updates, we will have full three-phase load monitoring data points, which are critical for the advanced functionality of ADMS and will improve our system planning capabilities.

VIII. DISTRIBUTION STUDY

As noted previously, we provide our Hosting Capacity study required under Minn. Stat. § 216B.2425, subd. 8 in a separate November 1, 2018 filing in Docket No. E002/M-17-777.

CONCLUSION

We appreciate the opportunity to provide this biennial Grid Modernization Report and to continue advancing the grid modernization discussion here in Minnesota. We support the evolution of the grid and anticipate meeting our customers' expanding energy needs at the "speed of value." We also look forward to continued discussions surrounding grid modernization with stakeholders. We respectfully request the Commission to:

- Certify a residential TOU rate pilot (as proposed in Docket No. E002/M-17-775),
- Certify FLISR, a reliability improvement investment;
- Allow the Company to file a Grid Modernization Report and certification request on November 1, 2018,
- Allow the Company to submit annual Grid Modernization and certification request reports annually through at least 2022, and
- Establish a procedural schedule for consideration of our TOU Pilot and FLISR certification request that aligns with a Commission decision no later than June 1, 2018, as provided in Minn. Stat. § 216B.2425, subd. 3.

Dated: November 1, 2017

Northern States Power Company

CERTIFICATE OF SERVICE

I, Carl Cronin, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

- xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

- xx electronic filing

Docket Nos. E002/M-17-776
E002/M-15-962
Xcel Energy's Miscellaneous Electric Service List

Dated this 1st day of November 2017

/s/
____
Carl Cronin
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar	721 W 26th st Suite 211 Minneapolis, Minnesota 55405	Electronic Service	No	OFF_SL_15-962_Official Service List
David	Amster Olzweski	david@mysunshare.com	SunShare, LLC	1774 Platte St Denver, CO 80202	Electronic Service	No	OFF_SL_15-962_Official Service List
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_15-962_Official Service List
Ellen	Anderson	ellena@umn.edu	325 Learning and Environmental Sciences	154 Buford Ave St. Paul, MN 55155	Electronic Service	No	OFF_SL_15-962_Official Service List
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_15-962_Official Service List
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_15-962_Official Service List
Donna	Attanasio	dattanasio@law.gwu.edu	George Washington University	2000 H Street NW Washington, DC 20052	Electronic Service	No	OFF_SL_15-962_Official Service List
John	Bailey	bailey@ilsr.org	Institute For Local Self-Reliance	1313 5th St SE Ste 303 Minneapolis, MN 55414	Electronic Service	No	OFF_SL_15-962_Official Service List
Kenneth	Baker	Ken.Baker@walmart.com	Wal-Mart Stores, Inc.	2001 SE 10th St. Bentonville, AR 72716-5530	Electronic Service	No	OFF_SL_15-962_Official Service List
Sara	Baldwin Auck	sarab@irecusa.org	Interstate Renewable Energy Council, Inc.	PO Box 1156 Latham, NY 12110	Electronic Service	No	OFF_SL_15-962_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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James J.	Bertrand	james.bertrand@stinson.com	Stinson Leonard Street LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-962_Official Service List
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William	Black	bblack@mmua.org	MMUA	Suite 400 3025 Harbor Lane North Plymouth, MN 554475142	Electronic Service	No	OFF_SL_15-962_Official Service List
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	OFF_SL_15-962_Official Service List
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Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_15-962_Official Service List
Sydney R.	Briggs	sbriggs@swce.coop	Steele-Waseca Cooperative Electric	2411 W. Bridge St PO Box 485 Owatonna, MN 55060-0485	Electronic Service	No	OFF_SL_15-962_Official Service List
Mark B.	Bring	mbring@otpco.com	Otter Tail Power Company	215 South Cascade Street PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_15-962_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Tony	Brunello	BADEMAIL-tbrunello@greentechleadership.org	Greentech Leadership Group	426 17th St Ste 700 Oakland, CA 94612-2850	Paper Service	No	OFF_SL_15-962_Official Service List
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_15-962_Official Service List
Michael J.	Bull	mbull@mncee.org	Center for Energy and Environment	212 Third Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_15-962_Official Service List
Jessica	Burdette	jessica.burdette@state.mn.us	Department of Commerce	85 7th Place East Suite 500 St. Paul, MN 55101	Electronic Service	No	OFF_SL_15-962_Official Service List
Jason	Burwen	j.burwen@energystorage.org	Energy Storage Association	1155 15th St NW, Ste 500 Washington, DC 20005	Electronic Service	No	OFF_SL_15-962_Official Service List
Douglas M.	Carnival	dmc@mcgrannshea.com	McGrann Shea Carnival Straughn & Lamb	N/A	Electronic Service	No	OFF_SL_15-962_Official Service List
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	OFF_SL_15-962_Official Service List
Kenneth A.	Colburn	kcolburn@symbioticstrategies.com	Symbiotic Strategies, LLC	26 Winton Road Meredith, NH 32535413	Electronic Service	No	OFF_SL_15-962_Official Service List
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_15-962_Official Service List
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_15-962_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Leigh	Currie	lcurrie@mncenter.org	Minnesota Center for Environmental Advocacy	26 E. Exchange St., Suite 206 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_15-962_Official Service List
Stacy	Dahl	sdahl@minnkota.com	Minnkota Power Cooperative, Inc.	1822 Mill Road PO Box 13200 Grand Forks, ND 58208-3200	Electronic Service	No	OFF_SL_15-962_Official Service List
David	Dahlberg	davedahlberg@nweco.com	Northwestern Wisconsin Electric Company	P.O. Box 9 104 South Pine Street Grantsburg, WI 548400009	Electronic Service	No	OFF_SL_15-962_Official Service List
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Curt	Dieren	curt.dieren@dgr.com	L&O Power Cooperative	1302 S Union St Rock Rapids, IA 51246	Electronic Service	No	OFF_SL_15-962_Official Service List
Ian	Dobson	Residential.Utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_15-962_Official Service List
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Kristen	Eide Tollefson	N/A	R-CURE	28477 N Lake Ave Frontenac, MN 55026-1044	Paper Service	No	OFF_SL_15-962_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Jennifer	Kefer	jennifer@dgardiner.com	Alliance for Industrial Efficiency	David Gardiner & Associates, LLC 2609 11th St N Arlington, VA 22201-2825	Electronic Service	No	OFF_SL_15-962_Official Service List
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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John	McWilliams	jmm@dairynet.com	Dairyland Power Cooperative	3200 East Ave SPO Box 817 La Crosse, WI 54601-7227	Electronic Service	No	OFF_SL_15-962_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_15-962_Official Service List
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Dale	Niezwaag	dniezwaag@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58503	Electronic Service	No	OFF_SL_15-962_Official Service List

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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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