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November 1, 2019

-Via Electronic Filing-

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

RE: INTEGRATED DISTRIBUTION PLAN DOCKET NO. E002/M-19- 666

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Integrated Distribution Plan (IDP) per the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251.

One of the major focuses of this IDP is our request for certification—pursuant to Minn. Stat. § 216B.2425—of an array of investments to modernize the Company's distribution system. Specifically, we are seeking certification of an Advanced Distribution Planning Tool that will enable us to deliver benefits to customers via more efficient planning, enhanced load forecasting capabilities, and better integration with the Company's other planning efforts. We also are seeking certification of a number of investments that are part of what is collectively referred to as the Advanced Grid Intelligence and Security (AGIS) Initiative:

- Advanced Metering Infrastructure (AMI). AMI is an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy Energy's business and operational data systems and customer meters.
- *Field Area Network (FAN).* A private, secure two-way communication network that provides wireless communications across Xcel Energy's service area to, from, and among, field devices and our information systems.

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- *Fault Location, Isolation, and Service Restoration (FLISR).* A form of distribution automation that involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and restore power thereby decreasing the duration of and number of customers affected an outage.
- *Integrated Volt Var Optimization (IVVO)*. An application that uses selected field devices to decrease system losses and optimize voltage as power travels from substations to customers.

These investments expand on the advanced grid investments previously approved by the Commission, namely the Advanced Distribution Management System (ADMS) that the Company is currently implementing. Each of these investments will take years to fully implement, and we are requesting that the Commission certify the AGIS projects pursuant to Minn. Stat. § 216B.2425, subd. 3, so that the Company may request recovery of costs in concurrent or subsequent filings, as necessary. This is consistent with other requests for certification for grid modernization investments, where certification enables the opportunity for the Company to request recovery of costs in a subsequent rider filing.

Today, we are also filing a General Rate Case (Docket No. E002/GR-19-564) with a three-year plan through which we seek cost recovery for much—but not all—of these AGIS investments. Because the span of the AGIS investments goes beyond the 2020 test year and 2021-2022 plan years identified in our rate case filing, and in light of the concurrent submission of this 2019 IDP, our AGIS rate case testimony provides support for our AGIS investments beyond the term of the rate case and addresses Commission requirements that pertain to both certification and cost recovery for grid modernization investments. In light of this support for our longterm strategy, we believe certification of the full scope of the AGIS investments alongside a rate case cost recovery determination is critical, so that we may complete our AGIS investments at an appropriate pace and potentially include the out-year costs in a rider. Consideration of our certification request in tandem with our rate request will also be most efficient for all stakeholders. The Commission would, of course, have another opportunity for review and approval of specific costs if the Company were to seek rider cost recovery in the future.

Because of this dual filing approach, and in order to minimize duplication, we have provided the support for our AGIS certification request in a testimony format within the rate case, and we are including relevant portions of the testimony as attachments to this filing. We have excised unrelated portions from some witness

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testimony in order to provide only the relevant material. For instance, Company Witness Mr. David C. Harkness provides testimony regarding our 2020-2022 Business Systems investments for purposes of the MYRP, but not all of them are related to AGIS; we have therefore included only those sections and attachments that relate to AGIS in this IDP filing.

In addition, today we also have filed a Petition for Approval of True-Up Mechanisms. This filing requests the approval of certain true-ups for 2020 which, if approved, would result in the withdrawal of our General Rate Case. In that event, we would no longer request AGIS cost recovery through base rates until the Company's next general rate case is filed. We would, however, ask the Commission to make the more limited determination to certify the AGIS investments and Advanced Distribution Planning Tool in this IDP, so that we may plan for the implementation of our AGIS initiative, and preserve the option to put the AGIS costs in a rider between general rate case filings.

Overall, the filing requirements related to grid modernization investments, as well as for certification, are extensive, and our supporting documentation is likewise extensive and thorough. We have therefore taken several steps to facilitate review of these materials, and make them as digestible and easy to read as possible for the Commission and our stakeholders. These steps include development of executive summaries, compliance matrices, and extractions from larger pieces of testimony as noted above.

The normal procedural schedule for certification under Minn. Stat. § 216B.2425 would require a determination by June 1, 2020, and under normal circumstances, we believe the process leading to certification should resemble a resource acquisition proceeding under the Commission's normal notice and comment procedures that could, in the Commission's discretion and depending on the scope of the investment, include one or more public hearings. We recognize, however, that the schedule in the General Rate Case does not align with that timing. In addition, the AGIS initiative includes large investments and is supported by a sizeable filing that may require analysis beyond the six-month certification timeframe, even if the General Rate Case is withdrawn. Thus, we offer to work with the Commission and stakeholders to set an appropriate deadline and procedural schedule for consideration of these investments.

On a procedural note, we respectfully request the Commission move to a bienniel filing cadence for the IDP, consistent with other Minnesota utilities and the grid modernization statute filing requirements. We believe a biennial filing

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would better allow time to fully engage with stakeholders on the Commission's planning objectives between IDP filings, as well as to address important issues such as distributed energy resources (DER) planning, a comprehensive approach to non-wire alternatives (NWA), and our advanced grid plans. The present annual filing schedule also does not allow the Company to make significant, meaningful progress on its objectives between these extensive filings. We therefore specifically request the Commission require our next IDP be submitted on or before November 1, 2021, and biennially thereafter.

Portions of this IDP contain protected data including Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b), Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a), and information that if made public would be counter to our requirement to protect the anonymity of our customers' energy usage information unless we have customers' consent to disclose it per January 19, 2017 Order in Docket No. E,G999/CI-12-1344. The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use and is subject to reasonable efforts by the Company to maintain its secrecy. The specific information designated as protected data is in IDP attachments as outlined in Attachment A1, which also includes the justification for its designation as protected data. Additionally, in connection with filing the IDP, the Company is submitting executable Microsoft Excel files as supporting documents, all of which are designated as Trade Secret as described on Attachment A1.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service lists. Please contact Jody Londo at jody.l.londo@xcelenergy.com or (612) 330-5601 or me at <u>bria.e.shea@xcelenergy.com</u> or (612) 330-6064 if you have any questions regarding this filing.

Sincerely,

/s/

BRIA E. SHEA DIRECTOR, REGULATORY & STRATEGIC ANALYSIS

Enclosures c: Service Lists



INTEGRATED DISTRIBUTION PLAN (2020-2029)

NOVEMBER 1, 2019

Docket No. E002/M-19-666



EXECUTIVE SUMMARY

On August 30, 2018, the Minnesota Public Utilities Commission ordered Northern States Power, doing business as Xcel Energy to file an Integrated Distribution Plan (IDP) annually beginning on November 1, 2018. The Commission accepted our first IDP, modified the filing requirements, and ordered that we submit our next IDP November 1, 2019. This IDP is the result of the Commission's requirements and input and feedback from our stakeholders.

This IDP presents a detailed view of our distribution system and how we plan the system to meet our customers' current and future needs. The backbone of our distribution planning is keeping the lights on for our customers, safely and affordably. For over 100 years, we have delivered safe, reliable electric service to our customers, and, through our robust planning process and strong operations, we will continue to do so.

We are also planning for the future, and with this IDP we propose to significantly advance our distribution grid and planning capabilities. We have a vision for where we and our customers want the grid to go, and we are taking measured and thoughtful action to ensure our customers receive the greatest value, and that the fundamentals of our distribution business remain sound.

I. PLANNING LANDSCAPE

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid is able to sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customerconnected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

The foundation on which these capabilities rest is safe, reliable energy. Our strategic priorities of enhancing the customer experience, leading the clean energy transition, and keeping customer bills low are embedded in everything that we do – including the way that we plan our distribution system.



Figure 1: Xcel Energy Strategic Priorities – Applied to Distribution

Distribution planning has historically – and still largely today –involved analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels, and utilization rates of major system components such as substations and feeders. Customers traditionally have had limited information about their energy usage and few choices in how they received information, had questions answered, and paid utility bills or conducted other necessary business with their utilities. For the most part, customers were content to receive a monthly paper bill from their utilities and were unaware and unengaged in whether the energy came from renewable or non-renewable sources.

Now however, customers increasingly want choices, control, and actionable

information. And utilities, instead of planning just for load, need to analyze the system for future connections that may be load *or* generation. Also, utilities increasingly need to view their operations and customer tools from their customers' perspectives. This step change in the distribution utility business requires utilities to plan their systems differently, which involves new processes and methodologies and also new and different tools and capabilities.

Like other aspects of the industry that are transitioning and advancing, we are on the forefront of integrated distribution planning and, as such, are taking steps to align and integrate our distribution, transmission, and resource planning processes. We have been in the process of evaluating the next generation of distribution planning tools to increase our forecasting and analysis capabilities – and the advanced planning tool we propose to procure and implement will also aid our integration of planning processes.

II. XCEL ENERGY IDP SUMMARY AND HIGHLIGHTS

With this background, we note that Minnesota is unique from other states implementing integrated distribution planning, in that we are not currently undergoing sizable additions of DER on our system. Rather, Minnesota remains ahead in its planning and therefore able to take a measured approach and pace to IDP that allows the requirements to be implemented in a cost-effective, systematic manner that is in the public interest for all Minnesota customers.

It is in this context that we prepared Minnesota's first IDP – and this now second IDP for Xcel Energy. In advance of this IDP filing, we conducted four stakeholder workshops – the first was in the wake of our first IDP, to overview the filed plan and facilitate a Q&A forum with stakeholders; the second and third were on the topics of greatest interest in our first IDP – non-wires alternatives (NWA) analysis and the cost benefit framework for advanced grid investments, respectively; and, our fourth workshop presented the load and DER forecasts, investment plans, and 5-year action plan contained in this IDP. In addition to complying with IDP requirements – these workshops served to educate and build a better understanding of both our work and stakeholders' needs and expectations. Our goal for the workshops was to continue an iterative and ongoing dialogue to build a mutual understanding of our processes and the IDP, specific to this report as well as in general for future reports.

Our IDP recognizes the emergent state of the industry and availability of enhanced distribution planning tools, Minnesota's specific circumstances, and the building-block approach we are taking to modernize and equip our system to increase our visibility, control, and planning capabilities. We believe this report is robust and meaningful and provides substantial transparency into our distribution function and planning.

Our report provides historical actual and budgeted expenditures, discusses many of our planning practices, and outlines present and forecasted levels of DER. One of the major focuses of this IDP is our request for certification – pursuant to Minn. Stat. § 216B.2425 – of an array of investments to modernize the Company's distribution system. Specifically, we are seeking certification of an Advanced Distribution Planning Tool (APT) and of a number of grid modernization investments that are part of what is collectively referred to as the Advanced Grid Intelligence and Security (AGIS) Initiative.

To highlight some of the key aspects of our report, we summarize below our advanced grid plans, capital investment and O&M budgets, and the current state and in-queue DER on our system.

A. AGIS Initiative

While we have made incremental modernization efforts on the distribution system over many years, the time is now to begin a more significant advancement of the grid. This modernization begins with foundational advanced grid initiatives that both provide immediate benefits and new customer offerings while also enabling future systems and customer value.

We are on the forefront of many of the issues and changes underway in the industry and have developed our AGIS initiative to address them. In addition to the significant steps we have taken to implement and improve our hosting capacity analysis, we are on the cusp of implementing an Advanced Distribution Management System (ADMS). The ADMS is foundational to advanced grid capabilities that will provide the visibility and control necessary for enhanced planning and significant DER integration. We are also implementing a Time of Use (TOU) pilot that involves the installation of Advanced Metering Infrastructure (AMI) meters in two communities in the Twin Cities metropolitan area, and that tests a new residential TOU rate.¹

Today, Xcel Energy customers have access to numerous energy efficiency and demand management programs, renewable energy choices, billing options, a mobile app, and outage notifications that include estimated restoration times. Customers also receive confirmations when our records reflect that the outages have been resolved – and they receive these via their preferred communication channel – text, email, or

¹ This pilot also provides participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods when the system is experiencing low load conditions.

phone. We have made advances on our grid and with the service we offer our customers – and these and other products and services have provided our customers with significant value over many years.

However, technologies are advancing, as are customer expectations. Customers want access to actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler and more seamless experience. Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. We plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

1. Advanced Grid Proposal

We are proposing to implement the following advanced grid capabilities:

- *Field Area Network (FAN).* A private, secure two-way communication network that provides wireless communications across Xcel Energy's service area to, from, and among, field devices and our information systems.
- *Advanced Metering Infrastructure (AMI)*. AMI is an integrated system of advanced meters, communication networks, and data processing and management systems that is capable of secure two-way communication between Xcel Energy Energy's business and operational data systems and customer meters.
- *Fault Location, Isolation, and Service Restoration (FLISR).* A form of distribution automation that involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and restore power, thereby decreasing the duration of and number of customers affected an outage.
- *Integrated Volt Var Optimization (IVVO)*. An application that uses selected field devices to decrease system losses and optimize voltage as power travels from substations to customers.

In addition to transforming the customer experience, these foundational and core investments will allow us to advance our technical capabilities to deliver reliable, safe, and resilient energy that customers value.

Fundamentally, we must act to replace our current Automated Meter Reading (AMR) service to ensure we continue to provide our customers with timely accurate bills; our current vendor is sun-setting its AMR technology in the mid-2020s. While this system has provided value to customers for many years through efficient meter reading, we

have an opportunity now to seize AMI technologies that are becoming available to maximize value for our customers. As we deploy advanced grid infrastructure, platforms, and technologies we expect three outcomes: (1) a transformed customer experience, (2) improved core operations, and (3) facilitation of future capabilities, which we discuss below.

Transformed customer experience. Our planned advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. We will use this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications.

We will offer options that give customers greater convenience and control to save money, provide access to rates and billing options that suit their budgets and lifestyles, and provide more personalized and actionable communications. As our system more efficiently manages energy flows, we can save customers money by reducing line losses and conserving energy. Smarter meters will be the platform that enables smarter products and services and contributes to improved reliability for our customers. Our customers will have more information to make more effective decisions on their energy use.

We will know more about our customers and our grid – and we will use that information to make more effective recommendations and decisions and continually use new information to develop new solutions. This will serve to help keep our bills low, as customers save money through both their actions and ours. It will also help ensure that our transition to a carbon-free system occurs efficiently – and harnesses the vast potential of all energy resources, from utility-scale to local distributed generation.

Improved core operations and capabilities. Smarter networks will form the backbone of our operations, and our investments will more efficiently and effectively deliver the safe and reliable electricity that our customers expect. We will have the capability to communicate two ways with our meters and other grid devices, sending and receiving information over a secure and reliable network in near-real time.

Our current service is reliable; however, we need to continue to invest in new technologies to maintain performance in the top third of U.S. utilities, particularly as we deliver power from more diverse and distributed resources and as industry standards continue to improve. Our advanced grid investments provide the platform and capabilities to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics and automation.

Our systems will more efficiently and effectively restore power when outages do occur using automation without the need for human intervention. For those outages that cannot be restored through automation, our systems will be better at identifying where the outage is and what caused it – benefitting customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

Facilitation of future capabilities. The backbone of our investments will also support new developments in smart products and services; in the short term by supporting the display of more frequent energy usage data through the customer portal – and over the long term, allowing for the implementation of more advanced price signals. Designing for interoperability enables a cost-effective approach to technology investments and means we can extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion, which unlocks new offerings and benefits that build on one another. We have planned our advanced grid investments in a building block approach, starting with the foundational systems, in alignment with industry standards and frameworks. By doing so, we sequence the investments to yield the greatest near- and long-term customer value, while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

In planning our advanced grid initiative, we have considered the long-term potential of our ability to meet our obligations to serve and our customers' expectations and needs – ensuring we extract cost-effective value from our investments and remain nimble enough to react to a dynamically changing landscape. The principles we applied to our advanced grid planning include the ability to remotely update hardware and software, security, reliability and resilience, and flexible, standards-based service components. We are planning our grid advancement with the future in mind, and to provide both immediate and increasing value for our customers over the long-term.

We are on the forefront of many of the issues and changes underway in the industry and have developed our advanced grid initiative and our customer strategy to address them and harness value for our customers. In addition to transforming the customer experience, these foundational investments will allow us to advance our technical capabilities to deliver reliable, safe, and resilient energy that customers value. These foundational investments also lay the groundwork for later years. The secure, resilient communication networks and controllable field devices deployed today through these investments will become more valuable in the future as additional sensors and customer technologies are integrated and coordinated.

Now is the time to modernize the interface where we connect directly with our customers – the distribution system. Technologies have evolved and matured; our peers have successfully implemented these technologies; and, the industry landscape is evolving. We must ensure our system has the necessary capabilities to meet our customers' expectations and needs – and, the flexibility to adapt to an uncertain future.

We are taking a measured and thoughtful approach to advancing the grid to ensure our customers receive the greatest value, the fundamentals of our distribution business remain sound, and we maintain the flexibility needed as technology and our customers' expectations continue to evolve.

2. Our Customer Strategy is Informed by Customer Expectations

Our customer strategy aims to transform the customer experience by implementing capabilities, technologies, and program management strategies to enable the best-inclass customer experience that our customers now expect. It is focused on shifting the customer experience dynamic to one where little action is required from customers around their basic service and where we offer personalized "packages" that customers can select from to meet their needs – similar to what customers experience when purchasing cable and internet services today. These packages may include options such as demand-side management, renewable energy, rate design, and non-energy services.

Figure 2: Customer Strategy Informed by Customer Expectations



Our implementation of the ADMS in early 2020 is preparing the grid for increasing levels of DER. It is also paving the way for further grid advancement with AMI and our ability to leverage the underlying and necessary FAN to reduce customers' energy costs through IVVO, improve customers' reliability experience through FLISR, and

more.

Customers will have access to granular energy usage data from our AMI through a customer portal, which we expect to pair with informed insights and helpful tips on how to change their behavior to save energy. Further, the AMI meters we propose include a Distributed Intelligence platform, which essentially provides a computer in each customer's meter that will be able to "connect" usage information from the customer's appliances for further insights – and be updated with new software applications, much like customers can currently update their mobile devices with applications.



Figure 3: Customer Value through Lifecycle

To develop the customer strategy, we committed to understanding customers' preferences, considerations, and thoughts regarding the benefits and value of an advanced grid investment. We gathered this information through primary research, such as focus groups and surveys. We also supplemented our research with information from secondary sources including the Smart Energy Consumer Collaborative, and GTM Research and other utilities' advanced grid plans.

Our key takeaways from these sources are as follows:

- Consumers care more about technology and enabling improvements than process. Safety and energy savings rated most highly.
- Addressing service interruptions are important to all customer classes. Improved reliability will allow the Company to focus more on other customer priorities.
- Customers expect that service interruptions will be less frequent in scope and duration.

- *Customers expect to receive detailed information from their utility.* They expect this information to be personal and frequent.
- *Customers expect more tools and information for them to make decisions about their energy usage.* Customers indicated more information allowed them to better identify opportunities and strategies to save energy and reduce their costs.
- Business customers have more awareness and familiarity with advanced rate designs. Residential customers expect the utility to provide them with rate comparison tools and information about new rate designs.
- Building trust is a key component to unlocking value. Trust is best built by identifying solutions and showing results specific to the customers
- Customers expect that there will be a cost associated with the advanced meter but that the meter will also provide benefits over time.

We have incorporated customer feedback and insights into our customer transition and communication plans – and the work we are doing to develop new and enhanced products and services as enabled by the advanced grid.

3. Our Advanced Grid Implementation will Educate, Inform, and Ensure a Smooth Implementation

During this transition to the advanced grid, we will take exceptional care of our customers to educate, inform, and ensure a smooth implementation. We are already developing processes that will ensure accurate, timely bills as customers change over to AMI. We are also developing dedicated, hands-on customer care processes that will provide our customers a single point of contact during implementation – and that will phase customer communications relative to our geographic deployment of AMI meter installation. Meter deployment and advanced meter capabilities will be phased in over the next several years, and communications strategies, messages and tactics will be executed in three phases to match the customer journey.

Figure 4: Customer Communications Journey Phases



For example, our customer communications will begin pre-implementation to educate on the possibilities enabled by AMI, as well as customers' ability to opt-out of an AMI

meter. As the AMI installation date gets closer, we will inform customers about what to expect with the AMI meter changeover at their homes or businesses. Finally, we will communicate post-AMI installation to reinforce early AMI messaging regarding possibilities and options – also providing practical steps to take advantage of the customer portal or other new or enhanced services available day one.

B. Advanced Planning Tool

In recognition that distribution planning needs were beginning to change and our existing tools could not accommodate all of the analysis we would need or want to do going forward, we began assessing options to upgrade our planning capabilities. We began this assessment in 2015 – and given market trends, our current software's lifecycle, evolving planning requirements, and changes to our grid, the time is ripe to implement a new, more dynamic forecasting tool.

The Advanced Planning Tool (APT) will enable us to meet our planning and regulatory requirements and we believe, result in incremental benefits for our customers. As we have discussed in relation to our advanced grid investment proposal, our customers are increasingly exercising more choice around their use of energy. Some of these choices, including DER and beneficial electrification such as electric vehicles (EV) make granular load forecasting a much more complex and important undertaking than it was only a few years ago. It is essential for our distribution planning tools to better assess how these technologies interact with the grid and how they may change potential distribution system needs.

Further, the Commission has instituted new planning and reporting requirements the Company must meet. These requirements include conducting load and DER scenario analysis and NWA analysis. Finally, our existing tool will no longer be supported in the near future. These factors all require the Company to implement a new solution. These tools will equip our system planners with enhanced capabilities to consider DER adoption scenarios and non-wires alternatives (NWA) in the analyses we perform to ascertain the best way to meet system capacity needs. Further, the APT will enable us to deliver additional benefits in the form of more efficient planning, enhanced load forecasting capabilities, and better integration with the Company's other planning efforts.

Given the capabilities and benefits the APT will enable for our distribution planning processes, we are confident that the investment is in the interest of both customers and the Company and will help the Company meet our regulatory requirements. We expect to procure and integrate the APT in early 2020, at an all-in upfront cost of approximately \$9.3 million Xcel Energy-wide. We estimate that the proportional

Northern States Power-Minnesota (NSPM) operating company upfront costs will amount to approximately \$4 million, with minimal ongoing costs for the annual software hosting fee and internal maintenance.

In this IDP, we request the Commission certify our request to procure the APT for distribution planning purposes.

C. Five-Year Budgets – Capital and O&M Expenditures

Distribution budgets are evolving based on the future of electric distribution and customers' increasing expectations for control, options, and ease of doing business. Additionally, our capital investment plans generally reflect our advanced grid initiative, as we have discussed it above. Historically, however, the overwhelming majority of our distribution budgets have been dedicated to the immediacy of customer reliability impacts and the dynamic nature of the distribution system. This includes building and maintaining feeders, substations, transformers, service lines, and other equipment – as well as restoring customers and our system in the wake of severe weather, and responding to local and other government requirements to relocate our facilities.

The distribution budget process prioritizes projects based on the Company's goal of providing our customers with smart, cost-effective solutions, recognizing that customers want reliable and uninterrupted power. Although the immediacy of customer safety and reliability is a reality and our primary focus, in addition to these core activities, our investment plan now reflects strategic investments to advance distribution grid capabilities, increase our system visibility and control, and enable expanded customer options and benefits. As noted above, we are planning investments to advance our grid and to procure an enhanced distribution planning tool are in our five-year action plan and budgets.

Table 1 below provides an overview of our 5-year capital budget in the IDP categories.

	Bridge						Budget Ave
	Year			Budget			
IDP Category	2019	2020	2021	2022	2023	2024	2020-2024
Age-Related Replacements and Asset Renewal	\$72.5	\$87.2	\$79.5	\$78.3	\$79.7	\$81.0	\$81.1
New Customer Projects and New Revenue	\$34.8	\$35.6	\$39.3	\$39.3	\$39.4	\$39.4	\$38.6
System Expansion or Upgrades for Capacity	\$19.5	\$44.4	\$40.1	\$32.3	\$32.9	\$37.9	\$37.5
Projects related to Local (or other) Government-Requirements	\$31.3	\$28.9	\$29.4	\$28.5	\$29.0	\$29.2	\$29.0
System Expansion or Upgrades for Reliability and Power Quality	\$19.8	\$21.5	\$114.7	\$117.4	\$117.3	\$117.3	\$97.6
Other	\$26.7	\$38.3	\$39.7	\$43.2	\$35.4	\$35.1	\$38.3
Metering	\$6.7	\$5.5	\$4.3	\$3.5	\$2.3	\$2.3	\$3.6
Grid Modernization and Pilot Projects	\$4.6	\$19.9	\$49.3	\$141.7	\$152.4	\$76.7	\$88.0
Non-Investment	(\$4.9)	(\$3.7)	(\$3.7)	(\$3.8)	(\$3.8)	(\$3.8)	(\$3.8)
τοται	\$210.9	\$277.5	\$392.6	\$480.3	\$484.6	\$415.2	\$410.0

Table 1: Distribution Capital Expenditures BudgetState of Minnesota Electric (Millions)

Notes: Excludes Grid Modernization –Other includes Fleet, Tools, Communication Equipment, Locating, Transformer Purchases and the Advanced Planning Tool; Reliability includes placeholder investments for a new reliability program (Incremental System Investment); and Non-investment includes Contributions In Aid of Construction (CLAC), which partially offset total project costs and 3rd party reimbursements for system upgrades due to interconnections and Solar, which is 100% reimbursable by the developers, annual totals will vary based on payment and project timing.

Significant investments in the Distribution 5-year budget include our incremental system investment, or ISI initiative, which is included in the System Expansion or Upgrades for Reliability and Power Quality category. The ISI initiative focuses primarily on the heath, reliability, and resiliency of the portions of our system that are closest to our customers such as feeder and tap lines. The advanced planning tool for which we seek certification in this IDP is in the Other category, which involves approximately \$4 million of upfront costs associated with the initial purchase. Finally, our Distribution budget reflects our commitment to advancing EVs in Minnesota, with over \$25 million budgeted in the Grid Modernization and Pilots category associated with approved and pending EV proposals.

Also significant are our grid modernization, or AGIS, investments, which we also seek certification for and present separately, because the overall project costs involve both Distribution and Business Systems amounts. See Table 2 below.

	MYI	RP Case P	5-Year Period	10-Year Period	
Component	2020	2021	2022	2023-2024	2025-2029 ²
ADMS ³	\$6.5	\$1.0	\$3.0	\$7.5	-
AMI ⁴	\$14.0	\$28.9	\$144.0	\$185.2	\$15.0
FAN ⁵	\$14.7	\$37.3	\$36.8	\$3.8	-
FLISR	\$3.5	\$8.6	\$6.6	\$18.8	\$29.7
IVVO	\$0.1	\$6.5	\$9.8	\$18.6	-
Total	\$38.8	\$82.3	\$200.2	\$233.9	\$44.7

Table 2: Grid Modernization Capital Expenditures Budget – NSPM Electric (Millions)

In terms of grid modernization, ADMS represents approximately \$18.0 million in the 2020-2024 timeframe. Our full AMI deployment is planned to begin in 2021 and continue through 2024, with projected capital costs for AMI and FAN of approximately \$275.7 million through 2022, and approximately \$204 through the 2029 IDP period, for a total of approximately \$480 million.⁶ FLISR implementation is planned to begin in 2021 and continue at a relatively steady rate through 2028, with projected capital costs of approximately \$18.7 million through 2022, and approximately \$48.5 through the 2029 IDP period, for a total of approximately \$18.7 million through 2022, and approximately \$48.5 through the 2029 IDP period, for a total of approximately \$67 million. Finally, IVVO implementation is planned to begin in 2019 and continue through 2024, with projected capital costs of approximately \$16.4 million through 2022, and approximately \$18.6 million through the 2029 IDP period, for a total of approximately \$20.4 million through 2022, and approximately \$18.6 million through 10.6 million through 2029 IDP period, for a total of approximately \$18.6 million through \$10.4 million through 2022, and approximately \$18.6 million through 10.9 million through 2029 IDP period, for a total of approximately \$18.6 million through 2029 IDP period, for a total of approximately \$18.6 million through 2029 IDP period, for a total of approximately \$18.6 million through 2029 IDP period, for a total of approximately \$18.6 million through 2029 IDP period, for a total of approximately \$18.6 million through 2029 IDP period, for a total of approximately \$18.6 million through 2029 IDP period, for a total of approximately \$18.6 million through the 2029 IDP period, for a total of approximately \$35 million.

In terms of O&M, large planned projects and programs to support our ongoing provision of regulated utility service are budgeted by function, and are key drivers of the O&M budgets. Programs include operational activities such as: *Vegetation Management*, which includes the work required to ensure that proper line clearances are maintained, maintain distribution pole right-of-way, and address vegetation-caused outages; *Fleet* represents costs associated with the Distribution fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and tools necessary to build out, operate, and maintain our electric distribution system. The O&M component includes annual fuel costs plus an allocation of fleet support. The *Damage Prevention* category includes

² Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.

³ Eligible for cost recovery through the TCR Rider.

⁴ Includes the TOU Pilot.

⁵ Includes the TOU Pilot.

⁶ Note: Table 3 includes the AGIS O&M budgets as outlined in more detail in the AGIS section.

costs associated with the location of underground electric facilities and performing other damage prevention activities. This includes our costs associated with the statewide "Call 811" or "Call Before You Dig" requirements, which helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents. And finally, we include AGIS O&M here as well, which represents the Distribution-only portion of the O&M expenditures needed to support the deployment of AGIS devices in the field – along with maintaining those devices.

Table 3 below provides a snapshot of our 2020-2024 O&M Distribution budget by Cost Element.

	Bridge			Budget			Budget Avg
Expenditure Category	2019	2020	2021	2022	2023	2024	2020-2024
Labor	\$53.8	\$58.3	\$59.8	\$60.5	\$61.6	\$63.6	\$60.8
Cont. Outside Vendor/Contract Labor	\$17.1	\$8.9	\$12.9	\$9.7	\$8.7	\$8.6	\$9.8
Damage Prevention Locates	\$8.3	\$8.5	\$8.6	\$8.6	\$8.6	\$8.6	\$8.6
Vegetation Management	\$29.0	\$28.2	\$28.9	\$28.4	\$30.2	\$30.1	\$29.2
Materials	\$5.9	\$6.9	\$6.8	\$6.8	\$6.8	\$6.8	\$6.8
Transportation Costs	\$7.4	\$6.9	\$6.8	\$6.8	\$6.8	\$6.8	\$6.8
AGIS	\$0.6	\$2.8	\$4.5	\$6.8	\$8.8	\$6.5	\$5.9
Misc. Other	(0.2)	(\$3.9)	(\$3.6)	(\$3.6)	(\$3.4)	(\$3.5)	(\$3.6)
TOTAL	\$121.9	\$116.6	\$124.7	\$124.0	\$128.1	\$127.5	\$124.2

Table 3: Distribution O&M Expenditures Budget –NSPM Electric (Millions)

- Capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; Misc Other includes employee expenses, first set credits, bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Significant O&M expenditures in the Distribution 5-year budget include O&M to support the AGIS and Incremental System Investment (ISI) deployments.

Consistent with how we present the capital budget for our grid modernization investments, we separately present the O&M to provide a complete view of both Distribution and Business Systems amounts. See Table 4 below.

	Rate	Case Peri	od	5-Year Period	10-Year Period
Component	2020	2021	2022	2023-2024	2025-2029 ⁷
ADMS ⁸	\$1.9	\$2.5	\$2.5	\$6.9	\$5.2
AMI ⁹	\$6.6	\$16.4	\$14.1	\$25.2	\$67.2
FAN ¹⁰	\$0.1	\$2.3	\$1.5	\$0.5	\$8.6
FLISR	\$0.2	\$0.4	\$0.3	\$3.3	\$2.5
IVVO	\$0.0	\$0.4	\$0.8	\$0.6	\$0.8
Total	\$8.8	\$22.0	\$19.2	\$36.5	\$84.3

Table 4: Grid Modernization O&M Expenditures Budget – NSPM Electric (Millions)

In terms of grid modernization, ADMS represents approximately \$19 million of O&M in through the 2029 period of this IDP. AMI and FAN comprise approximately \$41 million of O&M through 2022, and approximately \$101 million through the 2029 IDP period, for a total of approximately \$142 million.¹¹ FLISR has projected O&M costs of approximately \$0.9 million through 2022, and approximately \$5.8 through the 2029 IDP period, for a total of approximately \$6.7 million. Finally, IVVO has projected O&M costs of approximately \$1.2 million through 2022, and approximately \$1.4 million through the 2029 IDP period, for a total of approximately \$1.2 million through 2022, and approximately \$2.6 million.

Finally, we clarify that in the IDP context, while our budget process has generally proven to be an accurate gauge of overall budget levels, it is important to understand that plan details – exclusive of large and strategic investments approved for implementation by the Commission, when needed, and our internal governance process, will be inconsistent year-to-year. As we have explained, the Distribution budget is an ongoing and iterative process that is largely driven by the immediacy of reliability and other emergent circumstances that are the practical reality of the Distribution business. The distribution system is the connection to our customers, and we must respond to these circumstances to meet our obligation to serve and ensure we provide adequate service. This means that long-term plans, which, in a distribution context, include five-year action plans, have a much shorter shelf-life.

⁷ Period may include additional assumptions, including inflation and labor cost increases that are not part of the O&M budget in periods 2020-2024.

⁸ Eligible for cost recovery through the TCR Rider.

⁹ Includes the TOU Pilot.

¹⁰ Includes the TOU Pilot.

¹¹ Includes the TOU Pilot

D. Existing and In-Queue DER

For purposes of IDP in Minnesota, DER is defined as supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers, whether it is installed on the customer or utility side of the electric meter. The definition further clarifies that for the IDP, DER may include, but is not limited to distributed generation, energy storage, electric vehicle, demand side management, and energy efficiency resources.

Xcel Energy has one of the longest-running and most successful Demand Side Management (DSM) programs in the country. Our annual DSM achievements have often outpaced Minnesota's 1.5 percent of sales goal. Our Demand Response programs have 824 MW of registered, controllable customer load under contract in Minnesota, which is one of the largest portfolios of DR in the Midcontinent Independent System Operator (MISO) footprint – and we are on track to add an additional 400 MW to our portfolio by 2023. We have the largest community solar gardens program in the country, with 585 MW from 208 projects online. We anticipate this growing to over 650 MW by the end of 2019. Customer adoption of other DER in our Minnesota service area is otherwise relatively nascent. However, non-CSG distributed solar nearly doubled from last year's level to approximately 86 MW.¹² Distributed wind grew from 4 MW to 16 MW, and distributed storage projects interconnected to our system significantly increased from six to 35. Tables 5 and 6 below summarize current levels of distribution-interconnected DER and how much is in the queue.

Finally, we note that we have launched, or will soon, several pilots to build on our clean energy leadership by investing in infrastructure to increase access to electric vehicles (EV) and help drivers and fleet operators start driving electric. Our pilots include a Fleet EV Service Pilot, which is studying Company investment in EV infrastructure for fleet operators, such as Metro Transit, the Minnesota Department of Administration, and the City of Minneapolis. In addition we are launching a Public Charging Pilot, which is studying investment in EV infrastructure for public charging stations along corridors and community mobility hubs to reduce the upfront cost of public charging. For residential customers we are studying ways to reduce upfront costs for customers through our Residential EV Subscription Service Pilot. In addition, we have proposed to expand our Residential EV Service Pilot into a permanent offering, called EV Home Service. The Commission is considering that proposal at this time.

¹² As of July 2019.

In total, these efforts expand upon our vision for supporting the growth of EVs that will benefit drivers, customers, the environment, and the state.

Table 5: Distribution-Connected Distributed Energy Resources –State of Minnesota

	Comple	Completed Projects		d Projects
	MW/DC	# of Projects	MW/DC	# of Projects
Small Scale Solar PV				
Rooftop Solar	67	4,391	61	1,101
RDF Projects	19	25	1	2
Wind	16	61	<1	8
Storage/Batteries ¹⁴	N/A	35	N/A	20
	<u>Comple</u>	Completed Projects		d Projects
	MW/AC	# of Projects	MW/AC	# of Projects
Large Scale Solar PV				
Community Solar	585	208	313	286
Grid Scale (Aurora)	100	16	0	0

(as of July 2019)¹³

Table 6:Minnesota Distributed Energy Resources –Demand Side Management and Electric Vehicles

	<u>Comple</u>	ted Projects	Queued Projects		
	Gen. MW	# of Projects	Gen. MW	# of Projects	
Energy Efficiency	1,120	N/A	N/A	N/A	
Demand Response	824	413,783	N/A	N/A	
Electric Vehicles	N/A	7,081-8,500 ¹⁵	N/A	N/A	

Note: Energy efficiency is cumulative since 2005.

At a system level, tools and methodologies to forecast DER adoption are similarly nascent in the industry. These forecasts rely on predicting customer behavior based on macro-economic factors, understanding potential based on topography and weather, and incorporating policy- and rate-based incentives or disincentives.

All of this supports the conclusion that Minnesota is unique from other states

¹³ Energy Efficiency and Demand Response are as of December 31, 2018.

¹⁴ All current battery projects are associated with other generation projects, such as solar. As such, the interconnection application does not capture gen. MW, as it is accounted for in other categories.

¹⁵ We do not have information that ties our customer accounts to electric vehicle users. *See* IDP Requirement 3.A.21 below for the sources of this range.

implementing IDP in that we are not currently experiencing sizable additions of DER on our system. Rather, Minnesota is ahead in its planning and therefore able to take a measured approach and pace to IDP that allows the requirements to be implemented in a cost-effective, systematic manner that is in the public interest for all Minnesota customers.

The IDP requirements that are emerging in various states often require some form of DER analysis and forecasting – and incorporation of the results into distribution planning analyses. Traditional distribution planning involves forecasting loads for each feeder and each substation transformer, which for our system in Minnesota equates to approximately 1,700 individual forecasts. DER must be forecast by type because each type of DER has different characteristics and differing impacts on the grid. Forecasting DER penetration at a granular *feeder* level for purposes of informing distribution planning is exponentially more complex than doing so at a *system* level. We are unsure about the level of accuracy provided by any tools in such a nascent market and how refined we can get geographically without losing accuracy.

Like traditional load forecasting, DER forecasting requires utilities to use the best information about what has happened in the past and what may happen to develop a picture of what is likely to happen in the future. But DER forecasting diverges from traditional load forecasting when it comes to the inputs; the historical data used for traditional load forecasting is simply not available or necessarily accurate for most DERs. Industry tools and methodologies to incorporate DER into annual distribution plans and planning processes are emergent and immature. Nationally, regulators, utilities, stakeholders, service providers, and others are working to determine methodologies, processes, and tools that will meet the forecasting needs that are emerging in states such as California, New York, and Hawaii.

While we used our present tools and methodologies to inform overall system DER forecasts in this IDP, as we have noted, we are in the process of procuring an advanced planning tool that will help the Company better understand the locational and temporal impacts of DER. The good news from a distribution planning perspective is that Minnesota is presently at comparatively low levels of DER penetration that can reasonably be expected to remain stable in the near-term. Further, our present tariffs require interconnecting parties to mitigate adverse impacts identified in the interconnection application process.

III. ACTION PLAN SUMMARY

The first five years of our action plan will be busy – focused on providing customers with safe, reliable electric service, advancing the distribution grid with foundational

and core capabilities including AMI, FAN, FLISR, and IVVO – and procuring and integrating an advanced system planning tool to improve our distribution load forecasting, planning, and DER and NWA analysis capabilities. As discussed further below, all of these investments will provide our customers with value, which is why we are asking the Commission to certify them in connection with this IDP.

IV. PROCEDURAL PROPOSAL

As we have noted, we are seeking to certify an array of investments to modernize the Company's distribution system, pursuant to Minn. Stat. § 216B.2425. Specifically, we are seeking certification of an advanced distribution planning tool and a number of investments that are part of what is collectively referred to as the AGIS initiative: Advanced Metering Infrastructure, a private secure Field Area Network, a form of distribution automation that decreases the duration of and number of customers affected an outage (FLISR), and Integrated Volt Var Optimization, which decreases system losses and optimizes voltage as power travels from substations to customers.

These investments expand on the advanced grid investments previously approved by the Commission, namely the ADMS that will go into service in 2020. Each of these investments will take years to fully implement, and we are requesting that the Commission certify the AGIS projects so that the Company may request recovery of costs in concurrent or subsequent filings, as necessary. This is consistent with other requests for certification for grid modernization investments, where certification enables the opportunity for the Company to request recovery of costs in a subsequent rider filing.

We are also filing a General Rate Case (Docket No. E002/GR-19-564) today with a three-year plan through which we seek cost recovery for much – but not all – of these AGIS investments. Because the span of the AGIS investments goes beyond the 2020 test year and 2021-2022 plan years identified in our MYRP filing, and in light of the concurrent submission of this 2019 IDP, our AGIS rate case testimony provides support for our AGIS investments beyond the term of the rate case and addresses Commission requirements that pertain to both certification and cost recovery for grid modernization investments. In light of this support for our long-term strategy, we believe certification of the full scope of the AGIS investments alongside a rate case cost recovery determination is critical, so that we may complete our AGIS investments at an appropriate pace and potentially include the out-year costs in a rider. Consideration of our certification request in tandem with our rate request will also be most efficient for all stakeholders. The Commission would, of course, have another opportunity for review and approval of specific costs if the Company were to seek rider cost recovery in the future.

Because of this dual filing approach, and in order to minimize duplication, we have provided the support for our AGIS certification request in a testimony format within the rate case, and we are including relevant portions of the testimony as attachments to this filing. We have excised unrelated portions from some witness testimony in order to provide only the relevant material. For instance, Company Witness Mr. David C. Harkness provides testimony regarding our 2020-2022 Business Systems investments for purposes of the MYRP, but not all of them are related to AGIS; we have therefore included only those sections and attachments that relate to AGIS in this IDP filing.

In addition, today we also have filed a Petition for Approval of True-Up Mechanisms. This filing requests the approval of certain true-ups for 2020 which, if approved, would result in the withdrawal of our General Rate Case. In that event, we would no longer request AGIS cost recovery through base rates until the Company's next general rate case is filed. We would, however, ask the Commission to make the more limited determination to certify the AGIS investments and Advanced Distribution Planning Tool in this IDP, so that we may plan for the implementation of our AGIS initiative, and preserve the option to put the costs of these investments in a rider between general rate case filings.

Overall, the filing requirements related to grid modernization investments, as well as for certification, are extensive, and our supporting documentation is likewise extensive and thorough. We have therefore taken several steps to facilitate review of these materials, and make them as digestible and easy to read as possible for the Commission and our stakeholders. These steps include development of executive summaries, compliance matrices, and extractions from larger pieces of testimony as noted above.

The normal procedural schedule for certification under Minn. Stat. § 216B.2425 would require a determination by June 1, 2020, and under normal circumstances, we believe the process leading to certification should resemble a resource acquisition proceeding under the Commission's normal notice and comment procedures that could, in the Commission's discretion and depending on the scope of the investment, include one or more public hearings. We recognize, however, that the schedule in the General Rate Case does not align with that timing. In addition, the AGIS initiative includes large investments and is supported by a sizeable filing that may require analysis beyond the six-month certification timeframe, even if the General Rate Case is withdrawn. Thus, we offer to work with the Commission and stakeholders to set an appropriate deadline and procedural schedule for consideration of these investments. On a further procedural note, we respectfully request the Commission move to a biennial filing cadence for the IDP, consistent with other Minnesota utilities and the grid modernization statute filing requirements. We believe a biennial filing would better allow time to fully engage with stakeholders on the Commission's planning objectives between IDP filings, as well as to address important issues such as distributed energy resources (DER) planning, a comprehensive approach to non-wire alternatives (NWA), and our advanced grid plans. The present annual filing schedule also does not allow the Company to make significant, meaningful progress on its objectives between these extensive filings. We therefore specifically request the Commission require our next IDP be submitted on or before November 1, 2021, and biennially thereafter.

Finally, with respect to our ADMS initiative, we will be submitting an initial and ongoing annual reports in accordance with the Commission's September 27, 2019 Order in the Company's Transmission Cost Recovery (TCR) Rider Docket.¹⁶ We propose to submit a single ADMS report by January 25, 2020 in the TCR docket and this IDP docket that contains all of the required information. We also respectfully request that the Executive Secretary establish the same January 25th due date for the ongoing annual ADMS reports beginning January 25, 2021 – and that these annual ADMS reports be filed in most recent docket of future IDPs.

¹⁶ Docket No. E002/M-17-797.

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ATTACHMENTS

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N2	RFP – AMI		
N3	RFP – WISUN		
N4	RFP – IVVO		
O1	AGIS Combined CBA Summary		
O2	AGIS AMI CBA Summary		
O3	AGIS FLISR CBA Summary		
O4	AGIS IVVO CBA Summary		
Workpapers	Executable CBA Model – APT		
Workpapers	Executable CBA Model – AGIS		

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
ANSI	American National Standards Institute
BTM	Behind the Meter
BYOD	Bring your Own Device
CAIDI	Customer Average Interruption Duration Index
CIP	Conservation Improvement Program
CPE	Customer Premise Equipment
CPUC	California Public Utilities Commission
CRS	Customer Resource System
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DG-PV	Photovoltaic Distributed Generation
DOE	Department of Energy
DR	Demand Response
DRIVE	EPRI's Distribution Resource Integration and Value Estimation
	tool (for Hosting Capacity Analysis)
DRMS	Demand Response Management System
DSIP	Distribution System Implementation Plan
DSM	Demand Side Management
DSPx	DOE's Next Generation Distribution System Platform
EE	Energy Efficiency
EPRI	Electric Power Research Institute
ESB	Enterprise Service Bus
ERT	Estimated Restoration Time
EV	Electric Vehicle
FAN	Field Area Network
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
FLP	Fault Location Prediction
GIS	Geospatial Information System
HAN	Home Area Network
HECO	Hawaiian Electric Company
HEM	Home Energy Management
HPUC	Hawaii Public Utilities Commission
ICT	Innovative Clean Technology
IDP	Integrated Distribution Plan
IEEE	Institute of Electrical and Electronics Engineers

IP	Internet Protocol
ISO	Independent System Operator
IT	Information Technology
IVVO	Integrated Volt VAr Optimization
LBNL	Lawrence Berkeley National Laboratory
LCR	Local Capacity Resource
LTC	Load Tap Changers
MAIFI	Momentary Average Interruption Frequency Index
MDMS	Meter Data Management System
MISO	Midcontinent Independent System Operator
MPUC, PUC, or Commission	Minnesota Public Utilities Commission
M&V	Measurement and Verification
NIC	Network Interface Card
NIST	National Institute of Standards and Technology
MCOS	Marginal Cost of Service
NMS	Network Management System
NSPM or Company	Northern States Power Company-Minnesota Operating
	Company
NWA	Non-Wire Alternatives
NYPSC	New York Public Service Commission
OMS	Outage Management System
PSCo	Public Service Company of Colorado
PSIP	Power Supply Improvement Plan
РТМР	Point-to-Multi-Point
PV	Photovoltaic
QoS	Quality of Service
REV	New York's Reforming the Energy Vision initiative
RTO	Regional Transmission Operator
R&D	Research and Design
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SEPA	Smart Electric Power Alliance
SVC	Static VAr Compensators
TOU	Time of Use
VEE	Validation, Estimation, Editing
WAN	Wide Area Network
WiMAX	Worldwide Interoperability for Microwave Access
WiSUN	Wireless Smart Utility Network
Xcel Energy	Xcel Energy Inc.
I. INTRODUCTION

On August 30, 2018, the Minnesota Public Utilities Commission ordered Northern States Power, doing business as Xcel Energy to file an IDP annually beginning on November 1, 2018. We submitted our first IDP that included the information required in the Commission's August 30, 2018 Order in Docket No. E002/CI-M-18-251. We continue to provide that information in this second IDP, as well as the additional information required in the Commission's July 16, 2019 Order. As it relates to the advanced grid aspects of this IDP and the rate case filed concurrently with this IDP, the Commission's September 27, 2019 Order in Docket No. E002/M-17-797 also guided the information that we provide.

The IDP presents a detailed view of our distribution system and how we plan the system to meet our customers' current and future needs. The first five years of our action plan are focused on providing customers with safe, reliable electric service, advancing the distribution grid with foundational and core capabilities including:

- AMI, advanced metering technology which will expand the use of our meter system beyond basic billing functions for the benefit of our customers,
- A robust FAN communications network that will facilitate communications between and among advanced distribution grid equipment and AMI meters,
- FLISR, fault detection technology which will deliver significant reliability experience improvements for our customers, and
- IVVO, voltage optimization technology to realize energy savings and increase our DER hosting capacity.

We will also procure and implement an advanced planning tool that will enhance our ability perform NWA analysis, and DER and load forecast scenario analysis; it will also help to facilitate a greater alignment and integration of our distributiontransmission-resource planning.

A. Planning Landscape

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now

from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid is able to sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customerconnected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

IDPs continue to be an emerging industry practice intended to give regulators and other stakeholders a more transparent view into the planning process of the distribution grid through a standardized process. Integrated distribution planning first appeared in states where public policies were driving substantive changes to distribution business models and grids, including the need for utilities to integrate greater and significant levels of DER. Although individuals and developers are installing DER in Minnesota, present levels and the adoption rate continues to be lower than other states that have adopted integrated distribution planning. This gives utilities and stakeholders the time to take a measured approach to implement the tools, models, and processes that ensure the grid is prepared for a more distributed future – while also balancing the costs and other implications associated with such a future.

Distribution planning has historically – and still largely today –involved analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels, and utilization rates of major system components such as substations and feeders. Customers traditionally have had limited information about their energy usage and few choices in how they received information, had questions answered, and paid utility bills or conducted other necessary business with their utilities. For the most part, customers were content to receive a monthly paper bill from their utilities and were unaware and unengaged in whether the energy came from renewable or non-renewable sources.

Now, instead of planning just for load, utilities also need to analyze the system for future connections that may be load *or* generation. Also, utilities will increasingly need to view their operations and customer tools from their customers' perspectives. This

step change in the distribution utility business requires utilities to plan their systems differently, which involves not only new processes and methodologies but also new and different tools and capabilities.

Over time, integrated distribution planning in Minnesota is intended to facilitate scenario-based, integrated resource-transmission-distribution planning to ensure a reliable, efficient, robust grid that will flexibly meet the challenges of a changing and uncertain future. Like other aspects of the industry that are transitioning and advancing, we are on the forefront of integrated distribution planning and, as such, are taking steps to align and integrate our distribution, transmission, and resource planning processes.

Increasing DER penetration levels will drive integrated resource planning and distribution planning closer together, however today there are fundamental differences in how these two planning activities assess and develop plans to meet customers' needs that will need to evolve over time. Distribution planning is primarily concerned with location, and resource planning is primarily concerned with size, type and timing of resources – with transmission planning somewhere in the middle. Before a greater integration of these planning processes can occur, distribution planning tools and distribution system capabilities will need to advance.

We have begun this transition. This IDP presents a detailed view of how we plan our system to meet our customers' current needs and how we intend to evolve for the future. The backbone of our planning is keeping the lights on for our customers, safely and affordably. For over 100 years, we have delivered safe, reliable electric service to our customers, and, through our robust planning process and strong operations, we will continue to do so.

We are however, also planning for the future. With this IDP, we propose to procure the next generation of distribution planning tools, which we need to increase our forecasting and analysis capabilities and help integrate our planning processes. We also propose to implement AMI, a robust and secure FAN, technology to improve customers' reliability experience – FLISR, and IVVO, which will result in energy savings and increased hosting capacity on our system.

We have a vision for where we and our customers want the grid to go, and we are implementing and installing new technologies to support our vision. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value, and that the fundamentals of our distribution business remain sound.

B. Background

In 2015, the Commission opened an investigatory docket on grid modernization (Docket No. E999/CI-15-556) and issued the *March 2016 Staff Report on Grid Modernization*. Of various potential options outlined in the Staff Report, the Commission supported examining distribution system planning as the most reasonable and actionable way to assist in the forthcoming grid evolution. In doing so, the Commission also supported the staff-proposed principles as its Planning Objectives to guide further work, as follows:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid at fair and reasonable costs, consistent with the state's energy policies,
- Enable greater customer engagement, empowerment, and options for energy services,
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies, and
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

In August 2016, the Commission received the ICF International report, *Integrated Distribution System Planning*, and in October 2016, held a workshop seeking stakeholder input and discussion on a Minnesota-based distribution system planning framework. In April 2017, the Commission issued a Notice to utilities and stakeholders seeking to understand (1) how utilities currently plan their systems, (2) the status of current-year utility plans, and (3) recommendations for improvements to present planning practices. Xcel Energy submitted comments responsive to the Notice and stakeholder comments June 21, 2017, August 21, 2017 and September 21, 2017.

In January 2018, Commission staff proposed next steps to the Commission at a planning meeting – and in April 2018, established individual utility dockets and released proposed individual utility IDP filing requirements for Commission review; requirements for Xcel Energy were developed in Docket No. E002/CI-18-251. The Commission directed Staff to meet with each utility to discuss and clarify the proposed filing requirements – and afterward, release draft utility-specific IDP filing requirements for comment in June 2018. Xcel Energy submitted its comments June 20, 2018 and reply comments on July 20, 2018. The Commission determined final IDP requirements for Xcel Energy at its August 9, 2018 Agenda Meeting, and issued its Order containing the final requirements on August 30, 2018.

We submitted our first IDP November 1, 2018. Like development of the IDP requirements, the Order acknowledged integrated distribution planning as envisioned by the planning objectives will be an iterative process – set in motion with the Company's initial IDP. In setting the requirements, the Commission acknowledged the compressed timeline between the determination of final IDP requirements and the Company's initial report – and included an option for the Company to explain any gaps in its ability to fulfill each requirement. We held two stakeholder meetings – on September 12th and 26th, 2018 – that addressed the required: (1) load and DER forecasts, (2) proposed 5-year distribution system investments, and (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next five years, including consistency with the Commission's Planning Objectives. We also held a post-filing stakeholder workshop to provide an overview of our 2018 IDP and answer questions.

The Commission considered and accepted our 2018 IDP, and issued its Order Accepting Report and Amending Requirements on July 16, 2019. The Order required the Company to submit its next IDP November 1, 2019. The amended requirements clarified the cost-benefit analysis requirements for grid modernization projects and require the Company to:

- Discuss in future filings how the IDP meets the Commission's Planning Objectives (Order Point No. 5, *See* Attachment B),
- Provide additional information on the Incremental Customer Investment Initiative and the System Expansion or Upgrade for Reliability and Power Quality increases beginning in 2021 (Order Point No. 6, *See* Asset Health Section VII.B),
- Make the development of enhanced load and DER forecasting capabilities and tracking and updating of actual feeder daytime minimum loads a priority in 2019 (Order Point No. 7, *See* Section V.D.2 and Attachment D),
- Provide all information, analysis, and assumptions used to support the cost/benefit ratio for AMI, FAN and FLISR; and IVVO and CVR cost-benefit analysis as part of its 2019 IDP filing or other future filings (Order Point No. 8, *See* Grid Modernization Content Roadmap, Attachment C),
- Provide the results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology in future IDPs (Order Point No. 9, *See* Attachments E and F1),
- Provide information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary

information for feeders and substation transformers that have a risk score or planned investment in the budget cycle in future IDPs (Order Point No. 10, *See* Attachment F2), and

• File any long-range distribution studies the Company conducted in the time since the last IDP (Order Point No. 11, for which we note there are none for the 2018-2019 period).

The Commission additionally specified a number of requirements associated with cost recovery of future grid modernization proposals in our Transmission Cost Recovery rider proceeding in Docket No. E002/M-17-797, which are included in the Grid Modernization Content Roadmap provided as Attachment C.

We held four stakeholder meetings leading up to our 2019 IDP: (1) a December 12, 2018 presentation of our 2018 IDP and forum for questions and feedback; (2) a Non-Wires Alternatives analysis workshop on April 10, 2019; (3) a grid modernization project cost benefit analysis framework workshop on May 17, 2019; and (4) on September 25, 2019, the workshop required by the Commission's August 30, 2018 IDP Order to present the load and DER forecasts, budgets, and 5-year action plan.

C. Report Outline

This report is organized as follows:

Section	Title	Content Summary
Ι.	Introduction	Overview of the planning landscape and genesis of IDP in Minnesota.
II.	Distribution System Plan Overview	Summary of our near- and long-term distribution system plans, including summary-level budget information and drivers.
III.	Budget Development Framework	Provides snapshot of budget history and forecast.
IV.	System Overview	Provides snapshot of system statistics.
V.	System Planning	Describes the process of analyzing the distribution system's ability to serve existing and future loads. Also summarizes our proposed advanced planning tool.
VI.	Non-Wires Alternatives Analysis	Discusses project types, timelines, and screening process considerations for NWA as well as related analysis.
VII.	Asset Health and Reliability Management	Describes annual capacity planning and roadmap to mature capacity planning capabilities. Outlines reliability statistics, ongoing system health assessment processes, and ISI initiative.
VIII.	Distribution Operations	Discusses operational processes, such as vegetation management and escalated operations/storm response.
IX.	Grid Modernization	Summarizes our grid modernization strategy and plans.
Х.	Customer Strategy	Outlines our customer strategy and plans.
XI.	Distributed Energy Resources	Explains how DER is treated in load forecasts, present and forecasted DER levels, DER scenario analysis, and DER integration considerations.
XII.	Hosting Capacity, System Interconnection, and Advanced Inverters/IEEE 1547	Summarizes our hosting capacity analysis in the context of our overall interconnection processes. Provides interconnection statistics and related discussion.
XIII.	Existing and Potential New Grid Modernization Pilots	Outlines grid modernization and EV pilots.
XIV.	Action Plans	Outlines 5-year and long-term action plans.
XV.	Procedural Proposal	Summarizes the Company's requests and offers to work with the Commission and stakeholders to set an appropriate deadline and procedural schedule for consideration of our proposed AGIS and APT investments.
XVI.	Stakeholder Engagement	Describes stakeholder efforts related to the preparation of this IDP.
XVII.	Integrated Distribution- Transmission-Resource Planning	Discusses present state of D-T-R planning and longer-term view of deeper process alignment.
	Conclusion	

We provide as Attachment A to this IDP, a summary table of the Order Requirements that references locations in the IDP document where we provide the information responsive to each requirement. Some of these are more specific than others, which depends on the nature of the requirement. We also embedded the various requirements throughout this IDP, to signal to the reader when we would be generally or specifically responding to that requirement.

With respect to our grid modernization report, we include in the body of this IDP an executive summary of our plan and our related customer strategy. We provide as Attachment C, a roadmap of where in the attached AGIS Direct Testimony (Attachments M1 through M5) from our rate case filed concurrently with this IDP we meet the grid modernization investment and report requirements. Finally, we also provide a compact disk of the AGIS and advanced planning tool Requests for Proposals and live cost-benefit analysis models.

II. DISTRIBUTION SYSTEM PLAN OVERVIEW

In this Section, we provide a summary of our near- and long-term distribution system plans, including summary-level budget information and drivers. We first begin with a discussion of the policy goals underlying the development of our distribution system plan. We then discuss the Company's objectives in developing a distribution system plan and the framework of the Company's distribution system plan, and the development of the budget for the distribution system plan. Finally, we provide a summary of the distribution system plan, including the five-year and long-term action plans.

A. Distribution System Policy Goals

Federal and state policies and requirements – and customers – determine the key goals of regulated utilities. We believe the regulatory construct and the attributes of our service that our customers value are aligned around reasonable and affordable rates, reliable service, customer service and satisfaction, and environmental performance.

The principal source of state policy with respect to energy, utilities, and the environment are Minnesota statutes. Indeed, in the Legislative Findings section of Minn. Stat. Chapter 216B, the legislature provided a topline summary of state policy with respect to utility regulation:

It is hereby declared to be in the public interest that public utilities be regulated as hereinafter provided in order to provide the retail customers of natural gas and electric service in this state with adequate and reliable services at reasonable rates, consistent with the financial and economic requirements of public utilities and their need to construct facilities to provide such services or to otherwise obtain energy supplies, to avoid unnecessary duplication of facilities which increase the cost of service to the consumer and to minimize disputes between public utilities which may result in inconvenience or diminish efficiency in service to the consumers.¹⁷

We have a strong record on reliability, ranking in the first or second quartile nationally in terms of System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) – and have received national recognition for our storm response efforts. Also, significantly, we are achieving these outcomes with total residential electric customer bills that are nearly 20 percent below the national average.

Xcel Energy has one of the longest-running and most successful demand side management (DSM) programs in the country. Between 1990 and 2018, the Company spent \$1.5 billion (nominal) on Minnesota DSM efforts and saved nearly 9,700 GWh of energy and 3,600 MW of demand. We are finding new and better ways to communicate with our customers, including redesigning our website to be customercentric, developing a state-of-the-art storm center and outage notification system, and rolling out a mobile application. Finally, we are building on our clean energy leadership through significant capital investments to increase access to EVs and help drivers and fleet operators start driving electric.

As we discuss below, the goals of our Distribution business are aligned with the regulatory construct, Minnesota state policy objectives, and our customers' interests.

B. Distribution System Plan Objectives

The energy landscape is evolving. Supply resources are becoming less carbonintensive and more diverse; decentralization is accelerating – driven by advances in technology and new business models. While this evolution has been occurring at a system level, distribution systems – the portion of the system that connects directly with each and every customer – have also begun to advance. We are correspondingly planning for the future. We have a vision for where we and our customers want the grid to go, and we are implementing and installing new technologies to support our vision. We are taking a measured and thoughtful approach to ensure our customers

¹⁷ Minn. Stat. § 216B.01

receive the greatest value and that the fundamentals of our distribution business remain sound.

Xcel Energy's strategic priorities of enhancing the customer experience, leading the clean energy transition, and keeping customer bills low are embedded in everything that we do – including the way that we plan our distribution system.

Figure 5: Xcel Energy Strategic Priorities – Applied to Distribution



* NSP Upper Midwest System percentages

The Company's Distribution organization is responsible for operating, maintaining, and constructing the distribution system to ensure that the delivery of power to our customers is safe and reliable. In fact, the Distribution organization is the frontline group out in the field implementing the key Company priorities that drive our operations on a daily basis; namely reliability, safety, and customer focus.

In terms of reliability, customers want quality, uninterrupted power – and their expectations continue to evolve and increase. To address this priority, we regularly evaluate the overall health of our system and make investments where needed to reinforce our system. This includes an asset health analysis of the overall performance of key components of the distribution system such as poles and underground cables. Based on this analysis, we develop programs and work plans to both support our customers' needs for reliable service today – and also to lay groundwork for the grid of tomorrow.

We also must make significant investments to support system capacity needs due to increased loads from existing or new customers. For example, each year we evaluate substation transformer and feeder loads to identify overload risks and potential reliability issues, which drives the capacity-related projects that we plan. We update existing infrastructure, such as our recent initiative to install new energy-efficient LED streetlights – and we respond to increases in new business such as extending service to new housing developments, which are often driven by factors outside of our control.

In terms of safety, we make investments that support both the safety of our workforce and our customers. For example, our capital investments in fleet, tools, and equipment ensure our workers have the necessary provisions and support to do their job safely and efficiently. Other examples include:

- Our vegetation management program that helps reduce preventable tree-related service interruptions and address public and employee safety,
- Our damage prevention program that helps the public identify and avoid underground electric infrastructure,
- Our pole replacement program that ensures our lines and equipment are supported by quality wood poles, and
- Our LED street lighting program improves nighttime visibility, which in turn improves overall safety for both drivers and pedestrians.

Finally, we focus on service to our customers. For example, with certain investments in our distribution system such as in System Control and Data Acquisition (SCADA) capabilities and AMI, we enhance our capabilities to better monitor and respond to system conditions such as outages – and we can provide customers more choices related to their energy use. Additional examples are our industry-leading storm response, and our efforts to improve the estimated restoration times (ERT) we provide to customers.

The Distribution business area's goal is to provide safe, reliable, and affordable electricity to our customers in the near- and long-term. As such, our distribution investment and maintenance plans are designed to reduce risk, improve reliability, manage costs, and advance the grid at the speed of value to our customers. As discussed below, we plan and budget our distribution system investments in alignment with these goals.

C. Distribution System Planning Framework

The Distribution system is the portion of the electric system that delivers energy from the transmission system to our approximately 1.5 million electric customers across the Northern States Power Company-Minnesota (NSPM) operating company service area, including approximately 1.3 million customers in Minnesota. The distribution system is the final link that allows electricity to safely and reliably reach our customers' homes and businesses. The NSPM distribution system is comprised of approximately 1,200 feeders, approximately 15,000 circuit miles of overhead conductor on over 500,000 overhead poles and over 11,000 circuit miles of underground cable. This network of feeders and lines connects 240 distribution-level substations in Minnesota.

The work performed by Distribution is essential to ensuring that the electric service our customers receive is safe, reliable, and affordable. We extend service to new customers or increase the capacity of the system to accommodate new or increased load, repair facilities damaged during severe weather to quickly restore service to customers, and perform regular maintenance and repairs on poles, wires, underground cables, metering, and transformers. Distribution is also at the forefront of working to transform the distribution grid as part of the larger AGIS initiative to enhance security, efficiency and reliability, to safely integrate more distributed resources, support electrification, and to enable improved customer products and services.

The Distribution organization is one of the Company's business units whose investments and work directly impact the daily lives of our customers. As a result, it is important that our investments are focused on achieving the Company-wide priorities of leading the clean energy transition, keeping customer bills low, and enhancing the customer experience.

D. Distribution Financial Overview

Distribution budgets are evolving based on the future of electric distribution and customers' increasing expectations for control, options, and ease of doing business. Additionally, our capital investment plans generally reflect our advanced grid initiative, as we have discussed it above. Historically, however, the overwhelming majority of our distribution budgets have been dedicated to the immediacy of customer reliability impacts and the dynamic nature of the distribution system. This includes building and maintaining feeders, substations, transformers, service lines, and other equipment – as well as restoring customers and our system in the wake of severe weather, and responding to local and other government requirements to relocate our facilities.

These three requirements are intertwined, and we respond to them by providing the

following capital and O&M discussion, historical actuals, and 5-year budgets that respond to the related IDP requirements.

1. Overview

Historically, the overwhelming majority of Distribution's capital budget has been dedicated to maintaining the health and reliability of our facilities through replacement of aging or damaged equipment. Our planned investments continue to demonstrate a commitment to the Company's priorities of safety, reliability, and enhancing the customer experience. Our focus on the customer experience has been demonstrated through our timely response to customer electrical needs. For instance as the economy grew over the past several years, we met our customers' expectations for timely electrical connections. We also responded to customer demands to relocate our facilities due to an increased number of road construction projects in the metro area driven by the strong economy.

In the area of reliability, our capital budgets reflect a focus on maintaining the health of our existing facilities through established asset health and reliability programs with increasing investments in pole replacements. However, additional investment is needed and our capital budgets during this time period also include investments in our ISI initiative. The ISI initiative focuses primarily on the heath, reliability, and resiliency of the portions of our system that are closest to our customers such as feeder and tap lines.

Our capital budgets also show increasing strategic investments in the Company's AGIS initiative to advance distribution grid capabilities, increase our system visibility and control, and to enable expanded customer options. We will invest in the foundational elements of AGIS such as advanced meters, a FAN communication network, FLISR outage detection and restoration, and IVVO voltage improvement. These foundational elements, in concert with future investments, will provide cumulative benefits that will improve the operation and maintenance of the distribution system while also providing an improved customer experience. While we do not know exactly what the future will hold in terms of new technology or customer adoption rates of EVs and solar, we do know that the set of investments that we are proposing here are the right first building blocks.

We are also responding to customer expectations by expanding our EV programs. This includes several pilot programs that were recently approved by the Commission, a fleet EV service pilot, a public charging pilot, and a residential subscription service pilot, as well as our Petition to expand our existing successful residential service pilot and our work to develop further pilots and programs highlighted in the Company's recently filed Transportation Electrification Plan. These investments will provide the infrastructure necessary to promote greater EV use and to meet the demands of the growing EV market.

The budget process that we utilize has generally proven to be an accurate gauge of the routine work that will be performed each year. However, sometimes there are storms or new business fluctuations that can lead to unexpected increases in our routine work. When these circumstances arise, we seek to actively control our expenditures to stay as close to budget as reasonably practicable by prioritizing our work and allocating funds accordingly. In this way, the Distribution organization is unique from many other business units. While we are confident in our overall level of budgeting and our ability to manage within those annual budgets, the realities of our business require some flexibility within those budgets to respond to changing economic conditions, weather events, and evolving priorities. That being said, we are proud of our successful storm response efforts, reputation for reliable service, and our ability to manage our budget within its bounds and react and reprioritize as necessary each year to ensure our customers continue to receive safe and reliable electric service.

Our capital projects fall into eight capital budget groupings depending on the primary purpose of the project as follows: (1) Asset Health and Reliability; (2) AGIS (3) New Business; (4) Capacity; (5) Mandates; (6) Tools and Equipment; and (7) Electric Vehicle Program; and (8) Solar Gardens.

For purposes of the IDP, we are required to report and discuss distribution system spending in the following categories: (1) Age-Related Replacements and Asset Renewal, (2) System Expansion or Upgrades for Capacity, (3) System Expansion or Upgrades for Reliability and Power Quality, (4) New Customer Projects and New Revenue, (5) Grid Modernization and Pilot Projects, (6) Projects related to local (or other) government-requirements, (7) Metering, and (8) Other.

In the following sections, we portray our capital costs in the IDP categories. We note that we are unable to similarly portray our O&M costs in these categories, which we discuss in more detail below.

2. Specific Budget Information

IDP Requirement 3.A.26¹⁸ requires the following:

Historical distribution system spending for the past 5-years, in each category:
a. Age-Related Replacements and Asset Renewal
b. System Expansion or Upgrades for Capacity
c. System Expansion or Upgrades for Reliability and Power Quality
d. New Customer Projects and New Revenue
e. Grid Modernization and Pilot Projects
f. Projects related to local (or other) government-requirements
g. Metering

h. Other

For each category, provide a description of what items and investments are included.

a. Capital – Historical Actual and Budgeted Expenditures

As noted above, we have categorized our historical actuals and 5-year budgeted amounts into the IDP categories. Figures 6 and 7 below provide a summary of historical actual and budgeted capital expenditures in the IDP categories. We discuss these categories in more detail in below.

¹⁸ This IDP Requirement also provides that the Company may include in the IDP any 2018 or earlier data in the following rate case categories: (a) Asset Health; (b) New Business; (c) Capacity; (d) Fleet, Tools, and Equipment; and (e) Grid Modernization.

Figure 6: Actual Historical Distribution Capital Profile by IDP Category State of Minnesota – Electric 2014-2018 (Millions)



Figure 7: Budgeted Distribution Capital Profile by IDP Category State of Minnesota – Electric 2019-2024 (Millions)



Note: excludes non-investment/CLAC amounts.

IDP Requirement 3.A.28 requires the following:

Projected distribution system spending for 5-years into the future for the categories listed [in 3.A.26], itemizing any non-traditional distribution projects.

Table 7 below provides an overview of our 5-year capital budget in the IDP categories. We provide a list of planned projects as Attachment F1 to this IDP. We understand "non-traditional distribution projects" to include projects such as a NWA in place of a traditional distribution infrastructure investment, such as a new feeder or substation. Accordingly, we clarify that do not have any specific non-traditional distribution projects in our 5-year budget.

	Bridge Year			Budget			Budget Ave
IDP Category	2019	2020	2021	2022	2023	2024	2020-2024
Age-Related Replacements and Asset Renewal	\$72.5	\$87.2	\$79.5	\$78.3	\$79.7	\$81.0	\$81.1
New Customer Projects and New Revenue	\$34.8	\$35.6	\$39.3	\$39.3	\$39.4	\$39.4	\$38.6
System Expansion or Upgrades for Capacity	\$19.5	\$44.4	\$40.1	\$32.3	\$32.9	\$37.9	\$37.5
Projects related to Local (or other) Government-Requirements	\$31.3	\$28.9	\$29.4	\$28.5	\$29.0	\$29.2	\$29.0
System Expansion or Upgrades for Reliability and Power Quality	\$19.8	\$21.5	\$114.7	\$117.4	\$117.3	\$117.3	\$97.6
Other	\$26.7	\$38.3	\$39.7	\$43.2	\$35.4	\$35.1	\$38.3
Metering	\$6.7	\$5.5	\$4.3	\$3.5	\$2.3	\$2.3	\$3.6
Grid Modernization and Pilot Projects	\$4.6	\$19.9	\$49.3	\$141.7	\$152.4	\$76.7	\$88.0
Non-Investment	(\$4.9)	(\$3.7)	(\$3.7)	(\$3.8)	(\$3.8)	(\$3.8)	(\$3.8)
TOTAL	\$210.9	\$277.5	\$392.6	\$480.3	\$484.6	\$415.2	\$410.0

Table 7:Distribution Capital Expenditures Budget –
State of Minnesota Electric (Millions)

Notes: Excludes Grid Modernization –Other includes Fleet, Tools, Communication Equipment, Locating, Transformer Purchases and the Advanced Planning Tool; Reliability includes placebolder investments for a new reliability program (Incremental System Investment); and Non-investment includes Contributions In Aid of Construction (CLAC), which partially offset total project costs and 3rd party reimbursements for system upgrades due to interconnections and Solar, which is 100% reimbursable by the developers, annual totals will vary based on payment and project timing.

We clarify that the Metering category above reflects 'business-as-usual' metering costs – not metering expenditures associated with our AMI plans.

Significant investments in the Distribution 5-year budget include our incremental system investment, or ISI initiative, which is included in the System Expansion or Upgrades for Reliability and Power Quality category. The ISI initiative focuses primarily on the heath, reliability, and resiliency of the portions of our system that are closest to our customers such as feeder and tap lines. The advanced planning tool is in the Other category, and as we have noted previously, involves approximately \$4 million of initial investment for NSPM. Finally, our Distribution budget reflects our commitment to advancing EVs in Minnesota, with over \$25 million in the Grid Modernization and Pilots IDP category in associated with approved and pending EV proposals.

Ordering Point No. 6 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251 requires that we provide additional information on the Incremental Customer (now System) Initiative and the System Expansion or Upgrade for Reliability and Power Quality increases beginning in 2021. We note that we provide this discussion in Section VII.C.

Also significant are our grid modernization investments, which we present separately however, because the overall project costs involve both Distribution and Business Systems amounts. See Table 8 below.

	MYF	RP Case P	5-Year Period	10-Year Period	
Component	2020	2021	2022	2023-2024	2025-2029 ¹⁹
ADMS ²⁰	\$6.5	\$1.0	\$3.0	\$7.5	-
AMI ²¹	\$14.0	\$28.9	\$144.0	\$185.2	\$15.0
FAN ²²	\$14.7	\$37.3	\$36.8	\$3.8	-
FLISR	\$3.5	\$8.6	\$6.6	\$18.8	\$29.7
IVVO	\$0.1	\$6.5	\$9.8	\$18.6	-
Total	\$38.8	\$82.3	\$200.2	\$233.9	\$44.7

Table 8: Grid Modernization Capital Expenditures Budget – NSPM Electric (Millions)

In terms of grid modernization, ADMS represents approximately \$18.0 million in the 2020-2024 timeframe. Our full AMI deployment is planned to begin in 2021 and continue through 2024, with projected capital costs for AMI and FAN of approximately \$275.7 million through 2022, and approximately \$204 through the 2029 IDP period, for a total of approximately \$480 million.²³ FLISR implementation is planned to begin in 2021 and continue at a relatively steady rate through 2028, with projected capital costs of approximately \$18.7 million through 2022, and approximately \$48.5 through the 2029 IDP period, for a total of approximately \$18.7 million through 2022, and approximately \$48.5 through the 2029 IDP period, for a total of approximately \$67 million. Finally, IVVO implementation is planned to begin in 2021 and continue through 2024, with projected capital costs of approximately \$16.4 million through 2022, and approximately \$18.6 million through the 2029 IDP period, for a total of approximately \$204 million through 2022, and approximately \$18.6 million through 10.21 million through 2021 and continue through 2024, with projected capital costs of approximately \$16.4 million through 2022, and approximately \$18.6 million through the 2029 IDP period, for a total of approximately \$18.6 million through 2029 IDP period, for a total of approximately \$18.6 million through 2029 IDP period, for a total of approximately \$18.6 million through 2029 IDP period, for a total of approximately \$18.6 million through 2029 IDP period, for a total of approximately \$18.6 million through 2029 IDP period, for a total of approximately \$18.6 million through 2029 IDP period, for a total of approximately \$18.6 million through the 2029 IDP period, for a total of approximately \$35 million.

IDP Requirement 3.A.29 requires that we provide our planned distribution capital projects, including drivers for the project, timeline for improvement, and summary of

¹⁹ Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.

²⁰ Eligible for cost recovery through the TCR Rider.

²¹ Includes the TOU Pilot.

²² Includes the TOU Pilot.

²³ Note: Table 3 includes the AGIS O&M budgets as outlined in more detail in the AGIS section.

anticipated changes in historical spending – with the driver categories aligning with the IDP distribution spending categories. We provide this information as Attachments F1 and G1 to this filing.

b. O&M – Historical Actuals and Budgeted Expenditures

The O&M budget is composed of labor costs associated with maintaining, inspecting, installing, and constructing distribution facilities such as poles, wires, transformers, and underground electric facilities. It also includes labor costs related to vegetation management and damage prevention, which is primarily provided by contractors. Finally, it includes the fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system. We therefore generally track our Distribution O&M expenditures in the following groupings: (1) Internal Labor, (2) Contract Labor, (3) Fleet, and (4) Materials.²⁴

Unlike our capital budgets, where it was possible to undertake a manual process to assign projects to the proposed investment categories, the O&M budget does not lend itself to such a manual process. The Distribution O&M budgets are a compilation of many thousands of small expenditures, most of which are associated with operating or maintaining existing facilities. While there is often a small O&M component associated with capital projects, the amount is typically small, ranging from two to seven percent of project costs, on average, for distribution. This results in voluminous small O&M charges dispersed over many projects than cannot be aggregated in the now-required categories.

We have however been able to provide a partial "functional" view of both historical actuals and 5-year budgeted amounts. Because we have budgeted for AGIS as a specific initiative, we are able to portray the associated Distribution-only O&M amounts (Table 9), and a combined Distribution and Business Systems view (Table 10).

Additionally, while both the capital and O&M information we provide in this IDP are generally for the Distribution function, the O&M information is portrayed at the NSPM operating company level and the capital costs are for the State of Minnesota, and are not fully comparable.²⁵ An NSPM view of historical and budgeted O&M

²⁴ As we also explained in our 2018 IDP, the IDP categories do not correspond with our internal system tracking for capital or O&M.

²⁵ A "functional" view of a business area, in this case Distribution, are costs directly associated with that function, so will not include allocations for items such as shared services.

provides a directionally accurate view of the O&M costs for the state of Minnesota, as Minnesota represents the overwhelming majority of the NSPM operating company. Further, an NSPM operating company view also makes it possible to portray the corresponding Business Systems-related AGIS costs.

Figures 8 and 9 below provide a summary of historical actual and budgeted O&M costs in the most descriptive way that we were able to portray them given the reasons we have discussed. Following these Figures, we provide a description of the categories. Although only required for capital under IDP Requirement 3.A.29, we provide a similar view of our O&M costs over time, along with a brief narrative regarding year-over-year changes as Attachment G2 to this IDP.

Figure 8: Actual Historical Distribution O&M Costs by Cost Element NSPM Operating Company – Electric 2014-2018 (Millions)



Capital and OSM expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are \$27.9M and \$7.4M, respectively; Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Figure 9: Budgeted Distribution O&M Costs by Cost Element NSPM Operating Company – Electric 2020-2024 (Millions)



Capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are \$30.5M and \$8.6M, respectively; Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Labor and Labor (overtime/other). This category includes the labor and labor overtime associated with Xcel employee's to operation and maintain our electric distribution system. The labor pertains to the maintenance and operations of our electric distribution system. Overtime is primarily associated in response to outages, line faults, damages to our system and customer requested orders.

Contract Labor/Consulting. This category includes staff augmentation and contract outside vendors performing operations and maintenance work on our distribution systems. This also includes the delivery services for meters and transformers along with ancillary services such as barricades, flaggers, restoration, sand and gravel, etc. This is also the category where the majority of the AGIS dollars are budgeted.

Damage Prevention/Locating. This category includes costs associated with the location of underground electric facilities and performing other damage prevention activities. This includes our costs associated with the statewide "Call 811" or "Call Before You Dig" requirements, which helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents.

Vegetation Management. This category includes the work required to ensure that proper line clearances are maintained, maintain distribution pole right-of-way, and address vegetation-caused outages.

Employee Expenses. This category includes the costs associated with expenditures for training, safety

meetings, travel and conferences associated with our electric distribution systems.

Materials. This category represents costs associated with miscellaneous materials and tools necessary to build out, operate, and maintain our electric distribution system.

Transportation. This category represents costs associated with the Distribution fleet (vehicles, trucks, trailers, etc.) necessary to build out, operate, and maintain our electric distribution system, including annual fuel costs plus an allocation of fleet support.

Miscellaneous Other. This category represents the OCM expenditures that include office supplies, janitorial costs, dues, donations, permits, electric use costs, electric safety clothing for the crews, permits and other various items minor costs.

The First Set Credits. This category is the credit for the costs (labor, materials, transportation) in O&M associated with the installation of new meters and transformers.

Table 9 below provides a snapshot of our 2020-2024 O&M distribution budget.

	Bridge			Budget			Budget Avg
Expenditure Category	2019	2020	2021	2022	2023	2024	2020-2024
Labor	\$53.8	\$58.3	\$59.8	\$60.5	\$61.6	\$63.6	\$60.8
Cont. Outside Vendor/Contract Labor	\$17.1	\$8.9	\$12.9	\$9.7	\$8.7	\$8.6	\$9.8
Damage Prevention Locates	\$8.3	\$8.5	\$8.6	\$8.6	\$8.6	\$8.6	\$8.6
Vegetation Management	\$29.0	\$28.2	\$28.9	\$28.4	\$30.2	\$30.1	\$29.2
Materials	\$5.9	\$6.9	\$6.8	\$6.8	\$6.8	\$6.8	\$6.8
Transportation Costs	\$7.4	\$6.9	\$6.8	\$6.8	\$6.8	\$6.8	\$6.8
AGIS	\$0.6	\$2.8	\$4.5	\$6.8	\$8.8	\$6.5	\$5.9
Misc. Other	(\$0.2)	(\$3.9)	(\$3.6)	(\$3.6)	(\$3.4)	(\$3.5)	(\$3.6)
TOTAL	\$121.9	\$116.6	\$124.7	\$124.0	\$128.1	\$127.5	\$124.2

Table 9: Distribution O&M Expenditures Budget –NSPM Electric Jurisdiction

Capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; Misc Other includes bad debt, First Set Credits, use costs, office supplies, janitorial, dues, donations, permits, etc.

Significant O&M expenditures in the Distribution 5-year budget include the incremental programs of AGIS and ISI.

Consistent with how we present the capital budget for our grid modernization investments, we separately present the O&M to provide a complete view of both Distribution and Business Systems amounts. See Table 10 below.

	Rate	Case Peri	5-Year Period	10-Year Period	
AGIS Component	2020	2021	2022	2023-2024	2025-2029 ²⁶
ADMS ²⁷	\$1.9	\$2.5	\$2.5	\$6.9	\$5.2
AMI ²⁸	\$6.6	\$16.4	\$14.1	\$25.2	\$67.2
FAN ²⁹	\$0.1	\$2.3	\$1.5	\$0.5	\$8.6
FLISR	\$0.2	\$0.4	\$0.3	\$3.3	\$2.5
IVVO	\$0.0	\$0.4	\$0.8	\$0.6	\$0.8
Total	\$8.8	\$22.0	\$19.2	\$36.5	\$84.3

Table 10: Grid Modernization O&M Expenditures Budget – NSPM Electric (Millions)

In terms of grid modernization, ADMS represents approximately \$19 million of O&M in through the 2029 period of this IDP. AMI and FAN comprise approximately \$41 million of O&M through 2022, and approximately \$101 million through the 2029 IDP period, for a total of approximately \$142 million.³⁰ FLISR has projected O&M costs of approximately \$0.9 million through 2022, and approximately \$5.8 through the 2029 IDP period, for a total of approximately \$6.7 million. Finally, IVVO has projected O&M costs of approximately \$1.2 million through 2022, and approximately \$1.4 million through the 2029 IDP period, for a total of approximately \$2.6 million.

E. Distribution System Plan Summary

We summarize our near-term and long-term action plans below, and discuss them in more detail in Section XIV of this IDP.

The first five years of our action plan will be focused on providing customers with safe, reliable electric service, advancing the distribution grid with foundational capabilities including AMI, FAN, FLISR, and IVVO – and procuring and integrating

^{1. 5-}Year Action Plan

²⁶ Period may include additional assumptions, including inflation and labor cost increases that are not part of the O&M budget in periods 2020-2024.

²⁷ Eligible for cost recovery through the TCR Rider.

²⁸ Includes the TOU Pilot.

²⁹ Includes the TOU Pilot.

³⁰ Includes the TOU Pilot

an enhanced system planning tool to improve our load forecasting capabilities and increase our DER and NWA analysis capabilities.

After finalizing procurement of the advanced planning tool, we will begin design, implementation, testing over the next several months. We plan to begin using the new planning tool in our distribution planning processes by late 2020 – utilizing it for our annual planning process in Fall 2020 for the 2021-2025 period. We discuss the actions specific to our proposed advanced planning tool in more detail in Attachment D1.

We summarize our proposed AGIS deployment below:

Program	Implementation Timeline
ADMS	In-service 2020
AMI	Meter roll-out 2021-2024
FAN	Deployment 2021-2024 (preceding AMI deployment approximately six months)
FLISR	Limited testing 2020; Implementation 2020-2028
IVVO	Limited testing 2021; Implementation 2021-2024

Table 11: Deployment Timeline

With respect to our ADMS initiative, we will be submitting an initial and ongoing annual reports in accordance with the Commission's September 27, 2019 Order in the Company's Transmission Cost Recovery (TCR) Rider Docket.³¹ The timeline for the initial report is 120 days after the date of the Order (January 25, 2020); the timing and procedure for the annual report will be set by the Executive Secretary. Because the initial and ongoing annual reports contain most of the same elements, we propose to submit a single ADMS report by January 25, 2020 in the TCR docket and this IDP docket that contains all of the required information. We also respectfully request that the Executive Secretary establish the same January 25th due date for the ongoing annual ADMS reports beginning January 25, 2021 – and that they be filed in the same docket as future IDPs.

Finally, we will also begin implementing our ISI initiative, with projects starting in the 2021-2022 timeframe.

2. Long-Term Action Plan

Long-term, we are focused on continuing to provide our customers with reliable and

³¹ Docket No. E002/M-17-797.

safe service – and advancing the grid at the speed of value for our customers. In terms of grid advancement, the below figure shows the sequencing of planned and potential advanced grid investments over time and constitutes our advanced grid roadmap.



Figure 10: Advanced Grid Initiatives – Present to 2030 View

Each of these investments will provide discrete customer benefits and the combination of these investments over time will enable more sophisticated capabilities as we discuss and detail in the accompanying rate case AGIS Direct Testimony provided as Attachments M1 through M5 to this IDP.

3. Projected Customer and System Impacts

Our implementation of the ADMS in early 2020 is preparing the grid for increasing levels of DER. It is also paving the way for further grid advancement with AMI and our ability to leverage the underlying and necessary FAN to reduce customers' energy costs through IVVO, improve customers' reliability experience through FLISR, and more.

Customers will have access to granular energy usage data from our AMI through a

customer portal, which we expect to pair with informed insights and helpful tips on how to change their behavior to save energy. Further, the AMI meters we propose include a Distributed Intelligence platform, which essentially provides a computer in each customer's meter that will be able to "connect" usage information from the customer's appliances for further insights – and be updated with new software applications, much like customers can currently update their mobile devices with applications.



Figure 11: Customer Value through Lifecycle

In terms of bill impacts from our AGIS investments, the below table illustrates the incremental cost of pursuing our AGIS investments compared to the investments that would otherwise be necessary.

	2020	2021	2022	2023	2024
AGIS	\$0.44	\$1.33	\$1.84	\$2.58	\$2.87
Reference Case	\$.01	\$0.19	\$0.62	\$1.18	\$1.51
Difference	\$0.43	\$1.14	\$1.22	\$1.40	\$1.36

Table 12: Estimated Monthly Bill Impact –Typical Residential Customer

The costs of AGIS will be spread over the implementation period, which reasonably manages the cost impact for our customers. We discuss these calculations and the significant non-quantifiable impacts in Section IX and X of this IDP and in the accompanying MYRP Direct Testimonies of Company witnesses Mr. Gersack, Ms. Bloch, Mr. Harkness, Mr. Cardenas, and Dr. Duggirala.

III. BUDGET DEVELOPMENT FRAMEWORK

This section discusses Xcel Energy's overall budget development, as well as the Distribution organization's specific budget development processes.

A. Overview of Xcel Energy's Overall Budgets

Electric and gas utilities are long-term, capital intensive businesses. Every year, we prepare a five-year financial forecast that is used to anticipate the financial needs of each of the Xcel Energy operating utility companies, including NSPM. The five-year forecast provides the information necessary to make strategic and financial decisions to address these needs, and to develop supportable and attainable financial plans for each operating utility subsidiary and for Xcel Energy overall. Key components of the five-year financial forecast are the O&M and capital expenditure five-year budgets for each of Xcel Energy's operating utility subsidiaries, including the NSPM.

When a five-year budget is created and approved, the first year budget is essentially "locked in." However, budgets for the subsequent years 2-5 will be reevaluated in the next budgeting cycle, and will necessarily change in response to new developments and as business requirements change. As we get closer to when spending will occur, our forecasts become more refined, based on more relevant information for the upcoming period, and forecasted expenditures are adjusted accordingly.

To a large extent, the O&M and capital budgeting process are the same. The capital budget process however, requires additional steps and approvals for capital projects with expenditures over \$10 million. Likewise, capital projects with expenditures over \$50 million also require additional steps. In terms of review and oversight of expenditures after budgets are finalized, we conduct the same monthly review and variance analysis for both O&M and capital expenditures – and an additional comprehensive review on a quarterly basis.

B. Distribution Budget Framework

We begin our budgeting process in October by reviewing the recent summer peak loads to identify new or increased risks, as discussed in the System Planning section of this IDP. The state of the economy has a significant impact on the development of new and expanded business, conditions that drive new housing, large commercial load increases, and road work projects that affect distribution facilities. Consequently, our budgeting process begins with economic forecasting and analysis of historical spending trends to assess likely new business needs, required replacement of assets, and relocation of distribution facilities to accommodate road construction. We also assess the likely impacts of system growth on our capacity needs, including the risk of overloads and the system's ability to handle single contingency events.

Although economic factors drive much of our budget, we also must ensure that the existing system remains reliable. This includes proactively replacing assets near the end of their life as well as budgeting for replacement of facilities due to unanticipated failure or damage such as those facilities damaged during storms. To budget for proactive replacements, we evaluate the age and condition of facilities and determine the amount of replacement or refurbishments that are needed in a particular year. To budget for unanticipated failures, we forecast the likely costs of replacing assets that will fail or be damaged based on historical trends. This analysis results in an identification of capital projects that are needed for routine work necessary to maintain our existing system and the work required to support new customers or new construction.

The nature of the distribution system is that we must account for regular, common capital additions needed to support new business growth, system reinforcements, or rebuilds. This routine work can also include material upgrades to the distribution network, such as reconductoring a line, upgrading a distribution transformer, or replacing a substation regulator. The two largest categories of routine capital additions are cable replacements and transformer purchases.

Our budgeting process also provides flexibility to efficiently allocate funds for performing core business functions. After the preliminary forecasts estimating our new service needs have been determined, the data is reviewed with our management to determine if there will be substantial changes in the operations (e.g., crew mix, major projects, and labor issues). Depending on the outcome of these reviews, adjustments are made to the preliminary forecast and the proposed routine work order budgets are then submitted for final approval.

The budget process that we utilize has generally proven to be an accurate gauge of the routine work that will be performed each year. However, sometimes there are storms or new business fluctuations that can lead to unexpected increases in our routine work. When these circumstances arise, we seek to actively control our expenditures to stay as close to budget as reasonably practicable by prioritizing our work and allocating funds accordingly. For example, if we have a significant increase in required relocations in a given year, this may cause us to have to decrease funding in other areas. Our work on these required relocations – even when we have been given very short notice – cannot be deferred due to our contractual obligations. To maintain investment levels we must defer controllable projects which can reasonably be reduced upon short notice.

In addition to our routine work orders, the Distribution business area also budgets for and implements certain discrete projects that are identified to address a particular need that does not reoccur each year. At a high level, the identification and assessment of problems or "risks" along with their related solutions or "mitigations" is integral to identifying larger projects we must also fund. Risks are issues that can result in negative consequences to the Company's ability to provide safe and reliable service. Mitigations are solutions that address the risks. To help ensure that each risk is being addressed by the most efficient solution, we assess all mitigation alternatives and select the one that provides the best value to our customers and our Company.

All the risks and mitigations are submitted as project requests and entered into RiskRegister, a software tool developed by the Company and used to track and rank projects based on the inputs, which include information regarding their annual costs and benefits. Budgeting personnel focus on the health and age of our existing assets, standardization, and mitigation of risk, and provide coordination and consistency in evaluating individual project requests with the Distribution organization. Engineering and operations personnel then work with budgeting personnel around each risk to evaluate and score each mitigation individually before ranking the projects. The factors that are used to score the identified risks and proposed mitigations are as follows:

- Reliability Identification of overloaded facilities, potential for customer outages, annual hours at risk, and age of facilities;
- *Safety* Identification of yearly incident rate before and after the risk is mitigated;
- *Environmental* Evaluation of compliance with environmental regulations. To the extent this factor applies to the project being evaluated, it is prioritized, however this factor is not usually applicable;
- Legal Evaluation of compliance before and after the risk is mitigated; and
- *Financial* Identification of the gross cash flow, such as incremental revenue, realized salvage value, incremental recurring costs, etc., and identification of avoided costs such as quality of service pay-outs and failure repairs.

An analysis of these factors results in a proposed project list that is ranked. The highest priority is given to projects that Distribution must complete within a given budget year to ensure that we meet regulatory and environmental compliance obligations and to connect new customers.

1. Capital Budget Development

Historically, the overwhelming majority of Distribution's capital budget has been dedicated to maintaining the health and reliability of our facilities through replacement of aging or damaged equipment. Our planned investments continue to demonstrate a commitment to the Company's priorities of safety, reliability, and also enhancing the customer experience. As an example of our commitment to safety and the environment, as of the end of May 2019, we completed work on an LED street light replacement program that resulted in the conversion of 85,000 cobra head style streetlights from high-pressure sodium or mercury vapor streetlights to more energy efficient LED streetlights across Minnesota. The switch to LED lights improves safety as these lights improve nighttime visibility for both drivers and pedestrians. Another example of our commitment to safety is our pole replacement program which takes a methodic approach to replacing poles that have reached their life. This program ensures that our lines and equipment are supported by quality wood poles.

Our focus on the customer experience has been demonstrated through our timely response to customer electrical needs. For instance as the economy grew over the past several years, this spurred new residential and commercial development, which required Distribution to install an increased number of service extensions. We responded to this rise in requests and met our customer's expectation for timely electrical connections. We also responded to customer demands to relocate our facilities due to an increased number of road construction projects in the metro area driven by the strong economy.

In the area of reliability, our capital budgets reflect a focus on maintaining the health of our existing facilities through established asset health and reliability programs with increasing investments in pole replacements. However, additional investment is needed and our capital budgets during this time period also include investments in our ISI initiative. The ISI initiative focuses primarily on the heath, reliability, and resiliency of the portions of our system that are closest to our customers such as feeder and tap lines.

Our capital budgets also show increasing strategic investments in the Company's AGIS initiative to advance distribution grid capabilities, increase our system visibility and control, and to enable expanded customer options. We will invest in the foundational elements of AGIS such as advanced meters, a FAN communication network, FLISR outage detection and restoration, and IVVO voltage improvement. These foundational elements, in concert with future investments, will provide cumulative benefits that will improve the operation and maintenance of the distribution system while also providing an improved customer experience. While we

do not know exactly what the future will hold in terms of new technology or customer adoption rates of EVs and solar, we do know that the set of investments that we are proposing here are the right first building blocks.

We are also responding to customer expectations by expanding our EV program. This includes several pilot programs that were recently approved by the Commission, a fleet EV service pilot, a public charging pilot, and a residential subscription service pilot, as well as pilots and programs highlighted in the Company's recently filed Transportation Electrification Plan. These investments will provide the infrastructure necessary to promote greater EV use and to meet the demands of the growing EV market.

The budget process that we utilize has generally proven to be an accurate gauge of the routine work that will be performed each year. However, sometimes there are storms or new business fluctuations that can lead to unexpected increases in our routine work. When these circumstances arise, we seek to actively control our expenditures to stay as close to budget as reasonably practicable by prioritizing our work and allocating funds accordingly. We illustrate below the variability of storm restoration over the recent past.



Figure 12: Illustration – Storm Restoration Variability

In this way, the Distribution organization is unique from many other business units. While we are confident in our overall level of budgeting and our ability to manage within those annual budgets, the realities of our business require some flexibility within those budgets to respond to changing economic conditions, weather events, and evolving priorities. That being said, we are proud of our successful storm response efforts, reputation for reliable service, and our ability to manage our budget within its bounds and react and reprioritize as necessary each year to ensure our customers continue to receive safe and reliable electric service.

Our capital projects fall into eight capital budget groupings depending on the primary purpose of the project. Distribution has a well-defined process for identifying and determining our investments within these eight capital budget groupings. These groupings are:

• Asset Health and Reliability (IDP Categories: Age-Related Replacements and Asset Renewal and System Expansion or Upgrades for Reliability and Power Quality). Projects in this category are related to replacing infrastructure that is experiencing high failure rates and, as a result, negatively impacting the reliability of service and increasing O&M expenditures needed to repair this equipment. When poor performing assets are identified, projects that will improve asset performance are included in the budget. Projects in this category include replacement of underground cable, wood poles, overhead lines, substation equipment, transformers, and switchgear that have reached the end of their life. This category also captures replacements due to storms and public damage.

Beginning in 2021, the Asset Health and Reliability category will include investments associated with our ISI Initiative. The ISI Initiative will expand our existing Asset Health programs, such as cable replacement, and establish new programs such as targeted undergrounding to address the health, reliability, and resiliency of the portion of the distribution system that is closest to our customers. Additionally, portions of the ISI Initiative will further customer choice and control by improving elements of the grid closest to our customers that can improve the ability to host additional DER such as solar or EVs.

• *AGIS (IDP Category*: Gird Modernization and Pilots). Traditionally, investments that advance the grid were budgeted in our Asset Health category. This is because when we sought to replace aging equipment with new equipment we also evaluated whether the functionality of a particular asset could be or should be enhanced to promote grid modernization. For instance, we replaced electro-mechanical relays with solid-state relays, which are not only communication enabled – but are also capable of providing fault data to allow us to more quickly identify faults on our system and improve our response time. Beginning in 2019 as we launched our AGIS initiative, we separated these investments into their own budget category of AGIS. The AGIS

initiative will improve power reliability, reduce power outages, integrate increasingly clean energy onto the grid, and empower customers with more information to control and track their energy use.

- New Business (IDP Category: New Customer Projects and New Revenue): This work includes new overhead and underground extensions and services associated with extending service to new customers. Capital projects required to provide service to new customers include the installation or expansion of feeders, primary and secondary extensions, and service laterals that bring electrical service from an existing distribution line to a new home or business.
- *Capacity (IDP Category: System Expansion or Upgrades for Capacity)*: This category includes capital investments associated with upgrading or increasing distribution system capacity to handle load growth on the system and to serve load when other elements of the distribution system are out of service. This includes installing new or upgraded substation transformers and distribution feeders. Capacity projects generally span multiple years and are necessitated by increased load from either existing or new customers.
- *Mandates (IDP Category: Projects related to Local (or other) Government-Requirements).* This category covers projects to relocate utility infrastructure in public rightsof-way when mandated to do so to accommodate public works projects such as a road widening or realignment project. These projects generally trend with the availability of municipal and state funding for public works projects. Mandate projects typically result in updated distribution infrastructure.
- *Tools and Equipment (IDP Category: Other).* This category includes tools, equipment, communication equipment, and locate costs associated with modifications or additions to the distribution system or supporting assets.
- *Electric Vehicle Program (IDP Category: Grid Modernization and Pilots).* This category includes the capital costs associated with three EV pilot programs that were approved by the Commission in 2019 the fleet EV service pilot, the public service pilot, and the residential EV subscription service pilot. The fleet EV service pilot aim to make it easier for large fleet operators like Metro Transit, the Minnesota Department of Administration, and the City of Minneapolis to integrate electric vehicles into their fleets. The goal of the public service pilot is to begin to build a fast charging network along major corridors and community mobile hubs in the Twin Cities to allow people the ability to quickly charge their EVs away from home. The residential subscription service pilot is designed to provide a simple, easy-to-understand charging experience while encouraging off-peak charging. Additionally, the Company has included budget information for other pilots and programs we have highlighted in our

Transportation Electrification Plan.

• Solar Gardens (IDP Category: Non-Investment). This category includes the distribution costs associated with interconnecting solar gardens to the distribution system as well as providing service extension to allow electric service for any auxiliary electric needs. The costs for these facilities are billed to the developer at several different increments throughout the development and construction of the solar garden. Once payment is received and the work is completed by Distribution, a credit is applied to this category.

2. OcM Budget Development

The Distribution O&M budget includes labor costs associated with maintaining, inspecting, installing, and constructing distribution facilities such as poles, wires, transformers, and underground electric facilities. It also includes labor costs related to vegetation management and damage prevention. Finally, it includes miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system and fleet (vehicles, trucks, trailers, etc.). Specifically, the O&M component of fleet are those expenditures necessary to maintain our existing fleet. This includes annual fuel costs plus the allocation of fleet support to O&M based on the proportion of the Distribution fleet utilized for O&M activities as opposed to capital projects.

Our O&M budgeting process takes into account our most recent historical spend in all the various areas of Distribution and applies known changes to labor rates and non-labor inflationary factors that would be applicable to the upcoming budget years. We also "normalize" our historical spend for any activities and/or maintenance projects embedded in our most recent history that we would not expect to be repeated in the upcoming budget years (e.g., excessive storm activities or one-time O&M projects). We then couple that normalized historical spend information with a review of the anticipated work volumes for the various O&M programs and activities we perform, factoring in any known and measurable changes expected to take effect in the upcoming budget year. For example, for our major maintenance programs such as cable fault repairs and vegetation management, we review annual expected units/line-miles to be maintained and ensure required O&M dollars are adjusted accordingly.

We also factor in any expected efficiency gains we believe would be captured by operational improvement efforts we continuously are working on within our processes and procedures, along with productivity improvements we would expect to achieve via the implementation or wider application of new technologies. These improvements are already factored into our O&M budgets.

Given that no year ever transpires exactly as predicted or forecasted, we typically update our O&M expenditure forecasts during the year. As with our capital investments, one of our largest annual sensitivities for O&M expenditures is severe weather. The amount of O&M we spend on weather-related events, such as storm restoration and floods, can vary greatly from one year to the next. In addition, the Distribution business unit will periodically receive a request from the Company to adjust O&M costs within the financial year to account for changes in business conditions in other areas of the Company. When a greater need for expenditures in a particular area is identified, we try our best to re-prioritize and reallocate our budgeted O&M dollars while still operating within our overall O&M budget. However, there are times where circumstances dictate that, in order to maintain safe, reliable service at the levels our customers expect, we will need to spend more than our overall budget would allow to properly address certain items that come about during a given budget year.

Our annual O&M expenses are influenced by the magnitude and frequency of significant severe weather and storm restoration activities that occur throughout our service territory. The unpredictable nature of severe weather makes budgeting challenging as there is no such thing as a "typical" year for severe weather. The below table highlights the variability of O&M spending *over and above* base labor and transportation (i.e., overtime, materials, contractors) for storm restoration events from 2014 to 2018.

2014 Actual		2015 A	Actual 2016 Actual		Actual	2017 A	Actual	2018 Actual	
NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur
\$3.0	\$2.8	\$2.6	\$2.3	\$2.8	\$2.6	\$1.1	\$1.1	\$1.9	\$1.7

 Table 13:
 2014-2018 Annual O&M Storm Restoration Expenses (Dollars in Millions)

As shown in this table, we experienced a moderate increase in O&M expenses related to storm restoration due to severe weather in 2014 and 2016, but nothing as significant as the \$6.35 million NSPM (\$6.0 million Minnesota jurisdiction) storm restoration expenses incurred by the Company due to a series of severe storms in the Twin Cities in 2013. Thus far in 2019, we are forecasting storm expenses of \$5.0 million – or \$2.6 million higher than the average of the previous five years. This increase is the result in a greater than average number of storms for 2019 as compared to prior years.

During the current year, we are routinely monitoring our O&M actual expenditures as compared to the budget and identifying any variances of significance as they materialize. As budget pressures are identified in certain areas or programs, we review options to mitigate those pressures as best we can. One mitigation option is to reallocate from other areas of the budget where funds for budgeted work of a lower priority and/or more discretionary nature (in the short-term) to cover the areas or programs experiencing the budget pressures. Such reallocations are considered as long as the amount of funding needed to cover the budget pressure is within a level that can be prudently covered within our overall budget allocation. If the amount of the budget pressure is too significant to accommodate via reallocations to O&M budgets, we then seek adjustments to year-end targeted expenditures where we would forecast an overall expenditure level exceeding our overall Distribution O&M budget. Significant deviations from existing budgets must be formally requested of and granted or denied by the Finance Council.

IV. SYSTEM OVERVIEW

In this Section, we provide an overview of Xcel Energy and a snapshot of distribution system statistics for the Company, as well as a financial overview of the Distribution business area and budgets.

A. Xcel Energy Overview

Xcel Energy is a major U.S. electric and natural gas company based in Minneapolis, Minnesota. We have regulated operations in eight Midwestern and Western states – Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin – where we provide a comprehensive portfolio of energy-related products and services to approximately 3.6 million electricity customers and 2 million natural gas customers. Our Upper Midwest service area is part of an integrated system of generation and transmission made up of two operating companies –NSPM, which serves Minnesota, North Dakota and South Dakota; and Northern States Power Company –Wisconsin (NSPW), which serves Wisconsin and Michigan – collectively referred to as the NSP System. Xcel Energy serves over 1.9 million customers in its NSP service territories as shown below.


Figure 13: Xcel Energy Service Areas

Approximately 88 percent of our NSP customers are residential, with commercial and industrial customers comprising most of the remaining 12 percent. The distribution of electricity sales by type of customer, however, is significantly different. Residential customers make up approximately 29 percent of electricity sales, with commercial and industrial customers making up most of the remaining 71 percent.

B. Distribution System Overview

The electrical grid is composed of generating resources, high voltage transmission, and the distribution system, which is the vital final link that allows the safe and reliable flow of electricity to serve our customers as shown below.



Figure 14: Illustrative Electrical Grid

As illustrated above, the poles, lines, and cables that comprise the distribution system connect individual residents and business to the larger electrical grid.

The NSPM electric distribution system serves 1.5 million customers (1.3 million in Minnesota)³² – and is composed of 1,177 Feeders, approximately 15,000 circuit miles of overhead conductor on over 500,000 overhead poles, and over 11,000 circuit miles of underground cable. This network of feeders connects over 26,000 miles of distribution lines and 270 distribution-level substations across the NSPM system. The distribution portion of the grid, and the services that the Distribution organization provides, are generally the aspects of our electric service that are most visible to our customers. In terms of reliability, we rank nationally in the 2nd quartile.³³

The key functions of the Distribution organization include operating the distribution system, restoring service to customers after outages, performing routine maintenance, constructing new infrastructure to serve new customers, and making upgrades necessary to improve the performance and reliability of the distribution system. There are approximately 1,300 employees assigned to provide services to the NSPM distribution system. These employees are assigned to one of the five functional areas within Distribution: Distribution Operations, Engineering, Business Operations, AGIS and Metering, and Planning and Performance. The key responsibilities of these

³² In this context, the number of customers is based on the number of electric meters.

³³ Results for the NSPM operating company, as measured by SAIDI. *See IEEE Benchmark Year 2019, Results for 2018 Data* at: <u>http://grouper.ieee.org/groups/td/dist/sd/doc/</u>

four functional areas include:

- *Operations*. Responsible for the design, construction, and maintenance of the distribution system, as well as monitoring and operating the system from the Electric Control Center, responding to electric distribution trouble calls, and coordinating emergency response;
- *Engineering*. Provides technical support and system planning, including addressing distribution-related customer service issues;
- *Business Operations*. Responsible for several areas, including vegetation management, outdoor lighting, facility attachments, and the builders call-line.
- *AGIS and Metering.* Responsible for implementation of the AGIS initiative and metering.
- *Planning and Performance*. Provides business planning, consulting, analytical services and performance governance and management.

Distribution's 2019 key priorities are as follows:

- Achieve operational excellence: improve reliability performance level in 2019
- *Grid Modernization*: Targeted renewal of aging, unreliable, or obsolete components and systems (i.e. underground cable, poles, 4kV systems)
- *Distribution System Intelligence*: Installation of key equipment and systems to operate the new modern grid including, monitoring and control, DMS, and system efficiency
- *System Health*: Targeted maintenance of key assets designed to improve reliability and safety wood poles, substation transformers & breakers, vegetation management
- *System Capacity Additions*: Installation or reinforcement of key substations and feeders to serve new load and provide backup under emergency conditions (focus on high consequence events)

C. Distribution System Statistics

The Commission's Order setting the IDP requirements includes several distribution system statistics, which we provide below.

1. Summary of existing system visibility, measurement, and control capabilities

IDP requirement 3.A.2 requires the following:

Percentage of substations and feeders with monitoring and control capabilities, planned additions.

IDP requirement 3.A.3 requires the following:

A summary of existing system visibility and measurement capabilities (feeder-level and timeinterval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual).

These two requirements are intertwined with each other because they both pertain to system visibility. Therefore, we have combined the information required in Items 3.A.2 and 3.A.3 into Table 14 below.

FLM Type	% of subs ¹	Measurement	Measurement Interval	Automated /Manual	Frequency of reads	Min/ Max	Daytime/ Nighttime
Full FLM	42%	3 phase Amps, MW, MVar, MVA, kV	Hourly	Auto	Continuous ²	Yes- Manual effort	Both
Partial FLM	21%	Has some or most of the above data points, varies by location	Hourly	Auto	Continuous ²	Yes- Manual effort	Both
No FLM	37%	Only manual reads available (provides 3 phase Amps)	Varies	Manual	Varies	No	Neither

Table 14: Feeder Load Monitoring – State of Minnesota

Note: Approximately 90% of our customers are served by substations and feeders that have Full or Partial FLM.

¹ Percentages are based on a total of 240 substations in Minnesota.

² While there is continuous data flow to the operation center, only hourly data is maintained in the data warehouse.

Our SCADA system provides information to control center operators regarding the state of the system and alerts when system disturbances occur, including outages. This includes control and data of our system, and we frequently refer to the data acquisition portion as Feeder Load Monitoring (FLM). A substation that has SCADA almost always contains both FLM and control. However, there may be substations where we do not have FLM, but we do have control.

Generally, our SCADA collects hourly peak load information at the feeder and substation transformer levels over an entire year as the inputs to our planning process. Ideally, this includes three phase Amps, MW, MVar, MVA, and Volts. However, not all of these data points are available for all locations. For internal tracking and reporting purposes, when all three-phase Amps, MW, MVar, and kV are included on all feeders and two of the following three for the substation transformers (MW, MVar, or MVA) then that counts as full FLM. If we are missing one or more data points at the substation, it will fall under partial FLM. If we have nothing, then it falls under no FLM. Our SCADA-enabled substations and feeders serve approximately 90 percent of our customers (*Note*: Most of our non-SCADA substations are in rural areas).

Our SCADA also collects enough information throughout the course of a year to determine daytime minimum load for all feeders equipped with this functionality, but it takes extra manual effort to derive a daytime minimum load (DML). As discussed further below, in 2019 we prioritized the tracking and updating of DML and have determined and updated historical DML for all of our feeders and substation transformers that have load monitoring.

For no FLM and some partial FLM substations, on approximately a monthly basis, field personnel collect data, including peak demands for feeders and transformers. Peak load values are recorded in the field and entered into a database that engineering accesses and uses for planning purposes. After the recordings are documented, field personnel reset the peak load register, so the following period's data can be accurately captured without influence from the previous period. Because this is a manual process, the data may have gaps or may not occur at precise monthly intervals.

We additionally note that we have control capabilities at 63 percent of our substations. Similar to customers served from substations and feeders with full- or partial-FLM, approximately 90 percent of our customers are served by substations and feeders that have control capabilities.

Given the importance of SCADA capabilities to reliability and load monitoring (for planning and due to increasing levels of DER), in 2016 we embarked on a long-term plan to install SCADA at more distribution substations – calling for installation of SCADA at 3-5 substations each year. In addition, when we add a new feeder or transformer in a new or existing substation, we equip them with SCADA.

2. Numbers of AMI Customer Meters and AMI Plans

IDP requirement 3.A.4 requires the following:

Number of customer meters with AMI/smart meters and those without, planned AMI investments, and overview of functionality available.

We began installing AMI meters for Minnesota TOU pilot customers in 2019 and we expect to install a total of 17,500 AMI meters, which will be complete in early 2020. We propose to begin implementing a full rollout of AMI across our service territory

in 2021, and expect our implementation to be complete in 2024.

3. Estimated System Annual Loss Percentage

IDP requirement 3.A.8 requires the following:

Estimated distribution system annual loss percentage for the prior year.

The Edison Electric Institute (EEI) defines electric losses as the general term applied to energy (kilowatt-hours) and power (kilowatts) lost in the operation of an electric system.

Losses occur when energy is converted into waste heat in conductors and apparatus. Demand loss is power loss and is the normal quantity that is conveniently calculated because of the availability of equations and data. Demand loss is coincident when occurring at the time of system peak, and non-coincident when occurring at the time of equipment or subsystem peak. Class peak demand occurs at the time when that class' total peak is reached.

There are five categories or distribution subsystems where specific losses occur. Within these categories there may be load and no-load losses, as summarized in Table 15 below.

Category	Load Losses	No-Load Losses			
Distribution Primary Transformers	Yes	Yes			
Primary Distribution Lines	Yes	No			
Distribution Secondary Transformers	Yes	Yes			
Service Lines and Drops	Yes	No			
Meters	No	Yes			

 Table 15: Categories of Load and No-Load Losses

For example, transformers have both load and no-load losses. Load losses are function of the transformer winding resistance and the load current through the transformer; sometimes these losses are called copper losses. Transformers and electric meters have also no-load losses which are a function of voltage. Voltages in US power systems are relatively constant, so no-load losses are considered relatively constant. Sometimes no-load losses are called iron or excitation losses.

Losses are estimated using engineering calculations and load research class customer load profiles, because advanced technologies and equipment to specifically measure actual losses across the transmission and distribution systems have historically been cost-prohibitive to implement.

Advanced technologies have been implemented on the transmission system that makes actual calculations of transmission losses more of a practical reality within the next year or so. However, advancements like this at the distribution level lag transmission due to the nature of the distribution system, which requires the advanced technologies to be implemented on a much more wide scale. However, our investments in AMI, FAN, and grid sensing and controls technologies as part of our advanced grid initiative will further our capabilities to mature this analysis over time.

The engineering analysis underlying our calculated losses used Company equipment records to determine numbers and sizes of distribution system lines and transformers, and engineering models to calculate losses from average loadings based on metered sales data through various distribution system components.

The average loading method calculates losses based on the ratio loading on each of the following system components to the maximum of the components:

- Distribution substation transformers
- Primary lines
- Primary to primary voltage
- Transformers
- Distribution line transformers
- Secondary distribution lines

From this analysis, we perform calculations monthly to update the loss percentages for each system level, and then apply those percentages to sales.

The process to update the loss percentages is as follows:

- 1. Gather five years of monthly MWh energy and sales by state.
- 2. Calculate the difference of energy and sales for each of the months in the 5year timeframe.
- 3. Calculate a MWh loss percentage from the original MWh energy values by month in the 5-year history.
- 4. Calculate a 5-year average by month, using the values derived in step 3.
- 5. At this point, calculate a 5-year annual average using the values from step 4.

- 6. The values from step 5 are then used to represent current losses in each given state.
- 7. The overall losses by state described in step 6 are then used to update losses at each voltage level the engineering loss study completed.

This process resulted in the 2019 loss percentages for the state of Minnesota, as provided in Table 16 below.

Voltage Level	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bulk(UT)	0.9750	0.9745	0.9724	0.9727	0.9761	0.9778	0.9770	0.9770	0.9767	0.9755	0.9747	0.9745
Bulk(T)	0.9691	0.9687	0.9665	0.9671	0.9708	0.9726	0.9715	0.9716	0.9717	0.9704	0.9689	0.9687
Tran(UT)	0.9638	0.9634	0.9610	0.9620	0.9661	0.9676	0.9663	0.9666	0.9673	0.9659	0.9637	0.9633
Tran(T)	0.9621	0.9618	0.9594	0.9604	0.9647	0.9661	0.9647	0.9652	0.9659	0.9645	0.9621	0.9616
Subtran(UT)	0.9543	0.9541	0.9516	0.9529	0.9581	0.9590	0.9574	0.9583	0.9593	0.9582	0.9545	0.9537
Subtran(T)	0.9485	0.9483	0.9459	0.9472	0.9521	0.9527	0.9507	0.9519	0.9534	0.9525	0.9486	0.9478
Primary	0.9350	0.9361	0.9344	0.9354	0.9380	0.9341	0.9297	0.9331	0.9387	0.9399	0.9355	0.9344
Large secondary	0.9221	0.9227	0.9202	0.9211	0.9246	0.9209	0.9166	0.9199	0.9249	0.9254	0.9220	0.9214
Small Secondary	0.9133	0.9136	0.9110	0.9113	0.9125	0.9069	0.9016	0.9068	0.9127	0.9154	0.9127	0.9124

 Table 16:
 2019 System Loss Percentages – State of Minnesota

We discuss the amount of reduced line losses that we expect in Minnesota as a result of our proposed IVVO project in the AGIS Direct Testimony of Ms. Kelly Bloch provided as Attachment M2. Ms. Bloch also discusses the current methods for measuring distribution line losses and what it would take to measure actual distribution losses on the distribution system, which we summarize below. Company witness Mr. Ian R. Benson discusses transmission line losses.

To measure *actual* losses on the distribution system, we would need the ability to collect data from locations throughout the distribution system. Specifically, the Company would need the ability to collect energy data at both individual customer premises and from the transformers at each distribution substation. This would allow the Company to evaluate the amount of energy leaving each substation compared to the amount of energy being delivered to the customer. The difference between these two amounts would be used to determine the losses across the distribution system.

To obtain data at the customer level, AMI meters along with the FAN communication network would need to be installed throughout the system. To collect substation level data, we would need SCADA technology at each distribution substation. We discuss our SCADA capabilities in Table 14. We currently have full SCADA capabilities at 42 percent of our substations and partial capabilities at 21 percent. Even those distribution substations that currently have SCADA functionality only have it on the low side of the transformer, and similar equipment would need to be installed on the high side of the transformer to collect the data needed to quantify the losses that occur in the substation transformer.

In addition to the customer and substation level data, the Company would also need to collect secondary data regarding the transformers and service lines and lengths to perform an accurate line loss analysis. This information would need to be collected manually as it is not currently tracked by the Company in the detail needed for a line loss analysis. Once all of the customer and distribution station level data is available, the Company would need to develop or purchase software that could take the field data, integrate data from the DER on the system, and calculate the line losses.

In terms of timeframe, as we have discussed, AMI meters and FAN will be installed by the end of 2024. We expect that the installation of the necessary SCADA infrastructure to measure actual distribution losses will not be completed until much further in the future, or approximately 15 years from today.

4. SCADA Capabilities and Maximum Hourly Coincident Load (kW)

IDP Requirement 3.A.9 requires the following:

For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system.

The NSP System peak in 2018 was 8,923 MW, which occurred at 5:00 p.m. on June 29, 2018. The Minnesota portion of this peak was 6,800 MW.

We have SCADA capabilities that enable the Company to measure the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system at substations serving approximately 90 percent of our Minnesota customers. We have thus calculated the 2018 peak coincident load at 5,888 MW for the Minnesota portions of the distribution system with sufficient SCADA capabilities.

We clarify that in order to provide this information we must manually pull the maximum hourly load for each SCADA-enabled substation for the date and time of the NSP System. Due to the manual effort to fulfill this requirement, it would be helpful to understand how stakeholders intend to use this information – as there may be other information we could provide that would require less manual effort to meet that need.

5. Total Distribution Substation Capacity in kVA

IDP Requirement 3.A.10 requires the following:

Total distribution substation capacity in kVA.

NSPM distribution substation capacity = 14,837,308 kVA or 14,837 MVA

NSPM – State of Minnesota distribution substation capacity = 13,070,741 kVA or 13,071 MVA

The total distribution substation capacity is reflective of substations that are presently active, functional, and owned by the Company. We calculated this by summing each individual distribution transformer's nameplate power rating across our Minnesota service area. We note that with this 2019 IDP, we added a view of our total substation capacity in the state of Minnesota to the NSPM operating company view provided in our 2018 IDP filing.

6. Total Distribution Transformer Capacity in kVA

IDP Requirement 3.A.11 requires the following:

Total distribution transformer capacity in kVA.

Consistent with our 2018 IDP, we understand this requirement to be the total distribution substation transformer kVA. Given that understanding, please see our response to 3.A.10 above.

7. Total Miles of Overhead Distribution Wire

IDP Requirement 3.A.12 requires the following:

Total miles of overhead distribution wire.

As of June 30, 2019, we approximated our overhead conductor at 14,959 circuit miles for the NSPM operating company.

8. Total Miles of Underground Distribution Wire

IDP Requirement 3.A.13 requires the following:

Total miles of underground distribution wire.

As of June 30, 2019, we approximated our underground cable at 11,438 circuit miles for the NSPM operating company.

9. Total Number of Distribution Premises

IDP Requirement 3.A.14 requires the following:

Total number of distribution premises.

We clarify that a premise is a unique combination of meter number and address. As of June 30, 2019, we had 1,458,922 electric premises in the NSPM operating company, with 1,272,910 of those in our Minnesota service area specifically.

V. SYSTEM PLANNING

An important aspect of distribution planning is the process of analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels and utilization rates of major system components such as substations and feeders. We see this changing as our planning processes evolve, to analyze future electricity *connections*, rather than just loads. In this section we describe our present processes, and we discuss how we propose to advance our planning and forecasting capabilities with a new planning tool.

The purpose of these assessments is to proactively plan for the future and identify existing and anticipated capacity deficiencies or constraints that will potentially result in overloads during *normal* (also called "system intact" or N-0 operation) and *single contingency* (N–1) operating conditions. Normal operation is the condition under which all electric infrastructure equipment is fully-functional. Single contingency operation is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service.

Corrective actions identified as part of the planning process may include a new feeder or substation, adding feeder tie connections, installing regulators, capacitors, or upsizing substation transformers. As our planning processes evolve and technologies mature, we will continue to consider non-wires alternatives. For each project, we develop cost estimates and perform cost-benefit analyses to determine the best options based on several factors including operational requirements, technical feasibility and future year system need.

Proposed projects are funded as part of an annual budgeting process, based on a risk ranking methodology that also funds other distribution investments and expenditures including asset health, grid modernization, and emergent issues such as storm response and mandated projects to relocate utility infrastructure in public rights-ofway when mandated to do so to accommodate public projects such as road widening or realignment.

In this Section, we describe the Company's distribution system planning approach, including planning processes and tools used to develop the annual plans. In compliance with Ordering Point Nos. 9 and 10 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, we provide the following as Attachments E and F2, respectively to this IDP:

9. Xcel shall provide the results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology, in future IDPs.

10. Xcel shall provide information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for feeders and substation transformers that have a risk score or planned investment in the budget cycle in future IDPs.

We also discuss the advanced planning tool for which we propose certification, and how it will improve our load and DER forecasting capabilities.

A. Overall Approach to System Planning

We analyze our distribution system annually and conduct additional analyses during the year in response to new information, such as new customer loads, or changes in system conditions. In the fall of each year we initiate the planning process, beginning with the forecast of peak customer load and concluding with the design and construction of prioritized and funded capacity projects, as summarized in the below figure.



Figure 15: Annual Distribution Planning Process

As part of our annual distribution planning process, we thoroughly review existing and historical conditions, including:

- Feeder and substation reliability performance,
- Any condition assessments of equipment,
- Current load versus previous forecasts,
- Quantity and types of DER,
- Total system load forecasts, and
- Previous planning studies.

We begin our annual plans in the fourth quarter, using measured peak load data from the current year, as well as historical peak information to forecast the loads on our distribution system over a five-year time horizon. We then perform our risk analysis based on loads near the middle of the forecast period. Tangibly the annual system planning information presented IDP is the result of the planning process initiated in Q4 2018. For this process, we used 2018 actuals and historical peak information along with any known system changes to forecast the 2019 to 2023 peaks, and perform our risk analysis based on the forecasted 2021 peak.

1. Feeder and Substation Design

Distribution feeders for standard service to customers are designed as radial circuits. Therefore, the failure of any single critical element of the feeder causes a customer outage. This is an allowed outcome for a distribution system, within established standards for reliability, which typically measure the average duration (System Average Interruption Duration Index or SAIDI) and frequency (System Average Interruption Frequency Index or SAIFI) of interruptions. The distribution system is planned to generally facilitate single-contingency switching to restore outages within approximately one hour. Foundational components in distribution system design and planning are substations and feeders.



Figure 16: Distribution System: Basic Design Schematic of Typical Radial Circuit Design

We plan and construct distribution substations with a physical footprint sized for the ultimate substation design, which is based on anticipated load, but can occasionally be limited by factors such as geography and available land. The maximum ultimate design capacity established in our planning criteria is three transformers at the same distribution voltage. There is one exception to this criterion. In downtown Minneapolis, we have one substation that houses four transformers to serve the significant load. This maximum size balances substation and feeder costs with customer service, customer load density, and reliability considerations.

Cost considerations include the transmission and distribution capital investment in the lines, load losses (which are generally proportional to line length), land cost, and space to accommodate growth. Customer service and reliability implications include line length and route, integration with the existing system, access, and security. Over time, transformers and feeders are incrementally added within the established footprint until the substation is built to ultimate design capacity. Higher levels of DER will affect substation capacity, system protection, and voltage regulation.



Figure 17: Distribution Substation

Feeders are sized to carry existing and planned customer load. Where possible, we design-in redundancy, which has a positive impact on reliability. Feeders have a "range," like a mobile phone service tower, where they can effectively serve. For 15kV, which is common in the Twin Cities metro area, the range is approximately three miles. In rural areas where system load is less geographically dense, the range is higher – approximately one mile per kV. Thus, if customer load density remains the same, then higher voltages can serve a proportionately greater distance.

Feeders typically serve approximately 1,500 customers, though this varies based on voltage, location, customer load density, and the utilization of the feeder. The industry benchmark for feeder capacity is approximately 600 amps, which provides an efficient balance of the costs of conductors, capacity, losses, and performance. This translates to a maximum load-serving capability of about 15 MVA on 13.8 kV feeders, and 37 MVA on 34.5 kV feeders.

2. Planning Criteria and Design Guidelines

We plan, measure, and forecast distribution system load with the goal of ensuring we can serve all customer electric load under normal and first contingency conditions. Our goal is always to keep electricity flowing to as many customers on the feeder as possible. Designing our system for adequate first contingency capacity allows for restoration of all customer load by reconfiguring the system by means of electrical switching, in the event of the outage of any single element. For example, we strive to load feeders to approximately 75 percent of maximum capacity, which provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions.

Adequate substation transformer capacity, no normal condition feeder overloads, and adequate field tie capabilities for feeder first contingency restoration are key design and operation objectives for the distribution system. To achieve these objectives, we use distribution planning criteria to achieve uniform development of our distribution systems. Distribution Planning considers these criteria in conjunction with historical and projected peak load information in annual and ongoing assessment processes.

While the distribution guidelines vary depending on the specific distribution system attribute, there are several basic design guidelines that apply to all areas of our distribution system, as follows:

- Voltage at the customer meter is maintained within five percent of the customer's nominal service voltage, which for residential customers is typically 120 volts.
- Voltage imbalance goals on the feeder circuits are less than or equal to three percent. Feeder circuits deliver three-phase load from a distribution substation transformer to customers. Three-phase electrical motors and other equipment are designed to operate best when the voltage on all of the three phases is the same or balanced.
- The currents on each of the three phases of a feeder circuit are balanced to the greatest extent possible to minimize the total neutral current at the feeder breaker. When phase currents are balanced, more power can be delivered through the feeders.
- Under system intact, N-0 operating conditions, typical feeder circuits should be loaded to less than 75 percent of capacity.³⁴ We developed this standard to help ensure that service to customers can be maintained in an N-1 condition or contingency. If feeder circuits were loaded to their maximum capacity and there were an outage, the remaining system components would not be able to make up for the loss, because adding load to the remaining feeder circuits would cause them to overload.³⁵

³⁴ 34.5 kV follows a 50 percent loading rule.

³⁵ By targeting a 75 percent loading level, there is generally sufficient remaining capacity on the system to cover an outage of an adjacent feeder with minimal service interruptions. A feeder circuit capable of delivering 12 MVA, for example, should be normally loaded to 9 MVA and loaded up to 12 MVA under N-1 conditions.

All distribution system equipment has capacity, or loading, limits that must factor into our planning processes. Exceeding these limits stresses the system, causes premature equipment failure, and results in customer outages. Our planning processes primarily focus at the substation and feeder levels, but also consider limitations and utilization of other system components such as cable, conductors, circuit breakers, transformers, and more.

Spatial and thermal limits restrict the number of feeder circuits that may be installed between a distribution substation transformer and customer load. Consequently, this limits substation size. Normal overhead construction is one feeder circuit on a pole line; high density overhead construction is two feeder circuits on a single pole line (double deck construction). When overhead feeder circuit routes are full, the next cost-effective installation is to bury the cable in an established utility easement. Thermal limits require certain minimum spacing between multiple feeder circuit main line cables. Thermal limits for primary distribution lines are defined in our Electric Distribution Standards. We generally discuss our Electric Distribution Standards function in Section VII below.

When we add new feeder circuits to a mature distribution system, we are not always able to maintain minimum spacing between feeder circuit mainline cables due to rightof-way limitations or a high concentration of feeder cables. Cable spacing limitations and/or feeder cable concentrations frequently occur where many feeder cables must be installed in the same corridor near distribution substations or when crossing natural or manmade barriers.

When feeder cables are concentrated, they are most often installed underground in groups (banks) of pipes encased in concrete that are commonly called "duct banks." When feeder circuits are concentrated in duct banks they experience mutual heating, therefore those cables encounter more severe thermal limits than multiple buried underground feeder circuits. Planning Engineers use software tools to determine maximum N-0 and N-1 feeder circuit cable capacities for circuits installed in duct banks. When underground feeders fill existing duct lines, and there is no more room in utility easement or street right-of-way routes for additional duct lines from a substation to the distribution load, feeder circuit routing options are exhausted. This would require constructing facilities from a different area to serve this load.

As we have noted, our planning criteria aims to maintain feeder utilization rates at or below 75 percent to help ensure a robust distribution system capable of providing electrical service under first contingency N-1 conditions. Therefore, to assess the robustness of the system over time, Planning Engineers analyze the historical utilization rates and projected utilization rates based on forecast demand. They generally apply the 75 percent loading guideline when assessing the system across a larger area as part of an area study. The 75 percent guideline is appropriate for these larger area studies because it is often not practical to analyze the section and tie-transfer breakdowns for each individual feeder in each of the identified solution options similar to what is done in our annual planning process. Since the section and tie-transfer breakdowns are highly detailed and specific to the geography and topology of the individual feeders, it is easier to compare and articulate the differences between solution options with a 75 percent loading guideline.

Figure 18 below illustrates this concept with a mainline feeder. The feeder shows the three sections equally loaded to 25 percent of the total feeder capacity. The green and red symbols represent switches that can be operated to isolate or connect the sections of the feeder in the case of a fault. In that circumstance, the feeder breaker in the substation will operate to isolate the feeder where the fault is detected. Then, the normally closed section switches are opened to isolate the section of the feeder in which the fault is detected. Isolating the fault allows a portion of the customers served by that feeder to remain in service while we repair the fault and return the feeder to normal operation.





In this circumstance, Feeders 1 to 4 all have the same capacity – and are all loaded to 75 percent – so each of the feeder sections can be safely isolated and transferred to adjacent Feeders 2, 3, and 4 through the corresponding tie switches. This reconfiguration results in Feeders 2, 3, and 4 each being loaded to 100 percent (i.e., their original 75 percent, plus the transferred 25 percent from the adjacent Feeder #1

sections). This reconfiguration capability maintains electric service to customers while we repair the fault to the feeder and return the system to normal operation.

Area studies are typically initiated on a case-by-case basis, when Distribution Planning identifies a high number of individual risks or loading constraints within a localized area. These localized area studies vary in size, scope, and scale based on the issues identified, and can encompass a single substation, an entire city, or an entire geographic region. When the 75 percent guideline is applied in an area study, it provides an efficient means of approximating how much additional capacity is needed in that area. When the total feeder circuit utilization within the study area exceeds 75 percent (as calculated using Figure 19 below), it is generally no longer effective to perform more simple solutions – such as load transfers, or installing new feeder tie connections between existing feeders.

Figure 19: Total Feeder Circuit Utilization in Study Area

Total Fooder Circuit Utilization -	\sum Feeder Circuit Load in Area			
Total reeder circuit othization –	$\overline{\Sigma}$ Feeder Circuit Capacity in Area			

These simple solutions merely patch a capacity-deficient portion of the system temporarily; rather than solve the issue, they often result in shifting the overloads or contingency risks from one feeder to another. However, when the total feeder circuit utilization is within a reasonable margin below 75 percent, there is generally enough capacity in the area for simple solutions to be viable for resolving any remaining risks.

While a generalized 75 percent utilization is ideal, it may not be feasible depending on system configurations. Feeder utilization in Minnesota is on average 66 percent; approximately 38 percent of the feeders are above 75 percent utilization. When we analyze feeders and transformers, we use the specific loading and configuration to determine the N-0 and N-1 overloads. Because of the wide variety of system configurations, the evaluation may show certain transformers or feeders may be loaded to higher utilization without causing an overload.

The below figure shows an example of total feeder circuit utilization for feeders in a study area over a study period timeframe.





The feeder circuit load history is the actual non-coincident peak loading of all feeder circuits in the study area measured at the beginning of the feeder circuits in the substation. We compare the sum of the individual feeder circuit peak to the sum of the individual feeder circuit capacities to calculate feeder circuit utilization each year. We calculate average load growth for the time period by comparing total non-coincident feeder circuit loads from the beginning to the end of the comparison period. A peak load forecast starting from the historical peak level provides an upper forecast limit.

Isolated feeder overloads, which can be characterized by an individual feeder overload that occurs when average feeder utilization percentage is *less* than 75 percent, typically occur when there is new development or redevelopment that increases load demand within a small part of the distribution system. Widespread feeder overloads, which can be characterized by one or more individual feeder overloads that occur when average feeder utilization percentage is *more* than 75 percent, typically occur in distribution areas due to a combination of customer addition of spot loads and focused redevelopment by existing customers, developers or community initiatives.

Distribution systems that start out with adequate N-1 and N-0 capacity, can quickly progress beyond isolated overloads when a large part of the distribution system is redeveloped or focused redevelopment is targeted in an area or along a corridor.

In addition to feeder peak loads, Distribution Planning examines existing feeder load density by studying the distribution transformers serving the customers. Distribution transformers are the service transformers that step the voltage down from feeder voltages to the voltage(s) that the customer receives at their point of service. As customer load grows in developed areas, we change distribution transformers to higher capacity equipment when customer demand exceeds the capacity of the original transformer.

Distribution transformers are an excellent indicator of customer electrical loading and peak electrical demand, and are used to help validate the growth that is observed and forecasted in the annual peak demand and load forecast analysis.

Figure 21 below is an example of distribution transformer installation by size from a prior analysis we completed for western Plymouth. This view is helpful to understand present customer load density.



Figure 21: Distribution Transformer Installation by Size

Developed using Synergi Electric

After examining feeder circuit peak demands, we look at the loading levels for the transformers housed at the substations.

Transformers have nameplate ratings that identify their capacity limits. Our internal Transformer Loading Guide (TLG) provides the recommended limits for loading substation transformers adjusted for altitude, average ambient temperature, winding taps-in-use, etc. The TLG is based upon the American National Standards Institute/Institute of Electrical and Electronic Engineers (ANSI/IEEE) standard for transformer loading, ANSI/IEEE C57.92. The TLG consists of a set of hottest-spot and top-oil temperatures and a generalized interpretation of the loading level equivalents of those temperatures, which are the criteria used by Substation Field Engineers to determine normal and single-cycle transformer loading limits that planning engineers use for transformer loading analysis.

A transformer's *normal* loading limit is called the transformer "loadability," which represents the maximum loading that the transformer could safely handle for any length of time. A transformer's *single-cycle* loading limit represents the maximum loading that the transformer could safely handle in an emergency for at most one load cycle (24 hours), and is what we use for our substation transformer N-1 contingency analysis. When internal transformer temperatures exceed predetermined design maximum load limits, the transformer sustains irreparable damage, which is commonly referred to as equipment "loss-of-life." Loss-of-life refers to the shortening of the equipment design life that leads to premature transformer degradation and failure.

Transformer design life is determined by the longevity of all of the transformer components. At a basic level most substation transformers have a high voltage coil of conductor and a low voltage coil electrically insulated from each other and submerged in a tank of oil. Transformer loading generates heat; the more load transformed from one voltage to the other, the more heat; too much heat damages the insulation and connections inside the transformer. Hottest-spot temperatures refer to the places inside the transformer that have the greatest heat, and top-oil temperature limits refer to the maximum design limits of the material and components inside the transformer.

To ensure maximum life and the ability to reliably serve customers, our loading objective for transformers is 75 percent of normal rating or lower under system intact conditions. Substation transformer utilization rates below 75 percent are indicative of a robust distribution system that has multiple restoration options in the event of a substation transformer becoming unavailable because of an equipment failure or required maintenance and construction. The higher the transformer utilization rate, the higher the risk of a transformer outage that interrupts service to customers.

Each distribution substation has a demand meter that is read monthly for each substation transformer. These meters record the transformer's monthly peak. For

those distribution substation transformers that have a Supervisory Control and Data Acquisition (SCADA) system connection, we are able to monitor the real-time load on the transformer. Similar to distribution feeders, the transformer data feeds into a data warehouse, which can be combined with hourly historical and forecast peak load data in our Distribution Asset Analysis (DAA) system, so we can view the substation transformer's load history.

Each transformer's peak in a multi-transformer substation is non-coincident – meaning the transformers can each individually experience peak load at different times, and potentially on different days. This is a result of the fact that each transformer serves multiple feeder circuits that each serve different loads. Substation transformer peak load is proportional to, but usually less than, the sum of the feeder circuit peak loads served from that substation transformer. The detail of substation transformer loading is a larger granularity than feeder circuit loads with a corresponding greater impact on customer service due to the larger number of customers affected for any event on a transformer than on a feeder.

Figure 22 below is an example of load growth using historical and forecasted peak loads for a set of substation transformers



Figure 22: Greater Study Area – Historical and Forecasted Loads

The upper and lower dashed lines provide a bandwidth for growth, forecasted from the conservative peak and historical peak values, respectively.

As part of our analysis, we review the loading and utilization rates of distribution substations. We provide an example of our transformer utilization analysis in Figure 23 below, which illustrates the bandwidth of expected load growth that is forecasted to occur between the upper and lower dashed lines.

Figure 23: Total Transformer Utilization Percentage for Transformers – Focused Study Area



Even when using conservative peak load levels from the lower dashed line, in this circumstance forecasted load levels still exceed desirable loading levels for the substation transformers in the later years of the 20-year forecast in the study. The range of likely transformer utilization falls between the dashed lines of the conservative forecasted demand and the historical peak forecast load levels.

Using the planning criteria such as we have described above, Planning Engineers evaluate the distribution system, and are able to determine transformer and feeder loading and identify risks for normal and contingency operation of the system.

B. Distribution Planning Process

1. Planning to Meet the Peak Load

We begin our process by forecasting the load for both feeders and substations.



Figure 24: Annual Distribution Planning Process – Load Forecast

In this step, we run a variety of scenarios that account for all the various drivers of load changes. This includes consideration of historical load growth, weather history, customer planned load additions, circuit reconfigurations, new sources of demand (penetration of central air-conditioning, electric vehicles), DER applications, and any planned development or redevelopment.

Then we generate a five-year forecast, aggregate the results, and compare this analysis with system projections. See the Action Plan Section XIV for the load forecast resulting from this analysis in compliance with IDP Requirement D.2, which requires, in part, that we provide our load growth assumptions and how we plan to meet it in our 5-year action plan. We additionally provide our long-term system load projections in compliance with IDP Requirement D.3 in the Action Plan Section of this IDP.

We then provide our distribution forecast to our transmission planning staff, who incorporate the load forecast into their planning efforts. In addition to this load forecast hand-off, we also communicate with transmission regularly throughout the year. Specifically, any time we become aware of larger loads or significant DER at any time of the year, we share that information with transmission. Distribution and transmission personnel also meet twice a year as a cross-functional group to further ensure we are each aware of plans and projects which may impact either system.

Our load forecast focuses on demand (kVA) not energy (kWh) to ensure we can serve

loads during system peaks.³⁶ For planning purposes, we define "peak load" as the largest power demand at a given point during the course of one year. Measured peak loads fluctuate from year-to-year due to the impacts of duration and intensity of hot weather and customer air conditioning usage. In examining each distribution feeder and substation transformer for peak loading, we use specific knowledge of distribution equipment, local government plans, and customer loads to forecast future electrical loads. Planning Engineers consider many types of information for the best possible future load forecasts including: historical load growth, customer planned load additions, circuit and other distribution equipment additions, circuit reconfigurations, and local government-sponsored development or redevelopment.

2. Risk Analysis

The next step in the planning process is to conduct risk analyses.



Figure 25: Annual Distribution Planning Process

One of the main deliverables of distribution planning's annual analysis includes a detailed list of all feeders and substation transformers for which a normal overload (N-0) is a concern. A normal overload is defined as a situation in which the real time load of a system element (conductor, cable, transformer, etc.) exceeds its maximum load carrying capability. For example, a 105 percent N-0 for feeder FDR123 means that the peak load on FDR123 exceeds the limit of the feeder's limiting element by 5 percent.

³⁶ When three phase load data is available, we use the highest recorded phase measurement in our forecast.

Additionally, distribution planning delivers an N-1 Contingency Analysis, which is a list of all feeders and substation transformers for which the loss of that feeder or transformer results in an overload on an adjacent feeder or transformer. For example, a 1.5 MVA N-1 condition for feeder FDR123 means that for loss of FDR123, all but 1.5 MVA of FDR123's peak load can be safely transferred to adjacent feeders without causing an overload. The remaining 1.5 MVA that cannot be transferred is then referred to as "load at risk."

Our 2019 to 2023 annual planning process (initiated in Q4 2018), analyzed forecasted 2019 loads and identified the following total risks across NSPM:

- N-0 normal overloads on 71 feeder circuits
- N-0 normal overloads on 14 substation transformers
- N-1 contingency risks on 498 feeder circuits
- N-1 contingency risks on 112 substation transformers

This process of identifying N-0 overloads and N-1 risks for feeders and substation transformers is referred to as distribution planning's annual "risk analysis." We enter all of these risks into WorkBook, an internal tool used to help rank projects based on levels of risk and estimated costs. We provide our risk scoring methodology and results from the 2019-2023 planning process as Attachment E (portions of which are not public). The total number of risks identified in the risk analysis generally exceeds the number of risks that can be mitigated with available funds. There is always a balance that we must strike in mitigating risks, planning for new customers, and addressing both the aging of our system – as well as preparing it for the future. We discuss how we strike this balance and prioritize projects below.

3. Mitigation Plans

After identifying system deficiencies, the next step in the planning process is developing mitigation plans.



Figure 26: Annual Distribution Planning Process – Mitigation Plans

At this step, Planning Engineers identify potential solutions to provide necessary additional capacity to address the identified system deficiencies. We apply thresholds that risks must exceed before we develop a project to mitigate the risk. For N-0 conditions, the overload must exceed 106 percent; for N-1 conditions the load at risk must exceed 3 MVA before we develop a mitigation.

While many of the mitigation solutions are straightforward, others require a detailed analysis. At this point in the process the projects are high level and using indicative unit costs.

The below figure depicts the steps we take to identify potential solutions.



Figure 27: Solution Identification Process

Distribution capacity planning methods address and solve a continuum of distribution equipment overload problems, including isolated feeder overloads, widespread feeder overloads, and substation transformer contingency overloads associated with widespread feeder overloads. Alternatives include reinforcing existing feeder circuits to address isolated feeder circuit overloads, adding or extending new feeder circuits and adding substation transformer capacity up to the ultimate substation design capacity to address more widespread overloads.

Planning Engineers first consider distribution level alternatives including adding feeders, extending feeders and expanding existing substations. If these typical strategies would not meet identified needs because they had already been exhausted or would not be sufficient to address the overloads, the engineers then evaluate alternatives that would bring new distribution sources into the area. DER has not historically been considered a viable alternative for resolving distribution capacity issues due to cost, reliability, capacity, longevity, dispatchability, space constraints and dependability. However, we see these constraints lessening as the technologies mature and operational experience increases.

If we conclude that distribution level additions and improvements would not meet the identified need, we consider the addition of new distribution sources (*i.e.*, substation transformers with associated feeder circuits) to meet the electricity demands. Ideally, new distribution sources should be located as close as possible to the "center-of-

mass" for the electric load that they will serve. Installing substation transformers close to the load center-of-mass minimizes line losses, reduces system intact voltage problems, and reduces exposure of longer feeder circuits and outages associated with more feeder circuit exposure.

Once we identify a mitigation solution for the associated risk(s), we enter the mitigation description, indicative estimated costs, and the risks associated into WorkBook, which uses algorithms to develop a ranking score. The result of this entire step, including any necessary planning studies, is a slate of projects for consideration and review as part of the overall Distribution budgeting process.

a. Long-Range Area Studies

If we determine a long-range plan is necessary, we conduct a location-specific study to evaluate various alternatives, which may include DER or DSM. Depending on the scope and scale of the focused study, this process can take weeks or even months, and generally involves the following:

- Identifying the study area (for instance, a single feeder, a substation, or maybe even an entire community or larger).
- Projecting future loads.
- Estimating the saturation of area (limits of development, zoning, etc. on load growth).
- Coordinating with transmission planning to advise them of our work and learn if they have area concerns or projects.
- Generating options.
- Studying and comparing the economics and reliability of the alternatives.

With respect to DSM, we are developing updated methodologies and distributionavoided costs for energy efficiency.³⁷ Presently, for assessing distribution impacts, we allocate energy efficiency impacts to each distribution substation and feeder load proportionally based on percentage of system load share. We perform a subsequent summer peak analysis to determine if projects could be deferred. We calculate a deferral value, expressed as \$/kW, based on the Xcel Energy corporate cost of capital and using planning level costs for the deferral period. We note that we are also

³⁷ See In the Matter of Avoided Transmission and Distribution Cost Study for Electric 2017-2019 Conservation Improvement Program Triennial Plans, Docket No. E999/CIP-16-541.

participating in the Minnesota Department of Commerce's Statewide Energy Efficiency Demand-Side and Supply-Side studies, which are examining the future potential for both customers and the Company to reduce peak and energy usage. The Supply-Side study is targeted at utility infrastructure efficiency on the generation, transmission and distribution systems.

These analyses, along with others such as focused long-term area studies, are important complements to our annual planning analysis. We previously provided examples of area studies we have completed, which included non-traditional distribution system solutions.

IDP Requirement 3.A.30 requires that we

Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement.

We have not completed any long-term area studies since submitting our 2018 IDP. We discuss our NWA analysis that is part of this 2019 IDP in Section VI.

b. Plan comparison standards

If Distribution Planning determines a long range plan is needed, we use the following criteria to compare the potential solutions: System Performance, Operability, Future Growth, Cost, and Electrical Losses, which we describe in more detail below. All alternatives must have the ability to meet existing and forecast capacity requirements.

System performance. System performance is how the physical infrastructure addition of an alternative impacts energy delivery to distribution customers. Frequency of outages has been found to correlate to circuit length with longer feeders experiencing more outages than shorter feeders. Each unit of length of a feeder circuit generally has comparable exposure due to common outage causes, including underground circuit outages caused by public damage (*e.g.*, customer dig-ins to cable), equipment failure; and overhead circuit outages caused by acts of nature (*e.g.*, lightning). We use Synergi system models to examine loading levels and voltage impacts overall and on specific customers under normal and first contingency conditions. We evaluate performance based on the equipment and control systems required to maintain customer nominal voltage, and customer exposure to outages as differentiated by the length of the feeder circuit from the substation transformer to the customer.

Operability. Operability is how the alternative impacts the Company's distribution equipment, operating crews and construction crews operating the distribution system

during normal and contingency operations. We evaluate operability based on system planning criteria that represent the robust capability of the distribution response as described by feeder circuit and substation transformer N-0 and N-1 percent utilization and ease of operation as impacted by integration with the installed distribution delivery system. Integration of non-standard equipment using new and untested technology in the first several generations of implementation are often complicated to operate, or have unanticipated difficulties that require additional engineering to solve problems, additional expenditures, additional equipment, new operating techniques and crew training. New technologies often require several generations of changes to reach simplicity of operation required to maintain present levels of customer service and reliability.

Future Growth. Future growth is how the alternative facilitates and enables future infrastructure additions required to serve future customer demand. Possibility for future growth is enhanced by an alternative that addresses future customer demand with the least cost amount of additional distribution infrastructure. For example, when considering a standard solution, an alternative that locates a substation nearest the load center and has room to add feeder circuits and substation transformers has better future growth possibilities than an alternative that requires adding another substation with an additional transmission line into the area.

Cost. For each alternative, we calculate the present value of all anticipated expenditures required for that alternative to serve the forecasted customer loads. The present value calculations are based on indicative estimates for the proposed alternatives,

Electrical Losses. Electrical losses are most often discussed in reference to the additional amount of generation required to compensate for the incremental line losses. Increased efficiency in the electrical delivery system reduces the amount of generation needed to serve load. Electrical losses also impact the amount of distribution system equipment by requiring incrementally increased amounts of electrical feeder circuits and substation transformers to make up for electrical energy lost by transporting electrical energy at distribution voltages when compared to using transmission line voltages.

c. Capacity Risk Project Prioritization

From this evaluation, projects are assigned a risk score, similar to a cost-benefit ratio. This risk score applies to the mitigation as a whole and not the individual risks that make it up. It is useful for comparing the merits of disparate projects. We then select and prioritize the actual solutions for which we intend to move forward. Attachment

F2 contains a list of our capacity risks, their details, and the projects that mitigate them.

Based on the analysis of alternatives capable of meeting area customer load requirements, we select the alternative that best satisfies the five distribution planning criteria. For example, locating a new distribution substation closest to the greatest amount of customer load and having the shortest feeder circuits would result in the least amount of customer exposure to outages and the best system performance. It might also use the smallest addition of proven reliable elements to relieve existing overloads, resulting in the highest operability of the alternatives considered – and be the least expensive to construct and has the lowest electrical losses – making it the most cost-effective and efficient option of the four alternatives.

Once we have all the projects identified, we weigh each investment using a risk/reward model to determine which solutions should be selected and prioritized. While we recognize that risk cannot be eliminated and funding is always a balance, our goal is to provide our customers with smart, cost-effective solutions. Accordingly, we evaluate operational risk dependent on:

- The probability of an event occurring (fault frequency, failure history of device, etc.) causing an outage, and
- The consequence of the event (amount of load unserved, number of customers, restoration time, etc.).

4. Budget Create

The final step in the planning process before pursuing individual projects is prioritizing the proposed capacity projects into the distribution area's overall budget. At this step, the Company must also provide funding for asset health, new business, and meeting growing customer and policy expectations through support of new technologies and DER.



Figure 28: Annual Distribution Planning Process – Budget Create

The overall budget process recognizes that customers want reliable and uninterrupted power. To address this priority, we regularly evaluate the overall health of our system and make investments where needed to reinforce our system. This includes an asset health analysis of the overall performance of key components of the distribution system such as poles and underground cables. As we replace these key components, we do so with an eye to the future to ensure that the investments we make not only support our customers' needs for reliable service today, but also lay the groundwork for the grid of tomorrow. We must also take steps to implement new systems and technologies that improve our operations and provide customers with more choices related to their energy use. An example of this is investments in our SCADA system, as well as the ADMS we have underway. Together, these systems will provide our engineers and operational staffs significantly improved data from which to monitor and make decisions – all of which benefit our customers in both our planning and response to events occurring on the system.

Given these priorities, we must not only proactively maintain our system by making capital improvements when necessary to improve reliability and safety for our customers – we must also manage our budgets to be able to respond to outages caused by storms, mandatory work such as relocation of our facilities, and other conditions that cannot be foreseen with a high degree of accuracy. We factor-in all of these priorities as we weigh the risks associated with the various types of investments to develop our five-year budget commensurate with targeted funding levels.

As capital spending is determined and, throughout the year as new issues are

identified, each operating area brings risks (problems) and mitigations (solutions) forward based on their knowledge of the assets and operations within their territory. The operating areas' focus is on building, operating, and maintaining physical assets while achieving quality improvements and cost efficiencies. All the risks and mitigations are submitted as project requests and entered into a software tool we developed and use to track and rank projects based on the inputs provided – including their annual costs and benefits.

Budgeting personnel focus on the health and age of our existing assets, standardization, and mitigation of risk, and provide coordination and consistency in evaluating individual project requests with the Distribution organization. Engineering and operations personnel then work with budgeting personnel around each risk to evaluate and score each mitigation individually before ranking the projects. The factors we use to prioritize investments are as follows:

- Reliability Identification of overloaded facilities, potential for customer outages, annual hours at risk, and age of facilities,
- *Safety* Identification of yearly incident rate before and after the risk is mitigated,
- *Environmental* Evaluation of compliance with environmental regulations. To the extent this factor applies to the project being evaluated, it is prioritized, however this factor is not usually applicable,
- Legal Evaluation of compliance before and after the risk is mitigated, and
- *Financial* Identification of the gross cash flow, such as incremental revenue, realized salvage value, incremental recurring costs, etc. and identification of avoided costs such as quality of service pay-outs and failure repairs.

An analysis of these factors results in a proposed project list that is ranked. We accomplish this by ranking the assessment of each project against each other. The highest priority is given to projects that Distribution must complete within a given budget year to ensure that we meet regulatory and environmental compliance obligations and to connect new customers. We note that we must also apply judgment in the prioritization process. An example of this is two competing new feeder projects – one in the metro area that only involves a short distance, and the other in a rural area that involves installing infrastructure for two miles. The cost of the rural example in this circumstance is higher, and the benefits of the two projects are the same – so the metro project would score higher. However, the rural project is also needed. Our process therefore contemplates some back-and-forth with the planning engineers to validate priorities.

5. Project Initialization

After the capital expenditures budget is finalized, the approved project list becomes the basis for the release, or initiation, of projects during the calendar year.

Figure 29: Annual Distribution Planning Process – Project Initialization



This process must be somewhat flexible to allow for needed additions and deletions within a given year. For example, should an emergency occur during the year, priorities may change and result in an adjustment to the list of projects. Projects that were previously approved may be delayed to accommodate the emergency. Through our budget deployment process we are therefore able to meet identified needs and requirements, adjust to changing circumstances and prudently ensure the long-term health of the distribution system.

Distribution Planning takes the approved capacity projects stemming from this process and communicates them with design and construction. The Planning team continues to participate in the ongoing capital budget processes, as the Distribution business responds to changing circumstances, and interfaces with design and construction to adjust priorities as needed.

Once the five-year budget is determined, the Planning Engineers write Electric Distribution Planning (EDP) memos for the first two years of approved capacity projects. An EDP memo is a high level step-by-step description of the project that will mitigate an identified risk. The memos describe the problem, the substation design/construction steps to take (if any), and any distribution line design/
construction steps to take. The memos provide maps and text specifying where to place switches, capacitor banks, or where to cut into another feeder to transfer load to a new feeder. These memos initiate the design and construction portion of the project.

6. Design and Construct

Finally, the selected projects are communicated to substation engineering and distribution engineers and designers who bring the projects to life.



Figure 30: Annual Distribution Planning Process – Design and Construct

At this step, these engineers and designers perform detailed design work and initiate their construction. We summarize the groups generally involved and their roles below:

- *Substation Engineering.* If a project requires a new feeder bay at an existing substation or a new substation entirely, this group performs the detailed engineering, design and construction.
- *Distribution Design and Construction*. This area performs the permitting, design, and construction of new feeder circuits or modifications of existing circuits.

Ideally, projects can be implemented precisely as envisioned by Distribution Planning, but often this is an iterative process.

C. Current Planning Tools

Planning Engineers rely on a set of tools to perform the annual full system snapshot, ongoing distribution system assessments – including assessment of specific DER interconnections – and long-range area assessments. In response to the fundamental changes occurring on the distribution system, increasing customer expectations and regulatory requirements affecting how we plan the system, we are proposing certification of an advanced planning tool to increase our capabilities to develop load forecasts and plan the system.

In this section, we discuss our current planning tools in compliance with the following requirement. In Part D below, we discuss our future our proposed advanced distribution planning tool, which also complies with the following requirement.

IDP Requirement 3.A.1 requires the following:

Modeling software currently used and planned software deployments.

Table 17 below summarizes the tools and how we use them in our planning process. We then discuss in more detail how we use each of the tools.

Table 17: Planning Tool Summary

Tool	Process	Description
DNV-GL Synergi Electric	Power flow	Contains a geospatially accurate model of the electric distribution Feeder system with known conductor and facility attributes such as ampacity, construction, impedance, and length to simulate the distribution system
ITRON Distribution Asset Analysis (DAA)	Medium to long-range load forecasting of major distribution system components, including feeders and transformers	System of record for historical peak feeder and substation transformer load information that we use to evaluate historical load growth and weather adjustments to match prior peaks and identified known load growth to establish a forecast for 1+ years out
Microsoft Excel Spreadsheets	Contingency planning	Analyze feeder and transformer contingency capacity by evaluating the available capacity on neighboring feeder ties and substation transformers for the forecasted years
СҮМСАР	Determines normal and emergency ampacity for Feeder circuit cables	Determines the amount of amps that can flow through cables for various system configurations, soil types, and cable properties before they are thermally overloaded
Geographical Information System (GIS)	Provides the connectivity model source data to Synergi, as well as Feeder topology.	Contains location-specific information about system assets and components, allowing us to view, understand, question, interpret and visualize data in many ways that reveal relationships, patterns, and trends in the form of maps.
Distribution Supervisory Control and Data Acquisition (SCADA)	Peak load forecasting	Monitors and collects system performance information for feeders and substation transformers
WorkBook	Project Prioritization	An internal tool used to help rank projects based on levels of risk and estimated costs
PI Datalink	Load Forecast	Tool used in conjunction with Excel to help us determine our minimum loads, as well as our gross peak and minimum loads for feeders and transformers that have generation on them.

We additionally outline our hosting capacity tool that is not currently part of the planning process.

Table 18:Hosting Capacity Tool

Tool	Process	Description
Electric Power Research	Hosting capacity	Using the actual Company feeder characteristics, DRIVE
Institute Distribution		considers a range of DER sizes and locations in order to
Resource Integration and		determine an indicative range of minimum and maximum hosting
Value Estimation (DRIVE)		capacity by screening for voltage, thermal, and protection impacts.

Table 19:	Tool Summary	by	Distribution	Planning	Process
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	Planning Process Component							
Tool	Forecast	Risk Analysis	Mitigation Plans	Budget Create	Initiate Construction - EDP Memo	Long-Range Plans	Hosting Capacity	
Synergi Electric			Х			Х	Х	
DAA	Х	Х				Х		
MS Excel		Х		Х		Х		
СҮМСАР		Х						
GIS			Х			Х	Χ	
SCADA	Х							
WorkBook		Х	Х	Х	X			
PI Datalink	Х							
DRIVE							Х	

DNV-GL Synergi Electric. Synergi is the Company's distribution power flow tool, which we use to model the distribution system in order to identify capacity constraints, both thermal and voltage, that may be present or forecasted. It provides a geospatially accurate model of the electric distribution feeder system with known conductor, electrical equipment, and facility attributes such as material type, which contains ampacity and impedance values. We use it to model different scenarios that occur on the distribution system and to create feeder models that are an input to the DRIVE tool used for hosting capacity analysis; it can also be used to explore and analyze feeder circuit reconfigurations. As load is manually allocated to a feeder and we run a power flow process, exceptions such as voltage or thermal violations may occur. Areas of the feeder are then highlighted due to those exceptions to bring these issues to the engineer's attention.

Synergi can generate geographically correct pictures of tabular feeder circuit loading data, which is achieved through the implementation of a GIS extraction process. Through this process, each piece of equipment on a feeder, including conductor sections, service transformers, switches, fuses, capacitor banks, etc., is extracted from the GIS and tied to an individual record that contains information about its size, phasing, and location along the feeder. We provide a screenshot from Synergi as Figure 31 below.



Figure 31: Synergi Electric Application Example

To calibrate the model, we import peak day customer usage data into the system, and allocate it to service transformers or primary customer service points. The Customer Management Module within this software takes monthly customer energy usage data and assigns demand values based on the customer class (i.e. residential, commercial, etc.), the assigned "load curves" for that class, and the desired time period. This is done feeder-wide, so that all customers are accounted for. When historical or forecasted peak load data is added from the DAA software package, Synergi is capable of providing power flow solutions for the given condition. At that point, we can also scale the loads up or down across the entire feeder depending upon the estimated demand and scenario need.

The "load curves" that are being utilized come from our load research department and represent different customer classes on a state by state basis. They are not used to analyze different loading scenarios throughout the day, but rather to attribute more accurate peak demands at locations across a given feeder.³⁸

³⁸ For example, it ensures a potential residential customer receives more load at peak than a potential industrial customer with the same energy usage. This is because industrial customers typically have a flatter load profile curve. Accordingly, when industrial customers are compared to residential customers they have more consistent loading throughout the day and have less influence on the peak than the residential customer.

Ultimately, Synergi helps engineers plan the distribution system through modeling. It allows the ability to shift customers and load around, as well as add new infrastructure to simulate future additions to the system. It also can model distributed generation sources, such as solar or wind, so that those affects can be better accommodated.

ITRON Distribution Asset Analysis (DAA). We use DAA for medium to long-range load forecasting of distribution feeders and substation transformers. The DAA system is the historical peak system of record for those distribution elements. By having this collection of historical peaks we are better able to forecast future peaks by trending while taking into account other factors such as weather or known load growth. From this, we develop an annual load projection for future years.

Once our forecasted loads are updated every year we use DAA to create a peak substation load report for Transmission Planning and Transmission Real Time Planning. We also use these forecasts in our risk analysis evaluation, long range plans, and to populate models in Synergi for various purposes.

DAA is also a repository for feeder and substation transformer capacity limits that we use to identify areas of the system where there are capacity constraints. These limits are also passed on to Distribution Operations to ensure the correct notifications occur in the Control Center for any potential overloads.



Figure 32: Distribution Asset Analysis Application Example

Microsoft Excel Spreadsheets. We use Microsoft Excel spreadsheets to perform feeder and substation transformer contingency planning. A key part of distribution planning is identifying risks, not only for normal operating situations, but also for situations where the system is in a contingency state; that is not whole. This helps in creating a system with flexibility. To do this we use a series of spreadsheets that include the tie points to other feeders and the capacity that is available at peak times through those tie points. While this is fairly simplistic tool, these spreadsheets provide valuable information about our system that we call "Load at Risk" that we use to justify projects that keep our system reliably robust.

CYME CYMCAP. Planning Engineers use CYMCAP for determining maximum normal and emergency feeder circuit cable capacities. This helps to determine the amount of amps that can flow through a given cable before it is thermally overloaded (ampacity). CYMCAP takes into account appropriate factors in determining these values, such as duct line configuration, soil conditions, and cable properties. Unlike overhead conductors that are exposed to the air and wind, underground cables have a tougher time dissipating heat. To ensure the cables are not overloaded, we model the true ampacity of them with the help of this program.



Figure 33: CYMCAP Application Example

General Electric Smallworld Geospacial Information System. Our GIS contains locationspecific information about system assets and provides the connectivity model source data and feeder topology to Synergi, as well as other data to many other applications within Xcel Energy. The 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 also very helpful in capturing changes to the distribution system that may not always be visible to all. For example, we rely on GIS to show changes that would occur as the result of a new Community Solar Garden (CSG) installation. Any upgrades to the feeder that occurred as a result of that addition plus the details of the new CSG itself, would be added in to GIS. This would then be used to update our Synergi models for accurate modeling going forward.

Distribution Supervisory Control and Data Acquisition. Our SCADA system provides information to control center operators regarding the state of the system, provides appropriate alarms (including outage notifications), and provides for remote control of substation and certain field equipment. For operational purposes, every few seconds it provides system status information, such as operating parameters for our generation and substation facilities. It monitors and collects system is safely and efficiently operating within its capabilities. This performance information is also used by planning engineers 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. We have a long-term plan to install SCADA at each of our substations going forward.

For feeders where we have SCADA capabilities, we are able to monitor the real time average or three phase amps on the feeder for operational purposes. For planning purposes, the SCADA system collects enough information throughout the course of a year to determine daytime minimum load and peak demands for all feeders that have this functionality. However, it takes some manual effort beyond collecting the data to adequately decipher those values.³⁹ The data is maintained in a data warehouse and combined with the historical DAA hourly load data. When three phase load data is available, we use the highest recorded phase measurement to determine facility loading.

Access Database WorkBook. To help rank projects and perform cost-benefit analyses, we use an internally-developed Microsoft Access Database tool called WorkBook. This tool allows us to input our distribution system risks along with the proposed mitigations and their indicative costs that are intended to solve those risks. Algorithms in the tool result in a ranking score that helps to incorporate these projects in the budgeting process. The primary risk inputs that planning engineers develop for entry into WorkBook includes N-0 and N-1 risks for feeders and substation transformers. However, other inputs such as asset age and historical failures are also considered, which further aids prioritization of the projects as part of the budget process.

PI Datalink. A Microsoft Excel add-in that provides SCADA information from our equipment in the field. We utilize the data from this tool in our analyses for load forecasting, minimum daytime loads, and community solar gardens. By having this tool in Microsoft Excel, we are able to streamline complex and repetitive calculations. As a result, we gain better visibility of the distribution system which in turn enables us to make more informed decisions about how to mitigate risks.

D. Future Planning Tools

In this section, we discuss industry effort and the advanced planning tool we propose for Commission certification under Minn. Stat. § 216B.2425. The content in this

³⁹ This manual effort involves factoring out our minimum loads during non-daytime hours, adjusting for daytime minimum loads that occur under abnormal configurations, and eliminating other erroneous data possibly due to faults or other disturbances on the feeder.

section is also responsive to Order Point No. 7 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, which requires the Company to:

Make the development of enhanced load and DER forecasting capabilities, as well as, tracking and updating of actual feeder daytime minimum loads, a priority in 2019 and include a detailed description of its progress in the Company's 2019 IDP.

As we have discussed, we need to advance our planning tools and capabilities to facilitate more targeted and granular distribution forecast analyses and more systematically evaluate NWA, as well as enable better assessment of potential customer-driven DER growth. Toward that end, we have been participating with others in the industry to examine the types of capabilities that may be needed. Enhanced planning tools have started to emerge in the industry, and we have worked to evaluate and procure a next generation distribution forecasting tool. We are currently in the advanced stages of procuring such a tool that will better suit these needs going forward, and in this IDP, we seek certification of our proposed advanced planning tool. Below, we discuss ongoing industry efforts and summarize the planning and forecasting advancements that we believe are necessary, and that we expect our new tool to provide.

1. Industry Efforts

It has been helpful to be involved with various distribution grid research efforts throughout the industry. Our membership with the Electric Power Research Institute (EPRI) has played an important role in helping us keep abreast of innovations in technology in the areas of grid modernization, reliability, integrated planning, solar integration, battery storage and DER interconnection. We participate in several research programs in these areas and are able to learn and share the latest developments with other industry members.

EPRI was key in working with the industry to develop PV hosting capacity tools and we are also excited about their interest in in developing advanced planning tools. EPRI's objective is to develop a more automated and comprehensive platform that performs more robust scenario analysis for various grid investment decisions including non-wires alternatives. EPRI's long-term vision is to develop processes and prototypes that are incorporated and adopted into commercial planning tools.

The National Renewable Energy Lab is also conducting research in similar areas and we have had the opportunity to collaborate with them on various research projects. Some of the efforts with both NREL and EPRI include:

• We are partnering with NREL and a set of Colorado customers to examine

energy efficient and high renewable energy options for a new development focused on sustainable design. One aspect of the project will involve modeling the distribution system to assess the feasibility and costs of the design.

- We are participating with NREL in ARPA-E's *Network Optimized Distributed Energy Systems (NODES)* project with the vision to enable 50% renewables penetration at a feeder level through the use of innovative aggregation control methods. Both the University of Minnesota and MISO are participating in this project.
- We partnered with NREL to understand how data accuracy and sensor density influence the performance of the Advanced Distribution Management System's IVVO application. Through this research project, NREL modeled six different feeders and three substations to help assess the value and trade-offs with various levels of data and sensors to the system.
- We are partnering with EPRI on a research project designed to develop a model that helps identify where energy storage can play a role in addressing various grid issues such as system constraints, high renewable energy penetration and grid deferral. The tool helps evaluate more scenarios in a more efficient fashion and helps perform cost benefit analysis.
- Through EPRI, we are participating in an industry working group associated with DER interconnection standards and practices. A primary area of focus is discussing challenges with new options, technical requirements and responsibilities associated with adoption and application of IEEE 1547-2018.

2. Advanced Planning Capabilities and Tool

In response to the fundamental changes occurring on the distribution system, Distribution Planning has recognized a need for a new tool to aid in developing a load forecast and distribution plans. Current tools used for developing the load forecast only analyze the annual peak load for specific elements on the distribution system, such as feeders and substation transformers. As customer adoption of DER increases and our distribution system becomes more dynamic, the annual peak load view is no longer adequate. Further, we currently use a patchwork of tools to meet Commission requirements regarding scenario analysis, and even so, our capabilities to do scenario analysis are limited. Increasing penetrations of DER on the distribution system require Distribution Planning to better understand the conditions of the distribution system at a more detailed level – this could include hourly profiles in some cases for both feeders and substation transformers.

Recognizing that our current tool's capabilities would not be sufficient in a future with

more customer technology adoption, we began evaluating options for a new tool several years ago. As we evaluated different options, new requirements from the Commission emerged and solidified much of what we recognized would be important tool attributes going forward. The tool's core benefits include the ability to: more efficiently and cost-effectively forecast distribution-level load, conduct more advanced scenario and NWA analyses, and better integrate our distribution planning with other Company planning processes.

We believe this tool will position us well for the future of distribution planning, where its capabilities can grow with us and help us meet current and future Commission planning requirements. We summarize the tool's capabilities below, and provide a full discussion of our proposed advanced planning tool as Attachment D1.

> a. Forecast Granularity and Non-Wires Alternative Investment Analysis

As noted above, our current tool is capable of evaluating annual peak load at a feeder or substation level. A tool that provides more granular analysis options, in terms of both time intervals and proximity to the customer end point, enables us to make more accurate decisions regarding investment needs and options. For example, with the introduction of DER onto the system, the differentials between minimum and maximum load during the day become both a more valuable and harder to predict data point. With more customers adopting DER and beneficial electrification, peak loading on a specific feeder may result in different levels of load, or at a different time of day than another feeder or than the system as a whole. In order to adequately assess the impact of DER on a given part of the grid, therefore, we need a tool that can forecast hourly load at the selected analysis point. Further, the most granular analysis point we have been able to utilize in distribution planning thus far is the feeder level, but there may be value in analyzing sub-feeder data. Each feeder is generally associated with approximately 1,500 to 8,000 endpoints, depending on the area's population density. However, as DER are often localized to a specific end point, being able to analyze load and generate distribution forecasts at a sub-feeder level may provide valuable insights for both necessary grid upgrades and future potential customer offerings.

Combined, a tool that enables these more granular analyses will provide important information and efficiencies in assessing potential non-wires alternatives to identified system upgrade needs. An annual peak load analysis alone cannot communicate whether an identified upgrade is a candidate for non-wires alternative; more granular hourly data is required to determine the magnitude of overloads at specific durations. Currently this analysis is completed by extracting historical peak day load curves from feeder data, scaling them to the forecast study year, and then manually evaluating the normal and contingency load conditions. We then use these results to conduct risk analyses and develop theoretical load conditions if certain DER solutions were applied. However, a tool that can evaluate and project hourly load data on a feeder or other specific point on the grid would facilitate more efficient evaluation of potential future overloads and whether a non-wires solution – such as DER, efficiency or energy storage – is a viable alternative to traditional upgrades. In short, we anticipate a tool with these capabilities would reduce manual work and better identify opportunities for DERs to provide value on our grid.

b. Scenario Development

The Commission's Order setting out the requirements for our integrated distribution plan includes DER scenario analyses. In accordance with these requirements, we evaluate scenarios with a minimum level of assumed DER adoption, as well as medium and high adoption scenarios (corresponding to Base+10 percent and Base+25 percent, respectively). The objective of these analyses is to understand whether substantially increased levels of DER at a given point on the grid would result in different system overload conditions and upgrade needs. Currently these scenarios are developed and evaluated outside our load forecasting tool, given our current tool is incapable of generating such an analysis. A tool that can provide these scenario forecasting capabilities intrinsically would contribute to more efficient forecasting processes and better assessment regarding how these increased adoption scenarios would affect specific feeders and substation transformers. This will be particularly important going forward as DER and beneficial electrification adoption increases in our service area.

c. Aggregation and Integration with Other Resources and Planning Processes

Finally, a key aspect of a new distribution forecasting tool is its ability to integrate data source inputs, as well as communicate effectively with our other planning processes. Any new tool in which we invest will need to be able to surpass the existing tool's capabilities; preferably in its ability to handle data inputs from various sources beyond the current set of inputs such as feeder-level SCADA data and existing customer usage inputs. External data layers, such as more targeted economic and weather forecasts or projected DER adoption trends will help us more effectively forecast load changes into the future. The tool we select also needs to be able to integrate potential internal future sources of data, such as interval data from our proposed AMI investments.

Further, forecast aggregation and integration with other company planning efforts is an essential benefit we considered when evaluating replacement tools. As previously discussed, our existing tool evaluates potential load growth on a feeder or substation. However, this level of growth must be defined by the planner responsible for analyzing that specific point on the grid, and the tool cannot effectively aggregate forecasts from each point of analysis to ensure a reasonable fit with Company-wide top-line forecasts. Moreover, the forecast outputs from a future tool must be easily accessible and usable within other company planning processes. Currently, our transmission planners scale distribution forecasts to the corporate level manually, for use in transmission planning processes and tools. We also have an existing regulatory requirement to align distribution planning to integrated resource planning more closely, particularly in terms of DER forecasts. As our resource planning tools evaluate generation resources at an hourly level, a similarly granular distribution forecasting tool will facilitate this integration more effectively than the current manual translation processes.

d. Impact of the New Tool on other Distribution Planning Processes and Tools

In identifying the new planning tool as the best option for meeting these evolving requirements, we determined that it not only satisfies our forecasting requirements, but also will have a beneficial impact on other tools used by distribution planning to analyze the grid.

First, it will be able to generate, along with a load forecast, a forecast of daytime minimum loads (DML) for the various endpoints analyzed. DML are required information for DER interconnection studies, as well as hosting capacity analysis. This will greatly simplify and automate an otherwise manually-intensive process of building custom SCADA queries for each endpoint and manually parsing through the data to determine the DML.

Additionally, the APT has the ability to export forecast results directly to load flow programs, such as Synergi Electric. This will improve the efficiency of the load flow model build process, which is performed to build models for planning studies and hosting capacity analysis.

The proposed tool is able to make these improvements to the distribution planning process largely due to the fact that it ingests and outputs a significantly larger set of data as part of the forecasting process. We expect that after the tool is in use by Distribution Planning and these data sets come to fruition, we will begin to find other ways to use the new tool and its data to further benefit our processes and customers.

e. Estimated Tool Costs and Cost Benefit Summary

Given the capabilities and benefits the APT will enable for our distribution planning processes, we are confident that the investment is in the interest of both customers and the Company. As discussed previously, we have already started internal work to prepare for implementing the tool. While the contracting process and implementation planning remains in progress, we believe the costs outlined below represent an appropriate estimate for the Commission to consider as part of our certification request.

We expect the full up-front cost to procure and implement the tool at the Xcel Energy level will be approximately \$9.3 million. This includes costs related to the tool's procurement – such as the license, a pre-paid five-year maintenance and support contract, internal systems integration activities, as well as the first year of ongoing O&M costs. Because the vendor portion of the cost details are market sensitive, we provide summary level costs in Table 20 below and a non-public breakdown of the estimated costs in Attachment D1, Section V.

Table 20: Xcel Energy-Wide APT Procurement and ImplementationCost Estimate (\$, Nominal Millions)

Cost Category	Cost
APT License	Please refer
Company Integration – Capital Costs	to Att D1,
Pre-Paid Maintenance and Support for five years	Sec V for
Annual Software Hosting Fee	the non-
	public
C ON MC	detailed
Company O&M Costs	cost
	breakdown
Total Up Front Costs	\$9.3

Further, we note that our maintenance costs for the APT will be lower than the amount we currently pay for our current tool that, comparatively, has limited functionality; on an annualized basis, this savings amounts to over \$100,000 Xcel Energy-wide.

The upfront acquisition costs will be apportioned to Xcel Energy operating

companies based on each company's number of distribution feeders.⁴⁰ In total, we expect NSPM-specific costs to amount to approximately \$4.0 million in 2020, most of which will be capital. We further note that there are some minimal O&M-related costs that will recur each year, including the hosting server cost and Company internal support; we have also accounted for annualized maintenance and service contract costs beyond year five when our initial pre-paid period ends. These costs are factored into the cost-benefit analysis (CBA), summarized in Table 21 below and provided in detail as Attachment D2 (portions of which are non-public) to this filing.

Net Present Value Components	Total
Benefits (\$ millions)	1.3
O&M Benefits	0.8
Other Benefits	-
Capital Benefits	0.5
Costs (\$ millions)	3.7
O&M Expense	0.6
Change in Revenue Requirements	3.1
Benefit/Cost Ratio	0.35

 Table 21:
 NSPM APT Benefit-to-Cost Ratio

In this IDP, we request the Commission certify our request to procure the APT for distribution planning purposes consistent with our procedural proposal as outlined in Section XV of this IDP.

3. Daytime Minimum Loads

As discussed above, the new planning tool will more easily facilitate gathering and use of DML. We have however also otherwise prioritized the tracking and updating of DML in 2019. As we noted previously, our SCADA collects enough information throughout the course of a year to determine DML for all feeders equipped with this functionality, but it takes extra manual effort to derive a daytime minimum load.

In compliance with the Commission's requirement that we make tracking and updating actual feeder DML a priority in 2019, we determined and updated historical DML for all of our feeders and substation transformers that have load monitoring.

⁴⁰ While not an existing approved allocation methodology, we will propose this allocation method in our 2020 annual filing regarding our Service Agreement with Xcel Energy Services, Inc.

This was a large effort, and we are determining how to best include this action into the planning processes going forward. We have provided however, all of these values in our 2019 Hosting Capacity report filed concurrent with this IDP, along with other information.

We note that we will also be tracking DML and any changes to them year-to-year. Our Advanced Planning Tool will also aid in the actual forecasting of these values going forward. Minimum load forecasting is a newer concept, but our tool will allow us the ability to determine future load curves and the peak and minimum values associated with them.

VI. NON-WIRES ALTERNATIVES ANALYSIS

The discussion in this section responds to IDP Requirement 3.E.2, which requires the following:

E. Non-Wires (Non-Traditional) Alternatives Analysis

1. Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.

2. Xcel shall provide information on the following:

- Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)
- A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)
- Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed
- A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.

Non-Wires Alternatives (NWAs) are emerging as another advanced distribution planning application. While a nascent concept only a few years ago, the United States has seen a significant rise in the number of NWA projects proposed and being implemented. States with high DER penetration and/or aggressive regulatory reform, like New York, California, Oregon, and Arizona, are leading the way. Decreasing DER costs in combination with slow or flat load growth may present opportunities for utilities to address pockets of load growth using DER over traditional build out of distribution infrastructure, like reconductoring, transformer replacement, or even new substations. Unlike traditional infrastructure projects, which typically offer fixed capacity increases at known locations, non-traditional solutions often have varying operating characteristics based on their location or the time of day they are used.

More tactically, NWA analysis processes consider several things: a set of criteria for determining which traditional projects are suitable candidates for NWA, processes to develop portfolios of solutions (including both third party resources and nontraditional utility assets), a mechanism to evaluate the costs and benefits of the NWA relative to the traditional solution, procurement processes, and standards to ensure equitable reliability and performance. For implementation and deployment, currently we are seeing NWA solutions which require a disparate set of systems to separately operate the different elements of equipment that would comprise an NWA portfolio solution (e.g. a battery- only platform or demand response- only mode).

Without integration across different systems, this makes the facilitation of NWA a custom, one-off solution that requires extensive oversight and management. Recent analysis performed by Xcel Energy has determined that the cost of incorporating DERs as the primary risk mitigation is at this time still more costly than traditional solutions. However, as technology advances and manufacturing evolves, DER have the potential to quickly become a cost competitive option. As such, Xcel Energy is working diligently with research groups, internal and external stakeholders, and other utilities that are also incorporating DER planning in order to refine the process of having NWAs solve traditional distribution system deficiencies.

One of our external efforts was to engage with stakeholders due to the high interest in NWA during the course of our 2018 IDP proceeding. We held a stakeholder workshop in April 2019 to discuss and get feedback on our screening process and approach to the NWA analysis.

In this section, we discuss the viability of NWAs by project type, the Company's timeline to consider and incorporate any NWA projects, our screening process for NWA projects, and a summary of our analysis. We provide the full results of our NWA analysis as Attachment H. Finally, we also provide an update on our involvement with Center for Energy and Environment's (CEE) in the Geotargeted

Distributed Clean Energy Initiative.⁴¹

A. Viability of NWAs by Project Type

IDP Requirement E.2 requires, in part, that the Company provide

...information on ...Project types that would lend themselves to non-traditional solutions (ie. Load relief or reliability)

In this section we discuss three project types (mandates, asset health and reliability and capacity) and discuss why capacity project best lend themselves to a nontraditional solution.

1. Mandated Projects

Mandated projects are projects where the Company is required to relocate infrastructure in public rights-of-way in order to accommodate public projects such as road widenings or realignments. For technical reasons, NWAs would not work well for mandated projects. It is a priority to keep customers connected to the grid. If we chose not to replace distribution infrastructure due to a mandated project we would leave a segment of customers electrically unserved due to having no physical connection to the Xcel Energy system. Those customers would then need to be served via some other local means, like distributed generation. However, if they were served by some other means, that would take away from the interconnectedness of the distribution system. This is necessary to continue reliable service because it allows the Company the ability to switch customers to other feeders during periods of planned maintenance or unplanned outages. Removing that interconnectedness takes away added flexibility and redundancy that has been intentionally designed into the system and makes operating it more difficult and less reliable. The grid offers many benefits, such as affordable reliability, and removing customers from it is not a viable solution for either Xcel Energy or our customers.

Beyond the technical reasoning, these projects generally follow municipal and state funding availability and consequently, are not always specifically represented in our five year budget, especially beyond one to two years. What makes these projects even more time prohibitive is the fact that they must occur prior to the actual public project taking place. A typical example would include a project that was formally funded by a municipality two years in advance of the start of construction. This

⁴¹ See <u>https://www.mncee.org/resources/projects/geotargeted-distributed-clean-energy-initiative/</u>

means that the municipal project design will be completed within the first year after funding was allocated, giving the Company less than one year to design its project, allocate the necessary funds, and relocate facilities in the affected areas before construction on the municipal project can begin. Implementing a detailed NWA for such a situation would be extremely difficult, if not impossible, to accomplish within such a short period of time given the complexities inherent to a totally unique and new solution that an NWA would offer.

2. Asset Health and Reliability Projects

Asset Health and Reliability projects are projects required to replace equipment that are reaching the end of life or have failed. This is a broad category that covers pole replacements, underground cables, storms, public damage repair, conversions, etc. To maintain the existing reliability of the distribution system we must spend money annually to replace our assets.

Keeping customers connected to the grid is the major reason Asset Health and Reliability projects are not suitable for NWAs. If we chose not to replace distribution infrastructure due to aging assets, there is a high level of risk that certain assets would fail and customers would experience an outage. To avoid or prevent the outage the customers would need to be served via some other local islanded generation. From a reliability perspective, at some point our customers need to be hooked back up to the distribution grid rather than staying in a permanent microgrid. So money is spent on infrastructure renewal regardless; it is just a matter of if it is reactive or proactive replacements.

Unlike the mandated projects, with Asset Health and Reliability projects there is more potential for ongoing costs. A mandated project requires the movement of a particular piece of the system one time. An asset health project, because it is based on condition, can occur at many points on the system. One project could first be needed to replace deteriorating poles, then another needed to address underground cable that is going bad near the customer, then another to replace breakers inside the substation. Because asset health affects every part of the distribution system and is essential to maintaining reliability, an NWA is not workable.

3. Capacity Projects

Capacity projects are better suited for NWAs as they are driven by a capacity deficiency that can be offset or otherwise deferred by strategically-sited DER. DER that can generate, discharge, or reduce the consumption of electricity downstream on a feeder can decrease the amount of load that is drawn through the substation and

relieve overloads. In some cases power quality issues, such as voltage sags, could fall under the Capacity project heading. While this is not the usual case, this type of issue could also benefit from an NWA solution.

Because capacity projects do not have external requirements to build capacity, each project is scored on a cost/benefit basis, and that score is one of the key drivers for prioritizing projects for selection in the budget. Therefore, without some additional driving need, an NWA must be cost-competitive with a traditional solution to be viable in the budget create process.

Capacity risks are identified in two different categories: N-0 (system intact), and N-1 (first contingency). Existing Distribution Planning Criteria dictate that a project needs to be identified to resolve all N-0 risks greater than 106 percent loaded, and all N-1 risks with more than 3 MVA at risk. The viability of NWAs varies between N-0 and N-1 risks due to the nature of the risk types.

N-0 risks are normal overloads that occur under system intact conditions. These typically are manifested as substation transformers or distribution feeders that have just crossed their 100 percent loading capacity threshold. We provide an illustrative example of an N-0 overload below.



Figure 34: 2019 Peak Day Load Profile Reflecting an Illustrative N-0 Overload

This overload is relatively small with a peak magnitude of 0.71 MW. Additionally, due to the small magnitude the total duration of the overload is brief as well, yielding a

total of approximately 1 MWh overloaded. With a unit cost estimate of approximately \$400,000/MWh for battery storage, this indicates that the overload could be mitigated with DER for \$400,000. This cost estimate is cost-competitive with a typical traditional project to mitigate a comparable overload, which would consist of upgrading feeder cables or conductors, extending a feeder and transferring load, or installing a new feeder.

N-1 overload risks, on the other hand, are significantly less viable for NWAs. N-1 overloads occur when, for loss of a feeder, feeder load is transferred away to adjacent feeders, causing an overload. Per our planning criteria, projects are not required for N-1 risks until they exceed 3 MVA at risk – this means that total magnitude of the overload on the adjacent feeder(s) exceeds 3 MVA. At this level of overload magnitude, the duration of the overload extends by several hours. This excessive duration accumulates significant amounts of MWh overloaded, and in turn inflates the cost to mitigate the risk.

We show an illustrative example of a N-1 overload below. If an outage were to occur for the Feeder 2, the feeder's load would be broken up into sections and transferred to adjacent feeders. In the case of the Feeder 2, the load would be broken up into three sections. The first section can be transferred away to an adjacent feeder without causing any overloads. However, when the second section is transferred away to Feeder 1, it causes an approximate 4 MW overload. The resulting peak day load curve for Feeder 1 after the Feeder 2 second section load has been transferred is shown below.

Figure 35: Peak Day Load Curve for Feeder 1 After Feeder 2 Second Section Load has been Transferred



The magnitude of the N-1 overload is relatively normal for N-1 risks tied to a project at 4.0 MW at risk. However, just 4 MW of load at risks causes the duration of the overload to extend to 10 hours. Therefore, the accumulated MWh during the overload totals to 24.08 MWh. With a unit cost estimate of \$400,000/MWh for battery storage, the cost to mitigate this risk rises to \$9,632,000. This cost estimate is multiple orders of magnitude higher than a typical traditional project to mitigate a comparable risk. A typical traditional project could consist of upgrading feeder cables or conductors, extending a feeder for a new tie, or installing a new feeder.

The load profile shown above is of similar shape to most feeders that comprise a mix of residential and commercial customers. As such, the cost estimate for the NWA can be considered representative of a typical NWA for N-1 risks of this magnitude. However, even if a 4 MW overload were to occur for only a one hour duration (totaling to 4 MWh), it would still require \$1,600,000 of battery storage to mitigate the overload. While this overload duration is unrealistically short, it indicates that the cost to mitigate a 4 MW N-1 overload for even the minimum possible duration would not be cost-competitive with a comparable traditional solution. Therefore, it is not recommended that N-1 risk-driven projects are considered viable for NWAs.

B. Timeline

IDP Requirement E.2 requires in part that the Company:

...provide information on . . A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation).

With regard to the timeline that is needed to consider alternatives to any traditional projects, for purposes of this IDP we have assumed we need about three years to appropriately consider and incorporate a NWA solution. This timeline incorporates our internal time for analysis as well as all the steps surrounding a request for proposals (RFP) to actually procure a NWA solution. This includes issuing an RFP, obtaining response, screening the responses, technical and sourcing reviews, and then contract negotiations, and construction. It is our understanding that this timeline is consistent with the approach other utilities have used in similar analyses as well.

Perhaps as we get more experience in this process, the timeline could moderate a bit, however, these projects necessarily take a significant amount of lead time, even when we are addressing them entirely in-house.

C. Screening Process

IDP Requirement E.2. requires in part that the Company:

... provide information on the...Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed. And, a discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made

NWA Analysis, from a holistic standpoint, is an emerging analysis that many utilities across the U.S. are just beginning to tackle. Not only do these alternatives use some non-traditional solutions but they also use traditional ones in new ways and may combine solutions to fully mitigate an issue. These complexities along with differing implementation and operational strategies will take time and considerable effort to build and maintain.

We note that we are just at the beginning of the future NWA process. Xcel Energy and the industry as a whole, is trying to create a comprehensive method that will focus on the projects that have the most potential and then evaluate them in an efficient manner against traditional alternatives. We believe much work needs to take place both from the Company and the industry before success can happen. At present, the effort needed to analyze one project for potential NWA is substantial and increases greatly according to the number of risks associated with it. Recognizing the current IDP requirement to provide an analysis on how NWAs compare in terms of viability, price, and long-term value for projects with a total cost of \$2 million or greater is an interim step, we believe long-term that the right approach to identify candidate projects will involve more than a financial threshold.

As we discussed with stakeholders at our NWA workshop, we applied several filters in our screening process including project type, cost, timeline and number of risks for the 2019 IDP process. However, we expect to continue to refine our process to identify projects for NWAs for future reports. The project filters were applied as follows:

- *Project types* Project types includes mandates, asset health and reliability and capacity projects. As discussed above, mandates and asset health and reliability projects were filtered out.
- *Costs* Per the Commission's Order, we evaluated projects with costs greater than \$2 million. However, we believe there is additional work to be done to best identify the range of projects costs for this filter.
- *Timeline* The timeline included in this screening process includes projects that fall in the 2022-2024 timeframe due to the timing considerations discussed above.
- *Risks* The number of project risks includes both N-0 and N-1 risks. We did not use a hard cutoff for this filter, but factored it in as we determined which project would be best for a NWA analysis.

IDP Requirement E.1 requires the following:

Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.

Using the above screening process, the below table provides the list of capacity projects over \$2 million that fall within the required timeline. Nine projects fit the screening criteria for further evaluation as shown below.

Project	2020	2021	2022	2023	2024	Total
Install Hyland Lake HYL TR3 & Feeder	\$ 0	\$ 0	\$0	\$100,000	\$4,600,000	\$4,700,000
Install Goose Lake GLK TR3 & Feeders	\$ 0	\$ 0	\$ 0	\$700,000	\$4,000,000	\$4,700,000
Install Orono ORO TR2 & Feeder	\$ 0	\$ 0	\$100,000	\$4,000,000	\$ O	\$4,100,000
Install East Winona EWI TR2 & Feeder	\$ 0	\$ 0	\$ 0	\$100,000	\$3,100,000	\$3,200,000
Install Zumbrota ZUM TR & Feeder	\$ 0	\$0	\$100,000	\$2,950,000	\$ O	\$3,050,000
Reinforce Kasson KAN TR1 & Feeders	\$ 0	\$ 0	\$2,850,000	\$ 0	\$ O	\$2,850,000
Reinforce Burnside BUR TR2	\$ 0	\$0	\$100,000	\$2,600,000	\$ O	\$2,700,000
Install Viking VKG Feeder	\$ 0	\$0	\$0	\$2,500,000	\$ O	\$2,500,000
Install West Coon Rapids WCR TR	\$0	\$ 0	\$100,000	\$1,980,000	\$ 0	\$2,080,000

Table 22: Total Capacity Projects Exceeding \$2 Million andWithin the Timeline

Today, NWA analysis is very time consuming and manual – especially as the risks associated with a project increase. The process requires that we pull peak load curves for feeders and substation transformers from historical monitoring data and advance that to the forecasted year of interest. Those curves are then blended together, where applicable, for contingency situations that are unique for each. We then tailor and add in DR and existing generation curves and additional solar if necessary, in order to determine final energy and demand values that can be used to size an appropriate energy storage device. This is necessary for every identified risk that a traditional project is mitigating.

Most capacity projects budgeted at greater than \$2 million are intended to solve larger numbers of risks – this vastly increases the complexity of the problems to solve with a NWA, and in turn increases the amount of resources required to conduct the analysis. Projects with fewer capacity risks to solve are more localized and therefore more straightforward. We also look for any opportunities to utilize resources to solve more than one risk, such as optimally placing them at key locations on the system.

We expect future tool enhancements will help make this process less burdensome. Specifically, our proposed Advanced Planning Tool, for one, will help in the beginning of the analysis by providing the forecasted load curves. While the rest of the process will still be fairly manual for the foreseeable future, we are working within the industry to help affect change and improvement. Recently, we participated with EPRI in an effort to help build a tool capable of evaluating different alternatives in a model based format. Even though a comprehensive tool solution for NWA analysis is years away, we will continue to work with EPRI and others in the industry to make advancements and improve on existing processes.

D. Non-Wires Alternatives Analysis

In this section, we outline the results of our 2019 NWA analysis, which examined the nine projects summarized above. For each of these projects we focused on the forecasted 2022 peak load curve for each feeder or transformer risk involved. We then applied focused demand response in an effort to reduce the load and followed that with energy storage and/or solar generation to make up the rest of the deficiency. In some instances, we had existing solar on particular feeders that we could utilize in the analysis as well. We provide the results of the analysis, along with the load curves and assumptions used in Attachment H.

We only considered DR for the N-0 risks. This is partially due to the complexity of the N-1 analysis (combinations of feeders resulting in multiple configurations and customer make-ups) and the difficulty in obtaining necessary data such as individual customer loads. By focusing on the N-0 risks at this time, we are looking to develop a process, observe the value, and determine next steps for all risks.

Table 23 below highlights the nine projects, their costs, and the risk deficiencies that drive those costs. Comparing these analyses to traditional projects was difficult because in some instances, the NWA is not able to fully solve all of the risks that the traditional project solved. This was in part due to contingency situations where a NWA would have to act as a microgrid for large amounts of energy. The costs for such a solution would have been substantially greater. The NWA solutions also solved the risks up to 100 percent of the capacity rating, which means that any new load growth would create the need for an expanded or new NWA solution. In comparison, our traditional capacity projects contain "spare capacity" that allows us to accommodate some new growth in the near term.

Project Title	# of Risks	Aggregate Project Peak Demand (MW Overload)	Aggregate Project Energy Demand (MWh Overload)	Cost of NWA (\$ M)	Cost of Traditional Project (\$ M)
Reinforce Kasson TR1 and Feeders	7	14.14	126.69	\$49.34	\$2.85
Install West Coon Rapids WCR TR	4	18.59	167	\$94.64	\$2.08
Reinforce Burnside BUR TR2	3	9.76	92.59	\$46.86	\$2.7
Install Zumbrota ZUM TR & Feeder	3	2.8	28.25	\$8.84	\$3.05
Install Orono ORO TR2 & Feeder	3	9.62	59.35	\$31.32	\$4.10
Install Hyland Lake HYL TR3 & Feeder	5	11.31	52.49	\$20.99	\$6.20
Install Goose Lake GLK TR3&Feeders	8	20.94	155.77	\$63.31	\$4.70
Install Viking VKG Feeder	4	6.99	39.10	\$15.64	\$2.00
Install East Winona EWI TR2 & Feeder	9	9.2	98.16	\$88.90	\$3.2

 Table 23:
 2019 NWA Candidate Projects – Results Summary

We discuss each of these project analyses in Attachment H.

E. Geo-Targeting

We continue to partner on a non-wires alternative pilot led by Center for Energy and Environment (CEE). This initiative started in June 2017 and is focused on energy efficiency and demand response programs within our existing CIP portfolio. The pilot officially launched in June 2019 with customer outreach and is expected to go through the end of 2019. The project implementation costs are funded by a grant from the Legislative-Citizen Commission on Minnesota Resources and existing Conservation Improvement Project program budgets.

The pilot site covers the cities of Sartell and Sauk Rapids in central Minnesota where Xcel Energy is both the electricity and natural gas provider. These locations were chosen out of a list of nine potential project areas that had forecasted capacity needs three or more years into the future. At the time the pilot site was identified, the estimated capacity need was 1.5 MVA, and the traditional distribution solution anticipated a new transformer and feeder reconfiguration. The goal of the pilot is to offset projected peak demand growth in the target location by 500 kW, deferring a traditional infrastructure upgrade by one year.

CEE's goal for annual energy efficiency participation is 340 residents and businesses, which is an increase from an average of 95 participants in previous years. Throughout the spring, the pilot team worked closely with the cities to establish community-based marketing strategies and make use of local channels. Community leaders were invited to participate in a leading-edge communication strategy developed for this project to raise local awareness. Community response to the pilot rollout thus far has been favorable. From June through September 2019, 134 residents participated, and 104 business audits were completed.

While the pilot is not yet complete, it is experiencing challenges meeting the goals. For example, the sales cycle for business customers has been a challenge, perhaps suggesting that these customers may not be able to help address a short-term wires risk. On the residential side, the cost per customer is on the higher end of the spectrum for just an energy efficiency opportunity – including the cost of an extended, targeted promotion. Including the value of the local peak demand savings will likely be needed to make residential opportunities cost effective. However, a less than normal weather pattern for the June-September timeframe may also have impacted opportunities to install smart thermostats or adjust cooling equipment when customers did not see these as necessary or immediate needs. The pilot project team is reviewing these and other pilot aspects as the pilot comes to an end in December. We will report results in our 2019 Conservation Improvement Plan Status Report (filed April 2020) and in our next IDP.

The pilot project also developed operational protocols to test existing demand response resources for distribution system purposes as a second component of the pilot. During the research stage, the team determined over 4,000 residents and businesses in the pilot area were already participating in our Saver's Switch program.⁴² In addition, there has been a growing number of smart thermostat customers signed up for AC Rewards – and 56 new customers signed-up through the pilot to-date. While traditionally operated for bulk system level purposes, the pilot sought to operationalize them as a geo-targeted resource, and therefore to assist with local grid management. While CEE tested this concept in the 2019 summer, the weather conditions were not ideal to truly test peak demand, so results may be limited. The pilot evaluation will continue during the 2020 cooling season, where we hope to get more complete results. We will incorporate our learnings along the way into future IDPs and NWA analyses.

⁴² Saver's Switch allows the Company to directly control air conditioners on peak electricity use days.

VII. ASSET HEALTH AND RELIABILITY MANAGEMENT

In this Section we describe several analyses and functions that support distribution system reliability and resilience.

A. Electric Distribution Standards

Utility distribution systems are complex and dynamic, in that they involve thousands of pieces of equipment, must be resilient from outside forces over vast areas of geography, and must be able to respond to changes in customer loads and operational realities. Traditionally, distribution systems have been designed for the efficient distribution of power to provide customers with safe, reliable and adequate electric service – with geography playing a significant role in the design of the system. Our Minnesota service area has diverse geography and therefore diverse planning criteria and considerations.

One of the ways we plan the system is through a set of materials and work practice standards that apply to the construction, repair and maintenance of the electric overhead distribution, underground distribution, and outdoor lighting systems. The purpose of Electric Distribution Standards at Xcel Energy is to develop and maintain a broadly-accepted set of material and construction standards that meet the needs of each of the operating companies and stakeholders, while meeting all applicable regulatory and code requirements. The Standards function acts as an expert consultant to operations and engineering, collaborates to enhance public and employee safety, drives cost-effectiveness, and improves system reliability through defining electric distribution standard materials, methods, and applications.

Standards updates may stem from a number of circumstances including regulatory or code changes, company analysis, input or an issue raised by field personnel, and industry guidance, among others.

Xcel Energy's Design standard books consist of Overhead, Underground, and Outdoor Lighting Manuals. Each of these Manuals detail equipment and designs that have been previously reviewed against industry standards and best practices to ensure installation of facilities results in safe and reliable service. Documenting approved materials and equipment configurations allows for efficient design of construction projects. The Standards Manuals simplify electrical distribution projects and optimize a Designer's work because the engineering and code compliance is built-in – and typically only requires engineering input for special circumstances. Reference material on transformer sizing and conductor lengths, which already accounts for voltage and thermal limits, is also part of the Standards Manuals. We are providing a couple of examples of the work that Standards does, to further help put the Standards function into context:

Porcelain Cutout to Polymer Cutout Transition (2010-present day). Xcel Energy has a process to identify and analyze faulty material. In this case, material submitted from field crews and engineering identified an issue where porcelain cutouts stood out from other materials as having issues requiring further analysis. We had been using polymer cutouts in specialized applications, however not broadly, because industry standards had not yet been developed for the polymer material. We validated our observations on the porcelain cutouts and the potential viability of polymer as an alternative through peer group consultation with other utilities through Midwest Electrical Distribution Exchange and Western Underground Committee.

Electric Distribution Standards worked with local jurisdictional teams with an objective to identify and vet a polymer cutout to be used company-wide, and discontinue the use of porcelain cutouts. We additionally participated in the IEEE C37.41 and C37.42 revision to create testing requirements for polymer cutouts. Recently, we further improved this Standard by consolidating 125kV BIL to 150kV BIL cutouts –allowing a transition from three cutout types to two cutout types, and increasing the number of manufacturing sources from which we can procure polymer cutouts that meet our standards requirements. As we systematically replace remaining porcelain cutouts on our system with polymer, we are improving reliability for customers and the resilience of our system. This change also expanded material availability and resulted in cost savings.

Wood to Fiberglass Crossarm Transition (2010-present day). In 2011, the National Electrical Safety Code (NESC) changed the loading requirements for deadend crossarms. We conducted research with our industry peer groups and found that fiberglass was identified as being the best material for longevity and strength. We evaluated alternatives, and available fiberglass deadend crossarms met the NESC requirements and resulted in an approximate 17 percent cost savings. After our success implementing deadend fiberglass crossarms, we evaluated and ended-up implementing fiberglass tangent crossarms as a cost-neutral option – improving the resilience of our system in a cost-conscious way for our customers.

We have since made further improvements to the fiberglass crossarms after participating in an EPRI initiative to evaluate system materials in terms of system hardening. After conducting further internal research, to develop testing criteria based on galloping and ice loading witnessed by Xcel Energy line crews and Electric Distribution Standards, we updated Xcel Energy standards to obtain a better and longer life product – and are additionally working with the fiberglass crossarm industry to revise the national standards to better take these conditions into account.

For additional context, Table 24 below shows a list of some of the most common industry standard documents applied in distribution engineering. The list is not intended to be inclusive of all standards that may be applied to medium and low voltage systems, but rather is intended to provide insight into standards that are frequently used. Included are primarily documents from the Institute of Electrical and Electronics Engineers (IEEE) which are classified as Standards, Recommended Practice, and Guides. Standards carry more weight when compared to Recommended Practices. Guides often show a number of ways to achieve a technical objective and are the least prescriptive.

Condition	Standard
Safatu	National Electric Safety Code (NESC)
Salety	Xcel Energy Safety Manual
	ANSI C84.1 - minimum and maximum voltage limits, voltage
Voltago Limita	imbalance limits
vonage Linnis	Xcel Energy Standard for Installation and Use – voltage limits and
	imbalance (same as ANSI C84.1)
	Xcel Energy Design Manuals (Distribution Standards Engineering)
	Substation Field Engineering (SFE) transformer loading database -
	based off of IEEE standards
Thormal limits	IEEE 738 – Overhead conductor ampacity rating
Thermal mints	IEC 287 and IEC 853 – Cable ampacity rating methodology in
	CYMCAP program
	IEEE C57.91 – transformer and regulator loading guide
	IEEE C57.92– power transformer loading guide
Distribution	IEEE 1547 – Interconnection of Distributed Resources
Interconnection	
Harmonics	IEEE 519 - total harmonic distortion and individual harmonic limits
Voltage Fluctuation	IEEE 1453 – rapid voltage change and flicker limits

Table 24: Common Engineering Standards Summary

Additionally, North American Electric Reliability Corporation (NERC) standard FAC-002-2 applies to studying the impact of interconnecting facilities to the Bulk Electric System, which comes into play with distribution substations. Specifically, Requirement R3 applies when we seek to interconnect new "end-user facilities" or materially modify existing interconnections to the transmission system. It states we shall coordinate and cooperate on studies with our Transmission Planner or Planning Coordinator as specified in Requirement R1. This includes many requirements such as reliability impact, adherence to planning criteria and interconnection requirements,

conducting power flow studies, alternatives considered and coordinated recommendations.

B. Asset Health

The NSPM distribution system is composed of nearly 27,000 miles of distribution lines and 1,200 feeders that provide the path for delivering electricity from the distribution substation to the distribution customer transformer and then to customers. This vast system is key to ensuring customers receive safe, reliable and cost effective energy. We continually invest in our infrastructure through established reliability and asset health programs to ensure that we deliver the most reliable and efficient energy to our customers. While we have been able to historically deliver excellent value for customers, the utility industry is changing rapidly and customer expectations for power availability are also changing.

To this end, we noted in our 2018 IDP that we believe an incremental customer (now, system) investment (ISI) initiative is necessary to continue to meet the needs of our customers – and that shifting funding closer to the customer will be a foundational requirement for the grid of the future. We discuss our traditional asset health program below, and in compliance with Order Point No. 6 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, we provide in part C below:

...additional information on the Incremental Customer Investment Initiative and the System Expansion or Upgrade for Reliability and Power Quality increases beginning in 2021.

We monitor and address the health of our distribution assets – tracking for example, the fleet age of each of our major distribution assets, and use age as a partial proxy for asset health. We also analyze reliability data and work to tie that data to asset health to create and refine programs to manage reliability. We discuss these aspects of our current efforts in terms of examples in more detail below.

To use underground distribution assets as an example, reliability performance is heavily influenced by the performance of mainline and tap cable. We analyze cable failure rates for both types of cable, and budgets to manage the reliability. Analysis has shown us that the era of the cable projects its failure rate, which allows us to focus efforts on the cable most likely to fail. Historical performance of cable has also influenced our standards for future purchases for new construction and replacement work. Figure 36 below is one of the ways that we analyze asset performance in terms of maximizing customer value.

Figure 36: Example – NSPM Mainline Cable Replacement Investment Compared to Annual Failures



The overhead distribution reliability performance is dependent on many factors including vegetation, weather, and the health of the many pieces of the overhead system. The vegetation program is a key program to maintaining good reliability. The vegetation program includes quality checks by visiting outage locations associated with vegetation that impacted 100 or more customers. The check determines if the outage would have occurred if a vegetation crew had worked the line the day before. These checks are showing the value of our vegetation program in mitigating outages. Unfortunately vegetation events can cause damage to our asset health, especially to older assets, so minimizing events is a key factor in maintaining asset health.

Another key program is checking the health of our poles. Pole rot at the base of the pole can be a cause of pole failure, especially in stormy weather. We work to inspect poles on a 12-year cycle to mitigate risk of pole failures. The below figure portrays wood pole failure rates by their age.



Figure 37: Example – Wood Pole Failures by Age

We have also changed the standards for all new construction and replacement poles to larger poles as part of system hardening. Other programs include:

- Identification of the poorest performing feeders each year and doing an indepth analysis to identify opportunities for improvement.
- Identification of a protective device that operates frequently and performing a study to identify opportunities for improvement.
- Identification of customers experiencing multiple interruptions, performing a study to identify opportunities for improvement.

Analysis of these outages commonly includes site visits that allow the engineer to see firsthand the condition of the equipment. Mitigations for these programs frequently include updating deteriorating infrastructure and may overlap with other programs.

C. Incremental System Investment

The ISI initiative is driven by the need to improve reliability on those elements of the system that are the closest to our customers as well as provide the infrastructure to support increased DER integration. While historically Distribution has made investments in our infrastructure through our established asset health and reliability programs to ensure the reliability of our system, the utility industry is changing rapidly and customers have new expectations for power availability and reliability. As a result, we believe it is necessary to shift funding closer to those portions of the system

that directly connect to customers with the goal of enhancing the safety, reliability, and resiliency of the system while also enabling customer choice and the adoption of DER, such as EVs.

This initiative will both expand existing asset health programs and will create new programs to address areas of the system that have traditionally not received much focus. Specifically, this initiative will expand two of Xcel Energy's existing programs, one that replaces underground cables that are at risk of failure and another that identifies and replaces substation transformers that are nearing the end of their useful life. This initiative will create new programs that focus directly on our customers' reliability and DER adoption needs by expanding investments on the portions of our system closer to the customer. Typically these elements are the taps (radial extensions from our feeders) and secondary voltage systems.

The ISI initiative is divided into four main programs: substation, underground, overhead tap, and overhead mainline. We outline below, the capital expenditures for these ISI programs and the O&M costs in Tables 25 and 26.⁴³

ISI Programs		2020	2021	2022	2023	2024
Querboad Tap Drograms	Targeted Undergrounding		\$18.2	\$27.0	\$27.0	\$27.0
	Low Cost Reclosers		\$2.7	\$2.4	\$2.4	\$2.4
	Pole Top Reinforcements		\$2.7	\$2.4	\$2.4	\$2.4
Overnead rap Flograms	Transformer and Secondary Replacements		\$2.5	\$2.4	\$2.4	\$2.4
	High Customer Count Taps		\$3.0	\$3.0	\$3.0	\$3.0
	Community Resiliency		\$2.0	\$3.0	\$3.0	\$3.0
	Mainline Cable Replacement		\$7.0	\$7.8	\$7.8	\$7.8
	Underground Residential Distribution (URD) Cable Replacement		\$5.0	\$2.5	\$2.5	\$2.5
	Cable Assessment		\$7.0	\$6.0	\$6.0	\$6.0
Underground Programs	Network Monitoring		\$2.0	\$2.3	\$2.3	\$2.3
	St. Paul Tunnel Rehabilitation		\$5.0	\$5.0	\$5.0	\$5.0
	Feeder Exit Capacity		\$3.8	\$3.0	\$3.0	\$3.0
	Purchases / Tooling		\$4.5	\$0.2	\$0.2	\$0.2
Cubstation Drograms	Substation Asset Renewal		\$5.0	\$5.0	\$5.0	\$5.0
Substation Programs	Transformer Replacement		\$7.0	\$13.0	\$13.0	\$13.0
Overhead Mainline Programs	Lightning Protection Replacement		\$1.0	\$1.0	\$1.0	\$1.0
Overneau wainine Programs	Pole Fire Mitigation		\$2.5	\$2.0	\$2.0	\$2.0
TOTAL		\$0.0	\$81.0	\$88.0	\$88.0	\$88.0

Table 25:ISI Capital Expenditures – DistributionState of MN Electric (Millions)

⁴³ We also clarify that these O&M costs are also included in the overall Distribution O&M budget primarily in the Contract Outside Vendor category.
Table 26:ISI O&M Costs-DistributionState of MN Electric (Millions)

Cost Category	2020	2021	2022	2023	2024
O&M Expense	\$0.0	\$1.5	\$1.5	\$1.5	\$1.5
Total	\$0.0	\$1.5	\$1.5	\$1.5	\$1.5

1. Overhead Tap Program

The primary goal of the overhead tap program is to improve reliability and resiliency of the Company's electric distribution system through a series of six programs that target the overhead tap lines throughout the Minnesota service territory.

As shown below, tap lines are those that split off from the main feeder and travel through neighborhoods to connect to homes and businesses. The tap portion of the NSPM distribution system consists of nearly 22,500 circuit miles of line. Of those, approximately 58 percent, or 13,050 miles are overhead.

Figure 38: Illustration – Tap Portion of NSPM Distribution System



The six programs are: (1) targeted undergrounding; (2) low cost reclosers; (3) pole top reinforcements; (4) transformer and secondary replacement; (5) high customer count taps and (6) community resiliency program.

We outline the capital expenditures for each of these programs below.

State of MN Electric (Millions)							
ns		2020	2021	2022	2		
	Targeted Undergrounding		\$18 2	\$27.0	Ś		

 Table 27:
 ISI Capital Expenditures – Distribution

ISI Programs		2020	2021	2022	2023	2024
IST TOBIUMS	Targeted Undergrounding	2020	\$18.2	\$27.0	\$27.0	\$27.0
	Low Cost Reclosers		\$2.7	\$2.4	\$2.4	\$2.4
Overskeed Tex. Due success	Pole Top Reinforcements		\$2.7	\$2.4	\$2.4	\$2.4
Overnead Tap Programs	Transformer and Secondary Replacements		\$2.5	\$2.4	\$2.4	\$2.4
	High Customer Count Taps		\$3.0	\$3.0	\$3.0	\$3.0
	Community Resiliency		\$2.0	\$3.0	\$3.0	\$3.0
TOTAL		\$0.0	\$31.1	\$40.2	\$40.2	\$40.2

Specific to reliability, we intend this program to decrease the number of outages per year for those customers that experience frequent and long outages due to issues on the overhead tap system. As our customers live and work near the electrical system and its equipment and components, we also consider community aesthetics a factor of our customers' experience. Customer satisfaction depends on a Company's ability to meet customer expectations. Reliability is one of the foundational components for meeting customer expectations of an electric utility, and as electricity becomes increasingly entwined with every aspect of day-to-day life, the issue of reliability becomes increasingly important to customers.

Specific to distribution system resiliency, these programs aim to strengthen the electrical system to reduce weather-related impacts and outages, rather than the traditional focus on ensuring rapid response and restoration to a storm-vulnerable system. Community resiliency includes ensuring the most critical first responder services in a community are supplied by a safe, reliable, and storm-hardened grid system in the event of emergency. Additionally, we need to prepare our system for electric vehicle penetration in advance of rapid and widespread customer adoption.

a. Targeted Undergrounding

The goal of the targeted undergrounding program is to underground the outage-prone tap lines to reduce the likelihood of these outages and to enable our crews to focus restoration efforts on other areas of the system allowing for quicker response times for all customers. The primary benefit of this program is that by undergrounding the tap lines with the highest failure rate, we significantly improve the reliability of those tap lines for customers – and overall, we improve the resilience of the system because there will be fewer downed tap lines. Fewer downed tap lines means that restoration crews can focus efforts elsewhere during weather events and likely improve restoration times for other areas of the system. Also, since this targeted undergrounding will focus on areas with heavy vegetation, there will be a reduced need for vegetation management in these areas.

The Company has over 13,000 miles of overhead miles of tap lines in Minnesota. In relation to the underground tap system, failures on the overhead tap system occur 1.5 times more frequently, primarily driven by storm and weather events. Overhead power line segments with a history of high numbers of outages drive a disproportionate amount of outages that affect Xcel Energy's customers. These are typically segments of line that are aging and/or located in heavily vegetated areas. While we have systematic programs that manage vegetation to industry standard clearances, and where we replace components of our system, including conductor, that are aging or experiencing abnormal failure rates, approximately 17 percent of our overhead tap lines in Minnesota are an older vintage of conductor that generally have a higher failure rate compared to newer overhead lines.

We propose to start the targeted undergrounding program with several pilot areas – undergrounding 20 miles of overhead tap system in 2021 and 30 miles in 2022. These pilots will focus primarily on areas that have experienced outages with high quantities of tap outages due to vegetation. As the program matures, the Company expects to consider areas based on multiple criteria including but not limited to: interruption rates, interruption length, degraded infrastructure, and location of overhead line.

b. Low Cost Reclosers

A recloser is a breaker equipped with a mechanism that can automatically close the breaker after it has been opened due to a fault. Our current tap lines are predominantly equipped with fuses that, if opened, result in a sustained outage for both permanent and temporary causes. The low cost recloser program would reduce sustained outages by installing reclosers on tap lines. We plan to install up to 500 low cost reclosers in 2021 and 2022.

Low cost reclosers are single-phase devices, generally mounted in existing fuse holders. While they prevent sustained outages from temporary causes such as a tree branch falling into an overhead line, they lack the full capabilities of traditional reclosers – including the capacity and three-phase attributes of reclosers used on mainlines and with FLISR systems. Based on industry averages and internal reliability information it is estimated that 70 percent of overhead line failures are temporary and can prevented by installing a recloser. NSPM has an estimated 61,500 fuse locations with 12,500 fuses that have opened due to a fault at least once in the past three years. By replacing these fuses with reclosers, reliability will be improved as these devices will prevent sustained outages from temporary causes. In addition, these low cost reclosers will reduce O&M expenses as crews will not need to be deployed to replace the fuse. While this will prevent a sustained outage, customers will experience a momentary outage as the fault clears.

c. Pole Top Reinforcement

This program will improve the reliability and resiliency of the system by increasing our investment in identification and replacement of pole top equipment and poles (due to pole top degradation) that have reached the end of their useful life. Pole top equipment includes cross-arms, braces and insulators. Such equipment is a major contributor to outages and storm related interruptions. We plan to reinforce the equipment on up to 900 poles in 2021 and 2022.

Every year, our pole inspection program flags approximately 2,500 potentially degraded components that can be mitigated – and where doing so will increase system resilience. Some of this mitigation is being done currently as part of our pole replacement program. This program however, will broaden and extend the reach of that program to replace other pole top equipment based on performance history, condition, vintage, and other factors.

d. Transformer and Secondary Replacement

This program will improve customer reliability and resiliency of the system through replacement of aging secondary wire that is degraded and at risk of failure, and distribution transformers throughout the system that are undersized and at risk of overloads. We plan to replace the transformer and the associated secondary wire at up to 150 locations in 2021 and 2022.

Many of the transformers and secondary systems were designed many decades ago when home electric usage mainly consisted of lighting and appliances and did not contemplate the increased adoption of air conditioners, electric vehicles, and on-site solar. The addition of these new devices changes the amount of energy consumed by customers and in many cases is higher by several multiples than the equipment was designed to handle. This increase can lead to overloads on distribution transformers and low voltage at the customer's service. *Transformers.* The transformers that are at the greatest risk for overload are: (1) 25 kVA and smaller transformers, (2) transformers that are already overloaded during peak periods, (3) and transformers with more than 11 customers. We will solve the risks by either increasing the size of the transformer and secondary wires as appropriate, or adding an additional transformer and dividing the customer load between the two. Proactive replacement and upgrade of this equipment will enable DER/EV adoption by our customers.

We have approximately 31,500, 25 kVA transformers that serve 195,000 customers and over 15,900 transformers that are overloaded during peak periods and have more than 11 customers connected to them. In addition to mitigating outage risk, replacing these distribution transformers with higher capacity transformers will increase system resilience, allowing for more easily accommodating DER. As customers move to DER and EV technology, increases in the penetration of these loads may overload the current transformer serving several homes.

Secondary Wire. This program will also replace older open wire secondary – especially the small wire (#4, #6). We estimate there are nearly 3,300 miles of small open wire secondary in the NSPM operating company. The lower capacity of these smaller wires will often lead to voltage issues – and as electric vehicle penetration increases, and overloading can manifest itself as a reliability impact.

e. High Customer Count Taps

The greatest benefit of this program will be increased reliability for our customers by redesigning Taps with the greatest value potential for improvement in terms of number of customers, outage history, and implementation cost. We plan to address up to 200 different high customer count taps in both 2021 and 2022.

The industry has found one of the easiest methods to improve the customer reliability experience is to increase the number of protective devices, thus reducing the number of customers "behind" each device. This program focuses on redesigning the tap portion of the distribution system to reduce the number of customers that are located behind the protective device to an average of 40 to 50 customers. Redesigns will generally employ one of three solutions – adding phases, interjecting another source, or subdividing the tap.

Currently, there are approximately 20,000 failures per year on the Tap portion of the system that result in an outage for customers. Taps with over 100 customers are

responsible for approximately 50 percent of the tap-level SAIDI impact, yet they only represent around 10 percent of the total number of Taps. By decreasing the number of customers per Tap, we expect that fewer customers will be impacted by outages.

f. Community Resiliency

This program would fund projects that would benefit our customers by providing resiliency during a prolonged or widespread outage. The program involves working with communities to identify strategic locations, such as a community center or facility that provides essential services, where we would provide additional back-up power during an extended outage. Such projects would likely consist of a microgrid that would combine DER – energy storage (most likely batteries), local generation and other DER such as demand response – and the necessary equipment and controls to safely isolate a subset of the distribution system. During normal operations, the DER can benefit the distribution system to address capacity, reliability or other needs.

Local communities will benefit from the various services that the identified facility can provide during an extended outage. Customers will also benefit from value that the DER can provide during normal grid operations, such as investment deferrals and other needs. The Company will also benefit, as lessons learned from these projects will also inform future project specifications and engineering and design requirements, as well as overall value provided to our customers. We plan to install the equipment necessary to provide back-up power at one strategic location in 2022.

2. Underground Programs

The Underground Program is comprised of seven program: (1) mainline cable replacement, (2) underground residential distribution (URD) cable replacement, (3) cable asset life extension, (4) network monitoring, (5) St. Paul tunnel work (6) feeder exit capacity work, and (7) tools and equipment.

We outline the capital expenditures for each of these programs below.

ISI Programs		2020	2021	2022	2023	2024
	Mainline Cable Replacement		\$7.0	\$7.8	\$7.8	\$7.8
	Underground Residential Distribution (URD) Cable Replacement		\$5.0	\$2.5	\$2.5	\$2.5
	Cable Assessment		\$7.0	\$6.0	\$6.0	\$6.0
Underground Programs	Network Monitoring		\$2.0	\$2.3	\$2.3	\$2.3
	St. Paul Tunnel Rehabilitation		\$5.0	\$5.0	\$5.0	\$5.0
	Feeder Exit Capacity		\$3.8	\$3.0	\$3.0	\$3.0
	Purchases / Tooling		\$4.5	\$0.2	\$0.2	\$0.2
TOTAL		\$0.0	\$34.3	\$26.8	\$26.8	\$26.8

Table 28:ISI Capital Expenditures – DistributionState of MN Electric (Millions)

a. Mainline and URD Cable Replacements

Cable failures are a main contributor to outages for customers who are served by underground cable facilities. Proactively replacing cable allows us to avoid a potential outage caused by a cable failure and utilize a systematic approach in the replacement of this asset. As a result of our existing asset health cable replacement program, the failure rate for non-jacketed underground cables has been flat to slightly declining since 2013, averaging approximately 0.2 failures per mile each year. However, by making increased investments in cable replacements, the Company expects to reduce this failure rate even further.

Nearly 25 percent of the Company's underground cable in Minnesota is a type of cable (non-jacketed cross-linked polyethylene (XLPE) cable that was installed prior to 1985) that is more prone to failures and has a shorter useful life (approximately 35 years) than newer cable types. To address this issue, we have invested between \$14 million and \$26 million annually between 2014 and 2018 across Minnesota to replace non-jacketed cable that has failed or reached the end of its life with jacketed cable. Even with these investments, there is still approximately 2,700 miles of non-jacketed primary Tap cable (approximately 30 percent of total) and about 250 miles of non-jacketed mainline cable (approximately 15 percent of total) in Minnesota. This program will increase Minnesota investments for mainline cable and primary Tap cable per year starting in 2021.

Cable replacement can be time-intensive based on the complexity of the location and proximity to major thoroughfare or other utilities and geographical restrictions. When cable begins to fail, it can lead to subsequent failures that can reoccur in rapid succession based on the condition of the asset, thus impacting customers' reliability experience. Proactive replacement allows us to replace the cable before it fails – becoming unrepairable – and leading to an emergency replacement. Emergency replacements leave the system with less redundancy and switching options, which can lead to lengthy outages if additional failures occur.

The underground residential distribution (URD) system is comprised of an underground circuit in a loop arrangement, segmented by distribution transformers. With the URD cable replacement component of this program, we will replace the entire 1/2 loop rather than making segment replacement as sections fail. This proactive replacement of the entire 1/2 loop will avoid additional failures and outages for all customers located on this 1/2 loop.

This program will supplement our existing asset health cable replacement program. We will replace up to four additional miles of mainline cable in 2021 and up to nine additional miles of mainline cable in 2022. We will also replace 10 additional miles of URD cable in 2021 and up to 12 additional miles of URD cable in 2022.

b. Cable Asset Life Extension Program

The Company's current asset health cable replacement program focuses on replacing those underground cable systems that have had multiple failures. While this strategy has been successful at reducing cable failures, this strategy overlooks proactive assessment of the condition of the overall cable population. The program would use a cable assessment technology to assess and rehabilitate cable through use of partial discharge diagnostics to precisely assess the overall condition of the cable system and make recommendations on how to rehabilitate cables to like-new manufacturer standards. Cable systems that meet these standards perform like new and have an expected useful life of an additional 30-40 years after rehabilitation.

This assessment will allow us to determine precisely what and where defects exist within the cable system and replace only the defective portions of the cable system such as terminations, splices, or other weak points in the cable. This is opposed to a wholesale replacement, which replaces portions of the cable that still has years of useful life left. We expect that this will result in an improved reliability experience and cost savings for our customers.

With respect to reliability benefits associated with this program, cable failures are a significant contributor to the customer reliability experience. As also discussed above, cable failures can be difficult to locate and repair as they are underground and often difficult to access. Through implementation of targeted assessment and replacement of underground cable and associated termination points and splices, we will be able to reduce the failure rate of our underground cables resulting in fewer outages for our customers.

Other utilities have had success with similar cable life extension programs. For

example, CenterPoint Energy (CPE) implemented a similar program in Texas in 2013 and has seen their underground failure rates reduce by 98 percent. CPE used this technology to assess over 16,000 segments of cable that were 35 or more years old. Of the underground cable loops assessed thus far, 99.6 percent have required on-site mitigation or span replacement to return the cables and terminations to manufacturer specifications, or like-new performance condition. However, the cost to assess and restore an underground loop to like-new performance has been about 65 percent less than the cost to completely replace it. Another utility with a similar underground cable failure rate assessed over 2,000 miles of cable and found 82 percent of cable did not require further action. As a result, they were able to reduce replacement costs by 76 percent and associated cable outages by 98 percent.

These two utilities had two different results based on the assessment provided by this technology. One learned that they needed to rehabilitate a large portion of their underground system, while another learned that their system was mostly intact and they could focus their efforts elsewhere. Both of these results provided value for these utilities either in terms of reduced rehabilitation costs or the ability to turn attention to other critical needs on their system. At this time, we do not have a holistic assessment of the current condition of our underground cables. As a result, we do not know which of these categories we will fall into. We plan to perform up to 60 miles of cable assessment and rehabilitation in 2021 and 2022.

c. Network Monitoring

The Network Monitoring program will enable remote monitoring of the network grids for downtown Minneapolis and St. Paul to ensure continuity of service, health of these assets, and to improve operation and maintenance. The Network Monitoring system is comprised of transceivers and VaultGard devices that monitor and communicate the status of the downtown grid facilities along fiber optic cable installed concurrently with the network conductor. Installation of the Network Monitoring equipment will provide grid visibility and control utilizing real-time data from the downtown distribution networks that will enable the Company to:

- Locate faulty equipment more quickly and accurately;
- Identify distressed equipment prior to failure;
- Identify system deficiencies and manufacturer issues on installed equipment;
- Receive instantaneous, real-time email notifications of network events;
- Monitor the system on a real-time basis;
- More accurately document system performance;

- Customize breaker parameters;
- Reduce O&M expenses related to troubleshooting and identifying faulty network equipment; and
- Provide more granular individual transformer loading and planning data.

Additional benefits we expect from this initiative include improved employee and public safety, security, reliability, planning, and control.

Safety will be improved by enabling remote operation of the network circuits and by notifying personnel of potential dangers before entering a confined space in the underground distribution system. For instance, Company personnel will be notified that equipment has failed or is failing and/or operating abnormally, and can avoid entering the enclosed vault until the equipment has been de-energized or evaluated remotely. *Reliability* will be improved by monitoring the status of and being able to remotely control the Network Protectors. Planning will be improved by having load (kW and Amps) data available for each individual network transformer, improving and optimizing the ability to serve changing or new customer loads at specific locations. *Control* will be improved because the project will enable the Company to use the additional network information to make more educated decisions regarding system design and operations. In addition, understanding that equipment is not operating as designed will enable the Company to make the necessary repairs or replacement avoiding lengthy outages to customers in our central business districts.

We are confident in expecting these benefits. Our Colorado operating company affiliate, Public Service Company of Colorado (PSCo) implemented a similar monitoring system in the Denver underground network around 2010 and has since experienced these benefits. For example, prior to the implementation of network monitoring, when PSCo's system operators were notified of a system interruption, a crew would have to be dispatched to the general area to investigate. They would begin the troubleshooting process by starting at the head end of the feeder line, and then physically enter every single vault on that feeder to inspect the equipment and determine if the cause could be found. If no immediate cause was detected, the crew would reset all equipment and attempt to energize the feeder again. If another interruption of service was detected, the crew would be forced to further begin isolation activities to narrow the root cause. This process could take hours or days and may leave the network system vulnerable to outage and other service issues.

With the implementation of network monitoring, the PSCo system operators are notified immediately of a detected interruption by the monitoring system. A crew can

then be dispatched to the specific vault where the issue was detected for further testing and repair or replacement of any assets as needed. By reducing notification time for a fault and receiving data that considerably narrows down the location of the potentially faulty equipment, system faults can be identified and repaired much faster.

With respect to safety, allowing remote control of network equipment allows personnel to immediately respond to major faults from a safe location, which can help prevent catastrophic failure and system interruption. As an example, during a 2016 event in Denver, an email was sent to the PSCo system operators notifying them of a high-temperature alarm. The affected network equipment was located in an alley that had been filled with water due to a heavy rain storm. The resistors in the equipment began to boil the water inside the network protector. After receiving the alarm notification, the breaker was opened remotely by the PSCo system operator. The crew was then dispatched to dry out the equipment and prevent catastrophic failure and system interruption. The monitoring equipment kept PSCo personnel and the public safe by providing immediate notice of a serious issue and allowing the system operator to remotely open the breaker prior to sending out a crew to the scene.

We plan to have one network in service with live monitoring in 2022.

d. St. Paul Tunnel Rehabilitation

This project will improve the safety and security of our underground distribution facilities in St. Paul by eliminating the risk of system outages to downtown St. Paul if the tunnels were to collapse.

The electric distribution and network infrastructure in and around downtown St. Paul is housed underground in a sandstone tunnel system that was built in the late 1800s. There are approximately 10 miles of tunnels, and they vary in width and depth. The tunnels are made in sandstone and are eroding internally, causing a build-up of sand and debris within the tunnels; flooding can then cause complete blockage of the tunnels based on the washed-out debris. The placement of utility infrastructure in them is problematic and poses a potential hazard for our employees. Further, the tunnels are shared with other utilities, which can impact the safety and reliability of our system based on failure of the assets not owned or maintained by our Company, which may cause residual impacts to our electrical assets.

Under this program, we would build new infrastructure to retire and replace the existing tunnel system. This will include constructing new underground manhole and duct infrastructure, in accordance with current Company standards, city requirements – and in consideration of safe practices for our employees. Existing electrical facilities

would be relocated from the old tunnel system and into the new duct system as it is constructed.

We additionally have concerns regarding the access and security of these tunnels. Accessing the tunnels is done in a variety of ways, including doorways built into bluffs and manhole access from street grade. As depicted in the photo in Figure 39, our employees, when entering the tunnels from a street-level manhole, use long ladders to climb down to the grade in which our electrical assets are housed, as many tunnels are 30'-50' below street grade. They are then working out of cell phone range, and may face issues with communication, particularly in an emergency situation.



Figure 39: Illustration of an Actual Tunnel Access

The length, condition, and location of the tunnels presents unique construction challenges that will require extensive city, community and customer coordination, detailed planning and engineering, and system operations considerations to ensure service is maintained to all customers currently served by these parts of our electrical system. We expect, given these challenges and the required coordination, this project may take up to 15 years to complete. We expect however, the first assets will be placed in service in 2021 and 2022. These first assets will include the first conduit vaults and duct vaults that will be required to move our electrical equipment out of the tunnels.

e. Feeder Exit Capacity

The purpose of the Feeder Exit Capacity Project is to identify areas of the distribution

system in which the overall load carrying capacity feeder circuits are limited by undersized cables, conductors, or other equipment at the feeder's head end. The project will benefit customers by improving the existing distribution system's ability to accommodate new load growth. Increasing the capacity of the feeders will also reduce the overall loading on the feeder circuits, which in some cases can prevent premature equipment failure, therefore improving reliability.

The overall load carrying capacity of a feeder circuit is determined as the minimum series element's capacity rating on the feeder circuit between the feeder bay in the substation and the first customers served by the feeder – this portion of the feeder is typically referred to as the feeder's exit, or head end. This project will allocate funds toward feeders where these reduced capacity ratings can be readily increased by upgrading the feeder equipment as necessary along the feeder's exit from the substation. We will in-service up to eight feeder exits in 2021 and 2022.

f. Purchases and Tools

To support additional work volume and scope with internal resources, it is necessary and to purchase additional equipment and tools. The purchases will include Distribution fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system. Capital investments in fleet, tools, and equipment ensure our workers have the necessary provisions and support to do their job safely and efficiently. We expect to place approximately \$4.5 million of assets in-service in 2021 and up to \$200,000 in 2022 with this program.

3. Substation Programs

We propose two substation programs that will improve the reliability and resiliency of the Company's 224 substations in Minnesota. These two programs are: (1) substation transformer replacement; (2) substation asset renewal.

We outline the capital expenditures for each of these programs below.

	ISI Programs	2020	2021	2022	2023	2024	
		Substation Asset Renewal		\$5.0	\$5.0	\$5.0	\$5.0
Substation Programs	Substation Programs	Transformer Replacement		\$7.0	\$13.0	\$13.0	\$13.0
	TOTAL		\$0.0	\$12.0	\$18.0	\$18.0	\$18.0

Table 29:ISI Capital Expenditures – DistributionState of MN Electric (Millions)

a. Substation Transformer Replacement

Substation transformers are a fundamental to the reliability of our distribution system and are also one of the most expensive components of the substation. While the failure of transformers is not a common occurrence, when a substation transformer fails, the consequences are high and results in between 5,000 to 15,000 customers losing service.

This program will increase the rate at which the Company replaces its substation transformers from approximately three per year to approximately eight per year. Our current limited replacement of three transformers per year includes transformers that have been identified as needing replacement due to their age and condition, and transformers that have failed. The current average replacement life cycle is 60 years. Assuming we replace five additional transformers each year, we will reduce the replacement life cycle of our existing transformers to 57 years.

Under this program, we will replace up to four additional transformers in 2021 and approximately 10 additional transformers in 2022.

b. Substation Asset Renewal

Historically, we have separately replaced the individual parts within the substation as they fail or reach of the end of life. These individual parts include breakers, relays, and Remote Terminal Unit (RTUs)/Local Control Unit (LCUs). Rather than replacing individual components on a piecemeal basis, the Substation Asset Renewal program would replace the bulk of the equipment within a substation at one time. We will select and prioritize the substations using several factors, including: age and condition of equipment, amount and type of load served, system reliability and future growth and planning.

Similar to substation transformers, replacing these key components of the substation will improve the reliability of our substations. In addition, by upgrading this equipment, the new equipment will have additional functionality that will allow for improved communication and monitoring of the substation equipment. We plan to replace up to 32 breakers, 42 relays, and 5 RTU/LCUs at multiple substation locations across Minnesota during 2022.

4. Overhead Mainline Programs

This program targets overhead mainline feeders which are the larger capacity feeders found along major roadways that then branch off into smaller overhead tap lines and then to service laterals that connect to homes and businesses.

There are two components of this program: (1) pole fire mitigation; and (2) lightening arrestor replacement with capital expenditures as outlined below:

Table 30:ISI Capital Expenditures – DistributionState of MN Electric (Millions)

ISI Programs		2020	2021	2022	2023	2024
Overhead Mainline Programs	Lightning Protection Replacement		\$1.0	\$1.0	\$1.0	\$1.0
	Pole Fire Mitigation		\$2.5	\$2.0	\$2.0	\$2.0
TOTAL		\$0.0	\$3.5	\$3.0	\$3.0	\$3.0

a. Pole Fire Mitigation Program

This program seeks to reduce the risk of pole fires by identifying poles that are risk for fire and then replacing certain components (enhanced insulation, replacing wooden cross-arms with fiberglass) – or when necessary, replacing the pole or relocating the line away from airborne contaminants.

Pole fires can be a significant cause of service interruptions. We average more than 14 mainline pole fires a year; each mainline pole fire impacts more than 1,500 customers when the outage occurs. We are typically able to restore power to most of the customers through field switching. However a smaller number of customers are usually without power until the pole can be replaced, which can be as long as 12 hours. The Company currently has 2,600 mainline poles (of the approximately 500,000 total poles, or 0.52 percent) deemed to be at risk of fire in Minnesota. By strategically addressing these at-risk poles, customers will experience fewer power interruptions.

Poles that are at risk are typically found on busy streets with high usage of chemicals used for de-icing of rights-of-way, are typically older poles, and have a higher than average number of components located on the pole. Under this program, we will spend approximately \$2.5 million per year to identify at-risk poles and replace the necessary components. We plan to address up to 500 poles with this program in 2021 and 2022.

b. Lighting Arrestor Replacement Program

A lightning arrestor is a device on a distribution pole that protects the conductors and insulators from damage due to lightning. Outages due to arrester failure are one of the main causes of outages on the overhead system. It is estimated over 90 percent of

the SAIDI impact from lightning arrestor failure is attributable to a few vintage models, that make up fewer than 30 percent of the arrestors. By replacing these lightning arrestors that are at risk, we anticipate that customers will experience improved reliability.

This program identifies lightning arrestors with high failure rates and replaces these arrestors to ensure this equipment operates properly in the event of a lightning strike. Under this program, we will spend approximately \$200,000 per year to identify and replace lightning arrestors at risk of failure. We expect to replace up to 1,000 lighting arrestors in 2021 and 2022.

D. Reliability Management

1. Approach

Each year, Xcel Energy develops and manages programs to maintain and improve the performance of its distribution assets. We identify and implement these programs in an effort to assure reliability, enable proactive management of the system as a whole, and effectively respond when outages occur.

2. Reliability Indices

In this section, we provide a snapshot of our 2018 reliability results. We additionally outline our process for developing and implementing programs to maintain and improve our system, detail key indicators of the highest impact programs, and graphically chart current year outages by cause codes. We have also included three tables to illustrate our reliability performance trending as well as a discussion around CEMI (Customers Experiencing Multiple Interruptions) tools to better reflect the customer experience.

In 2018, we achieved a SAIDI result of 93.26 minutes, which exceeds our Quality of Service Plan tariff goal of 133.23 minutes.⁴⁴ Our 2018 SAIFI result of 0.85 outage events also exceeds the QSP tariff goal of 1.21 outage events.⁴⁵ The below graphs show overall system performance for the years 2015 through 2018, with storm days excluded, per the QSP tariff calculation method.

⁴⁴ Minnesota Electric Rate Book MPUC. No. 2 Section 6, Sheets 7.1 through 7.11, approved by the Commission's August 12, 2013 Order in Docket Nos. E,G002/CI-02-2034 and E,G002/M-12-383 ⁴⁵ In this context, "exceeding" the goals is a positive result, reflecting good system performance.



Figure 40: Minnesota SAIDI – QSP Method

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



Figure 41: Minnesota SAIFI – QSP Method

In an effort to provide the Commission a better idea of our reliability performance trending, we have provided three tables showing the historical performance, storm days and the current targets under three methodologies (including storms, our QSP Tariff, and the Minnesota Rules). These three tables are presented below as Table 31.

Table 31: Historical Reliability Performance and Storm Day Exclusions – Non-Normalized and QSP Performance & Annual Rules Performance

Historical Reliability Indices & Storm Day Exclusions												
With Storms ¹		2010	2011	2012	2013	2014	2015	2016	2017	2018	1	
Minnesota	SAIDI SAIFI	274.42 1.50	207.77 1.11	149.15 1.07	562.11 1.39	116.43 0.92	184.50 0.96	214.39 1.05	141.70 0.90	125.00 0.95		
Metro East	SAIDI SAIFI	270.43 1.59	113.90 0.96	139.51 190.95 1.20	404.38 352.30 1.27	128.00 123.54 0.98	192.32 177.19 1.04	204.84 223.67 1.08	136.51 0.95	131.22 112.11 0.96		
Metro West	CAIDI SAIDI SAIFI	170.23 301.09 1.54	118.95 238.03 1.19	159.23 139.19 1.10	278.46 810.01 1.55	125.93 105.98 0.89	169.86 229.78 1.00	206.85 198.25 1.00	144.37 148.58 0.86	116.71 88.23 0.92		
Northwest ⁴	CAIDI	196.10 181.38	199.66 470.05	126.85 109.75	523.66 468.22	118.70 82.82	229.92 75.61	198.86 225.74	173.27 173.71	95.70 109.50		
	CAIDI	143.66	334.78	0.87 126.17	335.53	0.82 101.00	0.66 115.40	211.50	0.98 177.46	126.02		
Southeast	SAIDI SAIFI CAIDI	251.24 1.24 203.04	125.28 0.95 131.69	97.25 0.71 137.84	179.29 1.06 168.93	173.45 0.98 176.51	98.23 0.79 125.07	249.05 1.15 217.15	96.37 0.84 114.75	353.32 1.15 307.95		
MN Tariff ²		2010	2011	2012	2013	2014	2015	2016	2017	2018	'18 Taro	
Minnesota	SAIDI SAIFI CAIDI	110.83 1.12 99.24	83.87 0.82 102.08	96.20 0.88 109.60	91.12 0.86 106.51	79.85 0.78 102.07	86.83 0.79	89.49 0.81 110.54	73.80 0.72 102.10	93.26 0.85	133.23 1.21	
Metro East	SAIDI	102.03 1.20	79.34 0.83	90.70 0.88	83.56 0.83	77.58	93.71 0.90	95.49 0.87	75.70	103.28 0.92	101	
	MED Days	85.09 4 6/25,7/17, 10/26 11/13	96.00 2 7/1,7/10	103.35 5 6/10,6/19,7/3, 8/3 11/10	3 6/21,6/22,	94.81 3 2/20,6/14,6/16	2 7/12, 7/18	3 7/5,7/6,7/21	3 6/11, 6/14, 7/12	112.40 1 5/24		
Metro West	SAIDI SAIFI CAIDI	123.25 1.22 101.10	88.20 0.87 101.09	103.42 0.97 106.83	101.24 0.96 105.85	81.85 0.82 100.15	88.98 0.82 108.90	82.90 0.82 101.51	69.28 0.70 98.40	81.25 0.84 96.63		
	MED Days	4 6/25,7/17, 10/26,11/13	5 5/22,7/1,7/10, 7/18,8/1	3 2/29,6/19,8/3	5 6/21,6/22, 6/23,6/24,8/6	1 6/14	1 7/18	3 7/5,7/6,7/21	2 6/11, 6/14	1 7/1		
Northwest ⁴	SAIDI SAIFI CAIDI	102.79 0.80 129.28	79.42 0.69 115.38	94.20 0.73 128.31	85.78 0.75 113.87	62.16 0.61 102.05	69.39 0.57 121.05	80.19 0.56 143.58	69.41 0.64 107.70	99.87 0.73 137.06		
	MED Days	2 8/13,10/26	6 2/20,5/30,7/1,7 /10,8/1,8/2	0 None	2 6/21,6/22	0 None	0 None	4 5/19,6/19,7/5 ,11/18	1 6/11	0 None		
Southeast ⁵	SAIDI SAIFI CAIDI	89.58 0.69 130.66	82.70 0.70 118.72	82.40 0.59 138.48	73.58 0.57 129.93	94.45 0.67 141.93	70.78 0.52 135.23	109.59 0.82 133.06	92.84 0.79 117.19	110.67 0.77 144.04		
	MED Days	5 6/25,6/26,7/24 ,8/13,11/13	2 7/1,7/23	1 8/4	4 4/9,5/2,5/26, 6/21	4 2/20,6/16,8/4, 12/15	1 7/18	3 6/10,7/5,7/6	0 None	2 4/14,9/20		

Annual Rules ³		2010	2011	2012	2013	2014	2015	2016	2017	2018	'18 Target
Minnesota	SAIDI SAIFI	113.86 1.17	88.17 0.88	101.86 0.93	94.27 0.90	84.00 0.84	89.95 0.83	90.45 0.83	75.04 0.74	96.07 0.89	NA NA
	CAIDI	97.31	100.53	109.78	104.60	99.67	108.09	108.93	100.90	107.39	NA
Metro East	SAIDI SAIFI CAIDI	102.32 1.22 83.90	79.89 0.85 93.83	105.74 0.96 110.03	85.05 0.86 99.33	79.73 0.86 92.46	93.73 0.90 104.25	95.52 0.87 109.70	76.22 0.76 100.48	103.69 0.93 111.74	86.05 0.85 101.31
	Storm Days	4 6/25,7/17,10/2 6,11/13	2 7/1,7/10	3 6/10,6/19,11/1 0	3 6/21,6/22,6/2 3	3 2/20,6/14,6/16	2 7/12,7/18	3 7/5,7/6,7/21	3 6/11,6/14,7/1 2	1 5/24	
Metro West	SAIDI SAIFI CAIDI	123.21 1.22 101.09	89.74 0.90 99.56	103.98 0.98 105.93	101.41 0.96 105.45	83.02 0.84 98.50	90.95 0.84 108.44	83.64 0.82 101.43	69.51 0.71 97.84	83.26 <mark>0.87</mark> 95.47	85.71 0.84 102.56
	Storm Days	4 6/25,7/17,10/2 6,11/13	5 5/22,7/1,7/10,7 /18,8/1	3 2/29,6/19,8/3	5 6/21,6/22,6/2 3,6/24,8/6	1 6/14	1 7/18	3 7/5,7/6,7/21	2 6/11,6/14	1 7/1	
Northwest ⁴	SAIDI SAIFI CAIDI	110.59 0.96 114.86	94.29 0.82 115.31	95.05 0.83 115.16	97.43 0.94 103.70	82.80 0.82 101.02	75.58 0.66 115.39	85.81 0.70 122.38	75.77 0.76 100.28	109.34 0.87 126.05	83.48 0.77 107.83
	Storm Days	2 8/13,10/26	6 2/20,5/30,7/1,7 /10,8/1,8/2	1 6/17	2 6/21,6/22	0 None	0 None	5 5/19,6/19,7/5 ,7/16,11/18	1 6/11	0 None	
Southeast⁵	SAIDI SAIFI CAIDI	111.00 0.98 112.90	101.86 0.90 112.82	85.95 0.67 128.50	87.98 0.73 120.39	103.45 0.80 129.20	86.51 0.75 115.16	110.23 0.85 130.02	96.33 0.84 114.73	118.80 0.92 129.64	96.90 0.79 122.04
	Storm Days	5 5/11,6/25,6/26 ,7/24,11/13	1 7/1	1 8/4	4 4/9,5/2,5/26, 6/21	4 2/20,6/16,8/4, 12/15	1 7/18	3 6/10,7/5,7/6	0 None	2 4/14,9/20	

1) With Storms - Includes All Days, Levels and Causes, Meter-based customer counts

2) MN Tariff - Normalized using IEEE 1366 at the Regional level after removing Transmission Line level. All Causes, Meter-based customer counts

3) Annual Rules - Normalized using IEEE 1366 at the Regional level, All Levels, All Causes, Meter-based customer counts

- Targets for recalculated New Annual Rules were determined for 2015-present due to the need for 5 years of prior historical actual results

4) Northwest - Includes customers counts and outages in the North Dakota work region that impact Minnesota customers

5) Southeast - Includes customers counts and outages in the South Dakota work region that impact Minnesota customers

We have developed tools that allow us to better track reliability from our customers' experience – or CEMI (Customers Experiencing Multiple Interruptions). In conjunction with a mapping tool we can look at our customers' experience as it identifies customers with multiple outages over a revolving 12 months and then provide a visual representation of those outages in our service territory. Although, the metric measures customers who have experienced at least six sustained outages during non-storm days, we can study customers' experience earlier. This customer centric tool helps highlight customers that have had outages from different causes rather than a single root cause. In other words, this tool does not look at the device that caused the outage, it examines how many times a customer was out of service regardless of the reason.

These tools compliment other programs, such as the Reliability Management System (REMs) that help us identify specific equipment issues (for instance, the same device tripping multiple times). The CEMI tools provide the link from the outage information to the specific customer information on a holistic basis. Since much of our analysis has focused on a system perspective, this new tool really rounds out our reliability planning by helping focus on the customers' experience.

Our Outage Exception Reporting Tool (OERT) combines the CEMI tool with an earlier tool that helped us identify specific equipment issues (for example, the same

device tripping multiple times). The OERT tool provides the link from the outage information to the specific customer information on a holistic basis. Since much of our analysis has focused on a system perspective, this new tool really rounds out our reliability planning by helping focus on the customers' experience.

There are many reasons a customer could have an outage. These causes include downed trees, animal contact, a car hitting a pole, or even a lightning strike. Each one of these causes could show up on a different report for a different piece of equipment that all flow down to the same customer. These tools allow us to analyze customer experience *truly* from a customers' experience. These tools help our efforts in the long term to reduce repeated outages for customers.

3. Cause Analysis

Our annual reliability planning process begins with an analysis of the causes for historical outages. We use pareto graphs in our analysis, as provided below, which show outage cause codes for a multi-year time period, ranked in descending order by the number of Sustained Customer Interruptions (SCI).⁴⁶

Pareto Analysis. The following pareto graphs show feeder, tap, substation and transmission level customer interruptions by primary cause code for the years 2014 through 2018. The "balloons" highlight areas our plans are currently focusing on.

⁴⁶ Electric service interruptions greater than five minutes in length.

Figure 42: Minnesota Customer Interruptions by Primary Cause



Minnesota Customer Interruptions By Primary Cause - (Tariff Method/Threshold) Distribution, Substation, & Transmission Level - By Calendar Year

Figure 43: Minnesota Customer Interruptions by Failed Device – Overhead Mainline



Minnesota Customer Interruptions By Failed Device - (Tariff Method/Threshold) Overhead Mainline - By Calendar Year

Figure 44: Minnesota Customer Interruptions by Failed Device – Overhead Tap

Minnesota Customer Interruptions By Failed Device - (Tariff Method/Threshold) Overhead Tap - By Calendar Year



Figure 45: Minnesota Customer Interruptions by Failed Device – Underground Mainline



Minnesota Customer Interruptions By Failed Device - (Tariff Method/Threshold) Underground Mainline - By Calendar Year

Figure 46: Minnesota Customer Interruptions by Failed Device – Underground Tap



Minnesota Customer Interruptions By Failed Device - (Annual Rules Method/Threshold) Underground Tap - By Calendar Year

Annual Rules Method: IEEE 1366 Normalized by region, All Levels, All Causes, Meter-based customer counts

Our current RMP investments are maintaining appropriate levels of overhead (OH) and underground (UG) system performance. We recognize that it is critical to combine our RMP process with a longer-term view of the aging distribution system in order to provide our customers with reliable electric service, and are taking actions to that end.

4. Reliability Management Programs

After considering the most common failures and their causes, as well as at-risk equipment, we develop work plans, or programs, to target our investments; we provide these programs in the 'Star Chart' on the following page. These programs represent those proactive investments in our transmission and distribution systems that we believe are most likely to improve overall reliability, asset health, and meet various contingency planning requirements. These investments are made in addition to other capital investments that provide for adequate capacity to meet customer requirements and to accommodate load switching during outage response to minimize customer impacts.

Table 32: Reliability Management Program Impacts (Star Chart)

	Funded Programs		2016 Actuals	2017 Actuals	2018 Actuals		IMF	ACTS	
	r undeu r rograms	Description	(k\$)	(k\$)	(k\$)	SAIFI	CAIDI	СЕМІ	Complaints
	Feeder Perf. Improvement Program (OH & UG)	FPIP evaluates and implements improvements for feeders experiencing an increased number of outages based on prior year information.	381	870	1,451	★		★	*
ity	Outage Exception Reporting Tool (OH & UG)	OERT process provides automatic notification to area engineers when repeating outage criteria have been met and engineering solutions are implemented to eliminate repursing problems.	637	455	490			*	*
	Mainline Cable Replacement, (UG)	Deteriorating problems.	2,184	3,056	1,930	*			*
	Tap (URD) Cable, (UG)	able reduces the outages.	16,980	18,329	19,593	★	★		*
liabil	Install Automated Switches	These automation solutions reduce restoration times for long lines with long drive times to bring CAIDI in-line with other distribution lines.	103	0	0	*		*	*
Re	Feeder Infrared Evaluation (OH)	Many pieces of equipment show excess heating prior to failure. The FIRE program provides infrared scans of overhead mainline which reveal specific equipment that is likely to fail so it can repaired prior to causing an outage.	20	20	58	*			
	Vegetation Management (Transmission & Distribution)	Cost benefit prioritized circuit trimming in NSPM. Continued reactive "Hot Spot" trimming.	26,247	29,024	29,352	*		*	*
	Program Replacements (Transmission)	Replaces end-of-life equipment (i.e switches, laminated arms, specific insulators, poles) in order to reduce maintenance costs and improve reliability.	656	11	229	*			*
y	Pole Inspection & Replacement (Distribution)	Pole Inspections indude an above groundline visual inspection. Groundline inspections are based on age and environment and may indude visual, sound and bore and excavation. Treatment of poles may be induded. Based on results poles may be tagged for replacement.	7,197	7,707	11,035	*	*		
egri	Transmission Substation	Replaces end-of-life equipment in order to reduce maintenance costs and improve reliability.	1,472	6,984	9,228	*			
Inte	Line ELR Work (Transmission)	Identifies lines that have components that have reached their end of life or where significant refurbishment work is needed to enhance system performance and reliability. Project focus may be to extend life of existing asset 20 + years or to replace and address future capacity upgrade concerns.	2,166	4,824	2,834	*			*

NSPM Program Summary

Footnote: The above table reflects multi-year initiatives that are part of the Reliability Management Program(RMP). Information is based on current RMP, and is subject to change.

Funding information for previous years is a combination of Capital and O&M dollars; most of the equipment replacement dollars are capital expense while the inspection and testing programs include O&M dollars; O&M dollars and capital for pole replacements and FIRE program are currently estimates since changes are included in broader programs of work(e.g., OH rebuild OH maintenance accounts).

We have indicated the primary performance impacts of these programs with a red star, where applicable; possible performance impacts include SAIFI (System Average Interruption Frequency Index), CAIDI (Customer Average Interruption Duration Index), CEMI (Customers Experiencing Multiple Interruptions), CELI (Customers Experiencing Lengthy Interruptions) and Customer Complaints.

These programs become part of the annual RMP. A Reliability Core Team (RCT), consisting of both Field and Planning functions monitors system performance and progress against the RMP on a monthly basis, taking actions as necessary to ensure the best possible system performance.

In addition to the programs shown above, in 2019 we will be initiating a pilot program in the Southeast Region. The pilot will be replacing porcelain fused cutouts with polymer cutouts. As seen in Figure 46 above, showing Interruptions by Failed Device for Overhead Tap, fused cutouts have seen an increasing failure rate and in 2019 were the device type with the highest impact to our customers on the overhead tap system. Replacement of porcelain cutouts should show a reduction in cutout failures since failures occur primarily on porcelain cutouts. If the pilot is successful, we intend to develop plans for a further roll-out.

The table below outlines primary program indicators for our key initiatives/programs. The actual amount of work completed under each program varies from year to year, and is based primarily on assessments of those areas requiring the greatest attention, as well as the results of our condition assessment (*i.e.*, the number of deficiencies requiring corrective action). For further description of the programs described in the Key Initiatives Table, please see the Star Chart above.

Kenability manag	cincin		liauves	/i iogia	iiis		
	2018	2017	2016	2015	2014	2013	2012
Outage Exception Reporting Tool (OERT) (Replaced REMS in	2016)						
# of Exceptions identified	4,014	3,398	6,635	4,935	5,105	5,107	4,720
# of Service & Work Requests identified	652	297	215	408	455	698	694
Vegetation Management Program							
Total Overhead Distribution miles completed	2,307	2,417	2,086	1,856	3,737	2,780	3,084
Total Overhead Transmission miles completed	768	762	1,039	909	879	846	1,071
Normalized Tree-coded Sustained Cust Ints.(W/O Storms)	214,299	145,422	155,370	106,215	93,010	103,795	123,876
Non-normalized Tree-coded Sustained Cust Ints.(With Storms)	243,867	277,068	305,946	220,787	154,642	439,030	236,474
Underground Cable Replacement Program							
# of Segments That Have Been Replaced (est.)	1,504	1,411	1,378	861	1,165	1,256	1,024
# of Failures(Only on Primary Cable)	1,366	1,453	1,607	1,560	1,386	1,564	1,907
Feeder Infrared Evaluation(FIRE)							
# of Feeders Scanned	209	248	275	256	267	239	350
# of Hot Spots Corrected	67	71	68	99	62	52	50
Feeder Performance Improvement Plans(FPIP)							
Investigations Completed	108	113	105	96	108	98	98
Wood Pole Inspection Plan							
Total Distribution Wood Poles Inspected	33,720	17,972	18,845	10,213	9,198	31,436	20,555
Total Transmission Wood Poles Inspected	2,464	4,000	4,660	4,119	3,565	4,413	5,049
	1						

Table 33: Reliability Management Key Initiatives

Poliability Management Key Initiatives/Programs

Information based on current RMP, subject to change

We note that programs typically require multiple years before their full impact is realized. At first, the programs may only halt SCI increases, but continuing investment eventually reverses adverse trends.

In addition to programs, we also implement work practices to improve reliability, which are also an important contributor to the customer reliability experience and our reliability performance. These are operational and/or procedural changes intended to either reduce the *duration* of outages should they occur, or to reduce the *frequency* of outages. These improvements to existing work practices that the RCT members and their staffs identify and implement are also an important contributor to the customer reliability experience and our reliability performance. These are operational and/or procedural changes intended to either reduce the *duration* of outages should they occur, or to reduce the *frequency* of occur, or to reduce the *frequency* of outages.

As noted in the Reliability Management Work Practices table below, we assess and prioritize the actions based on a balance of their ability to positively impact reliability (high, medium or low), as well our ability to incorporate into standard work practices – with most occurring concurrently. Many of these actions do not require additional funding to implement, and are achieved via ongoing employee training and/or incorporation into standard work procedures. We continuously monitor all actions, and update our plan as appropriate.

		J	8 8 1	
Areas of Opportunity	Key Initiative	Action/ Program	Description	Reliability impact
Resource Management	Duration	Contractor staffing	Use contractors for appointments, freeing up Xcel Energy crews to respond to outages	Medium
	Duration	Management Staffing	Schedule managers for staggered shifts in metro area to enable human response after hours: 3 managers working 5:30 a.m. to 4:00 p.m.; 1 manager 3:00 p.m. to 11:00 p.m.	Medium
	Frequency	System integrity	Substation inspection done on every substation specific to identifying animal incursion risk and vegetation issues	High
Substations	Frequency	Infra Red Substations	IR Subs after major equipment is switched out or thermal heating suspected	High
	Duration	Equipment Failure Response	Install Mobile subs and drag cables as quickly as possible when customers are out due to equipment failure	Medium
	Duration	Restore before repair	During a feeder event Control Center personal restore service to as many customers before making temporary/permanent repairs.	Medium
Feeders	Frequency	Intentional Outages	Reduce Impact of Intentional Outage to ensure all steps are being taken to keep the maximum number of customers on. Verify switching to reduce customer counts. Repair while hot instead of taking the outage.	Medium
	Frequency & Duration	VM Partnership	Partner with Vegetation Management leadership to prioritize trimming of circuits that are scheduled to be trimmed. Substations to be trimmed with associated Feeders	High
	Frequency & Duration	Feeder Patrol Program	Looking for unfused taps and animal protection. Identify 336 auto splices. Continued use of IR/thermo imaging to identify problems.	Medium
Control Center	Duration	Restore before repair	Advanced technology going into the control centers and the field	High
Control Conton	CAIDI	Model 1/0 Switching	This is a pilot project to model 1/0 urd as close to real time so the OMS model will reflect the configuration of the urd circuit after it has been switched	Medium
Control Center	CAIDI	Validate Restoration Times	Tighten up existing process on actual restoration times, utilize approver process to ensure outage times are correct	High
	CAIDI	COM Saturday Crews	6 Metro COM Saturday Crews. 3 Metro East and 3 Metro West	Medium
СОМ	SAIFI & CAIDI	Underground cable repair	Repair and/or replace cables as directed by engineering	High
	SAIFI	REMS/CEMI work	Complete work referred by engineering in a timely manner	Low
Reliability Team/ Communications	SAIFI & Caidi	On-going Regular Reliability meeting	Meet regularly to review reliability, and share ideas to improve reliability performance	Low
	CAIDI	Outage Review	Root Cause Investigation of outages greater than 90 minutes of 0.1 SAIDI	Medium

 Table 34: Reliability Management Program Summary

Note: The above table reflects multi-year initiatives that are part of the Reliability Management Program(RMP). Information is based on current RMP, and is subject to change.

VIII. DISTRIBUTION OPERATIONS

In this section, we discuss key aspects of our distribution operations. First, we discuss escalated operations – or how we plan for, approach, and respond to unplanned events impacting our system and customers – most frequently these are storm or weather-related. Part B of this section discusses other major components of our day-to-day work to provide our customers with reliable electric service. These activities include Vegetation Management, Damage Prevention, and Fleet and Equipment Management.

A. Reactive Trouble and Escalated Operations

We have discussed the many ways that we plan the system to ensure reliable service for our customers. However, sometimes we must quickly rally and respond to customer outages and infrastructure damage caused by outside forces, such as severe weather. In this section, we discuss our pre-event planning, outage restoration, and outline storm-related costs.

1. Escalated Operations Pre-Planning

To ensure we are prepared, we maintain a Distribution Incident Response Plan that guides our planning, execution, and communications – and we regularly assess and drill our readiness and response. Our planning and preparations start well in advance of an actual weather event with foundational elements such as agreements with contractors to supplement our field forces when needed – and mutual aid agreements with other utilities for the same purpose. One indicator of our preparedness and response is measured by the increase in storm events that do not meet Major Event Day exclusions. Due to detailed response plans, drills and pre-staging of crews we are able to complete restoration sooner for our customers, past process was to react after the storm past, this allowed for exclusions of customer minutes out and improved SAIDI, yet it's not the right thing to do for our customers. Our calculations show that in 2018 we could have reduced our SAIDI numbers by over five minutes, Xcel Energy choses to continue to prepare and respond to safely and efficiently respond to our customers.

We also maintain lists of hotel accommodations and conference facilities across our service area for when they are needed to house crews aiding in restoration activities, or serve as dispatch centers or areas to conduct tailgate or safety briefings. We also maintain lists of available transportation options such as for buses and vans, to move crews and support staff between locations. Finally, we also pre-identify staging sites across our service area so we are able to quickly implement plans that involve staging equipment or non-local crews – and ensure we have street and feeder maps readily available for them to use. Our planning also incorporates details are not top-of-mind when thinking about what might be needed for an effective storm response – such as ensuring we have ready access to catering to feed crews, adequate restroom availability, laundry facilities, garbage and debris containers, and security.

In terms of planning and preparations in the immediate timeframe before a weather event, we are continuously assessing the weather, system status and customer call volumes to recognize "early warning signs." As the storm picture becomes more clear, we inform office staff, field workforces, and strategic communications stakeholders, which includes the call centers, external communications, community relations, and regulatory affairs, among others. We begin to send regular weather and staffing updates to pre-defined internal distribution lists, and inform employees in identified storm support roles to prepare for an extended time at work. At this point, we are also informing support functions such as supply chain, fleet, safety, security operations, and workforce relations of our assessment of the impending weather. We also inform our local unions of our assessment and planning criteria. We may also begin to strategically move and stage field crews and equipment to areas expected to be significantly impacted – especially if we expect access to those areas to be limited or hampered as a result of the weather event.

At the point operations leadership believes the forecast presents risk to the distribution system, we hold an operational call where we review our assessment of conditions, staffing, and other preparations. When system impact is confirmed, we initiate "Everbridge," which alerts pre-defined lists of individuals representing key functions across the organization.⁴⁷ A regular cadence of escalated operations calls that follow a standardized agenda and checklist that both communicates key facts about the event including customer and infrastructure impacts and restoration staffing – and gathers information from support functions and external facing groups such as from the call center, community relations, and large managed accounts.

As soon as Xcel Energy knows there is an outage, a crew is dispatched to investigate. When the crew arrives on the scene, it assesses the problem and proceeds with the repair. Due to the complexity of the Xcel Energy electric system and the variety of probable causes, this process can take several minutes or, in extreme circumstances, hours. Time estimates can vary based on the extent of the outage, public safety issues that take priority, etc.

⁴⁷ Everbridge is a critical event management platform that helps organizations manage the full lifecycle of a critical event.

The Xcel Energy restoration process gives top priority to situations that threaten public safety, such as live, downed wires. Repairs are then prioritized based on what will restore power to the largest number of customers most quickly. Crews work around the clock until power is restored to all customers.

The number of customers affected by an outage will depend on where the cause of the outage occurred. Figure 47 below provides a high level view of the major electric grid components involved in restoring power to customers, whether the outages are part of an escalated operations event or a more isolated outage event.



Figure 47: Major Grid Components

Outage restoration prioritization generally follows the system components that will restore power to the greatest numbers of customers, which we describe below. We note however, that we also take into consideration critical infrastructure such as schools, hospitals, and municipal pumping operations.

Restoration of transmission lines and substations are a top priority, because they may serve one or several communities. Generally, damaged or failed transmission facilities do not cause customer outages due to the interconnected nature of the transmission grid. Regardless, they are a top priority because a failed or damaged component reduces our resilience by creating a vulnerability on the grid. Transmission lines and substations have a dedicated workforce, which allows Distribution to focus on restoring portions of the system that more directly impact customers.

Substations can be either transmission or distribution. Distribution substations

^{2.} Outage Restoration

distribute power to feeders. One feeder might serve between 1,500 to 8,000 customers. Feeders distribute power to power lines called taps. One tap line might serve between 40 to 400 customers. Tap lines distribute power to transformers. Transformers may serve a single building or home, or serve multiple customers (generally 4 to 12 customers). Service wires connect transformers to individual residences and businesses.

Sometimes, a tap, feeder or substation outage will be restored while a transformer or an individual customer (service) may remain without power. This type of outage may go undetected at first until the customer notices that their neighbors have power, or they receive a notification that their electricity has been restored, when in fact, it has not been. AMI will significantly improve our ability to initially "sense" and thus record individual customer outages – and track them all the way through to restoration. Similarly, with this detailed information enabled by AMI, we will have increased capabilities to avoid "okay on arrival" truck rolls, because we will have better data at an individual customer level than we do today.

3. Costs Summary

Our annual capital and O&M expenditures are influenced by the magnitude and frequency of significant storm restoration activities that occur throughout our service territory. The unpredictable nature of severe weather makes budgeting challenging as there is no such thing as a typical year for severe weather.

Figure 48 below portrays our capital- and O&M-related Escalated Operations costs for the recent past, demonstrating how variable this aspect of our operations can be.⁴⁸

⁴⁸ Represents escalated operations events significant enough for a workorder to be established.

Figure 48: Escalated Operations – State of Minnesota Electric Capital and O&M Expenditures 2013 to 2018 (Millions)



In terms of budgeting for storm restoration, due its significant variability from yearto-year, we budget dollars in a working capital fund that are not assigned to a specific project or program. When emergent circumstances, such as storm restoration arise, we reallocate budgeted dollars to address the circumstance while remaining in balance with our annual budget. For O&M, we do something similar – we factor-in a base level of funding within key labor accounts, such as productive labor and overtime.

B. Distribution Operations – Functional Work View

In this section, we highlight a few key aspects of the distribution function that contribute to providing customers with safe and reliable service – but that are not as prominent as storm response or constructing new feeders and substations. These include:

- Our *vegetation management* program that helps reduce preventable tree-related service interruptions and address public and employee safety,
- Our *damage prevention* program that helps the public identify and avoid underground electric infrastructure, and
- The fleet, tools, and equipment that support everything the Distribution function does every day.

1. Vegetation Management

The Vegetation Management activity includes the work required to ensure that proper line clearances are maintained, maintain distribution pole right-of-way, and address vegetation-caused outages. It includes the activity associated with the pruning, removal, mowing, and application of herbicide to trees and tall-growing brush on and adjacent to the Company's rights-of-way to limit preventable vegetation-related interruptions. An effective Vegetation Management program is essential to providing reliable service to our customers. We have established a five-year routine maintenance cycle for our distribution facilities, generally meaning that vegetation around our electric facilities will be maintained every five years.

Tree-related incidents are among the top two causes for electrical outages on the Company's distribution system. Being as close as practicable to 100 percent on a fiveyear cycle will better ensure that preventable tree-related interruptions are minimized, public and employee safety is addressed, and various regulatory compliance requirements are met. This category also includes the pole inspection program, because we use the same workforce to perform both of these activities.

We budget for Vegetation Management annually based primarily on the number of line-miles of transmission and distribution circuits needing to be maintained on an annual basis. To maintain on-cycle performance, varying miles of circuits come due each year that were last maintained five years previous, and need to be maintained again. Annual budgets are prepared based on the line-miles coming due in the given year. In addition to line-miles, key cost drivers are the number of line-miles due in a given year to maintain on-cycle performance, degree of difficulty (forestation) associated with scope of annual circuits due, and finally, the contract labor rates of our primary contractors.

2. Damage Prevention/Locating

The Damage Prevention category includes costs associated with the location of underground electric facilities and performing other damage prevention activities. This includes our costs associated with the statewide "Call 811" or "Call Before You Dig" requirements. This program helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents. We summarize in Table 35 below the volume of requests for electric facilities locates over the recent past:
Table 35:	NSPM Electric	Locates Volumes	s (2014-2018)
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	2014	2015	2016	2017	2018
Annual Total	413,469	446,838	444,773	427,791	459,499

The budget for Damage Prevention is based on several factors including our most recent historical annual locate request volume trends, regional economic growth factors including new housing starts, and the contract pricing of our Damage Prevention service providers.

3. Fleet and Equipment Management

From a functional perspective, this category represents costs associated with the Distribution fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system. Capital investments in fleet, tools, and equipment ensure our workers have the necessary provisions and support to do their job safely and efficiently, which includes the necessary replacement of vehicles and equipment that have reached their end of life. The O&M component of fleet is those expenditures necessary to maintain our existing fleet, which includes annual fuel costs plus the allocation of fleet support to O&M based on the proportion of the Distribution fleet utilized for O&M activities as compared to capital projects.

The largest cost driver for this category is for fleet vehicles. Our fleet managers maintain accurate records on vehicles and have performed analysis to determine the optimal investments to ensure a reliable, yet cost-effective fleet. Through our rigorous tracking of vehicle maintenance expenses, we are able to select vehicles to replace in order to achieve the lowest cost of ownership. We analyze which units have met their candidate age for replacement, quantitatively prioritize which assets will return the largest reduction in maintenance and repair as a proportion to their capital investment, qualitatively review condition assessments with the mechanics, and review work priorities and gather non-replacement fleet needs with users. The annual fleet budget can then be derived based on the proposed number of fleet replacements (by type of vehicle) coupled with the latest known pricing for each type and quantity of vehicle being proposed for replacement.

IX. GRID MODERNIZATION

The Company is filing its IDP concurrently with a multi-year rate case (MYRP) filing. The IDP would typically include the Company's grid modernization report, while a rate case filing typically focuses on the test year or MYRP plan years. In this case, however, while our focus in the MYRP is on investments during the MYRP period as the elements for which are seeking cost recovery, we also introduce longer-range plans to provide context for our overall distribution system vision. For example, we discuss the core components of AGIS – AMI, the FAN, FLISR, and IVVO – and the Company's building block approach to deploying these components. We also discuss ADMS as part of our overall strategy and distribution planning, even though ADMS has been previously certified by the Commission, and the first year of costs were recently approved for recovery under our Transmission Cost Recovery (TCR) Rider.

Together, our MYRP filing and the IDP bring the overall vision for AGIS into focus, and provide extensive detail regarding AGIS and our customer and distribution strategies and planned outcomes.

A. Introduction

Xcel Energy has a 100-year track record of outstanding service to our customers and communities – delivering safe, reliable, and affordable energy. We are also looking to the future and have a vision for an advanced grid that will provide both customer and operational benefits for many years to come, by addressing changes in our system needs and in distribution technology that require further investment for the future. We are taking a measured and thoughtful approach to maximize customer value, ensure the fundamentals of our distribution business remain sound, and maintain the flexibility needed as technology and our customers' expectations continue to evolve.

We are also constantly assessing our customers' experience, and their wants and needs from their electric and gas utility. Customers want access to actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler, and more seamless experience. Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. We plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

The AGIS initiative is our long-term strategic plan to transform our electric distribution system to update system technology and capabilities, meet changing customer demands, enhance transparency into the distribution and to system data, to promote efficiency, and reliability, and to safely integrate more distributed resources. Overall, the AGIS initiative consists of multiple elements that work together to create a more modern and advanced distribution grid.

The core components of AGIS are the Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI), and the Field Area Network (FAN). ADMS is underway, with costs being recovered in the TCR Rider. We now propose to implement AMI, FAN, and two advanced applications that we believe will provide substantial benefits to customers: Integrated Volt-VAr Optimization (IVVO) and Fault Location Isolation and Service Restoration (FLISR). More specifically:

- Advanced Distribution Management System is the backbone of the AGIS initiative, consisting of a real-time operating system that enables enhanced visibility into the distribution power grid and controls advanced field devices.
- Advanced Metering Infrastructure is the Company's proposed metering solution, consisting of an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy's business and data systems and customer meters.
- *Field Area Network* is a private, secure, flexible two-way communication network that provides wireless communications across Xcel Energy's service area to, from, and among, field devices and our information systems.
- *Fault Location, Isolation, and Service Restoration* is an ADMS application that improves customers' reliability experience, reducing the duration of outages and number of customers affected by them. FLISR takes the form of distribution automation and involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and automatically restore power.
- Integrated Volt VAr Optimization is an ADMS application that uses specific field devices to optimize voltage as power travels from substations to customers, reducing system losses and may result in energy savings for customers.

Of course, protective cyber security and information technology (IT) support underlie all these components, as they are essential to operating a secure, technologically-advanced grid in today's world.

B. Drivers of the AGIS Initiative

NSPM has made incremental modernization efforts on the distribution system over many years, maintaining a grid that is reliable and as efficient as it could be with the technology it currently employs. However, now is the right time to begin a more significant advancement of the grid through our AGIS initiative. Drivers of our AGIS strategy include:

- The Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills affordable;
- The Company's desire to meet the growing needs and expectations of our customers;
- Current distribution system needs; and
- Commission policy and direction, and stakeholder input relative to customer offerings, performance, and technological capabilities of the grid.

Over the last several years, we have experienced a variety of converging needs and opportunities related to distribution grid modernization - some driven by internal system needs, others by industry direction, and others by customers and other stakeholder considerations. The Company's extensive assessments of these multifaceted needs, as well as the alternatives to meet them, are described in detail in the Direct Testimony of Company witnesses Ms. Bloch, Mr. Cardenas, and Mr. Harkness. As one example, Ms. Bloch and Mr. Cardenas explain the status of the Company's current meters and the extensive planning, information gathering, RFP processes, and consideration of alternate vendors, devices, systems, and programs that we undertook prior to selecting our current AMI plan. Mr. Harkness discusses both the opportunities and challenges of integrating the IT aspects of AMI across the Company, and explains the work completed to select the appropriate IT solutions. We compared the capabilities, costs, benefits, and limitations of a variety of solutions, as well as the costs versus benefits of our preferred solutions, and ultimately propose an overall AGIS initiative that is designed to effectively address the drivers of the needs for grid advancement.

We are working every day to lead the transition to a clean energy future, enhance our customers' experience with their utility, and keep bills low. As discussed in the Direct Testimony of Mr. Gersack, our customers can be partners in a more environmentally sound future, especially if they are empowered with better information and data to manage their energy usage and make conservation-friendly choices. AMI and the associated components of the AGIS initiative are critical to these efforts. Likewise, IVVO has the potential to act as a demand side management-type tool with carbon reduction and energy savings benefits without requiring any action from customers. DER are also a key to this clean energy future, and two-way communications on the distribution grid, down to the meter level, are necessary to accommodate increased levels of DER on the system.

Further, customers are demanding more optionality and increasing levels of service from all their service providers – including their provider of electric service. The

AGIS initiative is intended to create better interfaces with customers, provide them with better information and more choices, and thus improve their overall experience. Coupled with efforts to improve the digital platforms through which we interact with customers, improved energy management, control, conservation, and bill management are all available with a more interactive, advanced distribution system. And it goes without saying that continually enhancing our customers' reliability experience is at the core of quality electric service.

Finally, our proposed AGIS initiative offers our customers opportunities to better control and manage their monthly bills by providing more timely and granular energy usage data and enabling advanced rate design. Additionally, the costs of AGIS will be spread over the implementation period, which reasonably manages the cost impact for our customers. Our grid advancement strategy is intended to support each of these strategic objectives.

Influenced by other services, customers have come to expect more from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use. Customers also expect greater functionality and interaction in how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, EV chargers, smart home devices, and even smart phones and energy-related digital applications, are evolving at a fast rate.

While Xcel Energy customers today have access to numerous energy efficiency and demand management programs, renewable energy choices, and billing options, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters can now more easily and flexibly gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid can detect, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

Now is the right time for the Company to implement the AGIS initiative. Like other electric utilities, our current distribution system is based on one-way flow of information on much of our system, which means that beyond the distribution substation, the Company has little insight into the workings of the distribution system

as it relates to outages, voltage levels experienced by the customer, and DER operations. Company witness Ms. Kelly Bloch describes this in further detail. Additional components that integrate with ADMS and advanced meters are necessary to better manage and shorten outages, and to maximize the voltage management on our system.

In addition, our current automated meter reading (AMR) technology in Minnesota is nearing end of life, and our meter reading services vendor, Landis+Gyr (Cellnet) has informed the Company that it will no longer manufacture replacement parts for this system after 2022. In fact, we are the last Cellnet customer still using this technology. Further, our current contract with Cellnet for meter reading services expires at the end of 2025. While we have maximized the value of this AMR system that has provided efficient meter reading services for nearly 30 years, we now have the opportunity to transition to AMI, a proven meter technology. AMI will allow us the ability to expand the use of our meter system beyond basic billing functions for the benefit of our customers.

AMI is the right direction, as AMR technology is becoming increasingly outdated – and the progressively complex needs of the distribution system require movement to technology that can accommodate these needs. As stated in the United States Department of Energy (DOE) Office of Electricity's November 2018 Smart Grid System Report to Congress,

[f]rom 2007 to 2016, the number of advanced meters has grown ten-fold. About 70.8 million meters out of a total of 151.3 million meters were smart meters as of 2016, representing about 47 percent of U.S. electricity customers[]. Bloomberg estimates that number has risen to 51 percent by the start of 2018. This is a significant increase compared to 14 percent of customers with smart meters in 2010 and only 2 percent in 2007.⁴⁹

Xcel Energy has always performed well with respect to system reliability, management, and customer service, but in light of the prevalence of advanced meters and smart grid technologies, we must make similar investments to ensure continuing alignment with industry direction and customer expectations.

The DOE Smart Grid System Report also recognized the broader need for attention to distribution infrastructure nationwide:

Our [country's] electric infrastructure is aging and it is being pushed to do more than

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https://www.energy.gov/sites/prod/files/2019/02/f59/Smart%20Grid%20System%20Report%20Novemb er%202018 1.pdf, as of October 1, 2019 (internal citations omitted) (DOE Smart Grid System Report).

it was originally designed to do. Modernizing the grid to make it "smarter" and more resilient through the use of cutting-edge technologies, equipment, and controls that communicate and work together to deliver electricity more reliably and efficiently can greatly reduce the frequency and duration of power outages, reduce storm impacts, and restore service faster when outages occur. Consumers can better manage their own energy consumption and costs because they have easier access to their own data. Utilities also benefit from a modernized grid, including improved security, reduced peak loads, increased integration of renewables, and lower operational costs.

"Smart grid" technologies are made possible by two-way communication technologies, control systems, and computer processing. These advanced technologies include advanced sensors... that allow operators to assess grid stability, advanced digital meters that give consumers better information and automatically report outages, relays that sense and recover from faults in the substation automatically, automated feeder switches that re-route power around problems, and batteries that store excess energy and make it available later to the grid to meet customer demand.⁵⁰

It is no coincidence that these needs are arising at the same time we have implemented ADMS and that our existing AMR meters are nearing the end of their life. And, as noted earlier, our customers are also demanding more optionality, environmentally-sound investments, more control over their energy usage, and better outage management and communications from their utility.

We have applied Commission guidance and stakeholder feedback gleaned through regulatory proceedings and Commission- and Company-sponsored stakeholder processes around grid modernization, DER hosting capacity, integrated distribution system planning, our integrated resource plan, and performance metrics for the Company's electric operations. We also considered the Commission's guidance and stakeholder feedback associated with the Company's proposed Time of Use (TOU) pilot and our EV pilot proposals, all of which were informed by extensive stakeholder input. This guidance and feedback helped shape our proposal in terms of the advanced grid capabilities, how we prioritized the advanced applications, and how we assessed and present the AGIS benefits and value for customers. As discussed further in the Direct Testimony of Mr. Gersack (Section IV), various Commission policies and specific goals of each of these efforts are supported or enabled by advanced grid technologies. We have considered these policies, goals, and the stakeholder input as we developed our overall strategy and specific project plans for AGIS implementation.

⁵⁰ <u>https://www.energy.gov/oe/activities/technology-development/grid-modernization-and-smart-grid</u>, as of Oct. 1, 2019.

Further, as the prevalence of DER continues to rise, the ability to manage these resources requires visibility into the grid and a more resilient and responsive grid. As the DOE Smart Grid Report stated, grid advancement is necessary to support:

the increasing presence of renewable generation and the proliferation of customerand merchant-owned DERs [that] are introducing significantly greater levels of variability and uncertainty in both the supply of electricity and the demand for it. Generation and load profiles, which have been predictable in the past, can now vary instantaneously and are subject to the behavior of consumers where DERs are present.⁵¹

Enhanced grid management through ADMS, meters with two-way communications that act as sensors, and greater voltage optimization will all support our ability to host increasing levels of DERs.

Given these circumstances and the additional customer and system benefits enabled by advanced grid technology, the Company determined now is the appropriate time to pursue a targeted AGIS initiative that will address system needs, customer needs, and our overall strategic priorities as a Company to lead the clean energy transition, enhance the customer experience, and keep bills low.

C. AGIS Implementation

With the Commission's certification and approval of our first year of costs, the ADMS is underway and scheduled to go into service in 2020. We are also in the process of implementing our TOU pilot, consistent with the Commission's Order in Docket No. E002/M-17-775, certifying it as a distribution project under Minn. Stat. §216B.2425 (*i.e.*, a grid modernization project). This pilot is intended to study time of use rates and how to maximize their value. This limited deployment of AMI meters and the FAN communications network in connection with the TOU pilot is a part of the overall AGIS initiative, and has been considered as we have developed plans for full deployment of advanced grid technologies. Likewise, we have conducted system research and testing around FLISR and IVVO, as discussed in the Direct Testimony of Ms. Bloch.

Implementation of the components of the AGIS initiative will occur over several years and be substantially complete by 2024 – with FLISR implementation expected to continue through approximately 2028. As such, a large portion of AMI, FLISR, IVVO, and FAN work will be undertaken and placed in service during the multi-year

⁵¹ DOE Smart Grid Report at p. 5.

rate plan period (MYRP), and are included in the Company's rate request in its MYRP case filed concurrently with this IDP. We outline our implementation timeline below:

Program	Implementation Timeline
ADMS	In-service 2020
AMI	Meter roll-out 2021-2024
FAN	Deployment 2021-2024 (preceding AMI deployment by approximately six months)
FLISR	Limited testing 2020; Implementation 2020-2028
IVVO	Limited testing 2021; Implementation 2021-2024

Table 36: AGIS Deployment Timeline

That said, the grid modernization effort is ongoing by nature, and we will continue to maintain the system as well as leverage evolving technology, platforms and optionality as appropriate over time. Likewise, the Commission's IDP requirements contemplate five- and ten-year outlooks. As such, our discussion of AGIS costs and benefits in the MYRP encompasses but also extends beyond the MYRP timeframe. Our cost-benefit analysis also runs through the lifecycle of the assets based on the information currently known (as with any integrated long-range plan). This long-range view also includes discussion of potential future AGIS investments, which are not yet specifically planned for implementation nor ready for full presentation to the Commission.

D. AGIS Initiative Overall Cost Summary

The Company anticipates incurring capital expenditures totaling \$582 million and O&M costs totaling \$152 million for the overall AGIS initiative as summarized in Tables 37 and 38 below.⁵²

⁵² This AGIS view excludes ADMS, as it is certified for TCR Rider recovery.

ACIS Dragman	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
AMI	\$14.0	\$28.9	\$144.0	\$185.2	\$15.0
FAN	\$14.7	\$37.3	\$36.8	\$3.8	\$0.0
FLISR	\$3.5	\$8.6	\$6.6	\$18.8	\$29.7
IVVO	\$0.1	\$6.5	\$9.8	\$18.6	\$0.0
Total	\$32.3	\$81.3	\$197.2	\$226.4	\$44.7

Table 37:Total AGIS Capital ExpendituresNSPM – Electric (Millions)

*Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.

Table 38: Total AGIS O&MNSPM Electric (Millions)

ACIS Drogram	Rate Case Period			5-Year Period	10-Year Period
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
AMI	\$6.6	\$16.4	\$14.1	\$25.2	\$67.2
FAN	\$0.1	\$2.3	\$1.5	\$0.5	\$8.6
FLISR	\$0.2	\$0.4	\$0.3	\$3.3	\$2.5
IVVO	\$0.00	\$0.4	\$0.8	\$0.6	\$0.8
Total	\$6.9	\$19.5	\$16.7	\$29.4	\$79.1

Period may include additional assumptions, including inflation and labor cost increases that are not part of the capital budget in periods 2020-2024.

E. Proposed AGIS Cost Recovery

The Commission's requirements state that the Company is to provide detailed support for its proposed grid modernization investments, including assessment of both quantitative and qualitative benefits associated with them. As we outline and describe below, our AGIS plan extends beyond the MYRP, and the Commission has required the Company to explain its grid modernization plan through the lifecycle of the assets. We present this information in our cost-benefit analysis, and in the Direct Testimony of each of the witnesses who present operational support for the costs and benefits we have identified and modeled (where quantification is possible).

Concurrent with the IDP and the MYRP, we also filed a Petition for Approval of True-Up Mechanisms. This latter filing requests the approval of certain true-ups for 2020 which, if approved, would have the effect of the MYRP being withdrawn.

While we have included the AGIS costs in our MYRP request, we are also seeking certification for these investments for two reasons: (1) should the Commission ultimately approve the True-Up Petition and the MYRP be withdrawn, we would preserve the option to put the AGIS costs in a rider until such time as we file our next general rate case and roll the costs into base rates; and (2) regardless of approval of the True-Up Petition, the span of the AGIS costs goes beyond the timeframe for the rate case, so we would look to include the out years of the costs in a rider. Again, the Commission would have another opportunity for review and approval before any of these costs were actually included in any future rider, this approach merely preserves our options.

Given the complete information we provide on overall AGIS implementation and costs, we respectfully request certification of the AGIS initiative. The costs for which we request recovery in the MYRP are as follows:

AGIS Component	2020	2021	2022
AMI	\$16.0	\$27.9	\$119.8
FAN	\$8.3	\$21.3	\$42.0
FLISR	\$3.4	\$8.4	\$6.4
IVVO	-	\$5.7	\$8.6
Total	\$27.7	\$63.3	\$176.8

Table 39: Capital Additions for the AGIS Components – Minnesota2020-2022 (includes AFUDC) (Millions)

Table 40:O&M for the AGIS Components – NSPM Electric2020-2022 (Millions)

AGIS Component	2020	2021	2022
AMI	\$6.6	\$16.4	\$14.1
FAN	\$0.1	\$2.3	\$1.5
FLISR	\$0.2	\$0.4	\$0.3
IVVO	-	\$0.4	\$0.8
Total	\$6.9	\$19.5	\$16.7

The normal procedural schedule for certification under Minn. Stat. § 216B.2425 would require a determination by June 1, 2020, and under normal circumstances, we believe the process leading to certification should resemble a resource acquisition proceeding under the Commission's normal notice and comment procedures that could, in the Commission's discretion and depending on the scope of the investment, include one or more public hearings. We recognize, however, that the schedule in the

General Rate Case does not align with that timing. In addition, the AGIS initiative includes large investments and is supported by a sizeable filing that may require analysis beyond the six-month certification timeframe, even if the General Rate Case is withdrawn. Thus, we offer to work with the Commission and stakeholders to set an appropriate deadline and procedural schedule for consideration of these investments.

F. Relative AGIS Initiative Costs and Benefits – Quantifiable and Non-Quantifiable

Our proposal contains comparisons of the costs and benefits of the AGIS components as well as alternatives comparisons. We have conducted a cost-benefit analysis (CBA) for each of the AGIS components and on a consolidated basis. The CBA provides one point of reference to assess the investments in the broader context of the goals of AMI, FLISR, and IVVO implementation, the current qualitative benefits they offer, Commission policy goals, and the opportunities for future customer benefits. Company witness Dr. Duggirala presents the overall CBA model and the witnesses noted in Table 47 of this IDP provide the inputs to the CBA for each component and for the consolidated AGIS initiative.

1. Summary CBA Results

On a consolidated basis the CBA results indicate that the quantifiable costs and benefits of the AGIS initiative total 0.87 in our baseline scenario, or 1.03 under a high benefit/no contingency scenario. Thus, although the combined components do not reach 1.0 (equal quantifiable benefits and costs) under our baseline scenario, the ratio for the overall AGIS initiative approaches 1.0 even before we factor in qualitative benefits such as customer satisfaction and operational, power quality, and safety enhancements.

NSPM AMI, FLISR, IVVO NPV	Total
Benefits	\$571
O&M Benefits	\$53
Other Benefits	\$222
Customer Benefits	\$103
Capital Benefits	\$193
Costs	\$(656)
O&M Expense	\$(186)
Change in Revenue Requirement	\$(470)
Baseline Benefit-Cost Ratio (IVVO CVR 1.25% energy, 0.7% capacity, with contingencies)	<u>0.87</u>
High Benefit/No Contingency Sensitivity (IVVO CVR 1.5% energy/0.8% capacity, no contingency)	1.03
Lower Benefit/With Contingency Sensitivity (IVVO CVR 1.0% energy/0.6% capacity, with contingencies)	0.86

Table 41: AGIS Initiative Combined Cost-Benefit Ratio (Millions)

We note that while the CBA, by itself, does not show that quantifiable benefits are equal to quantifiable costs, we would not necessarily expect that result. We are proposing an initiative to both replace fundamental components of our system that are approaching end of life, and to add capabilities for our customers and for a future that includes greater DER, distributed intelligence, and greater customer engagement. We would not expect to save money (on a net basis) when investing in these kinds of technologies, but we believe the total value of the initiative significantly outpaces the cost of the investments. For these reasons, the AGIS investments are prudent based on the need for the investments to serve customers, as well as consideration of the customer-facing benefits, efficiencies, and system benefits they provide.

2. Individual AGIS Component CBA Results Summary

As discussed in detail in Dr. Duggirala's testimony, AMI, FLISR, and IVVO have the following approximate quantitative benefit-to-cost ratios for each component, shown here with and without contingency amounts:

Table 42: NSPM AMI Benefit-to-Cost Ratio (Millions)

NSPM-AMI-NPV	Total
Benefits	\$446
O&M Benefits	\$53
Other Benefits	\$203
CAP Benefits	\$190
Costs	\$(538)
O&M Expense	\$(179)
Change in Revenue Requirements	\$(359)
Benefit/Cost Ratio	0.83
Benefit/Cost Ratio (no contingencies)	0.99

Table 43: NSPM FLISR Benefit-to-Cost Ratio (Millions)

NSPM FLISR- NPV	Total
Benefits	\$103
O&M Benefits	\$0
Customer Benefits	\$103
Costs	\$(79)
O&M Expense	\$(5)
Change in Revenue Requirements	\$(74)
Benefit/Cost Ratio	
Benefit/Cost Ratio (no contingencies)	

NSPM IVVO- NPV	Total
Benefits	\$22
Other Benefits	\$19
CAP Benefits	\$3
Costs	\$(39)
O&M Expense	\$(2)
Change in Revenue Requirement	\$(37)
Benefit/Cost Ratio (CVR 1.25% energy; 0.7% capacity)	0.57
Benefit/Cost Ratio (no contingencies)	0.61
Low Benefit Sensitivity:	-
Benefit/Cost Ratio (CVR 1% energy; 0.6% capacity)	0.46
Benefit/Cost Ratio (no contingencies)	0.49
High Benefit Sensitivity:	
Benefit/Cost Ratio (CVR 1.5% energy; 0.8% capacity)	0.67
Benefit/Cost Ratio (no contingencies)	0.72

Table 44: IVVO Benefit to Cost Ratio (Millions)

We show an additional range of IVVO benefit-to-cost ratios because as Ms. Bloch and Dr. Duggirala explain, the Company is deploying IVVO to a core area, and does not have widespread data on the likely results of IVVO implementation. However, we understand that many of our stakeholders are particularly interested in IVVO deployment. Our engineers feel confident they can achieve 1.0 percent energy savings and may be able to achieve 1.5 percent through voltage optimization; in light of the uncertainty and interest, we have utilized a 1.25 percent mid-range energy savings level to show a range of potential outcomes. Our baseline benefit-to-cost ratio overall assumes 1.25 percent energy savings, 0.7 percent capacity savings, and that we will need to utilize the IVVO contingency amounts.

3. CBA MYRP Witness Support Summary

In terms of MYRP witness support for the costs and benefits of our proposed AGIS initiative, Ms. Bloch, Dr. Duggirala, and Mr. Cardenas support the benefits of AMI. Mr. Gersack discusses the purpose and limitations of the CBA, as well as the unquantifiable qualitative benefits further in his Direct Testimony. While the IT work is necessary to both implement the AGIS initiative and ensure appropriate security measures, IT by itself does not provide independent benefits; therefore, Mr. Harkness's testimony is limited to a discussion of costs. Benefits of the AGIS initiative are many and varied, but the types of benefit and supporting witnesses can

be summarized as follows:

Table 45:	Summary	of Benefits	for AGIS	Components
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Benefit	Supporting Witness			
AMI				
Distribution System Management Efficiency	Bloch Direct, Section V(D)(4)(a)(1)			
Outage Management Efficiency	Bloch Direct, Section V(D)(4)(a)(2)			
Avoided Meter Purchases for Failed Meters	Bloch Direct, Section V(D)(4)(a)(3)			
Avoided Capital for Alternative Meter Reading System	Bloch Direct, Section V(D)(4)(a)(4)			
Avoided O&M Meter Reading Cost for Alternative Meter Reading System	Cardenas Direct, Section V(F)			
Reduction in Field & Meter Services	Bloch Direct, Section V(D)(4)(b)(1)			
Improved Distribution System Spend Efficiency	Bloch Direct, Section V(D)(4)(b)(2)			
Outage Management Efficiency	Bloch Direct, Section V(D)(4)(b)(3)			
Customer Outage Reduction	Bloch Direct, Section V(D)(4)(c)			
Reduction in Energy Theft	Cardenas Direct, Section V(F)			
Reduced Consumption Inactive Premise	Cardenas Direct, Section V(F)			
Reduced Uncollectible/Bad Debt	Cardenas Direct, Section V(F)			
Critical Peak Pricing	Duggirala Direct, Section II(B)(1)			
TOU Customer Price Signals	Duggirala Direct, Section II(B)(1)			
Reduced Carbon Dioxide Emissions	Duggirala Direct, Section II(B)(1)			
Improved Customer Choice and Experience	Gersack Direct, Section VI and Schedule 3			
Enhanced DER Integration	Bloch Direct, Section $V(D)(4)(d)(1)$			
Environmental Benefits of Enhanced Energy Efficiency	Bloch Direct, Section V(D)(4)(d)(2)			
Improved Safety to Both Customers and Company Employees	Bloch Direct, V(D)(4)(d)(3)			
Improvements in Power Quality	Bloch Direct, V(D)(4)(d)(4)			
FLISR				
Customer Minutes Outage –Savings	Bloch Direct, Section V(F)(5)(a)(1)			
Outage Patrol Time Savings	Bloch Direct, Section V(F)(5)(a)(2)			
Improved ability to plan distribution system needs	Bloch Direct, Section V(F)(5)(b)			
Overall Customer Satisfaction with Utility Service	Gersack Direct, Section VII(B)			

Benefit	Supporting Witness			
IVVO				
Fuel savings (Energy Reduction)	Bloch Direct, Section $V(G)(4)(a)(1)$			
Fuel Savings (Line Losses)	Bloch Direct, Section $V(G)(4)(a)(2)$			
Avoided Capacity Costs	Bloch Direct, Section $V(G)(4)(a)(3)$			
Reduced Carbon Dioxide Emissions	Duggirala Direct, Section II(B)(3)			
Customer bill savings for customers with feeders with IVVO assets	Bloch Direct, Section V(G)(4)(b)			
Greater Efficiencies from the Customer's Personal Electrical Devices	Bloch Direct, Section V(G)(4)(b)			
Increased Hosting Capacity for Distributed Energy Resources.	Bloch Direct, Section V(G)(4)(b)			

Additionally, Dr. Duggirala presents "Least-Cost/Best-Fit" analyses with respect to the costs/benefits of AMI and manual reading or drive-by AMR solutions; as well as for the costs of FAN versus cellular communications and dedicated AMI network alternatives.

4. Summary

As we have noted, while the consolidated CBA by itself does not show that quantifiable benefits are equal to quantifiable costs, we are proposing this equipment to replace a fundamental component of our system that is approaching obsolescence while also adding capabilities for our customers and for a future that includes greater DER, distributed intelligence, artificial intelligence, and greater customer engagement with all facets of their life. We would not expect to save money (on a net basis) when investing in these kinds of technologies.

G. Estimated Customer Bill Impacts

Keeping customer bills low is a core strategy of the Company and is a central consideration of our AGIS initiative. As we discuss, the combined AGIS investment will provide significant value to our customers. Of course, providing value to our customers through our AGIS investments has an impact to customer bills, resulting from the increased revenue requirement due to our investments and O&M spending necessary to implement the AGIS initiative.

To conduct this analysis, we performed a high-level revenue requirement analysis for

2020 through 2024 to illustrate the incremental revenue requirement and estimated bill impact of AGIS implementation.⁵³ We present the AGIS revenue requirement in the Direct Testimony of Mr. Gersack as Exhibit___(MCG-1), Schedule 9. While we did not perform an exhaustive class cost of service model for this subset of investments and O&M expenses, this analysis provides the annual cost of the AGIS initiative overall, and provides an estimate of a monthly bill impact for a typical residential customer.

We estimated the bill impact by utilizing a series of allocation assumptions applied to the AGIS costs, using allocators consistent with our 2020 proposed Class Cost of Service Study. Appropriate allocators were applied to distribution capital, distribution O&M, and the remaining costs to develop an estimated residential class revenue requirement. We then divided the estimated residential class revenue requirement by the sales forecast for each year, as provided in Company witness Ms. Janell Marks's testimony. This results in an estimated overall cost per kilowatt hour (kWh). We then calculated an estimated bill impact based the average monthly residential customer usage of 675 kWh. This assessment shows an estimated 2024 bill impact for our AGIS investments of approximately \$2.87 per month for an average residential customer.

We also assessed an alternative investment and costs if the Company does not implement the AGIS initiative. As described earlier, it is not feasible for the Company to continue to use its current AMR meters because they are nearing end of life, and the Company's contract with Cellnet for meter reading service and support expires at the end of 2025. As such, the Company would, at a minimum, need to invest in new meters and provide meter reading services in order to continue to provide electric service to our customers. This means that even without AGIS implementation, there would be an incremental impact to customers' bills for an alternative metering service.

Therefore, in addition to the AGIS revenue requirement, we developed a reference case scenario to represent an alternative to our AGIS investments. The reference case reflects the necessary investments and costs if the Company were to pursue a basic AMR drive-by meter reading alternative. Ms. Bloch and Mr. Cardenas discuss AMR meters and provide details on the costs of this alternative. We calculated the bill impact by using the revenue requirements for the AMR drive-by alternative and calculated the estimated bill impact as described above. We present the reference

⁵³ The costs included in 2019 are related to the Company's TOU pilot. As described in Section VI, the costs of implementing AMI and FAN in connection with the TOU pilot (in 2019 and 2020) have been included in the AGIS CBA to provide a complete picture of advanced grid investments and costs. We have also included these costs in our bill impact assessment.

case revenue requirement in the Direct Testimony of Mr. Gersack as Exhibit____(MCG-1), Schedule 10. This assessment shows an estimated 2024 bill impact for the AMR drive-by alternative of approximately \$1.51 per month for an average residential customer.

The key comparison and impact is the difference between the estimated bill impact of AGIS implementation versus the basic alternative, as shown below.

	2020	2021	2022	2023	2024
AGIS	\$0.44	\$1.33	\$1.84	\$2.58	\$2.87
Reference Case	\$.01	\$0.19	\$0.62	\$1.18	\$1.51
Difference	\$0.43	\$1.14	\$1.22	\$1.40	\$1.36

Table 46: Estimated Monthly Bill Impact –Typical Residential Customer

Table 46 illustrates the incremental bill impact of pursuing our AGIS investments compared to the investments that would otherwise be necessary. In other words, the difference reflects the costs that will enable all the benefits of the advanced grid, both quantifiable and non-quantifiable, that AMR meters simply will not provide. Additionally, Table 46 illustrates that costs of AGIS will be spread over the implementation period, which reasonably manages the bill impact for our customers.

H. AGIS Metrics and Reporting

The AGIS initiative will be implemented over a number of years, beginning with customer outreach and education efforts, followed by deployment of the systems and technologies, and then the roll-out of new products and services enabled by the AGIS initiative. Our efforts will also include development and implementation of future products and services that will capture additional benefits of the advanced grid capabilities as customer preferences and technologies evolve over time.

Recognizing the significant investment that the advanced grid initiative requires as well as the fact that we are the first utility in Minnesota to take on this holistic effort, we propose to report on several metrics. These metrics are intended to provide progress reports to the Commission and share information and learnings with stakeholders. The proposed metrics are defined in four categories:

- 1. *Customer Awareness* measuring the effectiveness of the communications on educating customers about the advanced grid and the potential benefits it entails.
- 2. *Customer Engagement* measuring the adoption rates of customers in new products and services that are enabled or enhanced by the advanced grid.
- 3. *Customer Satisfaction* measuring how satisfied customers are with the deployment or and services associated with the advanced grid.
- 4. *System Benefits* measuring the energy savings benefits associated with products and services enabled or enhanced by the advanced grid.

Reporting of these metrics can keep stakeholders informed of the progress and value that the advanced grid is bringing to customers and also identify areas where Xcel Energy can focus additional resources to improve results. Certain metrics would have a specific baseline in a steady state. The steady state would occur within 1-2 years of the completion of mass deployment of advanced meters.

In summary, we propose to file an annual report on the AGIS initiative that will include various progress metrics that relate to different areas of our business that are involved in AGIS implementation. We propose to file the AGIS report on May 1 each year, to include reporting for the prior calendar year. Our first AGIS report would be filed May 1, 2022. We expect the content of the report and relevant metrics will change over time as we move through the phases of AGIS implementation. We provide a summary in the Direct Testimony of Mr. Gersack, Exhibit____(MCG-1), Schedule 11.

We also note that our AGIS initiative may also impact certain service quality metrics that are included in reporting that is already in place. Specifically, the Company reports service quality metrics under our established Service Quality tariff⁵⁴ as well as the Minnesota Rules governing utility service quality.⁵⁵ We propose to continue reporting the service quality metrics in those reports, and intend to address any AGIS impacts to service quality metrics or thresholds in those separate proceedings.

We clarify that we do not propose specific metrics related to future operational capabilities or products and services that will be enabled by AGIS at this time.

⁵⁴ See the Company's Minnesota Electric Rate Book, Section 6, General Rules and Regulations, Subsection 1.9, Service Quality.

⁵⁵ See Minn. Rule 7826, Electric Utility Standards on safety, reliability, and service quality.

Rather, as we discuss in the MYRP Direct Testimony, we propose to report on metrics developed in those proceedings in the separate future dockets.

I. MYRP Witness Support for the Proposed AGIS Initiative

In this section, we outline the business areas involved in implementing the AGIS initiative, identify the MYRP witnesses supporting AGIS, and provide an overview of the topics covered by each. Because the large majority of information necessary to support the AGIS initiative in the MYRP and in the concurrent IDP is contained in the MYRP filing, we provide a roadmap to help navigate the extensive information and testimony we provide on our AGIS initiative and proposal.

We note additionally that while we have made every effort to provide a higher-level roadmap that identifies the location of specific topics and information to aid the reader, Exhibit___(MCG-1), Schedule 2 is the AGIS Completeness List, which identifies specific filing requirements and where the information is located. We also provide this as Attachment C, Grid Modernization Content Roadmap, to this IDP.

1. Business Areas Supporting the AGIS Initiative

The AGIS initiative is supported by and affects many operating and customer service areas of our business. In particular:

- Our Distribution Operations business area is responsible for the planning, implementation, and operations of the various advanced grid components. At a high level, this can be thought of as installing, maintaining, operating, and protecting the foundational hardware and support components of AGIS on the distribution system.
- The Business Systems area is responsible for the hardware and software systems necessary to deploy and secure the AGIS components from an IT perspective. Business Systems is also responsible for implementation of the IT platform that will enable the Company to interface with customers through various portals, and to provide customers access to additional information, products, and services that will be possible through the advanced grid initiative. Business Systems also works hand-in-hand with our security team to protect the Company's software systems from cyber attacks.
- Customer Care is responsible for meter reading, billing, credit, remittance processing, and customer contact center functions. The Customer Care team will manage customer questions and concerns as the AGIS initiative is being

deployed, as well as the new billing options and programs that will be made available.

Other customer-facing teams are also heavily involved. Customer Solutions is responsible for development and implementation of those customer-facing online and mobile applications, as well as new products and services that will be enabled by the advanced grid capabilities. Our Customer Insights group is responsible for survey and research efforts necessary to determine the needs and preferences of our customers with respect to development of new products and services, as well as to measure customer satisfaction with new products, services, or advanced grid capabilities. Corporate Communications is responsible for the customer education and communications related to implementation of new technologies and products and services related to advanced grid capabilities. In short, the AGIS initiative will touch many areas of Xcel Energy.

2. MYRP Witness Topics

The MYRP presents five witnesses who provide Direct Testimony and accompanying schedules supporting our request for approval of the capital and O&M budgets for the specific components of AGIS included in this case, as well as support for this IDP being filed concurrently with this case. These witnesses' respective topics are as follows:

- *Michael C. Gersack* presents the overview of the AGIS initiative, the background on our efforts to date, a review of governance planning, discussion of the customer experience upon implementation, explanation of our customer outreach and progress metrics proposals, and cost-benefit and bill impacts overviews.
- *Kelly A. Bloch,* Regional Vice President of Distribution Operations, addresses the AGIS initiative from the Distribution perspective, and specifically identifies those costs and benefits that derive from the Distribution portion of the business. Her testimony details the business case for AMI, FLISR, and IVVO, and provides extensive discussion of these technologies, alternatives considered, and supporting cost and benefit detail.
- *David C. Harkness*, Senior Vice President of Customer Solutions for XES, addresses the AGIS initiative from the Business Systems (IT) perspective, focusing on integration of the hardware and software necessary for the AGIS elements to function together and with existing Company systems. Mr. Harkness also details the business case for the FAN strategy and project management, as well as alternatives considered and supporting cost detail. Mr.

Harkness also discusses cyber security for the AGIS initiative, as well as the costs and benefits of the IT hardware and software systems necessary to deploy each of the AGIS components.

- *Christopher C. Cardenas,* Vice President of Customer Care for XES, explains the current status of the expiring Cellnet contract for wireless metering, meter change and billing impacts and options as AMI meters are deployed, and potential tariff changes the Company plans to pursue in the future. Mr. Cardenas also describes certain cost savings and customer benefits associated with moving away from our current meter reading system.
- Ravikrishna Duggirala, Director of Risk Strategy for XES, supports the Company's cost-benefit model for the both the independent core components and overall AGIS initiative. Dr. Duggirala explains the structure of the model and how inputs received from other business areas were utilized, and also explains certain benefits. Lastly, Dr. Duggirala explains the limitations of any cost-benefit modeling.

3. AGIS Policy Testimony Roadmap

The Direct Testimony of Mr. Gersack presents the AGIS policy perspective. It first provides background on grid modernization in Minnesota and discusses how our request in the MYRP relates to this IDP filed concurrently with the Commission on November 1, 2019. We believe this establishes an important backdrop for the Company's view of the future of the grid. It then identifies the Company's overall strategic goals, focusing on the environment, the customer experience, and cost of service. It also identifies customer expectations and wishes for the future of electric service based on extensive Company research, focusing on how these expectations relate to the future of the distribution system.

The Direct Testimony of Mr. Gersack then describes the Company's long-term strategic plan to use technological advances to transform our distribution system to meet changing customer demands, to enhance efficiency, reliability, resilience, and security, to safely integrate more distributed energy resources, and explain how that plan is aligned with core Company goals. It highlights the reasons now is the right time to undertake these initiatives, including our meters nearing end of life and the expiration of our meter reading contract with Cellnet, and discuss the key goals of AGIS and how they are consistent with Xcel Energy's strategic priorities.

It then addresses the scope of the core components of AGIS that are included in the MYRP, outlining the function, benefits, alternatives considered, timing of implementation, and costs of each; other Company witnesses flesh out these

components, costs, and benefit assumptions in more detail. Next, it discusses in detail the current customer experience compared to what will be different when the distribution system is transformed and advanced. It also provides our customer and community outreach plan for the AGIS initiative, designed to educate and inform customers about our progress, impacts they will experience during and after implementation, and advanced grid capabilities that will provide the basis for additional opportunities and services for our customers. It also discusses progress metrics and how the Company will measure and report on progress and outcomes of the AGIS initiative.

Finally, it describes why AGIS, and thus the foundational elements included in the MYRP are in the public interest. It introduces the cost benchmarking and costbenefit analyses we have undertaken, which are specifically supported and presented in detail in the Direct Testimony of Company witness Dr. Duggirala. It explains both the value and the inherent limitations of any cost-benefit analysis. It also summarizes the quantitative and qualitative benefits of the AGIS initiative, explaining how the benefits of certain components of AGIS are not limited to quantifiable items; they will also update aging systems, improve our customers' overall experience and satisfaction, position the Company for future grid developments, and help achieve broader energy goals.

The Direct Testimony of Mr. Gersack also provides as Exhibit___(MCG-1), Schedule 3 the Company's *Advanced Grid Customer Strategy*. This document the details the Company's AGIS strategy and plans to enhance the customer experience. The document includes, among other things, background on our customer surveys and research efforts that have informed our AGIS strategy, and details on the technologies and customer benefits of each AGIS component.

To help stakeholders further visualize our plans, the Company also prepared a brief video⁵⁶ entitled *Building the Future* to illustrate the advanced grid technologies and benefits and illustrate multiple situations where additional data and capabilities with respect to the distribution grid will facilitate a better, smoother, and more agile customer experience. While not as dynamic as the video itself, we have provided illustrations from this video as Exhibit___(MCG-1), Schedule 4.

4. MYRP Witness Cost Support

Because the costs of the AGIS initiative reside in our Distribution and Business

⁵⁶ <u>https://youtu.be/HoQoHFdF7kc</u>

Systems budgets, Ms. Bloch and Mr. Harkness support the costs of the AGIS components and most aspects of our initiative's development. Specifically, Ms. Bloch supports the selection of meters and the FLISR and IVVO field devices and associated implementation; whereas Mr. Harkness describes the associated software, hardware, security, and overall IT integration.

AGIS Program	Component	Witness
AMI	IT Integration and head and application	Harkness Direct,
	11 integration and nead end application	Section V(E)(3)
	Meters and deployment	Bloch Direct,
	Meters and deployment	Section V(D)
FAN	IT Integration and deployment	Harkness Direct,
	11 integration and deployment	Section V(E)(4)
	Installation of pole mounted devices	Bloch Direct,
	instantion of pole-mounted devices	Section V(E)
FLISR	System development	Harkness Direct,
	System development	Section V(E)(5)
	Advanced application and field devices	Bloch Direct,
	Advanced application and field devices	Section V(F)
IVVO	System development	Harkness Direct,
	System development	Section V(E)(6)
	Advanced application and field devices	Bloch Direct,
	Advanced application and new devices	Section V(G)

Table 47: AGIS Components MYRP Witness Summary

In addition, the Direct Testimony of Mr. Gersack supports program management for the AGIS initiative (Section V.D) and the Company's customer outreach plans (Section VI.E).

J. Our AGIS Proposal is in the Public Interest

Our distribution grid is the foundation of the service we provide our customers. We are at a point where investment in new technologies to further modernize our grid will return significant value to our customers. Our proposed AGIS initiative supports the Company's vision for an advanced grid that will provide both customer and operational benefits for many years to come and has been informed by:

• The Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills low;

- The Company's desire to meet the growing needs and expectations of our customers;
- Current distribution system needs; and
- Commission policy and stakeholder input relative to customer offerings, performance, and technical capabilities of the grid.

Our AGIS initiative will enhance transparency into the distribution system and provide detailed and timely data to promote efficiency, reliability, and enable increased distributed resources on our system. AGIS will also enhance our customers' experience by providing access to actionable information, more choices, and greater control of their energy use.

Based on this, we respectfully request the Commission certify our AGIS initiative

X. CUSTOMER STRATEGY SUMMARY

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, EV chargers, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid can sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

Xcel Energy has a 100-year track record of outstanding service to our customers and communities – delivering safe, reliable and affordable energy. At our core, is keeping

the lights on for our customers, safely and affordably. We are also planning for the future – and have a vision for where we and our customers want the grid to go. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value, and that the fundamentals of our distribution business remain sound.

Today, Xcel Energy customers have access to numerous energy efficiency and demand management programs, renewable energy choices, billing options, a mobile app, and outage notifications that include estimated restoration times. Customers also receive confirmations when our records reflect that the outages have been resolved – and they receive these via their preferred communication channel – text, email, or phone. We have made advances on our grid and with the service we offer our customers – and these and other products and services have provided our customers with significant value over many years.

However, technologies are advancing, as are customer expectations. Customers want access to actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler and more seamless experience. Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. We plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers.

While we have made incremental modernization efforts on the distribution system over many years, the time is now to begin a more significant advancement of the grid. This modernization begins with foundational advanced grid initiatives that both provide immediate benefits and new customer offerings while also enabling future systems and customer value. The foundational investments in our AGIS initiative include:

- Advanced Distribution Management System (ADMS). A real-time operating system that enables enhanced visibility into the distribution power grid and controls advanced field devices.
- *Field Area Network (FAN).* A private, secure two-way communication network that provides wireless communications across Xcel Energy's service area to, from, and among, field devices and our information systems.
- Advanced Metering Infrastructure (AMI). AMI is an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy Energy's business and operational data systems and customer meters.

- *Fault Location, Isolation, and Service Restoration (FLISR).* A form of distribution automation that involves the deployment of automated switching devices that work to detect issues on our system, isolate them, and restore power thereby decreasing the duration of and number of customers affected an outage.
- *Integrated Volt Var Optimization (IVVO)*. An application that uses selected field devices to decrease system losses and optimize voltage as power travels from substations to customers.

We are taking a measured and thoughtful approach to advancing the grid to ensure our customers receive the greatest value, the fundamentals of our distribution business remain sound, and we maintain the flexibility needed as technology and our customers' expectations continue to evolve.

A. Customer Strategy

This multi-year initiative aims to transform the customer experience by implementing capabilities, technologies, and program management strategies to enable the best-inclass customer experience that our customers now expect. Our customer strategy is focused on shifting the customer experience dynamic to one where little action is required from customers around their basic service and where we offer personalized "packages" that customers can select from to meet their needs – similar to what customers experience when purchasing cable and internet services today. These packages may include options such as demand-side management, renewable energy, rate design, and non-energy services.



Figure 49: Customer Strategy Informed by Customer Expectations

Our implementation of the Advanced Distribution Management System in early 2020 is preparing the grid for increasing levels of DER. It is also paving the way for further grid advancement with Advanced Metering Infrastructure and our ability to leverage the underlying and necessary Field Area Network to reduce customers' energy costs

through Integrated Volt-Var Optimization, improve customers' reliability experience through Fault Location Isolation and Service Restoration, and more.

Customers will have access to granular energy usage data from our AMI through a customer portal, which we expect to pair with informed insights and helpful tips on how to change their behavior to save energy. Further, the AMI meters we propose include a Distributed Intelligence platform, which provides a computer in each customer's meter that will be able to "connect" usage information from the customer's appliances for further insights – and be updated with new software applications, much like customers can currently update their mobile devices with applications.



Figure 50: Customer Value through Lifecycle

During this transition to the advanced grid, we will take exceptional care of our customers to educate, inform, and ensure a smooth implementation. We are already developing processes that will ensure accurate, timely bills as customers change over to AMI. We are also developing dedicated, hands-on customer care processes that will provide our customers a single point of contact during implementation – and that will phase customer communications relative to our geographic deployment of AMI meter installation. Meter deployment and advanced meter capabilities will be phased in over the next several years, communications strategies, messages and tactics will be executed in three phases to match the customer journey.

Figure 51: Customer Communications Journey Phases



For example, our customer communications will begin pre-implementation to educate on the possibilities enabled by AMI, as well as customers' ability to opt-out of an AMI meter. As the AMI installation date gets closer, we will inform customers about what to expect with the AMI meter changeover at their homes or businesses. Finally, we will communicate post-AMI installation to reinforce early AMI messaging regarding possibilities and options – also providing practical steps to take advantage of the customer portal or other new or enhanced services available day one.

B. Customer Research

To develop the customer strategy, Xcel Energy committed to understanding customers' preferences, considerations, and thoughts regarding the benefits and value of an advanced grid investment. We gathered this information through primary research, such as focus groups and surveys. We also supplemented our research with information from secondary sources including the Smart Energy Consumer Collaborative, and GTM Research and other utilities' advanced grid plans.

Our key takeaways from these sources are as follows:

- Consumers care more about technology and enabling improvements than process. Safety and energy savings rated most highly.
- Addressing service interruptions are important to all customer classes. Improved reliability will allow the Company to focus more on other customer priorities.
- Customers expect that service interruptions will be less frequent in scope and duration.
- *Customers expect to receive detailed information from their utility.* They expect this information to be personal and frequent.
- *Customers expect more tools and information for them to make decisions about their energy usage.* Customers indicated more information allowed them to better identify opportunities and strategies to save energy and reduce their costs.
- Business customers have more awareness and familiarity with advanced rate designs. Residential customers expect the utility to provide them with rate comparison

tools and information about new rate designs.

- Building trust is a key component to unlocking value. Trust is best built by identifying solutions and showing results specific to the customers
- Customers expect that there will be a cost associated with the advanced meter but that the meter will also provide benefits over time.

We have incorporated customer feedback and insights into our customer transition and communication plans – and the work we are doing to develop new and enhanced products and services as enabled by the advanced grid.

C. Advanced Grid Initiative

Fundamentally, we must act to replace our current Automated Meter Reading (AMR) service to ensure we provide our customers with timely accurate bills; our current vendor is sun-setting its AMR technology in the mid-2020s. While this system has provided value to customers for many years through efficient meter reading, we have an opportunity now to seize AMI technologies that are becoming available to maximize value for our customers. As we deploy advanced grid infrastructure, platforms, and technologies we expect three outcomes: (1) a transformed customer experience, (2) improved core operations, and (3) facilitation of future capabilities, which we discuss below.

Transformed customer experience. Our planned advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. We will use this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications.

We will offer options that give customers greater convenience and control to save money, provide access to rates and billing options that suit their budgets and lifestyles, and provide more personalized and actionable communications. As our system more efficiently manages energy flows, we can save customers money by reducing line losses and conserving energy. Smarter meters will be the platform that enables smarter products and services and contributes to improved reliability for our customers. Our customers will have more information to make more effective decisions on their energy use.

We will know more about our customers and our grid – and we will use that information to make more effective recommendations and decisions and continually use new information to develop new solutions. This will serve to help keep our bills low, as customers save money through both their actions and ours. It will also help ensure that our transition to a carbon-free system occurs efficiently – and harnesses the vast potential of all energy resources, from utility-scale to local distributed generation.

Improved core operations and capabilities. Smarter networks will form the backbone of our operations, and our investments will more efficiently and effectively deliver the safe and reliable electricity that our customers expect. We will have the capability to communicate two ways with our meters and other grid devices, sending and receiving information over a secure and reliable network in near-real time.

Our current service is reliable; however, we need to continue to invest in new technologies to maintain performance in the top third of U.S. utilities, particularly as we deliver power from more diverse and distributed resources and as industry standards continue to improve. Our advanced grid investments provide the platform and capabilities to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics and automation.

Our systems will more efficiently and effectively restore power when outages do occur using automation without the need for human intervention. For those outages that cannot be restored through automation, our systems will be better at identifying where the outage is and what caused it – benefitting customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

Facilitation of future capabilities. The backbone of our investments will also support new developments in smart products and services; in the short term by supporting the display of more frequent energy usage data through the customer portal – and over the long term, allowing for the implementation of more advanced price signals. Designing for interoperability enables a cost-effective approach to technology investments and means we can extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion, which unlocks new offerings and benefits that build on one another. We have planned our advanced grid investments in a building block approach, starting with the foundational systems, in alignment with industry standards and frameworks. By doing so, we sequence the investments to yield the greatest near- and long-term customer value, while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

In planning our advanced grid initiative, we have considered the long-term potential of our ability to meet our obligations to serve and our customers' expectations and needs – ensuring we extract cost-effective value from our investments and remain nimble enough to react to a dynamically changing landscape. The principles we applied to our advanced grid planning include the ability to remotely update hardware and software, security and reliability, and flexible, standards-based service components. We are planning our grid advancement with the future in mind, and to provide both immediate and increasing value for our customers over the long-term.

We are on the forefront of many of the issues and changes underway in the industry and have developed our advanced grid initiative and our customer strategy to address them and harness value for our customers. In addition to transforming the customer experience, these foundational investments will allow us to advance our technical abilities to deliver reliable, safe, and resilient energy that customers value. These foundational investments also lay the groundwork for later years. The secure, resilient communication networks and controllable field devices deployed today through these investments will become more valuable in the future as additional sensors and customer technologies are integrated and coordinated.

Now is the time to modernize the interface where we connect directly with our customers – the distribution system. Technologies have evolved and matured; our peers have successfully implemented these technologies; and, the industry landscape is evolving. We must ensure our system has the necessary capabilities to meet our customers' expectations and needs – and, the flexibility to adapt to an uncertain future.

D. Conclusion

Xcel Energy's advanced grid initiative supports our vision of a customer experience where customers' needs and preferences are met and the customer effort level is low. We understand what our customers expect and will deliver on those expectations with a seamless experience that both improves their comfort and satisfaction while reducing costs and improving the efficiency of the entire system.

XI. DISTRIBUTED ENERGY RESOURCES

In this section, we provide the DER-related information specified in the IDP Order. As a point of reference, the IDP Order defines DER as follows:

Supply and demand side resources that can be used throughout an electric distribution

system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter. This definition for this filing may include, but is not limited to: distributed generation, energy storage, electric vehicles, demand side management, and energy efficiency.

Specifically, IDP Requirement Nos. 3.A.6, 3.A.17-25, and 3.A.31-33, which includes explanations regarding how DER is treated in load forecasts, present and forecasted DER levels, and DER scenario analysis.

A. DER Consideration in Load Forecasting

IDP Requirement 3.A.6 requires the following:

Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology.

We discuss how DER is factored into both the corporate load forecast and the distribution system planning forecasts below.

1. DER Treatment in the Corporate Load Forecast

The Company's corporate sales forecast relies on econometric models and other statistical techniques that relate our historical electric sales to demographic, economic and weather variables. We also make adjustments for known and measureable changes by large customers, and to incorporate the effects of our customers' energy efficiency, distributed generation solar PV adoption, and light-duty electric vehicles in the Residential sector. The resulting sales forecasts for each major customer class in each state across the Xcel Energy footprint are summed to derive a total system sales forecast.

The sales forecast is converted into energy requirements at the generator by adding energy losses (See Section 4 for a discussion regarding loss factor percentages). The system peak demand forecast is developed using a regression model that relates historical monthly base (uninterrupted) peak demand to energy requirements and weather. The median energy requirements forecast and normal peak-producing weather are used in the model to create the median base peak demand forecast. Distribution Planning compares their summed/bottom-up feeder level forecast to the overall peak demand forecast for reasonableness, as discussed in Section V above. a. Forecast Adjustments

After determining the base forecast, we develop net forecasts that include adjustments for future demand-side management programs, distributed solar behind-the-meter generation, and electric vehicles. We also account for the effects on the system peak demand forecast of our load management programs by subtracting expected load management amounts to derive a net peak demand forecast.

Demand-Side Management Programs. One important adjustment to the forecasts is the impact from our conservation improvement programs. The sales model implicitly accounts for some portion of changes in customer use due to conservation and other influences by basing projections of future consumption on past customer class energy consumption patterns. In addition, the regression model results for the residential and commercial and industrial classes and for system peak demand are reduced to account for the expected impacts of Company-sponsored DSM programs.

The DSM methodology for the states of Minnesota (and South Dakota) follows these distinct steps:

- Collect and calculate historical and current effects of DSM on observed sales and system peak demand.
- Project the forecast using observed data with the impact of DSM removed (i.e. increase historical sales and peak demand to show hypothetical case without DSM).
- Adjust the forecast to show the impact of all planned DSM in future years.
- Also adjust the forecast to account for codes and standards changes for lighting in the Residential and Business segment resulting in decreased sales that are in addition to company-sponsored DSM.

The Company-sponsored Minnesota DSM adjustments are based on the Company's July 1, 2019 Minnesota Resource Plan Bundles 1 and 2. Figure 52 graphically illustrates the DSM adjustment described above.



Figure 52: Illustrative DSM Adjustment

Distributed Solar PV. For distributed solar, we adjust the Minnesota class-level sales forecasts and the system peak demand forecast to account for the forecasted impacts of customer-sited behind-the-meter solar installations on the NSP System. Specifically, this adjustment is based on solar capacity targets consistent with 2017 solar-related legislative outcomes and program activity that includes but is not limited to the removal of the Made in Minnesota program after 2017, increased Solar*Rewards incentives funding for 2018-2020, and no Solar*Rewards program after 2021. Capacity targets also are included for net-metering only installations. Impacts of customer-sited behind-the-meter solar installations are extracted from this forecast to develop adjustments to reduce the class-level sales for Minnesota and the NSP System peak demand forecast. The sales and peak demand forecasts are not adjusted for community solar gardens or distribution-connected utility-scale solar because these do not affect customers' loads.

Electric Vehicles. The Residential sales and system peak demand forecasts are adjusted to account for the impact of light-duty electric vehicles. The EV forecast is developed
internally based on assumptions related to both adoption (energy) and charging behavior (demand) as described in Part C of this section. Inputs to the adoption model include electricity prices, vehicle battery prices, gasoline prices, car ownership, car usage, and efficiency. The charging behavior is estimated using representative datasets from Idaho National Lab's EV Project, combined with assumptions about the share of charging done at homes and the penetration of managed charging solutions.

Large Customer Adjustments. We may also make adjustments to the forecast to account for planned changes in production levels for large customers. For example, we may add sales and demand related to a customer's new incremental additional capacity that we become aware of. We may also make adjustments to reduce our requirements due to the scheduled installation of a customer-owned Combined Heat and Power generator.

b. Data Sources

MWh Sales and MW Peak Demand. Xcel Energy uses internal and external data to create its MWh sales and MW peak demand forecast.

Historical MWh Sales and MW Peak Demand. Historical MWh sales are taken from Xcel Energy's internal company records, fed by its billing system. Historical coincident net peak demand data is obtained through company records. The load management estimate is added to the net peak demand to derive the base peak demand used in the modeling process.

Weather Data. Weather data (dry bulb temperature and dew points) were collected from National Oceanic and Atmospheric Administration weather stations for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. The heating degree-days and THI degree-days are calculated internally based on this weather data. The Company uses a 20-year rolling average of weather conditions to define normal weather.

Economic and Demographic Data. Economic and demographic data is obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically they are accessed from IHS Markit data banks, and reflect the most recent values of those series at the time of modeling.

In terms of changes to our load forecasting methodology as it relates to DER, we starting incorporating distributed solar PV beginning in 2014, and in 2018 began including EVs.

2. DER Treatment in the Distribution Planning Load Forecast

As we discussed in the System Planning section above, we do not currently factor DER into the feeder-level forecasts we use for system planning purposes. However, these forecasts are rooted in historical actual peak information, so are reflective of energy efficiency and load management. Additionally, we validate our rolled-up feeder level forecasts against the corporate load forecast, which as described in Part 1 above, is adjusted for several types of DER. As we have noted, we are taking action to mature our DER planning capabilities through foundational advanced grid capabilities and implementation of the APT.

The good news in terms of DER integration – from a distribution planning perspective – is that Minnesota is presently at comparatively low levels of DER penetration that can reasonably be expected to remain stable in the near-term. At this time, the level of DER on our system and the historical rate of interconnections have not had a significant impact on our forecasts. This changed somewhat in the recent past as a result of the initial response to our CSG program. Long-term, we believe integrating various forecasts will be beneficial to our planning efforts, and the implementation of the APT is expected to facilitate this integration.

The APT will change and improve the way we incorporate DER into our load forecasts. Through forecast aggregation, the tool can apply forecasts for various DER adoption trends to the distribution load forecasting, allowing distribution planning understand the potential impact that DER adoption could have on the load forecast. These forecasts can also be disaggregated from the load forecast, to show how the native load on the distribution system is expected to change over time in the absence of DER.

The APT also provides the ability to conduct scenario analysis against the load forecast, where multiple forecasts can be developed that represent sensitivities in the forecast. For example, scenarios can be implemented in the forecast to account for different possible DER adoption trends – varying, as defined by the user, to represent higher rates of DER adoption, or lower rates of DER adoption over time.

The ability of the APT to aggregate DER forecasts into the load forecast, then run scenario analysis against those forecasts, will greatly expand distribution planning's understanding of the impact that DER has on the load forecast. Whereas today with our current tools we aren't able to factor DER impacts into our load forecast, the APT w will enable us to analyze DER impacts in a probabilistic nature that will better inform our risk analysis and project development processes.

While there are no definitive answers at this point as to how, and how fast enhanced planning for DER will occur, experts generally agree that a deliberate, staged approach to increased sophistication in planning analyses – commonly referred to as "walk, jog, run,"– is important. See Figure 53 below for one potential scenario for how the progression may occur.



Figure 53: Staged Approach to Enhanced Planning Analyses

(Source: ICF White Paper, The Value in Distributed Energy: It's all About Location, Location, Location by Steve Fine, Paul De Martini, Samir Succar, and Matt Robison. See <u>https://www.icf.com/resources/white-papers/2015/value-in-distributed-energy</u>.

We agree that a staged and measured approach to enhanced planning is necessary. The ICF report where the above phased approach was portrayed explains that the answer to how best to provide needed capabilities will depend on the stage of distribution system evolution in any particular utility and state, considering both the current stage of DER adoption, level of distribution grid modernization, and the desired policy objectives.

Numerous efforts from states, the DOE, and other organizations have used the customer driven Distribution System Evolution Framework shown below in Figure 54 to describe how the growth in DER adoption and related policies correspond to the distribution modernization capabilities required. Public policy varies on a stateby-state basis, and state policy is a key driver of DER adoption. Policies like net energy metering, renewable portfolio standards, or investment tax credits may make the adoption of DER technologies more financially-attractive and drive higher levels of penetration.⁵⁷ As policy evolves and penetration levels of DER increase, it will be important for distribution system capabilities to keep pace.

Various changes in both distribution planning and operations are needed in each stage to ensure reliable distribution operations – all resting on foundational elements that enable increased utility tools and information to be in place. It is important to note that Minnesota's DER penetration is substantially lower than other states, such as California, Hawaii, Arizona, and Colorado. Much of the recent and expected DER growth in Minnesota is from CSG. In considering the staged evolution portrayed in Figure 54 below, we believe Minnesota falls squarely into Stage 1 in terms of DER penetration, which the DOE further describes as grid modernization, focusing on "enhancing reliability, resilience and operational efficiency while addressing aging infrastructure replacement."



Figure 54: Distribution System Evolution (Source: DOE)

Source: See Modern Distribution Grid, Volume III: Decision Guide, Page 15, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

The investments that we are currently making in asset health and grid modernization, such as ADMS help to lay the foundation for continued resiliency and reliability. Near-term planned investments such as AMI, FLISR, and IVVO further cement it,

⁵⁷ These policies are described broadly as influential across the country and may apply to Minnesota in varying degrees.

and will allow the Company to gradually respond to increased DER penetration.

The DOE has also observed that U.S. utilities are in Stage 1 in terms of timing and pace toward a modern distribution grid. As shown below, DOE also incorporated evolving distribution planning processes and tools into this evolution. Stage 1 also includes improving foundational capabilities such as availability, quantity, and quality of data, which is often achieved by implementing communication systems such as the FAN that is in our near-term advanced grid plans.



Figure 55: Timing and Pace Considerations

Source: *Considerations for a Modern Distribution Grid*, Pacific Coast Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017). *See* U.S. DOE DSPx presentation - More Than Smart

Stage 1 is also focused on other foundational infrastructure we are intending to implement, including additional sensing, analytics, and automation capabilities such as the FLISR initiative we are proposing to implement beginning in 2021. According to this concept, Minnesota is with the rest of the industry sitting squarely in Stage 1, with DER integration analysis and planning occurring in Stage 2 after maturing foundational advanced grid capabilities.

Using these concepts as a base, we provide a snapshot of how we contemplate evolving our planning tools and process, applying to our tools, process steps, and actions as sophistication of analysis and processes increase over time as Table 48 below. We note that this Table is an extension of Tables 17-19 in the System Planning section above, which portrays our present planning tools.

		Current Process Steps		Future Planning Actions				ns			
	TOOLS	Forecast	Risk Analysis	Mitigation Plans	Budget Create	Design and Construct / EDP Memo	Long Range Plans	Interconnection Processing**	Scenario Planning	Integrated Resource Planning	Locational Net Benefit Analysis
	Synergi Electric		Х	Х			Х	Х			Х
	Distribution Asset Analysis*	X	X	-	-	-	_	_			
sl	MS Excel		Х		Х		Х				
t Too	СҮМСАР		Х								
urren	GIS			Х			Х	Х	Х		Х
Ū	SCADA	Х									Х
	Workbook (internal)		Х	Х	Х	Х					Х
	DRIVE***		Х	Х				Х			
ed	Advanced Planning Tool*	Х					Х	Х	Х	Х	X
pand: Tools	ADMS	Х							X		
ÉX	SAP					Х					

Table 48: Potential Planning Tools Evolution

* New Advanced Planning Tool replaces DAA and adds more functionality

** Planning has larger role in interconnection process

*** Hosting Capacity becomes integrated into planning process

Walk Jog Run

B. Current Levels of Distributed Resources

In this section, we present current DER volumes for the DER types specified in the IDP DER definition on our Minnesota distribution system, volumes in the interconnection queue, and discuss geographic dispersion.

1. Current and In-Queue DER Volumes

In Tables 49 and 50 below, we present the DER volumes on our Minnesota distribution system in compliance with IDP Requirement Nos. 3.A.17, 18, 19, 20, 23, 24, and 25

Table 49: Distribution-Connected Distributed Energy Resources – State of Minnesota

(As of July 2019)

	Completed Projects		Queue	d Projects
	MW/DC	# of Projects	MW/DC	# of Projects
Small Scale Solar PV				
Rooftop Solar	67	4,391	61	1,101
RDF Projects	19	25	1	2
Wind	16	61	<1	8
Storage/Batteries ⁵⁸	N/A	35	N/A	20

	Completed Projects		Queue	d Projects
	MW/AC	# of Projects	MW/AC	# of Projects
Large Scale Solar PV				
Community Solar	585	208	313	286
Grid Scale (Aurora)	100	16	0	0

Table 50: Minnesota Distributed Energy Resources – Demand Side Management and Electric Vehicles

	<u>Comple</u>	Completed Projects		d Projects
	Gen. MW	# of Projects	Gen. MW	# of Projects
Energy Efficiency	1,120	N/A	N/A	N/A
Demand Response	824	413,783	N/A	N/A
Electric Vehicles	N/A	7,081-8,500 ⁵⁹	N/A	N/A

For reference, below are the IDP requirements fulfilled in Tables 49 and 50 above:

IDP Requirement 3.A.17 requires the following:

⁵⁸ All current battery projects within our DER process are associated with other generation projects, such as solar. As such the application does not capture gen. MW as it is accounted for in other categories.

⁵⁹ We do not have information that ties our customer accounts to electric vehicle users. *See* IDP Requirement 3.A.21 below for the sources of this range.

Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).

The Company provides total DER interconnection as part of our Distribution Interconnection filing on March 1 of each year. For 2018, these details were provided in Docket No. E999/PR-19-10. Additionally, the Company provides several other tracking sources for this information in other annual reports such as the Solar*Rewards Community Annual Report (Docket No. E002/M-13-867), Solar*Rewards Annual Report (Docket No. E002/M-13-1015) and Solar Energy Standard Compliance (Docket No. E002/M-18-205) to name a few.

Each of these reporting dockets have differing requirements, details and timing, therefore leading to inconsistent numbers depending upon filing. In an effort to resolve these conflicts, the Company is working as part of the Commission's Distributed Generation Advisory Group to finalize an updated and consistent reporting process for DER generation systems as part of the present Distribution Interconnection filing on March 1st of each year.

For purposes of this IDP requirement, we provide the information in Tables 49 and 50 above.

IDP Requirement 3.A.18 requires the following:

Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).

The Company provides total DER interconnection as part of our Distribution Interconnection filing on March 1 of each year. For 2018, these details were provided in Docket No. E999/PR-19-10. Additionally, the Company provides several other tracking sources for this information in other annual reports such as the Solar*Rewards Community Annual Report (Docket No. E002/M-13-867), Solar*Rewards Annual Report (Docket No. E002/M-13-1015) and Solar Energy Standard Compliance (Docket No. E002/18-0205) to name a few.

Each of these reporting dockets have differing requirements, details and timing, therefore leading to inconsistent numbers depending upon filing. In an effort to resolve these conflicts, we are working as part of the Commission's Distributed Generation Advisory Group to finalize an updated and consistent reporting process

for DER generation systems as part of the Distribution Interconnection filing on March 1st of each year.

For purposes of this IDP requirement, we provide the information in Tables 49 and 50 above.

IDP Requirement 3.A.19 requires the following:

Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).

The Company provides information on the number of installed and pending DER generation systems as part of our Distribution Interconnection filing on March 1 of each year. In 2019, with data as of end-of-year 2018, this information was provided in Docket No. E999/PR-19-10. We clarify however, that we are not able to provide the distribution system location for current energy efficiency and DR. This is due in part to the types of DSM programs offered. For example, we do not track individual, residential customer purchases of high efficiency lighting. Also, our systems to administer DSM programs are separate from the systems that support the planning and operations of our distribution system. As we continue to evaluate enhanced distribution planning tools, we will gain a better understanding of the breadth of capabilities available and whether tracking of DSM by points on the distribution system for purposes of reporting is possible.

IDP Requirement 3.A.20 requires the following:

Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).

See Tables 49 and 50 above.

IDP Requirement 3.A.23 requires the following:

Number of units and MW/MWh ratings of battery storage.

See Table 49 above. Also, we provide information on the number of installed and pending DER generation systems as part of our Distribution Interconnection filing on March 1 of each year. In 2019, with data as of end-of-year 2018, this information was provided in Docket No. E999/PR-19-10.

IDP Requirement 3.A.24 requires the following:

MWh saving and peak demand reductions from EE program spending in previous year.

See Table 50 above.

IDP Requirement 3.A.25 requires the following:

Amount of controllable demand (in both MW and as a percentage of system peak).

See Table 50 above for the MW. In terms of percent of system peak, our 824 MW of DR in the state of Minnesota is approximately 12 percent of our Minnesota system peak of 6,800 MW.

2. Electric Vehicles and Charging Stations in Service Area

IDP Requirement 3.A.21 requires the following:

Total number of electric vehicles in service territory.

Customers are not required to inform the Company when they purchase an EV, and we do not maintain this information. Therefore, we must estimate EV ownership in our service area. We provide two such estimates below, and reflect the range of these two estimates in Table 50 above:

IHS Markit (2019). This zip code-level analysis suggests there is up to 8,500 electric vehicles in our Minnesota service area. However, utility service areas do not follow zip code boundaries, so there will always be some margin of error using zip code level information.

According to an analysis completed by Minnesota Commission Staff as part of the Commission's Inquiry into Electric Vehicle Charging and Infrastructure (Docket No. E999/CI-17-879), there are 7,081 vehicles in our Minnesota service territory.⁶⁰ Based on zip-code level data we procure,⁶¹ approximately 49 percent of vehicles are plug-in hybrids (PHEV) and 51 percent are battery EVs. This is comparable to the Minnesota Department of Transportation information on the Commission's website, with 52 percent of EVs in Minnesota attributed to battery EVs and 48 percent PHEV.⁶² Most EV adoption is concentrated in the Twin Cities metro area, but there is EV adoption in most of the zip codes we serve. Over the past year, we have seen

 ⁶⁰ Minnesota Public Utilities. Electric Vehicles. See <u>https://mn.gov/puc/energy/electric-vehicles/(</u>as of Oct. 24, 2019)

⁶¹ We procure this zip code-level data from IHS Markit.

⁶² See <u>http://www.dot.state.mn.us/sustainability/electric-vehicle-dashboard.html</u> (as of Oct. 25, 2019)

the introduction of some of the first larger EVs (medium- and heavy-duty) in our service territory with Metro Transit adding eight electric buses to their fleet.

IDP Requirement 3.A.22 requires the following: Total number and capacity of public electric vehicle charging stations.

According to the Department of Energy's Alternative Fuels Data Center, there are approximately 350 public EV chargers in Minnesota, with 869 charging ports.⁶³ We estimate that about 200 of those charging stations are in our service territory, with 500 charging ports. The estimated total capacity of all the public chargers in our service territory could be up to 9.5 MW, if all of the charging ports were in use at once. Given the relatively low load utilization of most public charging today, it is very unlikely that all, or even most, of the EV chargers will be used at one time. Additionally, the public charger installations are geographically diverse from a distribution system perspective. System impact would vary greatly based on the charging stations in use, the capacity of the charging stations, and the design of the local distribution system.

3. Current DER Deployment – Type, Size, and Geography

IDP Requirement 3.A.31 requires the following:

Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.).

The DER deployment in our Minnesota system by type and size is set out above in part 1. We provide associated geographic dispersion information and the number of installed and pending DER generation systems as part of our Distribution Interconnection filing on March 1 of each year. In 2019, with data as of end-of-year 2018, this information was provided in Docket No. E002/PR-19-10.

IDP Requirement 3.A.32 requires the following:

Information on areas of existing or forecasted high DER penetration. Include definition and rational for what the Company considers "high" DER penetration.

We are not able to forecast DER in terms of its expected geography. As we discuss

⁶³ See public online portal at <u>https://www.afdc.energy.gov/stations/#/find/nearest</u> (Accessed Oct. 27, 2019). We note that in our 2018 IDP, we inadvertently attributed this number to our service territory rather than for the state.

elsewhere in this IDP, tools to perform or services available to purchase forecasts such as this are very limited at this time. Additionally, due to the Company's costcausation regulatory construct that requires interconnecting parties to mitigate potential system issues prior to interconnecting, DER is not expected to impact system operation.

In terms of defining "high" DER penetration, we note that this is somewhat of a general term that will likely vary across utilities and the industry. We believe one way to define high DER penetration is when the connected DER output exceeds feeder load, resulting in reverse power flow. When backward flow occurs, mitigations become necessary.⁶⁴ Under this definition, the amount of DER considered to be "high penetration" would vary from feeder to feeder by, among other things, the type of DER, and how it operates, the feeder design, and the feeder voltage and other attributes.

C. DER Forecasting in the Industry

In this section, we discuss the state of the industry with respect to forecasting DER. We also address Order Point No. 7 of the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, which requires the Company to:

Make the development of enhanced ... DER forecasting capabilities...a priority in 2019 and include a detailed description of its progress in the Company's 2019 IDP.

In the industry, there are limited tools and experience predicting customer behavior and other key drivers of DER adoption at a system level. DER penetration analysis and forecasting at a granular *feeder* level for purposes of informing distribution planning is much more complex and likely less accurate than doing so at a system level. As we have discussed, system planning involves forecasting each feeder and each substation transformer, which for our system in Minnesota equates to approximately 1,700 individual forecasts. DER must be forecasted by type, because each type has different characteristics and impacts on the system. This exponentially complicates an already complex feeder-level planning process.

Regulators, utilities, stakeholders, service providers, and others are working to determine methodologies, processes, and tools that will meet the forecasting needs that are emerging in states such as California, New York, and Hawaii. The good news – from a distribution planning perspective – is that Minnesota is presently at

⁶⁴ Mitigations may be required for other conditions below this level, such as potential voltage issues or line capacity.

comparatively low levels of DER penetration that can reasonably be expected to remain stable in the near-term. Further, our present tariffs require interconnecting parties to mitigate adverse impacts identified in the interconnection application process. This means that we have time to take the measured approach that is necessary to properly address this issue – and develop or acquire the necessary capabilities, methodologies, and tools that will facilitate this type of complex analysis.

There are several existing models to predict DER adoption, using policy outcomes, macro-economic factors, or rooftop potential to predict DER adoption. However, a recent EPRI technical report notes several shortcomings of these models, including the challenges in making granular adoption forecasts for individual circuits, challenges verifying consumer behavior, and scarce information about the physical premises that impacts actual potential.⁶⁵

In short, it is challenging to predict which customers will adopt which technologies, and what the impact on the circuit associated with those customers will be. This is exacerbated in Minnesota with comparatively low adoption levels for PV, EV and energy storage. Predicting accurate forecasts for new and emerging technologies at a system level is challenging, based in part on the lack of good historical, predictable data inherent with a fledging market. At a circuit or feeder level this issue becomes more exacerbated and more unpredictable, as there are accuracy issues with forecasting at smaller geographic levels. In addition, there is not a significant sample size of historical installations on a circuit to use for trend analysis and forecasting.

We note that we are engaging a third-party consultant to benchmark our EV forecast assumptions, including adoption of medium- and heavy-duty electric vehicles in our service territory – and the charging infrastructure necessary to support EV adoption. We intend to share more EV forecasting information in our next Transportation Electrification Plan filing in No. E999/ CI-17-879.

We have made it a priority to enhance our forecasting capabilities. We now include DER in our bulk system forecasts, and as otherwise discussed in this IDP, we have evaluated and propose to implement a new advanced planning tool to identify more granular inputs and impacts of DER on feeder-level load forecasts. We also expect to evolve our forecasting capabilities over time to include new approaches such as scenario analysis and probabilistic planning.

⁶⁵ See Applying Discrete Choice Experiment Modeling to Photovoltaic Adoption Forecasting, Electric Power Research Institute, Palo Alto, CA, p. 13 (November 22, 2017). See <u>https://www.epri.com/#/pages/product/3002011011/?lang=en</u>

We intend to use our proposed advanced planning tool to understand the locational and temporal impacts of DER. Although more sophisticated planning tools can provide more forecasting granularity, the challenge of achieving a more geographically accurate forecast in an emerging market remains. Market adoption in an early adoption stage is less predictable, there is less historical information, and the dynamic and competitive nature of the market impacts local adoption trends. By taking a measured approach, we are able to learn from early adopters in the industry and in turn reduce long run implementation and integration costs. That said, we used our present tools and methodologies to inform the forecasts we provide in this IDP.

D. DER Forecasts and Methodologies

In this section, we present our forecasts for each DER type and summarize our forecast methodologies, which respond to IDP Requirement 3.C.1 as follows:

In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER growth take place first.

This section also responds to IDP Requirement 3.C.2, which requires the following:

Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.

Given the context we have portrayed, we have fulfilled these DER forecasting requirements to the best of our ability. In some cases, additional information such as studies to inform additional scenarios are outstanding at this time. We discuss each type of DER in turn below, providing our forecast, as well as the information that informed the forecast.

1. DER Forecast – Distributed Solar PV

We offer several programs to customers interested in solar as a renewable opportunity. Specifically we provide incentives under our Solar*Rewards program,

and the opportunity to earn bill credits for community solar gardens in our Solar*Rewards Community program. Until its discontinuance, customers also had the opportunity to participate in the Minnesota's Made in Minnesota program. In addition, for larger systems we offer a net-metering option. We have factored all of these distributed solar PV options into our Reference Case, Medium, and High distributed solar forecast.

a. Reference Case Assumptions

In determining our Reference Case, we updated our goals to be consistent with 2017 legislative outcomes that: (1) increased 2018-2020 Solar*Rewards incentive funding, (2) eliminated new Made in Minnesota awards after 2017, with final installations completed by October 2018, and 3) eliminated new Solar*Rewards systems after 2021, with final installations completed by 2023. We assumed net-metering only system additions would continue at current annual levels through 2021 and increase in 2022 to accommodate for demand from the elimination of the Solar*Rewards program in this scenario. We based attrition and completion lag rates on historical analysis of cancelled and completed projects, and applied these to program application forecasts to derive final installation estimates.

Due to the large response to our Solar*Rewards Community program, which has no statutory budget or capacity limit, we are forecasting additions of 729 MW through 2020 in this filing. For our Reference Case assumptions through the IDP planning period, we assume Solar*Rewards Community adjusts to approximately 5 MW per year after 2024 to account for significant early adoption of CSGs and reduction in tax benefits.

Table 51 below provides our Reference Case forecast of distributed solar PV additions.

Year	Solar* Rewards	Made in MN	Made in MN Bonus	Net- metering	S*R Community
<=2019	22	13	5	24	698
2020	6	0	0	13	31
2021	4	0	0	12	77
2022	2	0	0	13	34
2023	1	0	0	14	11
2024	0	0	0	15	6
2025	0	0	0	15	5
2026	0	0	0	15	5
2027	0	0	0	15	5
2028	0	0	0	15	5
2029	0	0	0	15	5
Total	35	13	5	165	884

Table 51: Reference Case – Per-Year Distributed Solar Additions (MW/AC)

b. Medium and High Forecasts

The Medium and High scenarios hold the Reference Case for Solar*Rewards and Made in Minnesota constant for the reasons discussed above. For net metering and CSG, we assume that customers that participate in solar programs would consider, in the majority of cases, that these programs are substitutes for each. Therefore the incremental growth in one category is interchangeable with another category.

We used the average of a Bass diffusion and a Payback model estimate to derive the Medium scenario, which is around 1,261 MW for total installed distributed solar by 2029. For the High scenario, we used a Payback adoption model with lower installation costs. We applied a 10 percent reduction to the solar installation cost curve starting in 2020. Solar installation costs in the High scenario are set to be higher for the first year due to new import tariffs and contracts already in place. Hence, there is a low probability that the solar installation prices will drop significantly below the Medium scenario for 2019. The adoption of solar is flat in the early 2020s, because the decline in solar installation cost is offset by the decline in Investment Tax Credit (ITC). The Payback model results indicate around 1,481 MW for total installed distributed solar by 2029.

We provide a tabular and graphical view of the forecast in the following table and figure.

	Total	Total	Total
	Base	Medium	High
	(MW)	(MW)	(MW)
2019	763	780	856
2020	813	818	946
2021	906	903	1,028
2022	955	946	1,061
2023	980	969	1,074
2024	1,001	992	1,160
2025	1,021	1,039	1,173
2026	1,041	1,073	1,291
2027	1,062	1,143	1,311
2028	1,082	1,195	1,456
2029	1,102	1,261	1,481

Table 52: Distributed Solar PV Forecast

Figure 56: Distributed Solar PV Forecast



2. DER Forecast – Distributed Wind Generation

We presently have very little distributed wind our system, with a total of 61 projects that comprise 16 MW, and eight projects in the queue comprising less than 1 MW. We believe future DER growth will primarily be through solar PV and distributed storage. We believe distributed wind will continue to be a very small proportion of DER on our distribution system, largely due to the rapid development of solar and storage markets – and their relative ease of adoption compared to wind. Additionally,

there is little information available in the industry regarding the adoption of distributed wind. For these reasons, we do not provide a forecast in conjunction with this IDP.

3. DER Forecast – Distributed Energy Storage

From January 2017 through July 2019 we received 55 interconnection applications to connect energy storage to our Minnesota electric distribution system. Of these 55 storage system applications, 35 are complete and in operation. The current total behind the meter battery storage installed on our Minnesota distribution system is approximately 0.35 MW. We provide an annual breakdown of storage applications received and completed below:

	Time Period	# of Applications	# Complete
ĺ	2017	18	17
	2018	25	17
	2019 (thru July)	12	1
ĺ	Total	55	35

Table 53:	Storage Applications - NSPM State of Minnesota
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In order to forecast distributed storage for our system, we utilize available data from various industry consulting firms that specialize in tracking current market conditions and forecasting trends. We have found that the availability of detailed market information on distributed energy storage is limited for the state of Minnesota. Wood Mackenzie however, currently publishes a quarterly report (U.S. Energy Storage Monitor), which provides high-level trends and forecasts that can be utilized to extrapolate a possible scenario for distributed energy storage within the Company's Minnesota electric distribution system.

For **Scenario 1** entitled "High," we utilized the actual completed energy storage units for NSP Minnesota in years 2017 and 2018 and then applied the forecasted forward growth rates as provided by Wood Mackenzie's most recent forecast for behind the meter storage additions. For **Scenario 2**, entitled "Mid," we utilized a growth rate forecast from Navigant Research's Global DER Overview that estimates a growth rate of 21.9 percent for distributed energy storage systems. The model extrapolates the current number of installations on the NSP Minnesota system at the Navigant projected rate of growth. We used one additional modeling technique to develop **Scenario 3** entitled "Low," which uses a time series analysis of the historical average rate of internal applications received for energy storage systems, as tracked by NSP Minnesota. This alternate scenario models the average number of applications received per month during 2017 and 2018 and then extrapolates a continued growth rate of monthly applications received through 2029.

Scenario 1 results in a cumulative total of 170 energy storage units deployed within the NSP Minnesota electric distribution system by the end of 2021, while the "Low" case estimates a cumulative total of 104 units deployed. Beyond 2021, the various scenarios begin to diverge until the end of the forecast period. In 2029, the respective forecasts indicate a cumulative total of 1,752 units (High) and 411 units (Low), as shown below.





Utilizing all scenarios in conjunction with an estimated average MW for each respective unit deployed, the total cumulative MW of distributed energy storage is not expected to exceed 12.0 MW by 2029.

Figure 58: NSP Distributed Storage Forecast – Minnesota 2019 – 2029 (total MW)



Due to the emergent state of distributed energy storage within Minnesota, we note that the various scenarios we have developed are sensitive to externalities such as policy changes (e.g., incentive changes), technology changes (e.g., improvements in existing battery technologies and new disruptive battery technologies), and possible geopolitical risks that could negatively impact the availability of raw materials.

4. DER Forecast – Energy Efficiency

Xcel Energy has one of the longest-running and most successful Demand Side Management programs in the country. Between 1990 and 2018, the Company spent \$1.5 billion (nominal) on Minnesota DSM efforts and saved over 9,700 GWh of energy and nearly 3,600 MW of demand. Our efforts to continuously grow and modify our customer offerings prove worthwhile as we continue to meet and exceed the state's 1.5 percent of retail sales energy savings target.

Energy Efficiency creates a permanently reduction at the customer meter and reduces the capacity need on the distribution system.

a. Forecast

Our Reference Case for Energy Efficiency is set at 1.5 percent of retail sales energy savings. The graph below shows historical and forecast energy efficiency annual achievements included in the forecast reference case.



Figure 59: Minnesota Energy Efficiency Forecast – Reference Case

b. Sensitivities

The Company has set forth goals in our 2020-2034 Upper Midwest Integrated Resource Plan (IRP) (Docket No. E002/19-368) to significantly increase our energy efficiency efforts. These efforts will be incremental to the 1.5 percent of retail sales energy savings. In the IRP, we began the development of additional DSM scenarios with the Minnesota Statewide Potential Study analysis conducted on behalf of the Department. The study was used as the primary input for the Company's energy efficiency potential from 2020 through 2034. This study was conducted at a state level and does not go down to individual feeder or customer area.

The Medium Scenario is an optimal view of the achievable potential identified in the Minnesota Statewide Potential Study at a cost effective level of achievement. This is the scenario we have defined as our forecast above which utilizes a 2.8 percent of retail sales energy savings (referred to the Optimal Scenario in the IRP). In addition, the Company did review a Higher Scenario (3.8 percent) or maximum achievable option. Each scenario was reviewed based on total system costs assuming achievement, expressed as both Present-Value of Revenue Requirements (PVRR) and

Present-Value of Societal Costs (PVSC). The Medium Scenario was determined to have the greatest cost savings under both metrics.⁶⁶ The graph below shows historical and forecast energy efficiency annual achievements from this Medium Scenario and compared to those included in the forecast reference case.

5. DER Forecast – Demand Response

We offer several customer programs to customers for controlling load during system peak. The Residential Demand Response program provides products such as Saver's Switch and AC Rewards; both of which provides equipment and participation incentives to residential customers for controlling their heating, ventilation and airconditioning load (HVAC). For commercial customers we offer Saver's Switch and our Electric Rate Savings program—both interruptible rates helping customers lower their load during utility initiated events.

a. Demand Response Forecast

We set forth in our 2020-2034 Upper Midwest Resource Plan (Docket No. E002/19-368) an increase of 400 MW of incremental demand response resources by 2023. This aggressive path forward is predicated on existing programs, additional interruptible programs and new technologies and non-traditional demand resources that encourage customer action and participation rather than just utility controlled resources, such as Saver's Switch. Our Reference Case for the IDP matches the IRP analysis providing an increased amount of additional demand response to the system.

⁶⁶ For further information please refer to the 2020-2034 Upper Midwest Resource Plan, Appendix G1.



Figure 60: Minnesota Demand Response Forecast – Demand Savings

b. Sensitivities

In determining the Reference Case, we review existing programs and forecast future participation including attrition and adjusted commitments. The Medium and High scenarios assume an increase in demand response beyond current programs. These scenarios are based on the cost-effective analysis by The Brattle Group (See the 2019 Potential Study Analysis conducted by The Brattle Group found in Appendix G2 of the Company's July 1, 2019 2020-2034 Upper Midwest IRP) comparing differing levels of demand response based on customer pricing. These scenarios are explained in more detail within our IRP.⁶⁷ We provide a graphical view of these scenarios below.

⁶⁷ These scenarios are represented in the IRP as Reference Case (Demand Response Forecast), Medium Scenario (Bundle 1) and High Scenario (Bundle 2). The IRP proposes the medium scenario.



Figure 61: Scenario Analysis (Gen MW)

Ultimately, the preferred plan utilized the first bundle (additional incremental load identified as cost-effective).

c. Demand Response Considerations in Distribution

As we begin to refine our forecasting opportunities with updated forecasting tools and software as well as future AMI technology, we will begin to be able to look at the load impact of demand response at more granular level. Today, without knowing the specific load shapes and comparing them to specific capacity constrained areas it is difficult to predict the impact to distribution. As these processes are refined we hope to be able to match the needed load to active demand response programs and/or develop programs that can further meet these needs.

While these software tools are being implemented, the Company continues to test opportunities for demand response at a feeder level within our Geo-targeting pilot. In addition, we are conducting research and interest in our existing demand response offerings to determine future program frequency and customer interest as events lengthen and move from events limited to summer months to events happening in all seasons.

We further continue our exploration of new technologies and opportunities to shift load rather than shed only during system peaks. As noted in the IRP, in order to further address these opportunities, which have a significant impact to distribution, the Company will need to continue to pursue advance metering technology and identify cost recovery mechanism for program opportunities.

6. DER Forecast – Electric Vehicles

With the increase of available models EV market adoption has increased in the U.S. to approximately 1.2 million as of June. 2019. At the same point there are approximately 10,000 EVs in the state of Minnesota, and the number continues to increase.

We currently estimate EV adoption using two modeling techniques: (1) Bass Technology Diffusion, and (2) Econometric models. Bass Diffusion models are used to describe various technology adoptions that penetrate an existing market through an "S" shaped diffusion characteristic. Econometric models use simple payback to estimate potential adoption and represent the second approach in modeling EV adoption.

We have estimated a low, medium, and high simple payback scenario for EV ownership compared to traditional internal combustion engine (ICE) automobiles. An average of the two models is used as an estimate of EVs. Our cumulative medium adoption estimate for year 2029 is approximately 4.4 percent of all registered cars and light trucks in that year.

Our current approach is based on state specific and Xcel Energy service area specific data and represents an improvement from our previous methodology and vintage of data used in both our 2018 IDP and our July 2019 IRP. The Bass Diffusion model is now calibrated using state specific historical EV sales as well as data through December 2018. Additionally, we have incorporated into both the Bass diffusion and econometric models a factor for the percentage of vehicles in urban and rural areas. Presently higher adoption is occurring in urban areas with the rural areas anticipated to ramp up slowly. The IDP reflects consumption of 128 GWh in 2023 compared to 165 GWh in the IRP. Our previous approach was based on national electric vehicle adoption, which was significantly influenced by much higher adoption in the state of California.⁶⁸

We create high and low econometric model scenarios using a combination of battery prices and gasoline prices. The high scenario assumes the battery prices are 20 percent lower than the medium scenario, and gasoline prices are higher by one standard deviation. Similarly the low scenario assumes battery prices are 20 percent

⁶⁸ Minnesota electric vehicle adoption is lagging the national trend.

higher than the medium scenario, and gasoline prices lower by one standard deviation. The high and low scenarios for the Bass Diffusion models are created using data from states that reflect high historical adoption rates for the high scenario, and low historical adoption rates for the low scenario.

We note that efficiency could be negatively impacted by road conditions as well as weather conditions; we assume gasoline cars have 27 miles per gallon. Currently, Minnesota has approximately 2.1 cars per household, which we assume to stay constant throughout the forecast period.

Analysis indicates that battery costs are the primary factor for higher EV prices. Main variables impacting adoption are available tax incentives, price differential between EV and ICE cars, and gasoline prices. Models and estimates are updated as new data becomes available and estimates can vary significantly. Since we are in the early stages of EV adoption, we expect our future estimates will be increasingly robust with additional data available every year.

Our estimates show significant volatility between various scenarios. The estimates are also sensitive to several externalities like policy changes (*e.g.*, incentive changes, cybersecurity requirements, carbon requirements), technology changes (*e.g.*, improvements in existing battery technologies and new disruptive battery technologies, autonomous vehicles, alternate technologies like fuel cell cars), geopolitical issues such as trade and tariff issues, availability of raw materials such as lithium and cobalt, and infrastructure availability.

Additionally, many of the inputs change frequently and could produce significant swings in the model outputs. As can be seen the range of high and low estimates is fairly large, reflective of the sensitivities, volatility and uncertainty associated with the estimates.



Figure 62: Cumulative EV Adoption Rate – NSP Minnesota Service Area









As we noted earlier in this section, we have engaged a third party consultant to benchmark our EV forecast assumptions, including adoption of medium- and heavyduty electric vehicles in our service territory and the charging infrastructure necessary to support EV adoption. We intend to share more EV forecasting information in our next Transportation Electrification Plan filing in No. E999/ CI-17-879.

E. DER Integration Considerations

IDP Requirement 3.C.3 requires the following:

Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.

1. Processes and Tools

Modernization of the distribution infrastructure, new planning approaches, and investment in foundational and advanced technologies are all necessary to manage increasingly complex distribution systems and to safely enable higher penetrations of DER. To achieve these levels it will require myriad solutions and complex integrations across several information technology platforms – or more simply, it will "take a village" of solutions. Through additional monitoring and data analytics, we will have more visibility into DER and its impact on the system. Through additional control and automation, we can better manage the complexities of more dynamic grid. With these improvements we can move toward integrating higher amounts of renewable energy than today's thresholds. The industry as a whole continues to learn about technologies and best practices that can integrate more DER and these findings are often shared across the industry. Several of the tools listed below are a part of our AGIS initiative – an initiative we embarked upon with DER integration as a key driver.

Interconnection Review._ Through our existing DER interconnection review process, we review each project for its impact on the grid. Each project is evaluated to determine impact on the grid during minimum load and other key periods. If system upgrades are required based on the DER impacts, the customer or developer will need to pay for the upgrades. In other cases, the customer may be required to adjust inverter settings on the DER system. As we approach higher levels, current interconnection reviews become increasingly complex and, without changes, overly burdensome and costly. We plan to continue to optimize this process and continue to examine how the situational awareness information provided by the Advanced Grid platform (specifically, more detailed information from AMI and the load flow model from ADMS) can inform our analysis and review process.

Hosting Capacity Analysis (HCA). HCA also serves as a valuable precursor to the interconnection process – helping customers or developers guide future installations. These studies that provide an indication of feeder capacity for DER will also help the Company identify trends from year-to-year. We make improvements to this analysis with each one we do and continuously strive to increase its value. For example, this year we have provided minimum daytime load information and increased the functionality of our public facing heat map. The improvements are a direct response to stakeholder feedback.

Planning Tools. As otherwise discussed in this IDP, we are planning to implement a new advanced planning tool that will allow us to perform more robust planning and scenario analyses of DER penetration at or below the feeder level. This capability is critical for our ability to accurately and efficiently perform the analysis needed to safely achieve the listed penetration levels.

The APT will provide us with the ability to aggregate DER adoption forecasts into the distribution load forecast, and conduct scenario analysis against those forecasts. Our baseline DER adoption forecasts will be integrated directly with hourly load forecasts, where the tool uses best-fit analyses to determine potential impact of DER at the

feeder level. The tool will also make it easier to develop DER scenario analysis that can be applied at this more granular level, and allow us to test different adoption scenarios within the tool. All of this functionality allows us to conduct DER scenario analyses more efficiently, and will help us better assess how different levels of DER may change peak loads and load shapes on specific feeders throughout the service area.

In providing distribution planning with an hourly-level load forecast that includes the impact of forecasted DER adoption, distribution planning will have the data that is necessary to adequately perform risk analysis and inform the capital budgeting process. The data produced by the APT will help distribution planning understand the relative limits for DER penetration on feeders before potential issues crop up. The advanced planning tool's assessment of DER impacts will be probabilistic in nature and thus unable to replace the need for the interconnection review process. However, it will work in conjunction with HCA to give distribution planning a better understanding of where in the distribution system, both at present and in the future, the ability to accommodate additional DER is constrained.

Monitoring and control. The Company's existing distribution operating tools are generally adequate to integrate DER at the levels listed above. But for certain situations, and for DER levels beyond the listed projections, greater monitoring and control will become essential. The ADMS system and its advanced applications are well situated to fill much of that need. And we note that a DERMS (Distributed Energy Resource Management System) will become essential as well. Along with the monitoring and control benefits of ADMS, the side-benefit of improved system data will help with the integration of DER. We have previously discussed the necessity for system data improvements for ADMS to operate properly, and note that these data improvements fill in certain gaps in our records (size, material, etc.), which will serve to expedite our planning and hosting capacity analysis work as well. The investments we have made in the ADMS are timely (going into production in Q2 2020) and necessary, affording the capability for the required granular system knowledge and operation. Through our change management efforts, we have modified and implemented processes to secure these benefits including operator interactions with the systems, equipment installation and maintenance, communications and security controls, to design and data integrity.

We also note the necessity to continue deploying SCADA to the substations that are not so equipped, and thus our long-term plans call for the installation of SCADA at 3-5 substations each year. These additions improve our planning processes by shortening the time to collect and verify data. Dynamic voltage control will become more essential at higher DER levels as well. IVVO will provide that capability. Investments in enabling control for IVVO on feeders with higher penetrations of DER will increase hosting capacity where voltage constraints may otherwise limit. In all cases, we note that due to the quantity and dynamic nature of DER, all control systems will need to operate in automated fashion, which is part of our design.

AMI, along with our FAN are tools that are also essential to achieving higher DER levels. AMI will provide insights into DER presence, transformer loading, and voltage levels. And using the new Distributed Intelligence platform we will attain deeper insights into both our own secondary system and the operation of DER. We will alter existing processes and develop new ones to leverage that information to the benefit of our customers. A few processes that will be impacted include hosting capacity analysis, voltage monitoring, and power quality inquiry. Communication capabilities are a core enabler. We need robust, secure communication paths for all interconnected utility and connected DER – and the Company's FAN is a key enabler, providing for AMI and our distributed monitoring and control. Of course the critical nature of such a system requires excellent monitoring and maintenance processes and tools, which we have designed into our AGIS proposal.

Additionally, we envision the integration of technologies that do not connect directly to our FAN, but through other paths. Such communication pathways must be securely integrated. One key to that effort is the development of industry standards and communication protocols, the development of which we support.

2. System Impacts and Benefits that May Arise from Increased DER Adoption

DER has the potential to both provide system benefits and negatively impact the system. Some of the potential benefits include:

- Reduction of Peak Power Requirements. Demand Response has been called upon for years to reduce peak, and will continue to be a valuable DER. Energy storage such as battery storage can be managed to discharge during peaks. And while DER such as EVs may in the future provide dispatchable storage, we note that it is imperative to manage charging so as to not increase system or distribution peaks.
- *Emergency source of power.* Standby generation generally benefits only one customer, and thus is generally considered to provide system benefits. But the technologies involved lend themselves to broader system benefits. Additional DER technologies such as battery storage provide new options to back-up power, and we are starting to see residential customers adopt this strategy. When PV is present, it can be combined with energy storage so that the combined system can provide power to some or all of the customer's load

during an outage. These capabilities can be expanded – for example, a microgrid could provide community resilience for critical facilities.

- *Manage local capacity constraints.* Typically the PV does not have a perfect coincidence with demand, but offsets load in the earlier hours of the peak. Also, left unmanaged, PV can create a new capacity constraint due to high solar production during low-load periods. Energy storage can help modify this pattern by charging and discharging during certain times of the day. Each feeder is somewhat unique and we study how DER can provide benefits as part of our non-wires alternatives analysis process, which today is on a limited number of feeders; with our proposed advanced planning tool and other enhanced capabilities, we will be able to perform this type of analysis much more broadly.
- Reduction of system power. Customer-sited PV offsets the overall system power requirements, which is something that is considered in the Value of Solar analysis.
- *Improvements in power quality.* PV and energy storage inverters have the potential to provide improved load factor locally.

We will continue to study these benefits as we conduct our non-wires alternative processes and other DER analysis scenarios. As DER costs come down and technology software platforms mature, we expect the opportunities in this area to continue to grow.

The below table summarizes the potential negative impacts of higher penetration of distributed PV.

Distribution Impact/Constraint	Constraint Description	Cause
Primary Over- Voltage	Steady-state primary side voltage exceeds nominal voltage.	Minimum daytime loading combined with maximum solar generation leads to less net load on feeder, thus leading to higher feeder voltage.
Primary Voltage Deviation	Voltage change that happens from no DER (specifically distributed PV) to full DER in aggregate.	Potentially due to cloud cover or weather related issues that caused DER to go from no output to full output and vice versa.
Regular Voltage Deviation	Change in bandwidth from no DER output to full DER output at a regulated node.	Potentially due to cloud cover or weather related issues that caused DER to go from no output to full output and vice versa.
Thermal Loading Constraints for Discharging DER	Due to specific element rating (e.g. conductors).	DER deployment at low-load feeders could lead to reverse power flow, thus violating ratings on existing elements such as conductors.
Additional Element Fault Current	Deviation in feeder fault currents.	With increased installations of Distributed PV, there will also be an increase in the fault current contribution from each PV system.
Breaker Relay Reduction of Reach	Deviation in breaker fault current	Distributed PV with voltage support functions has the potential to reduce its contribution to fault currents. This will cause inadequate breaker reach that could lead to losing visibility to remote feeder faults.
Reverse Power Flow	Element minimum loading	Minimum daytime loading combined with maximum solar generation leads to generation surpassing load at the local level, which could lead to reverse power flow back to the substation.

 Table 54:
 Potential Distribution System Impacts from Distributed Solar PV

EV Impacts - Although EV adoption is low in the NSP service area, EV charging

could potentially be "clustered" around specific feeders, e.g. downtown areas or specific residential neighborhoods. EV chargers would not only increase the load on a feeder but also would change the load shape on the feeder. The below charts are from a study performed by NREL using an aggregate of 200 sampled households for a sample week with two EV penetration levels – showing the total demand at a residential distribution transformer.⁶⁹





This study assumed an unmanaged charging situation, i.e. there are no coordinated charging events such as a time-of-use (TOU) rate. With uncoordinated or unmanaged

⁶⁹ See Impact of uncoordinated plug-in electric vehicle charging on residential power demand, Matteo Muratori, Nature Energy, March 2018

charging, there would be an increase in EV charging during peak times of the day which could lead to overloading issues on local distribution equipment such as transformers. There is a current EV Pilot Program in MN that monitors EV charging energy usage at participating customers home. These customers are also enrolled in the TOU rate program, where peak hours are from 3-8 p.m. and this incentivizes customers to charge at off-peak hours. As the pilot progresses we will continue to analyze customer usage and evaluate whether customers respond to price signals as anticipated.

Currently, charging times are under two hours which could lead to an opportunity to stagger the charging periods through the evening and early morning, thus preventing the second peak. This stagger charging could be performed via a rate mechanism or a price signal. There is also the option to directly control the charging behavior through the Electric Vehicle Supply Equipment (EVSE).

Aggregated and widespread solutions that are able to cut across various automotive vehicles and EVSE are still emerging. More advanced managed charging techniques involved active charging and vehicle-to-grid (V2G) technology. V2G allows bidirectional power transfer from the EV to the grid and vice versa and is still an emerging technology with utilities in California still working out the interconnection recommendations.⁷⁰

Active charging depends on utilities or third-party aggregators dispatching the charging schedules of EVs based on local grid conditions. However, this technology requires partnerships with third-party based EV aggregators (e.g. ChargePoint, eMotorWerks, etc.) to dispatch EV charging schedules as well has the availability of a robust communication network to the EV or EV charging stations. Various utilities (mainly in California) have had different managed charging EV programs ranging from passive charging techniques such as TOU rate to a more active charging techniques such as directly controlling the charging of EVs via the car chargers or through third-party aggregators.

Xcel Energy is currently working with NREL to model and analyze the impacts of higher penetrations levels of EV on the Minnesota distribution system. This project is part of a widespread DOE research in this area.⁷¹ The project will be modeling 15 feeders on the distribution system with varying higher adoption levels of EV's among

⁷⁰ See Rule 21 Working Group 3 Issue 23 for the California Public Utilities Commission

⁷¹ See DOE Announces \$80 Million invested in Advanced Vehicle Technologies Research,

https://www.energy.gov/articles/department-energy-announces-80-million-investment-advanced-vehicletechnologies-research, Sept 2018

each feeder. The NREL model will compare distribution impacts for both unmanaged and managed charging scenarios. The research project is underway, but currently results aren't available. We look forward to sharing these results when they are available, likely later in 2020.

Energy Efficiency and Demand Response – There are no negative impacts foreseen with energy efficiency and demand response initiatives. It is expected that demand response programs would be able to alleviate a portion of the system peak loads.

Distribution-Sized Energy Storage Systems – Energy storage systems are a valuable asset to grid reliability and efficiency especially with increasing penetrations of DER on the distribution grid. However, the amount of installations in Minnesota is still relatively low and the cost-effectiveness of front-of-the-meter utility installations depends highly on the operational and location of the energy storage systems.

Similar to the PV interconnection review, customer-connected energy storage system would be reviewed through our interconnection process for impacts on the system. The customer chooses how to operate these systems and as such, might not be designed explicitly to provide value to the distribution grid.

Energy storage systems are well suited for many applications, especially to aid in increasing PV hosting capacity on a distribution feeder as well as relieve local congestion issues that could potentially defer an upgrade to distribution equipment.

3. Potential Barriers to DER Integration

Minnesota has a cost-causation regulatory construct for DER, which requires the "cost causer" to pay the costs – shielding other customers from the costs. As such, individuals or developers proposing to interconnect DER to the system may incur costs for necessary system changes to accommodate the DER. Based on our regulatory requirements in our Section 10 tariff, the customer or developer who installs a system pays for the cost of any necessary upgrade or modification necessary for DER integration. In some cases the developer or customer chooses not to pursue the modification and the project does not move forward. This construct limits the amount of negative impacts that DER can cause on the distribution system, enabling the Company to continue to provide safe and reliable service. It also protects the majority of customers from incurring costs generated by a few.

That being said, the Company acknowledges there are situations that may pose barriers to DER integration. For example, there may be times when a customer with a small DER system could be assessed a disproportionate amount of expenses to
upgrade a neighborhood transformer because the customer installed the DER system after others in the neighborhood already had installed similar systems (and did not incur a charge to upgrade the transformer). Similarly, some customers could face disproportionate interconnection costs associated with reconductering a feeder, if they seek to install a DER system after other larger systems (e.g. community solar gardens) have done so on the same feeder. Finally, if a large customer on a feeder that also has DER systems on it were to close or move, the drop in demand could require studies and reconductering or other changes to avoid adverse reliability impacts for the customers connected to that feeder; at this time it is unclear who should pay those costs.

4. Types of System Upgrades that Might be Necessary to Accommodate DER at the Listed Penetration Levels

In general, with the medium and high case PV scenarios provided in the DER Forecasts Section, we believe the system impact would be low. One of the primary reasons we believe the impact would be low is because of the current levels of customer-sited PV we have with our Xcel Energy Colorado operations. At the end of 2018, Colorado had 400 MW of customer-sited PV on our system. Currently, on our Minnesota system, the amount of customer-sited PV is about 20 percent of the overall total PV on system; most of the current PV capacity is related to community solar gardens. Table 52, Distributed Solar Forecast shows our PV estimates in 2029 for the medium and high scenarios as 1,261 MW and 1,481 MW, respectively. If we project that 20 to 40 percent of the Total High (MW) will be customer-sited, then that would be about 300 to 400 MW – and we already have experience with these levels. As discussed in the Interconnection Process Section of Section XII, B.2, each DER project is reviewed individually for impact on the system.

As we have outlined in other areas of this report, we expect that AGIS upgrades will help provide additional real-time information about our system. This information will provide feedback about how PV is affecting our operations, and may influence the assumptions we make with planning processes and interconnection reviews regarding PV integration. As we note in the smart inverters discussion within this IDP, there are also some smart inverter adjustments that could be considered.

Table 55 below shows the traditional mitigation solutions we employ for common issues that occur due to DER penetration on the system. In some instances, combinations of these mitigations need to occur in order to add additional DER.

Category	Impacts	Mitigation		
Voltage	Overvoltage	Adjust DER power factor setting, reconductor		
	Voltage Deviation	Adjust DER power factor setting, reconductor		
	Equipment Voltage Deviation	Adjust DER power factor setting, adjust voltage regulation equipment settings (if applicable), or reconductor		
Loading	Thermal Limits	Reconductor, replace equipment		
Protection	Additional Element Fault Current	Adjust relay settings, replace relays, replace protective equipment		
	Breaker Relay Reduction of Reach	Adjust relay settings, replace relays, move or replace protective equipment		
	Sympathetic Breaker Relay Tripping	Adjust relay settings, replace relays, move or replace protective equipment		
	Unintentional Islanding	Installation of Voltage Supervisory Reclosing		

Table 55: Potential Mitigations for Common Constraints

F. DER Scenario Analysis and Integration Considerations

In this section, we discuss the state of DER scenario analysis and integration of distribution-connected DER in wholesale and regional markets.

1. DER Scenario Analysis

Scenario analysis helps us understand future DER use cases. For example, we could analyze higher adoption scenarios or analyze how DER could impact or provide benefits to a feeder or certain area of the feeder. We have described how the new advanced planning tool will help us mature our capabilities and analysis. We believe probabilistic analysis will be a critical aspect of incorporating DER into the distribution planning process, and that distribution planning will evolve to include:

- Historical and forecasted weather,
- Forecasted quantities and availability of DER
- Forecasted impacts of conservation and load control,
- Electric vehicle adoption,
- More granular forecasts, and hourly data rather than solely the peak load to the extent we have sufficient SCADA capabilities,
- Storage implications, and

• Inputs from an integrated energy supply/transmission/distribution planning process.

As we have described, the advanced planning tool will provide us with scenario analysis capabilities and will enable the use of multiple user-defined scenarios in developing the distribution load forecast. This will provide the distribution planning process with the insights needed to better understand the range of possible forecast outcomes and their impacts on the distribution system.

We believe that there could be some scenarios that apply to all utilities, like there are in IRPs. However, this issue is being addressed different ways nationally. The California Working Group on DER and Load Forecasting recommended different forecasting methodologies/scenarios be used between the utilities – but that common principles be followed:⁷²

- Use statistically appropriate, data-driven methodologies for each DER, customer segment, and level of disaggregation.
- Develop approaches to manage uncertainty associated with granular allocation of DER.
- Periodically re-assess the modeling approach for each DER as increased adoption leads to better data.
- Share best practices and leverage learning process to strive for continuous improvement both in forecasting and in using the forecasts for distribution planning.
- Integrate data from DER industry partners to enhance forecasting accuracy.

As we have discussed, the distribution planning process is rooted in specific forecasts of load densities at a feeder level – and the distribution system is our direct connection point with customers, does not have the same redundancy and back-up as exists at the transmission and energy supply level, and generally requires solutions within short timeframes. Distribution planning outcomes therefore generally require more immediate action than an IRP, for example, to ensure customer reliability. So, any changes we make in our planning processes will need to ensure our focus remains on ensuring the reliability of the system for our end use customers.

⁷² See <u>http://drpwg.org/wp-content/uploads/2017/04/Joint-IOU-Draft-Assumption-and-Framework-Document.pdf</u>

2. Expected DER Output and Generation Profiles

IDP Requirement 3.D.2 requires the Company to provide ...costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.).

For more robust scenario analyses on a feeder, DER generation profiles are helpful. With PV systems, we can refer both to our internal generation profiles developed from load research on our customer PV systems or utilize a public tool like National Renewable Energy Laboratory's (NREL) PV Watts tool. We have also made some assumptions on EV charging usage, and hope to obtain additional information through our residential EV service pilot program. We additionally have several enduse load shapes available through our DSM program. These energy efficiency load shapes are generally used to determine the avoided marginal energy benefits of various DR and energy efficiency achievements.⁷³

AMI deployment provides valuable data to develop and refine load shapes. Additionally, ADMS is able to generate load profiles using AMI interval data, a feature we will use to obtain more accurate ADMS solutions. Regardless, through AMI interval data we will be able to refine DER profiles.

3. Changes Occurring at the Federal Level

IDP Requirement 3.C.4 requires the following:

Include information on anticipated impacts from FERC Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM-18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations [RTO] and Independent System Operators [ISO]).

In our 2018 IDP we discussed Federal Energy Regulatory Commission (FERC) Order No. 841, which addresses two different levels of participation of storage resources in wholesale markets. We outline the rule requirements and summarize the Company's comments below, and note that there has been no further action on this since our last IDP.

⁷³ The Company's Conservation Improvement Program (CIP) Annual Status report shows the energy efficiency and incremental demand response achievements including load shape information.

First, the rule requires that RTOs and ISOs accommodate the various types of services that transmission-interconnected resources can provide, including transmission system support, energy, capacity and ancillary services. Xcel Energy Services Inc. (Xcel Energy) filed comments supporting these aspects of the proposed rule in the FERC rulemaking process in FERC Docket No. RM16-23 on behalf of Northern States Power Company, a Minnesota corporation (NSPM) and the other Xcel Energy Operating Companies⁷⁴ and is optimistic that expanded utilization of electric storage resources interconnected at transmission level will bring added value to customers and add security and reliability of the grid, though the pace of adoption of storage technology remains unclear.

While Xcel Energy supports FERC Order No. 841 as it relates to resources interconnected at transmission level, we have concerns about implementation of Order 841 as it relates to storage resources interconnected at distribution level.⁷⁵ Xcel Energy also has concerns about FERC's proposal in Docket No. RM18-9-000, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, which would expand the requirements of FERC Order No. 841 to all types of energy resources interconnected at distribution level.⁷⁶

Even at low penetration levels of DERs, FERC's expectation that storage resources and DERs be enabled to participate in wholesale RTO or ISO markets poses challenges for both utilities and their customers. The implications of these challenges become more significant at higher penetration levels. For example:

• *Metering.* Participation of distribution-interconnected storage resources raises the question about how metering will distinguish between charging for wholesale purposes as opposed to charging for retail usage in the case of dual-

https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14538803.

⁷⁵ XES filed a request rehearing of various aspects of FERC Order No. 841 as it relates to resources interconnected at distribution level. A copy of XES's request for rehearing is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14651369

⁷⁴ XES has participated in several FERC rulemaking dockets regarding participation of storage resources and DER in wholesale markets filing comments on behalf of all of the Xcel Energy Operating Companies, namely NSPM, Northern States Power Company, a Wisconsin corporation (NSPW), Public Service Company of Colorado (PSCo), and Southwestern Public Service Company (SPS). A copy of XES's comments filed in Docket No. RM16-23-000 and AD16-20-000 is available at this link:

⁷⁶ A copy of XES's comments in FERC Docket No. RM18-9-000 is available at this link: <u>https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14682284</u>. These comments largely capture input provided in XES's original comments in Docket Nos. RM16-23-000 and AD16-20-000 and XES's request for rehearing in those dockets. FERC declined to accept these comments into the record in Docket No. RM18-9-000 because FERC deemed they were duplicative.

use facilities. Charging for retail usage should be subject to state-regulated retail rates while charging for wholesale purposes would, under Order 841, be subject to FERC regulated wholesale rates. We are not aware of any metering arrangement that can distinguish between charging for wholesale purposes and charging for retail purposes in the case of a dual-use facility. It should be incumbent upon the resource owner to provide sufficient documentation to ensure that any dual-use resource can be metered in a manner that can distinguish between charging for retail use as opposed to charging for wholesale use. Otherwise, cost shifts to other retail customers will occur as a result of such a resource for what will ultimately be usage for a retail purpose.

- Distribution Operations. Distribution system operators (DSO) will need to have the capability to monitor activities of DERs in the wholesale market and potentially take action to curtail market sales if such sales will impair reliable distribution system operations. The need for such capabilities will increase as DER penetration increases. The mechanisms to manage these operations will require enhanced communications systems between the DSO, DER, and market operator; software that can monitor distribution system impacts and identify reliability issues and solutions; and additional operations personnel to effectively manage the impacts of DER participation in markets. Cost causation principles dictate that the DER owners and operators should be responsible for the costs associated with these enhancements because such costs would not be incurred "but for" the participation of DERs in wholesale markets. However, absent fairly significant DER penetration levels it is not clear how these costs can be effectively allocated and recovered. At low penetrations there will simply be an insufficient number of customers to bear the costs of these infrastructure upgrades. FERC has not proposed a mechanism to address this issue. In the meantime, distribution system operators will have to find ways to manage DER resource participation reliably, cost-effectively, and in a manner that does not shift costs to other customers.
- *Distribution system upgrades.* Existing distribution systems were not built to manage large outflows of energy that would be associated with market sales. Further, distribution systems are not as flexible as transmission systems and therefore are less able to effectively handle the types of system flows that will occur with DERs participating in markets. Distribution interconnection studies will be more complex and will identify potentially significant feeder and substation upgrades needed to enable market participation by DERs. The costs of such upgrades should be directly assigned to the DER causing such costs to be incurred.

• *Wholesale market issues.* In addition to the direct distribution-level impacts of DERs participating in markets, there are a variety of other issues that must be addressed at the wholesale market level. These issues include the ability to determine where individual DERs involved in an aggregation are located in order to ensure that resources are paid the appropriate nodal price, whether technology exists to effectively manage the state of charge of storage resources, and whether market software can effectively be deployed to manage large numbers of relatively small resources. Xcel Energy expects these issues to be addressed by FERC on rehearing of Order No. 841, through the final rule in FERC Docket No. RM18-9-000, or through appeals thereof.

The provisions of Order No. 841 regarding participation of distributioninterconnected storage resources in wholesale RTO markets have not been stayed pending rehearing. It was necessary for MISO to make a compliance filing with FERC by December 3, 2018, and MISO has a year thereafter to implement provisions of its compliance filing. MISO is actively working through its stakeholder process to develop its compliance filing.

MISO filed their compliance filing in December 2018 with the provisions regarding DERs as we laid out in our November 2018 IDP.⁷⁷ Subsequently, in their response to FERC's request for more information filed in April 2019, MISO updated their Distribution Connected Electric Storage Resource (ESR) form agreement to require an attestation from the ESR that all necessary metering and other arrangements are completed before they can participate as a DER ESR in MISO. The Company supported this revision. However, in that same filing, MISO requested a deferral of the effective date from December 3, 2019 to early 2021. MISO reasoned that their original system build and delivery plans were highly dependent upon the MISO Market System Enhancement project milestones and were altered by the lack of the Commission's acceptance of their Order 841 Compliance Filing by April 2019. MISO has suspended all work on ESR activities until a Commission Order on the deferral of

⁷⁷ Excerpt from 2018 IDP regarding key aspects of MISO's compliance filing: "One of the key aspects of MISO's compliance filing will be the relationship between MISO, the DER, and the applicable distribution system operator (DSO). After reviewing MISO's draft agreement with the DER, we have tentatively concluded that it may be appropriate to file a tariff at FERC that would address aspects of DER participation in wholesale markets. If the Company were to go forward with this concept, the tariff would address matters such as direct assignment of distribution system upgrade costs incurred due to DER participation in wholesale markets, the need for a DER to establish to the satisfaction of the utility that it has metering capability needed to ensure that it does not charge a storage resource at wholesale rates for retail usage, mechanisms to limit DER output to the extent that reliability of the distribution system operator to the DER's activities, and cost recovery for services provided by the distribution system operator to the DER."

the effective date is received. As of October 25, 2019, the Commission has not ruled on this request.

We plan to evaluate this issue further and take appropriate steps to move forward to ensure that DER participation in wholesale markets is not subsidized by other retail customers and that such participation is conducted in a manner that does not threaten reliability of the distribution system.

We provide additionally as Attachment I, an October 7, 2019 response to a FERC data request in FERC Docket RM-18-9-000 regarding MISO's policies and procedures that affect the interconnection of DER. Comments in response to MISO's filing are due to FERC on November 6, 2019.

Finally, we also provide a summary of relevant actions by FERC and MISO, and various entities' work on IEEE 1547-2018, which is a recently published DER interconnection and interoperability standard, as also provided in our biennial transmission projects report, filed concurrently with this IDP.

Federal Energy Regulatory Commission (FERC)

FERC Order No. 841, which was issued in February 2018, amended FERC regulations to remove barriers to the participation of electric storage resources in the capacity, energy, and ancillary service markets operates by regional transmission organizations and independent system operators by requiring RTOs and ISOs to revise its tariff to recognize the physical and operational characteristics of electric storage resources and facilitate their participation in markets. FERC has received requests to consider similar rules for DERs. In May 2018, FERC held a two day technical conference on DERs. There are two ongoing FERC dockets related to DERs. The first is Docket No. RM18-9, which relates to the Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, and is a continuation of the rulemaking FERC originally commenced in Docket No. RM16-23. The second is Docket No. AD18-10, which relates to Distributed Energy Resource – Technical Considerations for the Bulk Power System.

MISO

According to its website, MISO has noted that "[a] high penetration of Distributed Energy Resources (DERs) could have notable implications for MISO and require a stronger transmission and distribution interface. The DER issue [in the MISO stakeholder process] is intended to explore, and advance collaboratively developed DER priorities with stakeholders." To that end, MISO has been hosting a series of workshops on DERs throughout the year. MISO is currently working with the Organization of MISO States (OMS) and other MISO stakeholders to develop a DER participation model that accounts for the distinctive characteristics of the MISO region and promotes reliability on a least cost basis.

Institute of Electrical and Electronics Engineers (IEEE)

Another important aspect related to distributed energy resources and distribution planning is various entities' work on IEEE 1547-2018, which is a recently published distributed energy resources (DER) interconnection and interoperability standard.

The revised standard addresses three new broad types of capabilities for DER: local grid support functions; response to abnormal grid conditions; and exchange of information with the DER for operational purposes. The standard was written with a large set of required capabilities with an expectation that not all capabilities would be immediately implemented in the field. In this way, it offers options for grid operators preparing for scenarios with high penetration of DER. Some details associated with implementing the standard are part of the Commission's E002/M-16-521 docket, especially in Phase II which considers statewide technical standards, and other details are expected to be associated with Xcel Energy's business practice decisions.

In terms of specifying DER response to abnormal grid conditions, IEEE 1547 indicates that the Authority Governing Interconnection Requirements and Regional Reliability Coordinator possess a guidance role in implementing these capabilities, which, in Minnesota, are the Minnesota Commission and MISO respectively. Commission Staff requested information and guidance from MISO through a working group associated with the E002/M-16-521 docket. The response from MISO included a plan to convene a stakeholder group so that guidance on the topic could be provided on a regional basis. The Commission's interest in resolving questions associated with adopting these capabilities is helping to drive important stakeholder conversations.

Local grid support functions have generated interest in the industry in recent years based on implementation of these functions in states such as Hawaii and California in areas of high DER deployment. The IEEE 1547-2018 standard allows a utility to specify how local grid support functions are used. Xcel Energy proposed in the E002/M-16-521 docket that use of the local grid support functions should be published in utility-specific technical manuals.

The interoperability aspects of IEEE 1547-2018, which include concepts of DER monitoring and control, mark the most future-leaning required capabilities. When certified equipment is available, every DER will have a standardized communication interface for exchanging data and performing remote operations. A communication

network would be necessary for making use of the interoperability interface.

XII. HOSTING CAPACITY, SYSTEM INTERCONNECTION, AND ADVANCED INVERTERS/IEEE 1547

In this Section, we summarize our hosting capacity analysis (HCA) in the context of our overall interconnection processes and how we have evolved our HCA. In part B, we generally discuss our interconnection processes and provide interconnection statistics. In Part C, we discuss advanced inverter functionality and recent changes associated with IEEE 1547.

A. Hosting Capacity

IDP Requirement 3.B.1 requires the following:

Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems), how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which Xcel anticipates customer benefit stemming from the annual HCA.

Xcel Energy recognizes hosting capacity as a key element in the future of distribution system planning. We anticipate it has the potential to further enable DER integration by guiding future installations and identifying areas of constraint. In compliance with Minn. Stat. § 216B.2425 and by order of the Commission, we conducted and submitted annual hosting capacity studies in 2016, 2017, and 2018.⁷⁸ We will submit our latest HCA study on November 1, 2019 concurrently with this IDP. These studies provide hosting capacity results by feeder serve three purposes: (1) provide an indication of distribution feeder capacity for DER, (2) streamline interconnection studies, and (3) inform annual long-term distribution planning.⁷⁹

On December 1, 2016 we submitted the results of our first hosting capacity study in Docket No. E002/M-15-962. We used the EPRI DRIVE tool for our analysis. EPRI defines hosting capacity as the amount of DER that can be accommodated on the

⁷⁸ See Distribution System Study, Docket No. E002/M-15-962 (December 1, 2016), Hosting Capacity Report, Docket No. E002/M-17-777 (November 1, 2017) and Hosting Capacity Report, Docket No. E002/M-18-684 (November 1, 2018).

⁷⁹ See Integrated Distribution Planning Report Prepared for the Minnesota Public Utilities Commission, ICF International (August 2016).

existing system without adversely impacting power quality or reliability – and introduced the DRIVE tool as a means to automate and streamline hosting capacity analysis. The analysis is based on EPRI's streamlined hosting capacity method, which incorporates years of detailed hosting capacity analysis by EPRI in order to screen for voltage, thermal, and protection impacts from DER. Using the actual Company feeder characteristics, DRIVE considers a range of DER sizes and locations in order to determine the minimum and maximum range of hosting capacity. The electric system's hosting capacity is mainly impacted by DER location and system characteristics.



Figure 66: Balancing Speed and Accuracy in Analysis

As indicated by Figure 66 above, EPRI's method is intended to strike a balance between speed and accuracy. While it does not replace a detailed analysis, it provides more value than a traditional interconnection screening, such as the criteria found in the FERC Small Generator Interconnection Procedure. The result is a more complete and efficient way to understand a feeder's ability to integrate new DER, which includes PV and energy storage, at multiple points on the distribution system

For our hosting capacity analysis, we created over 1,000 feeder models in our Synergi Electric tool. The information for these models primarily came from our GIS, but was supplemented with data from our 2018 load forecast – as well as actual customer demand and energy data. Once the models were verified, load was allocated to the feeders based on demand data and customer energy usage – and analyzed using the DRIVE tool.

Generally, it is challenging to fully predict where future DER will be located – even with an interconnection queue. For instance, a large PV interconnection may be required to make some line upgrades to accommodate the proposed generation. The line upgrades and configuration changes for that interconnection are not reflected in our GIS until the design and construction phases are complete. This means that those system modifications do not enter GIS and subsequently the feeder models in a timeframe that is well-suited for forecasting accurate hosting capacity results. Through engaging with our customers and stakeholders, learning from other utilities around the country, and leveraging our partnership with EPRI, we have made notable improvements from our initial hosting capacity analysis in 2016. These improvements include:

- Presenting results as heat-map visual with additional data contained in pop-ups for specific locations, in addition to tabular results
- Including existing DER into the analysis
- Adopting a simplified methodology (IEEE-1453) to determine voltage fluctuation thresholds
- Application of Reverse Power Flow and Unintentional Islanding Thresholds to better align with the criteria we use in the interconnection process.
- Adjustment of Voltage Deviation Threshold to better align with how we perform interconnection studies
- Using a methodology for large centralized generators to more accurately reflect the characteristics of DER deployment most commonly seen in Minnesota and associated with programs such as Solar*Rewards Community
- Refining our hosting capacity tool to include advanced inverter settings for fixed power factor (discussed in more detail in the IEEE-1547 section below)
- Including energy storage that is acting as a source of power
- Excluding back-up DER to improve the accuracy of hosting capacity results by analyzing of only those systems that are operating in grid-connected mode
- Modifying breaker reduction of reach thresholds to strike an appropriate balance between identifying areas where system protection impacts require closer review while not masking other limiting factors
- Use of actual Daytime Minimum Loads for approximately 25 percent of our feeders
- Use of actual feeder power factors on the vast majority of our feeders
- Developing guidance on mitigations costs, including a detailed analysis for feeders with zero hosting capacity

As EPRI continues to enhance the DRIVE tool, and we continue to refine our use of DRIVE for the Minnesota HCA, we will continue to improve our HCA results – including the report we are submitting in a separate docket November 1, 2019.

Furthermore, we anticipate the near-term advanced grid investments we outline in this IDP will provide enhanced system visibility to improve the data inputs and the analytical tools to further refine the analysis output. Additionally, in the longer term, investments like more advanced control schemes coordinating action with smart inverters and utility devices will improve the hosting capacity of circuits with voltage threshold constraints.

Hosting capacity analysis also serves as a valuable input prior to the interconnection process, helping customers or developers gather information about a location before an application is submitted. Interconnection studies are necessary to ensure the proposed generator can safely interconnect without adversely impacting electric delivery to surrounding customers and at what cost. With better data inputs and more analytical tools available to distribution engineers, we will be able to more efficiently respond to interconnection study requests and streamline the process for interconnecting customers. The interconnection process and associated studies will make use of the latest in technology and standards, such as IEEE-1547-2018, discussed in further detail in the section below and align with applicable regulatory guidance developed in the Interconnection and Operation of Distributed Generation Facilities proceeding (Docket No. E999/CI-16-521).

B. System Interconnections

In this section, we provide Company cost and customer charge information associated with interconnections on our distribution system. We also provide other information about the interconnection process as specified in the IDP requirements.

1. Company Costs and Customer Charges Associated with DER Generation Installations

The information we provide below fulfills the following IDP requirements:

IDP Requirement 3.A.15 requires the following:

Total costs spent on DER generation installation in the prior year. These costs should be broken down by category in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc).

IDP Requirement 3.A.16 requires the following:

Total charges to customers/member installers for DER generation installations, in the prior year. These charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.).

IDP Requirement 3.A.27 requires the following:

All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g., CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation).

We calculate our actual DER costs on a project basis and perform this calculation at the time we charge this actual cost to the DER customer. This occurs after the DER is interconnected to our network. Large projects, such as community solar gardens, may straddle more than one calendar year. This means that when we calculate the costs for a given project, the calculated costs typically include costs from prior calendar years. Similarly, if a bill for a given project under construction is not issued in a given calendar year then our tracked and reported costs will not reflect these costs until we issue a bill.

Beginning on June 17, 2019, we began following the Minnesota Distribution Interconnection Process as approved by the Minnesota Public Utilities Commission (Docket No. E002/M-16-521). This process requires the Company to track DER installation costs for substation and distribution levels for all DER customers. We began collecting this data in 2019. We do not have a full data set to provide under these conditions for historical DER projects as it would take a significant amount of time and resources to gather this information. However, we have calculated costs at a substation and distribution level for all community solar gardens (Docket No.E002/M-13-867) and can report on the DER costs for community solar garden projects as shown in bills sent in a calendar year. In 2018, the Company billed Community Solar Garden projects \$12 million dollars in substation costs and \$32.5 million dollars in distribution costs for an approximate total of \$44.5 million dollars.

In addition to this, we separately charge an engineering study fee for all DER interconnections. In 2018, these fees totaled approximately \$3,361,600. Our administrated fee for administering the analysis of DER generation applications in addition to the customer fees was approximately \$565,000. For the sake of clarity, the information we provide for 3.A.15 is only Xcel Energy costs. Where a customer has provided the Company information on its costs to install the generation system, we report this in our annual DG interconnection filing each March 1 in the "xx-10"

Docket.⁸⁰

We provide further detail for regarding our other programs and the compliance filings completed yearly below.

Solar*Rewards Community - Docket No. E002/M-13-867

- Annual Report filed by April 1 every year (2018 Annual Report filed on April 1, 2019).
- *Deposits*: In 2018, we received \$11.4 million for new projects into our deposit accounts and refunded \$35 million, including any deposit that the Company was holding that the Garden Operator moved to escrow.
- Application Fees: The Company collected a total of \$224,400 in application fees.
- *Participation Fees*: Annual participation fees were \$84,000.
- *Metering Fees*: The Company administers metering charges for single-phase projects at \$5.50 per month and for three-phase projects at \$8.00 per month. These monthly metering fees are specified in the Section 9 Tariff, Sheet 75 and are consistent with previously approved metering charges for the A51 tariffed rate.

Solar*Rewards - Docket No. E002/M-13-1015

- Annual Report filed by June 1 every year (2018 Annual Report filed on May 31, 2019).
- Engineering Fees administered in 2018: \$171,250

For future DER applications that will be subject to the MN DIP, we will begin to collect additional data at a more detailed level such as the inclusion of specific engineering fees by interconnection process.

2. Interconnection Process

In this section, we generally discuss our interconnection process and respond to IDP requirement 3.B.2 regarding data sources and methodology to complete the initial

⁸⁰ See, for example, Docket No. E999/PR-18-10, available at this link:

https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=viewDocument&docu mentId={C079E361-0000-C21F-8058-219C34801664}&documentTitle=20183-140701-02&userType=public

review screens in the MN DIP process.

The determination of exactly where and how much DER can be added to our system is determined through the interconnection process. Our annual HCA study has the potential to streamline the interconnection process both in the short- and longerterm. Today, the hosting capacity results are available to the public and can assist developers in choosing sites that require only screening or a less involved study. Screening is less expensive than engineering studies and typically can be completed on a shorter timeline.

Figure 67 below shows how the different components of our interconnection process currently works. The lower cost and complexity options of hosting capacity and preapplication data provide information developers information they can use to target points on the distribution system for interconnection prior to submitting an application. The screening and study processes occur after an application has been submitted and entered into engineering review.



Figure 67: Interconnection Processes

IDP Requirement 3.B.1 requires the following:

Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process.

MN DIP initial review screens use simple analysis with assumptions or readily available data to determine if a project requires further analysis due to the potential for grid impacts. The ten MN DIP initial review screens must be applied in concert to determine if a project has needs further analysis on voltage, thermal, or protection impacts. A few of the screens are related to the proposed DER being located in the Company's service territory and of a compatible wiring configuration. The specific initial review screen(s) that fail can inform more targeted analysis for the specific impact (i.e. voltage constraints). For example, one initial review screen states that the aggregate DER shall not exceed 15 percent of the peak annual loading on a given line segment. This screen approximates when reverse power flow may occur – a condition necessitating further analysis for steady state voltage rise and voltage fluctuation. For failure of any screens, the next level of analysis is performed in the MN DIP supplemental review process.

The MN DIP initial review screening methodology is relatively simple analysis that we implement in part through a spreadsheet tool. Other screens that check qualitative aspects of the interconnection are performed through review of application documentation. The initial review screens use system data and load characteristics available through a number of Company systems. We use our Geospatial Information System (GIS) to determine if the interconnection is within the Company's service area. GIS also assists in determining the aggregate amount of generation on a segment of interest. Feeder maps or GIS can be used to determine the presence of a voltage regulator, which is a relevant factor in one screen. Peak load information is retrieved from our DAA system, which we also use for system planning. Fault current can be retrieved by the OMS or a spreadsheet analysis tool.

C. Advanced Inverter and IEEE 1547 Considerations and Implications

In this section, we begin with general discussion regarding inverter advancements, then address IDP Requirements 3.A.7 and 3.A.33, as follows:

IDP Requirement 3.A.7

Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities and constraints related to interoperability and advanced inverter functionality).

IDP Requirement 3.A.33

Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.

Finally, we discuss our view of the impact of IEEE Std. 1547-2018 on interconnection standards/processes.

1. Inverter Advancements

Advancements in inverters can be utilized as one measure to reduce system impacts from PV and other inverter-based DER. A revision to the standard governing of the interconnection of DER with electric power systems (IEEE 1547) was published in April 2018.⁸¹ The standard provides requirements on the performance, operation, testing of the interconnection and interoperability interfaces of DER. This revision includes several new requirements that address the technical capabilities associated with smart inverters and considerations necessary for the proliferation of DER on distribution systems, such as the ability to keep DER online – 'ride-through' – during abnormal conditions, controlling real power, and regulating reactive voltage. Furthermore, the latest revision of the standard specifies interoperability requirements, a design consideration in all of our advanced grid investments.

Currently, smart inverters that are compliant with and certified to the new standard are not available, but will be required by statewide technical requirements when available. The standard for test and conformance procedures necessary to certify inverters, IEEE 1547.1 is under development. Once available, Underwriters Laboratory will develop their testing certification standard (UL 1741). Once the inverter certification standard is available, equipment manufacturers will require time to change product lines. While the timeframe for standards development activities is fluid, we anticipate compliant and certified equipment will be available in or after the year 2020 or 2021.

An early step will be to adopt well-understood and in-use functions like fixed power factor, which are in use today and offer many of the benefits of the revised standard's functions. A recent EPRI study on a modeled radial distribution feeder with a large (almost 2 MW) solar system concludes that fixed power factor control resolves almost all voltage violations and that "modest control of reactive power can significantly reduce the voltage rise from the generator"⁸² This is particularly important in Minnesota for the CSG large distributed generation systems, which are often deployed in remote areas where maintaining adequate voltage can be more challenging due to smaller conductor and a lower system strength.

Fortunately, we will have the opportunity to learn from peer utilities in states such as

⁸¹ See IEEE Publishes Standard Revision for Interconnection and Interoperability of Distributed Energy Resources (DER) with Associated Electric Power Systems Interfaces, Piscataway, NJ (April 2018). http://standards.ieee.org/news/2018/ieee 1547-2018 standard revision.html

⁸² See Voltage Regulation Support from Smart Inverters, Electric Power Research Institute, Palo Alto, CA, Page 8 (December 2017).

Hawaii and California, who have greater DER penetration levels. Since 2014, California has required smart inverters with seven autonomous functions, including both fixed power factors and dynamic Volt-VAr operation; however, even though inverters were installed with advanced capabilities, the use of these functions is being phased deliberately to confirm the various functions work as modeled.⁸³

There are commercially-available inverters that meet this advanced functionality based on California rules without being certified to the IEEE 1547-2018 standard. As we learn more about the capabilities of inverters that are IEEE 1547-certified – or that meet California's standards – and we phase-in the investments of our advanced grid roadmap, we will be able to advance our related capabilities over time. Our stepped approach begins primarily with managing inverters to a fixed power factor – and as they become available, adopting the standard settings for Volt-Var and Volt-Watt operations based on industry recommendations and experience. The inverters will inherently have "ride-through" capabilities that in aggregate will prevent contributing to grid instability during a short-term transmission or generation event. Looking ahead, as we develop our modeling and simulation capabilities and phase in our investments, we will be able to evaluate more updated inverter capabilities and evaluate the benefits.

2. Planning Considerations Associated with IEEE 1547-2018

IDP Requirement 3.A.7 requires the following:

Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities and constraints related to interoperability and advanced inverter functionality).

Advanced functions offer additional capabilities from the DER side to mitigate the impacts of the interconnected DER. While modeling and simulation tools for distribution planning are evolving to include these functions, the impacts, study practices, and requirements of how to implement and use these while protecting grid integrity (i.e. safety and reliability) and generation with queue priority, still need to be developed.

The standard IEEE 1547-2018 scope is focused on the interconnection and interoperability requirements for DER. These requirements are specified through

⁸³ See Interim Decision Adopting Revisions to Electric Tariff Rule 21 FOR Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company to Require "Smart" Inverters, Decision 14-12-035, Rulemaking 11-09-011, Page 4 (December 2014).

standard interfaces for both power and communications for the purpose of integrating DER into safe and reliable grid operations. A degree of optionality exists in the standard for advanced functions and capabilities. For example, the standard required DER be capable of a producing or consuming a range of reactive power, while it also specifies the default setting use of reactive power.

Distribution System Planning considerations including integrating DER into capacity expansion plans and grid support functions required by IEEE 1547-2018 may provide additional tools to mitigate voltage conditions caused by DER. It is important that the standard requires DER equipment be capable of providing a range of reactive power control for the lifetime of the DER as it provides necessary future proofing for mitigating voltage issues due to changes in system configuration or other anticipated changes to grid conditions. The Company currently uses a non-unity fixed power factor approach for mitigating DER caused voltage issues and reserves a power factor range of +/-0.9 in operating agreements. While the reactive power range in use today aligns with IEEE 1547-2018, the standard offers additional control modes. The Company is evaluating the use of other real and reactive power control modes to determine benefits, drawbacks, and most suitable use of each.

In order for the advanced function to be fully integrated into distribution planning processes, the appropriate study practices and requirements must evolve to incorporate advanced functions. Because of the active response of advanced inverter function study methodologies need to move to time series analysis to fully understand their impact on the system. For example, an inverter volt-var function can interact with utility voltage regulation equipment since both have a time element to their control logic. This type of interaction could create a reliability issue due to voltage regulation equipment failing prior to end of life. We are tracking the progress of industry modeling tools that incorporate advanced inverter functions and how they are being used and studied. While we do not anticipate the advanced functions to lead to a substantial increase in hosting capacity when compared to current approach, they do offer the potential for increasing the efficiency of power delivery on the distribution system (i.e. reduced losses).

The interoperability capabilities required by IEEE 1547-2018 are related to exchanging information with the DER, including monitoring and control points. This aspect of the standard is the most future-leaning and is unlikely to be in widespread use across the United States in the near term. Using the DER interoperability interface, any DER advanced function required by the standard can be changed remotely if a communication network is established between the utility and DER system. In the more distant future, it is possible that different advanced functions are employed during different times of the day or year through a centralized control system such as DERMS. This flexibility to change between functions to better meet grid conditions at the time might offer yet another tool for mitigating DER-caused issues during distribution planning processes that involved power flow studies. As this functionality and associated products develop, it will be important to understand the costs and associated benefits to implement such a strategy.

The modeling and simulation tools needed for real time control of these systems are not in place today for the use described here. The field communication networks and backend control systems are also not in place to employ this type of use, but the Company continues to explore how the interoperability interface can best be used for integrating DER into all aspects of utility operations.

3. Advanced Inverters Response to Abnormal Grid Conditions

IDP Requirement 3.A.33 requires the following:

Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.

A driving factor for modifying national interconnection standard IEEE 1547-2018 is to require DER to provide support for wide area grid disturbances originating from the bulk electric system (Transmission and Generation). The standards apply to all DER, including PV inverter-based generation. Historically, DER was required to trip for minor grid disturbances. A large amount of DER tripping all at once has the potential to worsen the grid condition that caused the DER to trip in the first place. IEEE 1547-2018 requires the capability to ride-through grid voltage or frequency disturbances and allows a wide range of trip settings to provide Regional Transmission Operators, Independent System Operators, Transmission Operators, and Distribution Operators with options that balance the sometimes differing technical objectives of these stakeholders. MISO has initiated a process to collect stakeholder input and provide guidance on preferred DER settings associated with response to abnormal grid conditions.

Abnormal grid conditions such as voltage or frequency disturbances are difficult to forecast as they are typically associated with rare events such as large generators tripping or transmission line faults. Furthermore, the location of a faulted circuit greatly impacts the resulting voltage disturbance observed across the system. In contrast, any frequency disturbances observed in Minnesota are system wide phenomena across the entire Eastern Interconnect. Transmission line faults and voltage disturbances are the more common when compared to generator tripping and frequency disturbances. In general, system studies that evaluate the impact of abnormal conditions look at the worst case anticipated condition. Using a voltage disturbance to illustrate, one would look to find the most severe voltage depression caused by a transmission line fault in order to anticipate and mitigate any adverse impact to the electric system. The Company anticipates analysis along these lines will be part of the MISO stakeholder process and that appropriate guidance will be issued on the use of advanced inverter abnormal response function. The Company views Minnesota statewide DER Technical Interconnection and Interoperability Requirements being developed in Phase II of E999/CI-16-521 docket as the proper place to address DER abnormal response functions.

4. Impact of IEEE 1547-2018 on Statewide Interconnection Standards

As we have discussed, IEEE 1547-2018 is a recently published DER interconnection and interoperability standard. We are in the process of adopting the standard and determining implementation pathways for the numerous options it offers.

The revised standard addresses three new broad types of capabilities for DER: (1) local grid support functions; (2) response to abnormal grid conditions; and (3) exchange of information with the DER for operational purposes. The standard was written with a large set of required capabilities with an expectation that not all capabilities would be immediately implemented in the field. In this way, it offers options for grid operators preparing for scenarios with high penetration of DER. Some details associated with implementing the standard are part of the Commission's E999/CI-16-521 docket, especially in Phase II, which considers statewide technical standards, and other details are expected to be associated with Company business practice decisions.

In terms of specifying DER response to abnormal grid conditions, IEEE 1547 indicates that the Authority Governing Interconnection Requirements and Regional Reliability Coordinator possess a guidance role in implementing these capabilities, which, in Minnesota, are the Minnesota Commission and MISO respectively. Commission Staff requested information and guidance from MISO through a working group associated with the E999/CI-16-521 docket. The response from MISO included a plan to convene a stakeholder group so that guidance on the topic could be provided on a regional basis. The Commission's interest in resolving questions associated with adopting these capabilities is helping to drive important stakeholder conversations.

Local grid support functions have generated interest in the industry in recent years based on implementation of these functions in states such as Hawaii and California in areas of high DER deployment. The IEEE 1547-2018 standard allows the Company to specify how local grid support functions are used. The Company is exploring a stepped approach for implementing more advanced functions, such as volt-var, with the objective of enabling for segments of DER in a way that has the greatest benefit on hosting capacity while maintaining grid operating capabilities. The Company proposed in the E999/CI-16-521 docket that use of the local grid support functions should be published in utility-specific technical manuals.

The interoperability aspects of IEEE 1547-2018, which include concepts of DER monitoring and control, mark the most future-leaning required capabilities. When certified equipment is available, every DER will have a standardized communication interface for exchanging data and performing remote operations. A communication network would be necessary for making use of the interoperability interface. The Company is evaluating pathways for implementing the interoperability interface in the future.

XIII. EXISTING AND POTENTIAL NEW GRID MODERNIZATION PILOTS

In this section, we discuss the status of existing grid modernization pilot projects and potential new pilot programs.

IDP Requirement 3.D.2 requires the Company to provide:

[the] ... status of any existing pilots or potential for new opportunities for grid modernization pilots.

A. Grid Modernization Pilots

1. Time of Use Rate Pilot

As discussed in this document previously, we received Commission approval for a residential TOU rate pilot that involves two-way communication FAN infrastructure and AMI.⁸⁴ The pilot is scheduled to start in early 2020. As a part of the pilot, selected residential customers will switch to a rate design 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. The pilot is designed to encourage shifting energy usage to daily periods when system load conditions are normally lower. Strategies that shift load away from

⁸⁴ See Docket No. E002/M-17-776.

peak times may reduce or avoid the need for system investments in fossil fuel plants that serve peak electric load.

We have begun deployment of advanced meters to approximately 17,500 residential customers. The customers are spread between two geographic locations, customers served out of the Hiawatha West/Midtown substation in Minneapolis, and the Westgate substation in Eden Prairie and surrounding communities. Deployment of meters began in Q3 2019 and will continue until early 2020. Approximately 10,000 of the customers receiving new meters will be enrolled in a new rate structure, while 7,500 will be included in a control group. The new rate structure is designed with pricing for three time periods corresponding to our system's profile at on-peak, midpeak, and off-peak times.

The pilot was developed with the engagement of stakeholders and with the benefit of learnings from our 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 TOU rate deployment in Minnesota.

2. Charging Perks-Colorado Pilot

PSCo filed a Charging Perks pilot in late August with the Colorado Public Utility Commission as a pilot for inclusion in its 2019/2020 Demand Side Management Plan. The Company is seeking to work with several automobile original equipment manufacturers to manage home charging on behalf of up to 600 electric vehicle drivers. By managing when an EV charges at home, the pilot proposes to test how smart charging can shift charging outside of system peak hours and into hours that have lower production costs. In addition, the pilot will test how smart charging can support renewable integration by increasing load during hours when wind power is being curtailed due to high production and low demand. Participating customers will receive \$100 for enrolling and another \$50-\$100 for each year they participate in the pilot. For more information, see <u>https://www.xcelenergy.com/staticfiles/xe-</u> <u>responsive/Company/Rates & Regulations/Charging-Perks-Pilot-Product-Write-Up.pdf</u>.

3. Residential Battery Demand Response Pilot

The Colorado Commission approved a Residential Battery Demand Response Pilot that will test how batteries can provide energy during peak hours, perform solar time shifting, and absorb energy during hours of low cost production as part of PSCo's 2019/2020 Demand Side Management Plan. The Company is currently selecting one or more vendors that will allow it to manage a battery that a residential customer installs at their home. Participating customers will receive \$500 upfront and \$10/month during the course of the pilot. For more information, see https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates & Regulations/Regulatory Filings/DSM-Plan.pdf (*Note*: Pilot description starts at page 321 of the PDF).

4. Continuing Projects

In our 2018 IDP, we reported on two PSCo projects: (1) Pena Station/Panasonic Battery Demonstration Project, and (2) Stapleton Battery Storage Project – summarized below:

Pena Station Project. Through a public/private partnership, Xcel Energy, Panasonic, and Denver International Airport are partnering on a battery demonstration project.⁸⁵ 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.⁸⁶ 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.

Stapleton Project: The Stapleton project is aimed at examining how battery storage can help integrate higher concentrations of PV solar energy on our system.⁸⁷ As part of

⁸⁵ See Colorado PUC Docket 15A-0847E.

⁸⁶ For additional information, see

https://www.xcelenergy.com/staticfiles/xe-responsive/Energy%20Portfolio/CO-Panasonic-Fact-Sheet.pdf ⁸⁷ See CPUC Docket 15A-0847E

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.⁸⁸

We have been providing status reports in Docket No. E002/M-17-776 for these projects. Our most recent status report from August 16, 2019 can be accessed on eDockets at:

https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&d ocumentId={90D19A6C-0000-C233-B680-8B1CEC95C8E3}&documentTitle=20198-155243-02

Electric vehicles are often combined into discussions related to grid modernization – and EVs are included in the Commission's definition of DER for purposes of integrated distribution planning in Minnesota. Therefore, we also summarize EV pilots we have underway and that we have recently proposed.

B. Electric Vehicle Pilots

We have received Minnesota Commission approval of four electric vehicle (EV) pilot programs: (1) a Residential EV Service Pilot, (2) a Residential EV Subscription Service Pilot, (3) a Fleet EV Service Pilot, and (4) a Public Charging Pilot. Each of the pilots was developed with significant engagement of stakeholders.

1. Residential EV Service Pilot

While participation in our Residential EV Charging Tariff has grown steadily, the upfront cost of installing a second meter has been a barrier to some customers enrolling. To address the issue of upfront installation costs, we developed a Residential EV Service Pilot. As a part of the pilot, the need for a second meter is eliminated and is replaced by Company-provided Electric Vehicle Service Equipment (EVSE). The EVSE provides billing-quality data through a wireless internet connection at the customer's premises, which makes off-peak charging rates available

⁸⁸ See also <u>https://www.xcelenergy.com/staticfiles/xe-responsive/Energy%20Portfolio/CO-StapletonBatteryProject-Info-sheet.pdf</u>

without a second meter to measure usage. Interest in the pilot was high, and the limit of 100 participants was reached in a short period of time.

With continued interest in this type of service, the Company has proposed to expand the service into a conventional offering, called Electric Vehicle Home Service. The permanent service will be functionally similar to the pilot. Our proposal is currently pending Commission consideration; we hope to launch the conventional offering sometime in 2020.

2. Residential Subscription Service Pilot

We further expanded our residential offerings by developing a Residential EV Subscription Service Pilot, which is based on much of the structure of the Residential EV Service Pilot. The pilot will allow customers to charge off-peak for a preset monthly fee. This will encourage off-peak charging and offer customers certainty in monthly charging costs. Similar to the Residential EV Service Pilot, Companyprovided EVSE will be used to measure charging. Enrollment in the pilot is capped at 100 participants. We expect to launch this pilot at the start of 2020.

3. Fleet EV Service Pilot

Under this three- year pilot, the Company will install, own, and maintain EV infrastructure for fleet operators in order to reduce these customers' upfront costs for EV adoption. Fleet operators participating in the pilot are required to take service under time-of-use rates for their EV charging and all chargers will need to have smart charging capabilities. Additionally, the Company will provide advisory services to fleet operators, including information relative to fleet conversion decisions. We are currently working with three fleet customers as a part of the pilot: Metro Transit, the Minnesota Department of Administration, and the City of Minneapolis. Additional participants will be considered. The Company is required that at least one must be a public entity with a primary location outside Ramsey and Hennepin Counties.

We have had discussions with Metro Transit on partnering for even larger fleet electrification efforts. Metro Transit is considering adding bus charging capabilities to a new bus garage planned for the North Loop area of Minneapolis. Our discussions with Metro Transit have included Metro Transits plans to add charging infrastructure for up to 100 buses at this new facility. The current estimate is that work on this facility will begin in the second half of 2020, with completion in 2021. Beyond charging infrastructure, the new garage project may also include work that supports advanced energy infrastructure.

4. Public Charging Pilot

In the Public Charging Pilot, the Company will install, own, and maintain EV infrastructure for developers of public charging stations along corridors and at community mobility hubs. Unlike the Fleet EV Service Pilot, the Company would not own or maintain any charging equipment. The goal of such investments is to increase publicly available charging options by decreasing these customers' upfront costs. Customers participating in this pilot would be required to pay time-of-use rates for their EV charging. Under this pilot, we estimate we would be able to facilitate installation of approximately 350 charging ports.

There are two main parts to this pilot. The first is the development of community mobility hubs. For this, we will be partnering with the cities of St. Paula and Minneapolis to develop the hubs, with HOURCAR serving as a car-sharing anchor tenant. These charging hubs may also be utilized by transportation network companies (*e.g.*, Uber and Lyft), and the public, including customers who do not have EV charging capabilities at home. Secondly, we will be working with applicants to leverage available public and private funding. Specifically, the pilot is available to applicants who plan to invest in deploying fast-charging stations along corridors in our service territory, specifically targeting applicants seeking funds from Minnesota's Diesel Replacement Program funded by the Volkswagen Environmental Mitigation Settlement (VW Settlement) and administered by the Minnesota Pollution Control Agency (MPCA).

Although there has been limited deployment of public charging to date, it is a critical enabler for EV market expansion. Key reasons for including the public charging component in our EV portfolio are that it can support longer distance driving, address range anxiety, and provide charging solutions for those who are not able to charge at home.

C. Potential New Pilots

With regard to new opportunities for grid modernization and electric vehicle pilots, since our 2018 IDP, we proposed an ENERGY STAR-certified Level 2 electric vehicle "smart" charger pilot with the Department of Commerce as a modification to our current Conservation Improvement Program. The pilot proposed to study how a combination of incentives or rewards encourages smart charging of EVs – enabling the management of EV charging as a demand response resource. The pilot was

denied approval on June 12, 2019.89

We are currently evaluating the following pilot and will bring it forward to the Commission for approval as necessary in the future.

• *Vehicle-to-Grid Demonstration with School Buses:* This demonstration project would test the use of electric school bus batteries as grid resources. We believe this type of pilot can deliver learnings about the use of bus batteries as energy storage resources and also collect information related to local peak demands. We are currently in the process of identifying vendors and school districts to participate in a demonstration project. This is a relatively new area of vehicle electrification and work is needed to determine program viability.

XIV. ACTION PLANS

In this section, we provide a 5-year action plan as part of a long-term plan for the distribution system, as required by filing requirement 3.D.2. We note that in the Commission's July 16, 2019 Order in Docket No. E002/CI-18-251, the Commission merged the separate action plan required by IDP requirement 3.D.1 into 3.D.2, as indicated in redline below.⁹⁰ The Order also modified the cost-benefit analysis requirement in requirement 3.D.2 as shown in redline below.⁹¹

Xcel shall provide a 5-year Action Plan <u>as part of a 10-year long-term plan</u> for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:

- Overview of investment plan: scope, timing, and cost recovery mechanism
- Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.
- Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations

⁸⁹ See Docket No. E,G002/CIP-16-115, Department of Commerce Decision, (June 12 2019).

⁹⁰ See Ordering Point No. 4.

⁹¹ See Ordering Point No. 3

made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.

- System interoperability and communications strategy
- Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)
- Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)
- Customer anticipated benefit and cost
- Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)
- Plans to manage rate or bill impacts, if any
- Impacts to net present value of system costs (in NPV RR/MWh or MW)
- For each grid modernization project in its 5-year Action Plan, Xcel should provide a costbenefit analysis <u>based on the best information it has at the time and include a discussion</u> <u>of non-quantifiable benefits. Xcel shall provide all information used to support its</u> <u>analysis.</u>
- Status of any existing pilots or potential for new opportunities for grid modernization pilots.

We summarize our 5-year and long-term action plans and associated customer impacts below. However, rather than attempt to summarize our fulfillment of each of the above requirements in this section, we provide a roadmap of where we have addressed them elsewhere in the body of this IDP filing via an Action Plan Roadmap, provided as Attachment J.

A. Near-Term Action Plan

The first five years of our action plan will be focused on providing customers with safe, reliable electric service, advancing the distribution grid with foundational capabilities including AMI, FAN, FLISR, and IVVO – and procuring enhanced system planning tools to advance our localized load forecasting capabilities and our abilities to perform scenario analysis, and incorporate DER and NWA analysis into our planning.

In the balance of this section, we summarize near-term actions by subject, where we intend or expect to take specific actions. We also use this section to comply with the portions of IDP Requirement D.2 that we have not yet addressed elsewhere in this IDP.

1. Load Growth Assumptions

IDP Requirement D.2 requires, in part:

The 5-year action plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years...

Figure 68 below provides the load growth assumption stemming from our Fall 2018 system planning analysis, as described in Section V.B. above.

Figure 68: Distribution System Planning Load Growth Assumptions NSPM Electric Jurisdiction



We additionally provide load growth assumptions for smaller portions of the NSPM geography in Minnesota that stemmed from this same analysis as Attachment K to this IDP. Please also see the capital projects list sorted into the IDP driver categories that we provide as Attachment F1 to this IDP. These pieces of information together with the detailed discussion in this IDP about our analyses and assumptions fulfill this IDP requirement.

2. Grid Modernization

While discussed in detail above and as attached to this IDP, we summarize here that

our advanced grid roadmap is the continuation of efforts that have been underway for several years. The early steps of this transition are focused on building the foundational elements needed to enable more advanced applications at the "pace of value" for our customers. This means that investments are logically sequenced to build capabilities as they are needed and incrementally upon each other.

Accounting for this foundational approach and grid modernization principles and goals, our near-term plans involve the following advanced grid projects: (1) AMI, (2) FAN (3) FLISR and (4) IVVO as we have described in this IDP, and as summarized below:

Program	Implementation Timeline		
ADMS	In-service 2020		
AMI	Meter roll-out 2021-2024		
FAN	Deployment 2021-2024 (preceding AMI deployment by approximately six months)		
FLISR	Limited testing 2020; Implementation 2020-2028		
IVVO	Limited testing 2021; Implementation 2021-2024		

 Table 56:
 AGIS Implementation Timeline

We also intend to submit the following associated filings during the 5-year action plan period, requesting necessary Commission approvals and eliciting stakeholder input:

- Opt-out provisions requesting approval of the processes, cost structure, and tariffs necessary to allow customers to opt out of AMI meter installation (2020);
- AMI billing requesting approval of a rule variance and any tariff changes necessary to enable AMI interval billing (2020);
- Future filing to enable remote connect/disconnect capabilities;
- Future filing to request approval of a pre-pay option for customers; and
- Future service quality reporting under Minnesota Rules (beginning April 1, 2022) and the Company's Quality of Service Plan (QSP) (beginning May 1, 2022) to address any impacts to service quality metrics as a result of AGIS implementation.

As discussed further in part 4 below, the TOU pilot will be underway beginning in April 2020 and is expected to conclude in 2022. The learnings from this pilot, with respect to both the rate and new products and services, will help inform our plans for advanced rates in the future, such as a full TOU rate for residential customers, or other pricing options.

Finally, with respect to our ADMS initiative, we will be submitting an initial and ongoing annual reports in accordance with the Commission's September 27, 2019 Order in the Company's Transmission Cost Recovery (TCR) Rider Docket.⁹² The timeline for the initial report is 120 days after the date of the Order (January 25, 2020); the timing and procedure for the annual report will be set by the Executive Secretary. Because the initial and ongoing annual reports contain most of the same elements, we propose to submit a single ADMS report by January 25, 2020 in the TCR docket and this IDP docket that contains all of the required information. We also respectfully request that the Executive Secretary establish the same January 25th due date for the ongoing annual ADMS reports beginning January 25, 2021 – and that they be filed in the same docket as future IDPs.

3. Investment Plan and Customer Rate Impacts

IDP Requirement D.2 requires the following, in part:

Overview of investment plan: scope, timing, and cost recovery mechanism.

As we have outlined in Section XV, Procedural Proposal, we summarize here that one of the major focuses of this IDP is our request for certification of an array of investments to modernize the Company's distribution system, pursuant to Minn. Stat. § 216B.2425. Specifically, we are seeking certification of an advanced distribution planning tool and a number of investments that are part of what is collectively referred to as the AGIS initiative: AMI, FAN, FLISR, and IVVO. Each of these investments will take years to fully implement, and we are requesting that the Commission certify the AGIS projects pursuant to Minn. Stat. § 216B.2425, subd. 3, so that the Company may request recovery of costs in concurrent or subsequent filings, as necessary.

We are also filing a General Rate Case (Docket No. E002/GR-19-564) today with a three-year plan through which we seek cost recovery for much – but not all – of these AGIS investments. Because the span of the AGIS investments goes beyond the 2020 test year and 2021-2022 plan years identified in our MYRP filing, and in light of the concurrent submission of this 2019 IDP, our AGIS rate case testimony provides support for our AGIS investments beyond the term of the rate case and addresses Commission requirements that pertain to both certification and cost recovery for grid modernization investments. In light of this support for our long-term strategy, we

⁹² Docket No. E002/M-17-797.

believe certification of the full scope of the AGIS investments alongside a rate case cost recovery determination is critical, so that we may complete our AGIS investments at an appropriate pace and potentially include the out-year costs in a rider.

Additionally, IDP Requirement D.2 requires the following, in part:

...Plans to manage rate or bill impacts, if any. Impacts to net present value of system costs (in NPV RR/MWh or MW)...

Ordering Point No. B.2 in the TCR Docket E002/M-17-797 also requires several cost and benefits information and analyses, in addition to a long-term bill impact analysis. We provide this information in detail in the attached AGIS-related Direct Testimony provided as Attachments M1 to M5, and summarize the bill impact analysis in this section.

Keeping customer bills low is a core strategy of the Company and is a central consideration of our AGIS initiative. The combined AGIS investment will provide significant value to our customers and will have an impact to customer bills from the increased revenue requirement due to our investments and O&M spend necessary to implement the AGIS initiative.

To estimate customer bill impacts, we performed a high-level revenue requirement analysis for 2020 through 2024 to illustrate the incremental revenue requirement and estimated bill impact of AGIS implementation. We summarize our approach, which results in an overall cost per kilowatt hour (kWh), in Section IX.G of this IDP – and present the AGIS revenue requirement in the Direct Testimony of Mr. Gersack as Exhibit___(MCG-1), Schedule 9. Based on average monthly residential customer usage of 675 kWh, this assessment shows an estimated 2024 bill impact for our AGIS investments of approximately \$2.87 per month for an average residential customer.

We also assessed an alternative investment and costs if the Company does not implement the AGIS initiative. As we have discussed, it is not feasible for the Company to continue to use its current AMR meters because they are nearing end of life, and the Company's contract with Cellnet for meter reading service and support expires at the end of 2025. As such, the Company would, at a minimum, need to invest in new meters and provide meter reading services in order to continue to provide electric service to our customers. This means that even without AGIS implementation, there would be an incremental impact to customers' bills for an alternative metering service. Therefore, in addition to the AGIS revenue requirement, we developed a reference case scenario to represent an alternative to our AGIS investments. The reference case reflects the necessary investments and costs if the Company were to pursue a basic AMR drive-by meter reading alternative, which is discussed in the Direct Testimonies of Ms. Bloch and Mr. Cardenas. We calculated the bill impact by using the revenue requirements for the AMR drive-by alternative and calculated the estimated bill impact as described above. We present the reference case revenue requirement in the Direct Testimony of Mr. Gersack as Exhibit___(MCG-1), Schedule 10. This assessment shows an estimated 2024 bill impact for the AMR drive-by alternative of approximately \$1.51 per month for an average residential customer.

The key comparison and impact is the difference between the estimated bill impact of AGIS implementation versus the basic alternative, as shown below.

	2020	2021	2022	2023	2024
AGIS	\$0.44	\$1.33	\$1.84	\$2.58	\$2.87
Reference Case	\$.01	\$0.19	\$0.62	\$1.18	\$1.51
Difference	\$0.43	\$1.14	\$1.22	\$1.40	\$1.36

Table 57: Estimated Monthly Bill Impact – Typical Residential Customer

Table 57 illustrates the incremental bill impact of pursuing our AGIS investments compared to the investments that would otherwise be necessary. In other words, the difference reflects the costs that will enable all the benefits of the advanced grid, both quantifiable and non-quantifiable, that AMR meters simply will not provide. Table 57 also illustrates that costs of AGIS will be spread over the implementation period, which reasonably manages the bill impact for our customers.

We provide a calculation of the NPV of the Distribution function as Attachment L to this IDP, in compliance with the above requirement.

4. Grid Modernization and EV Pilot Projects

As we have discussed previously, we have several grid modernization and EV-related pilot programs that have been approved by the Commission, and others that have been proposed.

On the Grid Modernization side as we noted above, our TOU Rate Pilot has been approved and will be launched in early 2020. The goals of the TOU pilot are to study adequate price signals to reduce peak demand, identify effective customer engagement strategies, understand customer impacts by segment, and support demand response goals. This pilot will provide us with an opportunity to better understand how customer react to a four-part rate (off peak, two shoulder peaks, and an on-peak period) as well as test tools and resources that may help customers adjust their energy usage to keep their bills low and better control their energy costs. The TOU pilot is expected to conclude in 2022.

On the EV-related side, the Company has several approved pilots that have launched, or will launch soon. Those pilots include:

- Residential EV Home Service Pilot
- Fleet EV Service Pilot
- Public Charging Pilot
- Residential EV Subscription Service Pilot

The Company has a proposal in front of the Commission to expand our Residential EV Home Service Pilot to a broader, conventional offering called Electric Vehicle Home Service. We have also previously outlined several new opportunities for grid modernization and electric vehicle pilots that we are currently evaluating. We intend to bring them forward to the Commission for approval, as appropriate.

5. Advanced Planning Tool

We are currently finalizing the contract details with the vendor, which will enable us to move through the purchasing process early in the first quarter of 2020.



Figure 69: Planned APT Implementation Timeline⁹³

⁹³ Note this implementation schedule remains fluid and subject to change.
After finalizing the procurement, design, implementation, testing, which will take place over the next several months, we anticipate the APT will be fully operational in time to use it in our 2021-2025 distribution planning cycle in late 2020.

6. Incremental System Investment Plan

The ISI initiative is driven by the need to improve reliability on those elements of the system that are the closest to our customers as well as provide the infrastructure to support increased customer choice and the adoption of DER, such as EVs. This initiative will both expand existing asset health programs and will create new programs to address areas of the system that have traditionally not received much focus. The ISI initiative is divided into four main programs: substation, underground, overhead tap, and overhead mainline, and is expected to get underway in 2021.

In the interim, we will be planning the implementation of the various programs, and taking actions as part of the programs such as:

- Start the targeted undergrounding program with several pilot areas undergrounding 20 miles of overhead tap system in 2021 and 30 miles in 2022.
- Install up to 500 low cost reclosers in 2021 and 2022.
- Reinforce the equipment on up to 900 poles in 2021 and 2022.
- Under our Transformer and Secondary Replacement program, we plan to replace the transformer and the associated secondary wire at up to 150 locations in 2021 and 2022.
- Address up to 200 different high customer count taps in both 2021 and 2022.
- Under our Community Resiliency program, we plan to install the equipment necessary to provide back-up power at one strategic location in 2022.
- Our cable replacement program will supplement our existing program, and we plan to replace up to four additional miles of mainline cable in 2021; up to nine additional miles of mainline cable in 2022; replace 10 additional miles of URD cable in 2021; and, up to 12 additional miles of URD cable in 2022.
- We plan to perform up to 60 miles of cable assessment and rehabilitation in 2021 and 2022.
- Under our Network Monitoring program, we plan to have one network in service with live monitoring in 2022.
- We expect, given the challenges St. Paul Tunnel Rehabilitation program and the required coordination that this project may take up to 15 years to complete. We expect however, the first assets will be placed in service in 2021 and 2022. The first assets will include the first conduit vaults and duct vaults that will be required to move our electrical equipment out of the tunnels.

- We will in-service up to eight feeder exits in 2021 and 2022.
- Under the Substation Transformer Replacement program, we will replace up to four additional transformers in 2021 and approximately 10 additional transformers in 2022.
- We plan to replace up to 32 breakers, 42 relays, and 5 RTU/LCUs at multiple substation locations across Minnesota during 2022 as part of our Substation Asset Renewal program.
- We plan to address up to 500 poles with our Pole Fire Mitigation program in 2021 and 2022.
- We expect to replace up to 1,000 lighting arrestors in 2021 and 2022.

7. Demand Side Management

The five year action plan for Demand Side Management, which includes both energy efficiency and demand response, will be largely determined through our IRP and future Minnesota CIP Triennial filings.

a. Energy Efficiency

In terms of energy efficiency, our expectation is that the 2.5 percent goal proposed in the IRP will be the central focus of energy efficiency during the 10-year IDP period. In order to continue meeting and exceeding this goal, we will invest in expanding existing opportunities and bringing new opportunities to market. We will also be looking to new ways to maximize benefits for customers that may alter traditional delivery strategies and tactics that will support the integration of renewable resources and DER. We will detail our specific plans and implementation strategies for these in our upcoming 2021-2023 CIP Triennial filing, which we will submit in June of 2020.

b. Demand Response

Demand Response will be heavily influenced by our efforts to achieve the incremental 400 MW by 2023 requirement that stemmed from our 2015 IRP in Docket No. E002/RP-15-21. We expect our delivery of DR in the next 5-year period to shift in order to achieve this goal in the future, and take a broader approach to where DR opportunity can be achieved. Traditionally, DR has focused on load curtailment; however, a broader approach will likely be needed to take advantage of load shifting and behavioral actions. Modifications to existing programs or additions of new programs will require regulatory filings, at a minimum, several months in advance of implementation. Additionally, we are anticipating changes at the MISO level to influence future programs and cost-effectiveness screens, which will factor into our

plans and program design. We provided a detailed 5-year plan with our IRP in 2019.

8. Daytime Minimum Loads

As discussed in conjunction with our Planning Tools, we made determination of daytime minimum loads a priority in 2019, in compliance with the Commission's July 16, 2017 Order in Docket No. E002/CI-18-251. We determined and updated historical DML for all of our feeders and substation transformers that have load monitoring. This was a large effort, and we are determining how to best include this action into the planning processes going forward. We note that we will also be tracking DML and any changes to them year-to-year. As we implement our advanced planning tool, it will also aid in the actual forecasting of these values going forward.

B. Long-Term Action Plan and Customer Impacts

In this section, we address the long-term plan IDP requirements – discussing primarily the long-term trajectory of our near-term investments.

IDP Requirement 3.D.3 requires the following:

In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term plan discussion should address the long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.

1. Long-Term Grid, Tools, and Capabilities Focus

As we have discussed, our long-term focus for the distribution system is to advance the grid and our capabilities through first building foundational capabilities then further leveraging that foundation with advanced capabilities. This includes enhanced distribution planning tools to advance our capabilities to bring DER into our planning – and to perform DER futures analyses, as we have discussed in this IDP.

Although also provided above in this IDP, for easy reference, we again provide a 15year view of the sequencing of planned and potential advanced grid investments in Figure 70 below.



Figure 70: Advanced Grid Initiatives - Present to 2030 View

The sequencing of initiatives aligns with the measured approach adopted by the Company that initially focuses on foundational investments, while also realizing some early capabilities and benefits for customers. This approach positions the Company to make prudent investments over time in more advanced capabilities, while maintaining flexibility to adapt to changing customer priorities, trends in DER penetration, and future policy direction. As previously discussed, the Company has received certification approval for both ADMS and the TOU Pilot. Each of these investments is underway and are important steps along the advanced grid roadmap.

In addition to discrete advanced grid investments, our corporate information technology infrastructure will require attention and investment on an ongoing basis to continue to meet increasingly demanding cybersecurity, data traffic, reliability, and compliance requirements along with the service expectations of our customers. Many of the investments discussed within this report involve additional data and communication needs, and a current information technology infrastructure is critical to supporting those efforts. As shown in Figure 70 as a single foundational investment, these advanced grid components are actually composed of a series of investments in equipment, data management hardware, systems integrations, and cybersecurity protections. Each of these investments will provide discrete customer benefits and the combination of these investments over time will enable more sophisticated capabilities as we have discussed.

2. Long-Term Load Growth Assumptions

As we have discussed in this IDP, distribution system planning is performed for a 5year planning horizon. In the case of this IDP, that period is 2020-2024. In part 1 above, we provided our load growth assumptions that resulted from our Fall 2018 distribution planning process.

For load growth assumptions beyond the distribution planning period, we provide our corporate load growth forecast, as follows:



Figure 71: NSP System Annual Energy and Peak Demand Forecast

XV. PROCEDURAL PROPOSAL

As we have noted, we are seeking certification for our AGIS investments to modernize the Company's distribution system, pursuant to Minn. Stat. § 216B.2425. Specifically, we are seeking certification of an advanced distribution planning tool and a number of investments that are part of what is collectively referred to as the AGIS initiative: Advanced Metering Infrastructure, a private secure Field Area Network, a form of distribution automation that decreases the duration of and number of

customers affected an outage, and Integrated Volt Var Optimization, which decreases system losses and optimizes voltage as power travels from substations to customers.

These investments expand on the advanced grid investments previously approved by the Commission, namely the ADMS that will go into service in 2020. Each of these investments will take years to fully implement, and we are requesting that the Commission certify the AGIS projects pursuant to Minn. Stat. § 216B.2425, subd. 3, so that the Company may request recovery of costs in concurrent or subsequent filings, as necessary. This is consistent with other requests for certification for grid modernization investments, where certification enables the opportunity for the Company to request recovery of costs in a subsequent rider filing.

We are also filing a General Rate Case (Docket No. E002/GR-19-564) today with a three-year plan (Multi-Year Rate Plan (MYRP)) through which we seek cost recovery for much – but not all – of these AGIS investments. Because the span of the AGIS investments goes beyond the 2020 test year and 2021-2022 plan years identified in our MYRP filing, and in light of the concurrent submission of this 2019 IDP, our AGIS rate case testimony provides support for our AGIS investments beyond the term of the rate case and addresses Commission requirements that pertain to both certification and cost recovery for grid modernization investments. In light of this support for our long-term strategy, we believe certification of the full scope of the AGIS investments alongside a rate case cost recovery determination is critical, so that we may complete our AGIS investments at an appropriate pace and potentially include the out-year costs in a rider. Consideration of our certification request in tandem with our rate request will also be most efficient for all stakeholders. The Commission would, of course, have another opportunity for review and approval of specific costs if the Company were to seek rider cost recovery in the future.

Because of this dual filing approach, and in order to minimize duplication, we have provided the support for our AGIS certification request in a testimony format within the rate case, and we are including relevant portions of the testimony as attachments to this filing. We have excised unrelated portions from some witness testimony in order to provide only the relevant material. For instance, Company Witness Mr. David C. Harkness provides testimony regarding our 2020-2022 Business Systems investments for purposes of the MYRP, but not all of them are related to AGIS; we have therefore included only those sections and attachments that relate to AGIS in this IDP filing.

In addition, today we also have filed a Petition for Approval of True-Up Mechanisms. This filing requests the approval of certain true-ups for 2020 which, if approved, would result in the withdrawal of our General Rate Case. In that event, we would no longer request AGIS cost recovery through base rates until the Company's next general rate case is filed. We would, however, ask the Commission to make the more limited determination to certify the AGIS investments and Advanced Distribution Planning Tool in this IDP, so that we may plan for the implementation of our AGIS initiative, and preserve the option to put the costs of these investments in a rider between general rate case filings.

Overall, the filing requirements related to grid modernization investments, as well as for certification, are extensive, and our supporting documentation is likewise extensive and thorough. We have therefore taken several steps to facilitate review of these materials, and make them as digestible and easy to read as possible for the Commission and our stakeholders. These steps include development of executive summaries, compliance matrices, and extractions from larger pieces of testimony as noted above.

The normal procedural schedule for certification under Minn. Stat. § 216B.2425 would require a determination by June 1, 2020, and under normal circumstances, we believe the process leading to certification should resemble a resource acquisition proceeding under the Commission's normal notice and comment procedures that could, in the Commission's discretion and depending on the scope of the investment, include one or more public hearings. We recognize, however, that the schedule in the General Rate Case does not align with that timing. In addition, the AGIS initiative includes large investments and is supported by a sizeable filing that may require analysis beyond the six-month certification timeframe, even if the General Rate Case is withdrawn. Thus, we offer to work with the Commission and stakeholders to set an appropriate deadline and procedural schedule for consideration of these investments.

On a further procedural note, we respectfully request the Commission move to a biennial filing cadence for the IDP, consistent with other Minnesota utilities and the grid modernization statute filing requirements. We believe a biennial filing would better allow time to fully engage with stakeholders on the Commission's planning objectives between IDP filings, as well as to address important issues such as distributed energy resources (DER) planning, a comprehensive approach to non-wire alternatives (NWA), and our advanced grid plans. The present annual filing schedule also does not allow the Company to make significant, meaningful progress on its objectives between these extensive filings. We therefore specifically request the Commission require our next IDP be submitted on or before November 1, 2021, and biennially thereafter.

Finally, with respect to our ADMS initiative, we will be submitting an initial and ongoing annual reports in accordance with the Commission's September 27, 2019

Order in the Company's Transmission Cost Recovery (TCR) Rider Docket.⁹⁴ We propose to submit a single ADMS report by January 25, 2020 in the TCR docket and this IDP docket that contains all of the required information. We also respectfully request that the Executive Secretary establish the same January 25th due date for the ongoing annual ADMS reports beginning January 25, 2021 – and that these annual ADMS reports be filed in most recent docket of future IDPs.

XVI. STAKEHOLDER ENGAGEMENT

In this Section we discuss our stakeholder engagement in advance of this IDP.

IDP Requirement 2 requires the following:

Xcel should hold at least one stakeholder meeting prior to the November 1 filing of the Company's MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 MN-IDP filing as deemed appropriate by the utility.

At a minimum, Xcel should seek to solicit input from stakeholders on the following MN-IDP topics: (1) the load and distributed energy resources (DER) forecasts; (2) proposed 5year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP.

In an effort to educate and build a better understanding of our work and stakeholder's needs, and to comply with the Commission's August 30, 2018 Order, we held four Distribution Planning stakeholder workshops leading up to our November 1, 2019 IDP. The goal for the workshops was to have an iterative and ongoing dialogue to build a mutual understanding of our processes and the IDP- both for this instant report as well as future reports.

We summarize the stakeholder workshops we held below:

 1 – December 12, 2018, to provide a recap of our 2018 IDP, seek feedback, and engage in a questions and answers session with our subject-matter-experts. The objectives for the meeting were to learn about Xcel Energy's experience in developing the first Minnesota IDP filing; clarify and better understand the information included in Xcel Energy's IDP filing to help parties develop their

⁹⁴ Docket No. E002/M-17-797.

comments in response to PUC questions; and identify specific parts of the filing or topics that would benefit from further stakeholder discussions. We also offered to engage in further meetings and discussions with stakeholders upon request.

- 2 April 10, 2019, seeking general feedback on our next IDP, and also focused discussion on our non-wires alternatives analysis framework. The objectives for this session were to develop a list of criteria for what would make any future IDP filing acceptable to all stakeholders, including: what stakeholders want to see and why (the desired end state); any major steps stakeholders think are needed to meet that principle (the suggested means to achieving the desired end state); and when stakeholders think those major steps should take place and, if applicable, what information should inform that timing. We also reviewed and sought feedback on our current non-wires alternatives analysis process in advance of the November 1st deadline for the 2019 IDP filing, using the design principles as a framework for discussion.
- 3 May 17, 2015, focused on the cost benefit framework for advanced grid investments. This was another key area of focus in our 2018 IDP proceeding. Objectives for this session included developing a list of stakeholders' collective expectations around Xcel Energy's grid mod investments and associated costbenefit analysis; gain a better understand Xcel Energy's currently planned grid mod investments and cost-benefit analysis framework, using the previously discussed expectations as a framework for discussion; and, identify any next steps and discuss oral comments to the commission, if desired. We discussed the IDP requirements, discussed different ways to evaluate the value of grid modernization investments and that a CBA is just one tool, only quantifies that which can be quantified, and implies that something is only valuable if its benefits outweigh its costs; we discussed the foundational advanced grid elements in our plan; and, we illustrated our CBA framework using our 2018 FLISR project as an example discussing cost inputs, benefits, financial assumptions, impact on the reliability metrics and the customer reliability experience, and model outputs.
- 4 September 25, 2019, to provide an overview of the forecasts and other information specified in the Commission's IDP requirements. This was a broad stakeholder workshop where we reviewed the Commission's distribution planning objectives and the functions and technologies needed to achieve those objectives; established a shared understanding of how Xcel Energy does Distribution Planning today and how distribution planning is evolving; we presented our load and DER forecasts and five year budgets; discussed our advanced grid plans and components; and, we summarized our 5-year action plans. We also summarized the feedback we received at Workshops 2 and 3.

We engaged Great Plains Institute (GPI) as a third party facilitator and for the first

and last session, invited all interested parties and commenters from our 2018 IDP docket as well as our most recent IRP due to the overlap between the two efforts. The second and third sessions were more focused topics, so we invited only those parties who had submitted comments in our 2018 IDP proceeding. These sessions resulted in rich dialogue and robust feedback.

Highlights of the feedback we received at these sessions follows:

What did you like about the Company's 2018 IDP that should be repeated?

- 1. Transparency:
 - Provided a lot of helpful transparency about how Xcel Energy does distribution planning
 - Appreciate Xcel Energy saying honestly what they can provide and how much work it will take to meet the requirements.
- 2. Level of detail and usefulness of information:
 - Focus on reliability
 - Good faith effort comprehensive, especially considering distribution planning in other states
 - The filing put more detail to the "walk, jog, run" metaphor the direction in which Xcel Energy is heading -- than utilities in other states, which was helpful.
 - Report helps to correct information asymmetry that has existed between the company and everyone else.
 - Appreciate translating from engineering to more generally understood language.

3. Effort given timing constraints:

- Strong considering timing constraints
- NWA's good job with the analysis given such a short turnaround

4. Stakeholder engagement process:

- Stakeholders felt invited to share input
- Provided solar businesses an opportunity to engage with the utility/developers
- Learning from other state distribution planning processes encourage this to continue (e.g., MI PSC website to make process accessible to stakeholders)

What changes would you like to see?

- 1. Make the information more accessible and digestible
 - Question about repeating "baseline" info that may not change year-toyear – is this needed?

- A balance between complexity and accessibility to communities/customers
- It would be helpful to Xcel Energy to know how the various required information will be used so that they can provide it in the most helpful format.
- Interest in understanding how much of an effort it is for Xcel Energy to provide certain items.
- More clarity/focus on aspects of IDP that will provide value to ratepayers better investment, better utility planning. What is the public interest value?

2. Use the IDP as a forward-looking tool

- Would like to see a "SMART" goal that says between now and the next IDP filing, Xcel Energy will do the following things, with a list of specific action steps that are time-bound.
- Use the IDP as a platform to start putting out forward-looking ideas/proposals have the opportunity to take a holistic look at the distribution system
 - Xcel Energy would like to develop the tools to do this more efficiently going forward

3. Integrate other related topics, dockets, issues:

- Integrate storage as the technology advances
- Integration of other like processes should be explicit and transparent inputs should be the same or if different, explained (e.g., IRP, PBR, rates for DERs).
- Challenging to draw a box around this, when actually this is interrelated with multiple other topics/proceedings would like to see more intentional integration and efforts to link together where applicable.
 - Integration will require the Commission's active input it was driven by the PUC, so hopefully they will see it through. Constant evaluation will help with this.

4. Strengthen the stakeholder engagement process:

- Would help to have more general education and resource-sharing and to help raise the level of education on distribution planning.
- Have agreement on the "anchor" of what plans should look like in 5-10 years this can help to inform what technologies or approaches are needed to get there (and what analytical tools are needed).

- Would like more discussion between stakeholders and Xcel about what tools could help with NWA analysis operating side and mental model side of where NWAs fit in this discussion. Hierarchy of needs, and where NWAs fit.
 - Xcel Energy still working on deploying customer-facing programs for distribution purposes
- Learning from other state distribution planning processes encourage this to continue (e.g., MI PSC website to make process accessible to stakeholders)

Key takeaways from our grid modernization CBA framework session included:

- Clearly articulate the assumptions and the level of certainty/ uncertainty behind them.
- Articulate the dependencies (or non-) between different advanced grid investments.
- Failure is discussing whether to invest in AMI, with success being how to build on AMI.
- Consider framing in concert with performance based rates outcomes (from the Commission's investigation into performance metrics for the Company's electric utility operations in Docket No. E002/CI-17-401).
- Prioritize investments i.e., what comes after the foundational components.
- Demonstrate innovation and creativity around the customer value proposition.
- Differentiate between easy-to-quantify and hard-to-quantify benefits for customers.

We internalized this feedback and the feedback we received on our 2018 IDP and factored it into the information we present in this IDP, including how we present the costs and benefits of our advanced grid components – and our proposal to implement IVVO in Minnesota. We discuss how stakeholder feedback and input factored into our advanced grid proposal in the Direct Testimony of Mr. Gersack, which accompanies this IDP as Attachment M1.

XVII. INTEGRATED DISTRIBUTION-TRANSMISSION-RESOURCE PLANNING

In this Section, we discuss the present state of Distribution-Transmission Resource Planning and our longer-term view of how we envision them becoming increasingly integrated.

IDP Requirement 3.A.5 requires the following:

Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans.

Currently, the distribution and transmission planning groups meet twice per year, and additionally work together as their respective planning processes impact or rely on one another. For example, distribution planning supplies transmission planning with substation load forecasts that are an input into the transmission planning process. These two groups also interact when distribution planning identifies the need for additional electrical supply to the distribution system – and similarly with interconnections, distribution is on point, and involves the appropriate planning resource as needed. The work that we are doing now on customer adoption-based of DER and electrification is helping to bring these planning processes closer together – and we believe will result in better informed sensitivities to ultimately inform both IRP and IDP. However, there are fundamental differences in these planning processes that will continue to challenge integration, at least in the near-term.

While increasing DER penetration levels will drive integrated resource planning and distribution planning closer together, there are fundamental differences in how these two planning activities assess and develop plans to meet customers' needs. Distribution planning, like IRPs, charts a path to meet customers' energy and capacity needs, but is more immediate and subject to emergent circumstances because distribution is the connection with customers. Unlike IRPs, five-year plans are considered long-term in a distribution context; and, IRPs are concerned with size, type, and timing, whereas the primary focus of distribution planning is location. Thus distribution loads and resources are evaluated for each major segment of the system – on a feeder and substation-transformer basis – rather than in aggregate, like occurs with an IRP.

Before a greater integration of distribution planning, transmission planning, and IRP can occur, distribution planning will need to become even more granular than it is

today to address the challenges – and harness the benefits – of DER. The advanced planning tool and advanced grid investments we propose with this IDP are an important step to realizing this future.

Minnesota is among a few states, including California, New York, and Hawaii, on the forefront of advancing its distribution planning as part of its grid modernization efforts. However, each is driven by differing policies and considerations; each is taking a different approach; and, each may result in its own solution that may not fit the circumstances elsewhere. While there are no definitive answers at this point, experts generally agree that a deliberate, staged approach to increased sophistication in planning analyses – commonly referred to as "walk, jog, run" – is important. The stages are illustrated below.



Figure 72: Staged Approach to Enhanced Planning Analyses

INCREASING POTENTIAL DER BENEFITS AND SOPHISTICATION OF ANALYSIS NEEDED OVER TIME

(Source: ICF White Paper, The Value in Distributed Energy: It's all About Location, Location, Location by Steve Fine, Paul De Martini, Samir Succar, and Matt Robison. See White Paper.

Movement from one stage to another is generally driven by growth in volume and diversity of distribution-connected, DER, the level of evolution of supporting planning practices and tools, and integration with other planning efforts, such as transmission, or resource planning.

Similarly, the Berkeley Lab report, *Distribution Systems in a High Distributed Energy Resources Future, Planning, Market Design, Operation and Oversight* proposes a three-stage evolutionary structure for characterizing current and future state DER growth, with stages defined by the volume and diversity of DER penetration – plus the regulatory, market and contractual framework in which DERs can provide products and services to the distribution utility, end-use customers and potentially each other.⁹⁵ The report emphasizes the need to ensure reliable, safe and efficient operation of the physical electric system, DERs and the bulk electric system, which correlates to Minnesota utility requirements under Minn. Stat. § 216B.04 to furnish safe, adequate, efficient, and reasonable service. The report describes Stage 1 as having low adoption of DERs, where the focus is on new planning studies when DER expansion is anticipated, which also correlates to where we are in Minnesota presently.

The U.S. Department of Energy, as part of its collaboration with state commissions and industry to define grid modernization in the context of states' policies is developing a guide for modern grid implementation that similarly recognizes foundational elements upon which increased utility tools and information and changes in infrastructure planning, grid operations, energy markets, regulatory frameworks, ratemaking, and utility business models rest, as shown in below.

⁹⁵ Future Electric Utility Regulation series (Report No. 2), by Paul De Martini and Lorenzo Kristov (October 2015). *See* <u>https://emp.lbl.gov/publications/distribution-systems-high-distributed</u>

Figure 73: Platform Considerations



ESTIMATED STATUS OF NSPM AGIS IMPLEMENTATION

Source: *Considerations for a Modern Distribution Grid*, Pacific Coat Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017). *See* <u>U.S. DOE DSPx presentation - More Than Smart</u>

The DOE's efforts also recognize timing and pace considerations, as shown in below.



Figure 74: Timing and Pace Considerations

Source: *Considerations for a Modern Distribution Grid*, Pacific Coast Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017). *See* U.S. DOE DSPx presentation - More Than Smart

As part of the May 24, 2017 Pacific Coast Inter-Staff Collaboration Summit, DOE observed that the U.S. distribution system is currently in Stage 1, with the issue being whether and how fast to transition to Stage 2. Underlying this question however, is the issue of identifying customer needs and state policy objectives – with a goal to implement proportionally to customer value – all of which will differ significantly across states. We would agree that Minnesota is in Stage 1. We are focused on foundational infrastructure and starting to evolve our planning tools to enable integrated distribution planning.

A potential progression in planning practices could involve the evolution shown in Figure 75 below, with the drivers of progress being:

- Customer value, such as need, public policy, and cost/benefit,
- Utility readiness, including proper foundational tools and systems, and
- Supporting regulatory frameworks that address cost recovery, and any changes in federal or state market operations, etc.



Figure 75: Potential Evolution in Planning Practices

We expect this progression will need to occur over time as tools improve, policy drivers become clear, and customer value is determined.

Evolving distribution planning to be more like integrated resource planning will need to be thoughtful and planful. Today, IRPs are grounded in Minnesota statutes and rules – and chart a long-term direction of how load can be served in a broad service area. The IRP process is grounded in Minn. R. 7843, which prescribes the purpose and scope, filing requirements and procedures, content, the Commission's review of resource plans, and plans' relationship to other Commission processes, including certificates of need and the potential for contested case proceedings.⁹⁶ These processes work for IRPs due to the long-term nature of macro resource additions and changes.

However, distribution planning is more immediate; its full planning horizon correlates

⁹⁶ Minn. R. 7843.0500, subp. 3 prescribes the factors for the Commission to consider in reviewing IRPs. "The Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to: maintain or improve the adequacy and reliability of utility service; keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; minimize adverse socioeconomic effects and adverse effects upon the environment; enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control."

to the five-year action plan period of an IRP, which is generally a continuation of past IRPs. Distribution systems are utilities' point of connection for customers. While an unexpected loss of a macro system component, such as a power plant, can often be covered by the MISO system without interruption of power to customers, loss of a distribution system component often results in a power outage to the customers it was serving. While there is some redundancy in the system to avoid this circumstance, the types of issues addressed by distribution planning are typically much more immediate than IRPs – and do not have a back-up like MISO. Therefore, evolving distribution planning practices will need to be thoughtful – and ensure the focus remains on the immediacy of customer reliability.

While the timeline remains uncertain, it is clear that the distribution grid of the future will look and perform differently than it has over the past 100+ years. Minnesota is in the forefront on the issue of advancing its distribution planning practices with other leaders such as California, New York, and Hawaii. Lessons learned from these states that Paul De Martini, ICF International, shared as part of his presentation at the Commission's October 24, 2016 grid modernization distribution planning workshop included:

- Changes to distribution planning should proactively align with state policy objectives and pace of customer DER adoption.
- Define clear planning objectives, expected outcomes and regulatory oversight avoid micromanaging the engineering methods.
- Define the level of transparency required for distribution planning process, assumptions and results.
- Engage utilities and stakeholders to redefine planning processes and identify needed enhancements.
- Stage implementation in a walk, jog, run manner to logically increase the complexity, scope, and scale as desired.

No one state has yet figured out the progression of distributing planning enhancements; each is taking a different approach to address the complexities inherent in implementing changes at the right pace and that is proportional to both customer and grid needs – and that realizes net value and benefits for all customers. While the national perspective and other state actions provide helpful points of reference, Minnesota has long been a leader in developing supportive regulatory frameworks to align achievement of policy objectives with business objectives. The increasing complexity of our industry requires a rethinking of the current framework to ensure it is still aligned. We support the evolution of the grid, and are taking actions to evolve our planning tools and improve our foundational capabilities to support our customers' expanding energy needs and expectations. We support a shift toward more integrated system planning, where utilities assess opportunities to reduce peak demand using DER and to supply customers' energy needs from a mix of centralized and distributed generation resources. However, at a measured pace that correlates to Minnesota policy objectives and customer value.

We are currently evaluating our existing planning processes and tools to determine how to better align and integrate the distribution, transmission, and resource planning processes in the future. Fundamentally, they are rooted in contradictory planning paradigms – with resource planning concerned with size, type, and timing, distribution concerned with location, and transmission somewhere in between. In the near term, these groups are working together around customer adoption-based DER forecasting and electrification. This is allowing us to consider many different possible outcomes, and think about how we can design an optimal portfolio of resources that best meets our overall customer load needs under a range of potential outcomes.

CONCLUSION

This IDP presents a comprehensive view of our distribution system and how we plan the system to meet our customers' current and future needs. The backbone of our planning is keeping the lights on for our customers, safely and affordably. For over 100 years, we have delivered safe, reliable electric service to our customers, and, through our robust planning process and strong operations, we will continue to do so.

We are also planning for the future. We have a vision for where we and our customers want the grid to go, and we are implementing and installing new technologies to support our vision. We are taking a measured and thoughtful approach to ensure our customers receive the greatest value and that the fundamentals of our distribution business remain sound.

We respectfully request the Commission certify our proposed AGIS investments and advanced planning tool as outlined in Section XV, Procedural Process. On a further procedural note, we respectfully request the Commission move to a biennial filing cadence for the IDP, consistent with other Minnesota utilities and the grid modernization statute filing requirements – and specifically request the Commission require our next IDP be submitted on or around November 1, 2021, and biennially thereafter. Finally, with respect to our ADMS initiative, we propose to submit a single ADMS report by January 25, 2020 in the TCR docket and this IDP docket that contains all of the information required in the Commission's September 27, 2019 Order in the TCR Docket No. E002/M-17-797. We also respectfully request that the Executive Secretary establish the same January 25th due date for the ongoing annual ADMS reports beginning January 25, 2021 – and that these annual ADMS reports be filed in the most recent docket number of future IDPs.

Attachment	Title	Non-Public Designation
Δ 1	IDP Attachments with Non-Public	
Λ1	Designations	<i>n/ u</i>
A2	Compliance Matrix	n/a
	Correlation of IDP Content to	
В	Commission's IDP Planning	n/a
	Objectives	
С	IDP Grid Modernization Content	n/a
<u>`</u>	Roadmap	<i>iii</i> , <i>w</i>
D1	Advanced Distribution Planning Tool Desciption and Certification Request	Attachment D1 has contractual cost terms for the proposed Advanced Distribution Planning Tool (APT) and current tool costs that will be negated by the APT. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. In particular, the information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.
D2	APT Cost Benefit Analysis Summary	Attachment D2 has marked and shaded contractual cost terms for the proposed APT and current tool costs that will be negated by the APT. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. In particular, the information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use.

Attachment	Title	Non-Public Designation
		Attachment E Parts II (reliability impacts) and III contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service.
Е	Distribution Risk Scoring Methodology	Part III (Examples) contains information Xcel Energy maintains as trade secret data as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.
		 Part III is marked as "Not-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material: 1. Nature of the Material: Calculations of expected Customer Minutes Out given electric distribution asset load and failure rate data 2. Authors: Electric Systems Performance and the Risk Analytics Department 3. Importance: Key values to determine the potential reliability of certain projects 4. Date the Information was Prepared: October 29, 2019
F1	Capital Project List by IDP Category	n/a
F2	Risk Scored Project Details	Attachment F2 contains two shaded and marked columns that contain (1) forecasted peak demand and (2) peak capacity by feeder and/or substation that Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Additionally, these fields for certain feeders contain information that if made public would be counter to our requirement to protect the anonymity of our customers' energy usage information unless we have the customers' consent to disclose it (Commission Order dated January 19, 2017 in Docket No. E,G999/CI-12-1344).
G1	Capital Profile Trend	n/a
G2	O&M Profile Trend	<i>n/a</i>
Н	Non-Wires Alternatives Analysis	n/a
I	Request Docket RM-18-9-000	n/ a
J	Action Plan Roadmap	<i>n/a</i>
K	Assumptions	n/a
	Distributed Function NPV	n/a

Attachment	Title	Non-Public Designation
M1	AGIS Direct Testimony – Gersack	n/a
M2	AGIS Direct Testimony – Bloch	 Bloch Schedule 10 is an internal presentation given to provide a summary of the Company's analysis supporting the AMI meter vendor selection. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Bloch Schedule 10 is marked as "Non-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material: 1. Nature of the Material: An internal presentation given providing a summary of the Company's analysis supporting the AMI meter vendor selection. 2. Authors: Major Products & Programs Sourcing 3. Importance: The analysis and information contained therein has not been publicly released. 4. Date the Information was Prepared: The presentation was prepared in the second quarter of 2019.
М3	AGIS Direct Testimony – Harkness	 Harkness Schedules 11 and 12 are internal assessment summaries that the Company has designated as Trade Secret information as defined by Minn. Stat. § 13.37, subd. 1(b). The analysis and information contained therein has not been publicly released. Harkness Schedules 11 and 12 are marked as "Non-Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material: 1. Nature of the Material: These Schedules contain information regarding bidder responses to requests for proposal (RFPs) issued by the Company, including sensitive pricing and other bid data; the Company's proprietary analysis of selected bids; market intelligence; and potential comparative bidder cost and negotiation planning information. 2. Authors: Business Systems and Sourcing employees and their representatives in conjunction with the Company's review of hardware and software needs for its Advanced Metering Infrastructure (AMI) and Field Area Network (FAN) projects, respectively. 3. Importance: They include sensitive pricing and other bid data. 4. Date the Information was Prepared: Schedule 11 was prepared in 2017 and Schedule 12 was prepared in 2015.
M4	AGIS Direct Testimony – Cardenas	n/a
M5	AGIS Direct Testimony – Duggirala	n/a
N1	RFP - APT	n/ a
N2	RFP - AMI	n/a
N3	RFP - WISUN	n/a

Attachment	Title	Non-Public Designation
		The Low Voltage VAr Compensator RFI contains a table in Section 2.0 that has a list of vendor names and contact information.
N4	RFP - IVVO	Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use.
O1	AGIS Combined CBA Summary	n/a
O2	AGIS AMI CBA Summary	n/a
O3	AGIS FLISR CBA Summary	n/a
O4	AGIS IVVO CBA Summary	n/a
Workpapers	Workpapers - Executable CBA Model - APT	 The APT CBA model represents a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data. This additional trade secret data includes negotiated and contractual pricing. Please note the CBA is marked as "Non-Public" in its entirety. Pursuant to Minnesota Rule 7829.0500, subp. 3, we provide the following description of the excised material: 1. Nature of the Material: The Cost Benefit Analysis Model developed by the Company. 2. Authors: Risk Analytics and Regulatory and Distribution 3. Importance: The Company work product is proprietary to the Company. 4. Date the Information was Prepared: The CBA Model was created in the third quarter of 2019.

Attachment	Title	Non-Public Designation
Workpapers	Workpapers - Executable CBA Models - AGIS	The AGIS CBA executable model represents a Company work product. Xcel Energy maintains this information as a trade secret pursuant to Minn. Stat. §13.37 (1)(b) based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain economic value from its disclosure or use. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data. This additional trade secret data includes negotiated pricing (including labor, materials, technology, and services) and contract terms; internal labor rates; number of customers per feeder; and device retirement and failure rates. Please note the CBA is marked as "Non-Public" in its entirety. Pursuant to Minn. R. 7829.0500, subp. 3, we provide the following description of the excised material: 1. Nature of the Material : The Cost Benefit Analysis Model developed by the Company. 2. Authors: Risk Analytics 3. Importance: The Company work product is proprietary to the Company. 4. Date the Information was Prepared: The CBA Model was created in the third quarter of 2019 .

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
2	Stakeholder Meetings	Xcel should hold at least one stakeholder meeting prior to filing the November 1 MN- IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 filing as deemed appropriate by the utility. At a minimum, Xcel should seek to solicit input on the following MN-IDP topics: (1) the load and DER forecasts, and 5-year distribution system investments, (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP. Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, a stakeholder meeting may be held in combination with the comment period to solicit input.	XVI
3.A.1	Baseline Distribution System and Financial Data System Data	Modeling software currently used and planned software deployments	V.C-D
3.A.2	Baseline Distribution System and Financial Data System Data	Percentage of substations and feeders with monitoring and control capabilities, planned additions	IV.C.1, Table 14
3.A.3	Baseline Distribution System and Financial Data System Data	A summary of existing system visibility and measurement (feeder-level and time interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)	IV.C.1, Table 14
3.A.4	Baseline Distribution System and Financial Data System Data	Number of customer meters with AMI/smart meters and those without, planned AMI- investments, and overview of functionality available	IV.C.2 IX, X, Attachment C
3.A.5	Baseline Distribution System and Financial Data System Data	Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans	XVII
3.A.6	Baseline Distribution System and Financial Data System Data	Discussion of how DER is considered in load forecasting [and thus system planning] and any expected changes in load forecasting methodology	V.D, XI, Attachment D1
3.A.7	Baseline Distribution System and Financial Data System Data	Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities & constraints related to interoperability and advanced inverter functionality). [IEEE Standard 1547-2018, published April 6, 2018).	XI.F, XII.A, XII.C
3.A.8	Baseline Distribution System and Financial Data System Data	Estimated distribution system annual loss percentage for the prior year	IV.C.3
3.A.9	Baseline Distribution System and Financial Data System Data	For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system	IV.C.1, IV.C.4
3.A.10	Baseline Distribution System and Financial Data System Data	Total distribution substation capacity in kVA	IV.C.5
3.A.11	Baseline Distribution System and Financial Data System Data	Total distribution transformer capacity in kVA	IV.C.6
3.A.12	Baseline Distribution System and Financial Data System Data	Total miles of overhead distribution wire	IV.C.7
3.A.13	Baseline Distribution System and Financial Data System Data	Total miles of underground distribution wire	IV.C.8
3.A.14	Baseline Distribution System and Financial Data System Data	Total number of distribution premises	IV.C.9

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.A.15	Baseline Distribution System and Financial Data System Data	Total costs spent on DER generation installation in the prior year. These costs should be broken down by category in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc).	XII.B.1
3.A.16	Baseline Distribution System and Financial Data System Data	Total charges to customers/member installers for DER generation installations, in the prior year. These charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)	XII.B.1
3.A.17	Baseline Distribution System and Financial Data System Data	Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	XI.B.1
3.A.18	Baseline Distribution System and Financial Data System Data	Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	XI.B.1
3.A.19	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	XI.B.1
3.A.20	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	XI.B.1
3.A.21	Baseline Distribution System and Financial Data System Data	Total number of electric vehicles in service territory	XI.B.2
3.A.22	Baseline Distribution System and Financial Data System Data	Total number and capacity of public electric vehicle charging stations	XI.B.2
3.A.23	Baseline Distribution System and Financial Data System Data	Number of units and MW/MWh ratings of battery storage	XI.B.1
3.A.24	Baseline Distribution System and Financial Data System Data	MWh saving and peak demand reductions from EE program spending in previous year	XI.B.1
3.A.25	Baseline Distribution System and Financial Data System Data	Amount of controllable demand (in both MW and as a percentage of system peak)	XI.B.1
3.A.26	Baseline Distribution System and Financial Data Financial Data	 Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other The Company may provide in the IDP any 2018 or earlier data in the following rate case categories: a. Asset Health b. New Business c. Capacity d. Fleet, Tools, and Equipment e. Grid Modernization 	II.D.2
3.A.27	Baseline Distribution System and Financial Data Financial Data	All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g., CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation.)	XII.B.1
3.A.28	Baseline Distribution System and Financial Data Financial Data	Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects	II.D.2, Figure 7, Table 7

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.A.29	Baseline Distribution System and Financial Data Financial Data	Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other	Attachments F1 & G1
3.A.30	Baseline Distribution System and Financial Data Financial Data	Provide any available cost benefit analysis in which the company evaluated a non- traditional distribution system solution to either a capital or operating upgrade or replacement	Attachment H
3.A.31	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)	XI.B.3
3.A.32	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.	XI.B.3
3.A.33	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.	XII.C.3
3.B.1	Hosting Capacity and Interconnection Requirements	Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems), how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources4, and any other method in which Xcel anticipates customer benefit stemming from the annual HCA.	XII.A
3.B.2	Hosting Capacity and Interconnection Requirements	Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process.5 (Footnote: Forthcoming Order, E999/CI-16-521, MN DIP 3.2 Initial Review)	XII.B.2
3.C.1	Distributed Energy Resource Scenario Analysis	In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER growth take place first.	XI.D
3.C.2	Distributed Energy Resource Scenario Analysis	Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.	XI.D
3.C.3	Distributed Energy Resource Scenario Analysis	Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.	XI.E
3.C.4	Distributed Energy Resource Scenario Analysis	Include information on anticipated impacts from FERC Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM-18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators)	XI.F.3

Section	Heading	MPUC IDP Requirement (8/30/18 Order in Docket No. E002/CI-18-251)	Location
3.D.1	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Merged into 3.D.2 per July 16, 2019 Order in Docket No. E002/CI-18-251.	N/A
3.D.2	Long-Term Distribution System Modernization and Infrastructure Investment Plan	See 07/16/19 Order requirements below for merged wording. See Attachment J, which lays out the full 3.D.2 requirements and where they are addressed.	XIV Attachment J
3.D.3	Long-Term Distribution System Modernization and Infrastructure Investment Plan	In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.	V.D, IX, X, XI, XIV, Attachments C and D1
3.E.1	Non-Wires (Non-Traditional) Alternatives Analysis	Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than \$2 million. For any forthcoming project or project in the filing year, which cost \$2 million or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.	VI Attachment H
3.E.2	Non-Wires (Non-Traditional) Alternatives Analysis	 Xcel shall provide information on the following: Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability) A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation) Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made. 	VI

Order Pt.	Heading	MPUC IDP Requirement (7/16/19 Order in Docket No. E002/CI-18-251)	Location
3	Long-Term Distribution System Modernization and Infrastructure Investment Plan	IDP Requirement 3.D.2 shall be amended as follows: For each grid modernization project in its 5-year Action Plan, require Xcel to provide a cost-benefit analysis <u>based on the best information it has at the time and include a</u> <u>discussion of non-quanitfiable benefits. Xcel shall provide all information used to</u> <u>support its analysis.</u>	IX, Attachments C, M1- M5 and O1-O4
4	Long-Term Distribution System Modernization and Infrastructure Investment Plan	IDP Requirement 3.D.2 shall be amended to merge Requirement 3.D.1 into 3.D.2 as follows: Xcel shall provide a 5-year Action Plan <u>as part of a 10-year long-term plan</u> for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER fugtures analysis, hosting capacity analysis, and non-wire alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel shall include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum: [As stated in the Aug 30, 2018 IDP filing requirements at 6].	XIV Attachment J
5	N/A	 Xcel shall discuss in future filings how the IDP meets the Commission's Planning Objectives, including: A. An analysis of how the information presented in the IDP related to each Planning Objective, B. The location in the IDP, C. Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and D. Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives. 	Attachment B, Section XV
6	N/A	Xcel shall provide additional information on the Incremental Customer Investment Initiative and the System Expansion or Upgrade for Reliability and Power Quality increases beginning in 2021.	VII.C, XIV
7	N/A	Xcel shall make the development of enhanced load and DER forecasting capabilities, as well as, tracking and updating of actual feeder daytime minimum loads, a priority in 2019 and include a detailed description of its progress in the Company's 2019 IDP.	V.D.2-3, XI.F Attachment D1
8	N/A	Xcel shall provide all information, analysis, and assumptions used to support the cost/benefit ratio for AMI, FAN and FLISR; and IVVO and CVR cost-benefit analysis as part of its 2019 IDP filing or other future filings.	IX, Attachments C, M1- M5 and O1-O4
9	N/A	Xcel shall provide the results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology, in future IDPs.	Attachments E and F2
10	N/A	Xcel shall provide information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for feeders and substation transformers that have a risk score or planned investment in the budget cycle in future IDPs.	Attachments F1 & F2
11	N/A	Xcel shall file any long-range distribution studies it had conducted in the time since the last IDP.	N/A for 2019

Correlation of IDP Content to Commission's IDP Planning Objectives

The Commission's July 16, 2019 Order in Docket E002/CI-18-251 requires the Company to discuss in future filings how the IDP meets the Commission's Planning Objectives, including:

- A. An analysis of how the information presented in the IDP related to each Planning Objective,
- B. The location in the IDP,
- C. Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and
- D. Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives.

The Commission's August 30, 2018 Order in Docket E002/CI-18-251 provided the Commission's Planning Objectives. Specifically, it noted that Xcel Energy's distribution system planning is to be guided by the following principles and planning objectives:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products and services, with opportunities for adoption of new distributed technologies;
- Ensure optimized use of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value

We have followed the format the Department used in their February 22, 2019 Comments in Docket E002/CI-18-251 in complying with the Commission's requirement.

A. Planning Objective #1

As noted above, the first planning objective of the IDP is designed to maintain and enhance the safety, security, reliability and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies. We provide a high-level analysis of the location of these topics in the IDP in Table 1 below.

Торіс	IDP Location
Safety	Executive Summary
	IB
	II B, D
	III B
	IV B
	VB
	VIII A. C
	VIII A. B
	IXF
	ХВ
	XII C
Security	Executive Summary
	IB
	ПС
	V A
	VIIC
	VIII A
	IX A. B. F
	XC
	XIE F
	XIV B
Reliability	Executive Summary
	I A. B. C
	II A. B. C. D. E
	III B
	IV B. C
	V A. B. C. D
	VI A. C. D
	IX A. B. H. I. I
	X A. B. C
	XI A. E. F
	XII A. C
	XIII A
	XIV A. B
	XVI
	XVII
Resilience	Executive Summary
	IB
	VII A. C
	VIII A
	XI A. E
	· · · · · · · · · · · · · · · · · · ·

Table 1: Location of Topics of the First Planning Objective in the IDP

Fair and Reasonable Costs	Executive Summary
	II A, B, C
	IX A, B, G, I,
	Х
	XIV A
Consistent with State Energy Policies	Executive Summary
	IIA, B, C
	III B
	IX A, B, J
	X

Table 1: Location of Topics of the First Planning Objective in the IDP (Cont'd)

As suggested by the table above, the Company addressed each of the topics of the first planning objective in a substantive way.

B. Planning Objective #2

The second planning objective of the IDP is to enable greater customer engagement, empowerment, and options for energy services.

Our IDP Report has a robust discussion with regard to these three topics. First, our distribution system planning processes, discussed in Section II (nearly 20 pages) are in part designed to enable greater customer engagement, empowerment, and options for energy services.

The Executive Summary (over 20 pages) of the IDP provides an overview of the customer-oriented outcomes expected from deploying advanced grid infrastructure and advanced technologies.

Our IDP provides great detail and discussion of these aspects of our distribution system planning when discussing our plans for Advanced Metering Infrastructure (AMI), Field Area Network (FAN), Fault Location, Isolation, and Service Restoration (FLISR), Integrated Volt Var Optimization (IVVO), and Integrated Volt Var Optimization (IVVO), and Advanced Distribution Management System (ADMS), each of which are technological innovations that are geared toward fulfilling the second planning objective. These are discussed throughout the filing but particularly in Section IX, Grid Modernization (which is over 25 pages) and Section X, the Customer Strategy Section (which is nearly 10 pages).

Namely, the IDP says this with regard to our Advanced Grid Intelligence and Security (AGIS) initiative investments:

Our planned advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. We will use this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications.

We will offer options that give customers greater convenience and control to save money, provide access to rates and billing options that suit their budgets and lifestyles, and provide more personalized and actionable communications. As our system more efficiently manages energy flows, we can save customers money by reducing line losses and conserving energy. Smarter meters will be the platform that enables smarter products and services and contributes to improved reliability for our customers. Our customers will have more information to make more effective decisions on their energy use.

The IDP also provides an extensive discussion on Distributed Energy Resources (DER) in Section XI (nearly 50 pages), Hosting Capacity in Section XIII (over 10 pages), and Grid Modernization Pilots in Section XIII (over 6 pages) which all also support the Commission's second planning objective to enable greater customer engagement, empowerment, and options for energy services.

Specifically, when discussing the Time of Use Pilot (TOU), the IDP states:

The goals of the TOU pilot are to study adequate price signals to reduce peak demand, identify effective customer engagement strategies, understand customer impacts by segment, and support demand response goals.

We note that this list is not exhaustive of the items discussed in the IDP that relate to the second planning objective. However, this does represent that we provided extensive information and discussion of items related to the second planning objective.

C. Planning Objective #3

The third planning objective of the IDP is designed to move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies.

Much of the information and discussion provided in the IDP related to the second planning objective are also applicable to the third planning objective. Our description of our AGIS initiative, of which AMI, FAN, FLISR, IVVO, and ADMS were discussed, provides information and discussion relevant to the third planning objective. These are discussed throughout the filing but particularly in Section IX, Grid Modernization (which is over 25 pages) and Section X, the Customer Strategy Section (which is nearly 10 pages).

Additionally, the advanced planning tool (APT) discussed throughout the document but particularly in the Executive Summary, Section V.D (8 pages), and Attachment D1 (nearly 25 pages), also relates to the third planning objective. We note the following:

We will also procure and implement an APT that will enhance our ability to perform NWA analysis, and DER and load forecast scenario analysis; it will also help to facilitate a greater alignment and integration of our distribution-transmission-resource planning.

We also provide this excerpt with respect to APT and the third planning objective:

Additionally, APT has the ability to export forecast results directly to load flow programs, such as Synergi Electric. This will improve the efficiency of the load flow model build process, which is performed to build models for planning studies and hosting capacity analysis.

The IDP Customer Strategy Section X (nearly 10 pages) also discusses how our AGIS plans will help improve the existing customer portal as well as the potential for additional opportunities in the future, saying:

Customers will have access to granular energy usage data from our AMI through a customer portal, which we expect to pair with informed insights and helpful tips on how to change their behavior to save energy. Further, the AMI meters we propose include a Distributed Intelligence platform, which essentially provides a computer in each customer's meter that will be able to "connect" usage information from the customer's appliances for further insights – and be updated with new software applications, much like customers can currently update their mobile devices with applications.
Finally, Section XIII Existing and Potential New Grid Modernization Pilots (over 6 pages) also relates to the third planning objective. Specifically, we provide information on our TOU Rate Pilot, four electric vehicle (EV) pilot programs as well as one additional new EV pilot, and several storage projects. Each of these pilots supports the third planning objective as they provide potential new platforms for new products, new services, and opportunities for adoption of new distributed technologies.

We note that this list is not exhaustive of the items discussed in the IDP that relate to the third planning objective. However, this does represent that we provided extensive information and discussion of items related to the third planning objective.

D. Planning Objective #4

The fourth planning objective of the IDP is designed to ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

In the IDP, we provide an entire section (nearly 10 pages) discussing our efforts toward integrating Distribution, Transmission, and Resource Planning in Section XVII, which entirely supports the fourth planning objective.

We also state that we have planned our "AGIS investments in a building-block approach, starting with the foundational systems, in alignment with industry standards and frameworks." Additionally, we provide a discussion comparing our current state systems and process against the DOE DSPx framework in addition to potential progression in planning practices along with a discussion regarding the drivers of progress.

Developing "core components" as the foundation for our advanced grid roadmap first and subsequently building on that foundation to enable advanced applications is well aligned with the DSPx framework. Many of these core components are already in place, and others we plan to implement in the near future will build additional core capabilities to support grid modernization applications.

In the context of the Company's planning efforts related to distributed energy resources (DER), we also provide an entire section (nearly 50 pages) within the IDP discussing this issue, specifically Section XI Distributed Energy Resources.

The investments that we are currently making in asset health, discussed in Section VII, and grid modernization, such as ADMS, AMI, FLISR, and IVVO help to lay the foundation for continued resiliency and reliability. Near-term future planned AGIS investments such as AMI further cement it, and will allow us to gradually respond to increased DER penetration. These are discussed throughout the filing but particularly

in Section IX, Grid Modernization (which is over 25 pages) and Section X, the Customer Strategy Section (which is nearly 10 pages).

The DOE has observed that U.S. utilities are in Stage 1 in terms of timing and pace toward a modern distribution grid and the DOE incorporated evolving distribution planning processes and tools into this evolution. Stage 1 also includes improving foundational capabilities such as availability, quantity, and quality of data, which is often achieved by implementing communication systems such as the FAN that is in our near-term advanced grid plans.

Again, we note that this list is not exhaustive of the items discussed in the IDP that relate to the fourth planning objective. However, this does represent that we provided extensive information and discussion of items related to the fourth planning objective.

E. Planning Objective #5

Finally, and as noted above, the fifth planning objective of the IDP is to provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

The IDP provides a comprehensive discussion about our short-term and long-term distribution system plans and investments within Section II.D, Distribution Financial Overview (over 12 pages), Section II.E, Distribution System Plan Summary (over 4 pages), Section IX, Grid Modernization (over 25 pages), and Section XIV, Action Plans (over 10 pages).

In addition, we provide a through description of how we plan the distribution system in Section II, Distribution System Plan Overview (nearly 20 pages) and Section V, System Planning (nearly 40 pages); as well as how we develop the budget in Section III Budget Development Framework (nearly 10 pages).

With regard to the costs and benefits of specific investments, we discuss this at length throughout the IDP. In particular, we provide Section VI Non-Wires Alternatives Analysis (10 pages in the IDP and 40 page Attachment H), which provides the cost benefit analyses we performed to evaluate non-traditional distribution system solutions to our traditional distribution solutions. We also provide cost benefit analysis for all of our AGIS investments and the Advanced Distribution Planning Tool. These can be found in Section IX Grid Modernization (over 25 pages) (as well as supporting Attachments M1-M5, totaling nearly 900 pages), Section V.D Future Planning Tools and Supporting Attachments D1 and D2 (nearly 25 pages), and Attachments O1-O4.

With regard to ratepayer value, in Section IX Grid Modernization (over 25 pages) we discuss the overall customer proposition for AGIS, including drivers of the initiative, expected customer and system benefits, and a cost benefit analysis. In this section we also provide the quantifiable impact to a customer's bill as a result of the increased revenue requirement due to our investments and O&M spending necessary to implement the AGIS initiative.

We note that this list is not exhaustive of the items discussed in the IDP that relate to the fifth planning objective. However, this does represent that we provided extensive information and discussion of items related to the fifth planning objective.

F. IDP Filing Requirement Refinements

Finally, with respect to the last discussion point requesting the Company provide suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives, we reiterate our request that the Commission move to a biennial filing cadence for the IDP, consistent with other Minnesota utilities and the grid modernization statute filing requirements.

We believe a biennial filing would better allow time to fully engage with stakeholders on the Commission's planning objectives between IDP filings, as well as to address important issues such as DER planning, a comprehensive approach to non-wire alternatives (NWA), and our advanced grid plans. The present annual filing schedule also does not allow the Company to make significant, meaningful progress on its objectives between these extensive filings.

IDP Grid Modernization Content Roadmap

Planning Objectives: The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to: Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;

Enable greater customer engagement, empowerment, and options for energy services;

· Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and,

· Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

Provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

Source	Requirement/Description	IDP	Rate Case: AGIS [as presented in Gersack as Exhibit(MCG-1), Schedule 2]
Docket No.	A. Baseline Distribution System and Financial Data: Financial Data		
E002/CI-18-231 Aug. 30, 2018 Order (Updated to include changes from Jul 16, 2019 Order)	 26. Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other 	11.D, 111.B, X111, XIV	Addressed in IDP
	28. Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non- traditional distribution projects	II.D-E, IX, XIV, Attachments M1, M2, M3, M5	Gersack II(C) AGIS Expenditures 2020-2029 Gersack V(D)(2) AGIS PM Costs 2020-2029 Bloch V(A) AGIS - Distribution 2020-2029 Bloch V(D)(5) AMI - Distribution 2020-2029 Bloch V(F)(6) FLISR - Distribution 2020-2029 Bloch V(F)(6) FLISR - Distribution 2020-2029 Harkness V(E)(3)(c)(4) AMI - IT 2020-2029 Harkness V(E)(5)(c) FLISR - IT 2020-2029 Harkness V(E)(5)(c) FLISR - IT 2020-2029 Harkness V(E)(6)(c) IVVO - IT 2020-2029 Harkness V(E)(6)(c) IVVO - IT 2020-2029 Harkness V(E)(7) AGIS - IT 2020-2029 Duggirala Schedules 2, 3, 4
	 29. Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should include: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other 	II.D, IX, XIV, and Attachments F1, G1, M1, M2, M3	Gersack II(B) Exec Summary - Drivers Gersack IV Drivers of AGIS Strategy Gersack II(C) Exec Summary - Implementation Gersack V(A) Component Implementation Bloch V(A) Projects and Timeline/Implementation Bloch V(B) Overall Timeline/Implementation Bloch V(D) AMI Bloch V(D) FAIS Bloch V(E) FAN Bloch V(E) FAN Bloch V(E) FIAS Bloch V(C) IVVO Harkness V(B)(E) AGIS Overview Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO
	30. Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement	VI and Attachment H	Addressed in IDP

Source	Requirement/Description	IDP	Rate Case: AGIS [as presented in Gersack as Exhibit(MCG-1), Schedule 2]
Docket No. E002/CI-18-251 Aug. 30, 2018 Order (Updated to include changes from Jul 16, 2019 Order)	D. Long-Term Distribution System Modernization and Infrastructure Investment Plan		
	2. Xcel shall provide a 5-year Action Plan <u>as part of a 10-year long-term plan</u> for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures analysis, hosting capacity analysis, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:	XIV and Attachments J, M1	Gersack II Exec Summary Gersack IV Drivers of AGIS Strategy Gersack V AGIS Components and Implementation Gersack VI Customer Experience
	· Overview of investment plan: scope, timing, and cost recovery mechanism	II, IX and XIV and Attachment M1	Gersack II Exec Summary
	• Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.	IX, X, XIV, Figure 73 and Attachments M1- M4	Gersack V AGIS Components and Implementation Bloch V(D) AMI Bloch V(E) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(4) FAN Harkness V(E)(6) IVVO Harkness V(E)(6) IVVO Harkness V(F) Quantifiable Benefits Gersack VI Customer Experience (Benefits)
	• Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.	IX and Attachments M1- M3	Gersack V(C) Alternatives to AGIS Bloch V(D)(6) AMI Alternatives Bloch V(F)(7) FLISR Alternatives Bloch V(G)(6) IVVO Alternatives Harkness V(E)(4)(g) FAN Alternatives
	· System interoperability and communications strategy	IX, X and Attachments M2, M3	Bloch V(D)(7) AMI Interoperability Bloch V(F)(8) FLISR Interoperability Bloch V(G)(7) IVVO Interoperability Harkness V(E)(4) FAN Overview Harkness V(E)(4)(b) FAN Interoperability Harkness V(E)(3)(b) AMI Integration
	 Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.) 	IDP XI (F)	Addressed in IDP
	• Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)	Attachment M1	Gersack VI(B)(4) Energy Savings Programs
	· Customer anticipated benefit and cost	V.D.2, IX.F-G, XVI and Attachments M1-M5, O1-O4	Gersack VII Prudence of AGIS Investments (CBA) Duggirala Overall CBA Costs, Benefits, Results Gersack VIII Bill Impacts Costs and Benefits are also discussed throughout Bloch V (AGIS), Harkness V (AGIS), and Cardenas V (AGIS)
	• Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)	IX, X and Attachments M1, M3	Gersack VI Customer Experience (overall) Gersack VI(B)(3) Digital Experience (web portal) Gersack Schedule 3 Customer Strategy (Appendix B: Data Access, Privacy, Governance) Harkness V(D) Cyber Security
	• Plans to manage rate or bill impacts, if any	IX.G, XIV.A and Attachment M1	Gersack VIII Bill Impacts
	Impacts to net present value of system costs (in NPV RR/MWh or MW)	XIV and Attachment L	Addressed in IDP

Source	Requirement/Description	IDP	Rate Case: AGIS [as presented in Gersack as Exhibit(MCG-1), Schedule 2]
Docket No. E002/CI-18-251 Aug. 30, 2018 Order (Updated to include changes from Jul 16, 2019 Order)	• For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis <u>based on the</u> best information it has at the time and including a discussion of non-quantifiable benefits. Xcel shall include all information used to support its analysis.	IX, X and Attachments M1-M5, O1-O4, filed Workpapers	Gersack VII(A) CBA Gesack VII(B) Qualitative Benefits Duggirala II(B) Quantitative Inputs Duggirala II(C) Results Duggirala IV Qualitative Benefits
	· Status of any existing pilots or potential for new opportunities for grid modernization pilots	IX, X, XIII and Attachment M1	Gersack III Grid Mod Background (Res TOU Pilot) Gersack IV(C)(2) Advanced Rate Design/Billing Options
	3. In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.	IX, X, XIV and Attachments M1, M2	Gersack II Exec Summary Gersack V AGIS Implementation Gersack VI(D) Customer Experience (Long Term) Bloch D(4)(d) (1) AMI Benefits (DER) Bloch G(4)(b) IVVO Benefits (DER)
Docket No. E002/CI-18-251 July 16, 2019 Order	8. Provide all information, analysis and assumptions used to support the cost/benefit ratio for AMI, FAN, and FLISR; and IVVO and CVR cost-benefit analysis as part of its 2019 IDP filing or other future filings.	IX.F and Attachments M1-M5, O1-O4, filed Workpapers	Duggirala Overall - CBA testimony points to the other witnesses who provide detailed cost and benefit forecasts.
Docket No. E002/M-17-797 Sept. 27, 2019 Order	and when Xcel requests cost recovery for Advanced Grid Intelligence and Security investments, the filing must include a ness case and comprehensive assessment of qualitative and quantitative benefits to customers, considering, at a minimum, following:		Gersack II Exec Summary Gersack III Grid Mod Background Gersack IV(D) Commission Policy and Stakeholder Input Gersack V(A) AGIS Components
	A. Scope of Investment		Gersack V(B) Overall Implementation
	a. Detailed description of proposed investment and project life	IV V and	Gersack VII(B) Qualitative Benefits
	b. If multiple components, overview of costs and descriptions of each	Attachments M1-M5	Bloch V(D) AMI
	i. Include purpose and role		Bloch V(E) FAN
	ii. Explain known and potential future use cases for each component		Bloch V(G) IVVO
	 iii. Explain known and potential value streams and how each component fits with state policy, statues, rules and Commission orders iv. Describe beneficiaries of each investment (who, how many, over what time period) c. Articulation of principles, objectives, capability, functionalities, and technologies enabled by investment; and d. Investment of investment investment for the principles. 	-	Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO
	 Internation and interdependences with oner existing of rudic investments, including overlapping costs, scope, anothin, dining. Alternatives considered 		Gersack V(C) Alternatives to AGIS Bloch V(D)(5) AMI Cost Development (RFP discussion) Bloch V(D)(6) AMI Alternatives Bloch V(F)(6) FLISR Cost Development Bloch V(F)(7) FLISR Alternatives Bloch V(G)(5) IVVO Cost Development
	a. If a Request for Proposal was used provide:		
	i. The RFP issued, including list of all services or assets scoped in the RFP	Attachments M1-M3,	
	ii. Provide summary of responses	N1-N4	
	iii. Provide assessment of bids and factors used for selection		Bloch V(G)(6) IVVO Alternatives Harkness V(E)(4)(e) EAN Cost Development
	iv. The scope of offerings or services included in the selected bid		Harkness V(E)(4)(g) FAN Alternatives
1	b. If not, what was used.		AGIS Supporting files, Vol. 2B (on disc)
	3. Costs	IX and Attachments M5, O1-4, filed Workeapers	Duggirala II(A) Model Structure and Requirements Duggirala Schedules 2, 3, 4, 5
	a. Provide sufficient information to determine what is included in the investment in each of the following categories:		
	i. Indirect Costs (product, service, customer, project, or activity)		
1	iii. Tangible Costs		
	iv. Intangible Costs v. Real Costs		
	b. If needed, provide the utility's definition of each category and whether internal or external labor costs are included in the category and the instant petition. If the costs are not included in the petition, include information on where and when those costs will be sought to be recovered.	Attachment M5	Duggirala II(A) Model Structure and Requirements
	c. If there is overlap or costs included in both categories, outline the overlapping costs and explain.	Attachment M5	Duggirala II(A) Model Structure and Requirements Duggirala Schedules 2, 3, 4, 5
	d. For each of the cost categories outline whether the investment has been partially approved or included in previous or on-going docket riders, rate cases, or other cost recovery mechanisms or note all costs are included in the instant petition.	II.D-E, IX, XIV, XV	Gersack II(C) Exec Summary - AGIS Implementation Gersack III Grid Mod Background Bloch V(C) Grid Mod Efforts to Date Harkness V(E)(2) Grid Mod Efforts to Date

Source	Requirement/Description	IDP	Rate Case: AGIS [as presented in Gersack as Exhibit(MCG-1), Schedule 2]
Docket No. E002/M-17-797 Sept. 27, 2019 Order	4. Detailed Analysis of the type of proposed or multiple cost effectiveness analysis utilized:	Attachment M5	Duovirala III
	a. Least-cost, best-fit (Xcel proposes in IDP Reply comments)		
	b. Utility Cost-test; and		
	c. Integrated Power System and Societal Cost test		
	B. Provide a cost benefit analysis for (1) each investment component with overlapping costs or benefits in isolation and (2) each bundled components, as appropriate	V.D, IX and Attachments D2, M1- M5, O1-O4, filed Workpapers	Duggirala II(C) CBA Results AGIS Supporting files, Vol. 2B (on disc) Gersack VII(A)(1) CBA Overview
	1. Provide Discount Rate Used and Basis; and	Attachment M5 and filed Workpapers	Duggirala II(A) Model Structure and Requirements
	Identify cost categories and benefit categories used (explain metrics), including an explaination of how benefits can be monitored over time and proposal for reporting to Commission:	IX and Attachments M1, M5	Duggirala II(B) Quantitative Inputs Gersack IX Metrics and Reporting
	 a. Identify quantitative costs and qualitative costs: i. Use quantitative methods to address qualitative benefits to the extent possible. ii. Explain system used to assess value and priorities to qualitative benefits (points and/or weighting); and iii. Identify sensitivity ranges on estimates or value 	V.D, IX and Attachments D1, D2, M5, O1-O4	Duggirala Overall CBA Costs, Benefits, Results
	b. Include a long-term bill impact analysis	IX , XIV and Attachment M1	Gersack VIII Bill Impacts
	c. Include a reference case/scenario without the project (or group of projects); and	IX, XIV and Attachments M1, M5	Duggirala II(A) Model Structure and Requirements Gersack VIII Bill Impacts
	d. Apply the following principles to ensure the investment analysis has:		The Company has incorporated these priciples throughout its analyses, including: Gersack V AGIS Components and Implementation Bloch V(D) AMI Bloch V(F) FAN Bloch V(F) FLISR Bloch V(G) IVVO Harkness V(E)(3) AMI Harkness V(E)(4) FAN Harkness V(E)(5) FLISR Harkness V(E)(6) IVVO
	i. compared with traditional resources or technologies;		
	ii. clearly accounted for state regulatory and policy goals;		
	iii. accounted for all relevant costs and benefits, including those difficult to quantify;		
	iv. provided symmetry across relevant costs and benefits;		
	v. applied a full life-cycle analysis;	Attachments M1-M5	
	vi. provided a sufficient incremental and forward-looking view;	Truteriniento III 110	
	vii. is transparent;		
	viii. avoided combining or conflating different costs and benefits;		
	ix. discuss customer equity issues, as needed;		Cardenas V(F) Quantifiable Benefits
	x. assessed bundles and portfolio where reasonable; and		Gersack VI Customer Experience (Benefits) Duggirala Overall CBA Costs, Benefits, Results
	xi. addressed locational and temporal values.		