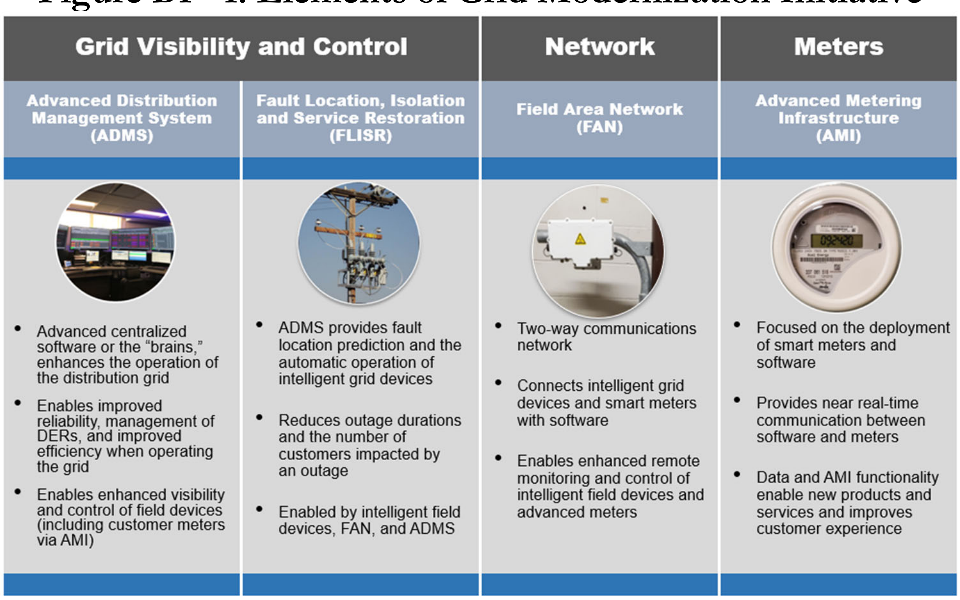
APPENDIX B1: GRID MODERNIZATION

For more than 100 years, Xcel Energy has provided its customers and communities with outstanding service – delivering safe, reliable, and affordable energy. We are looking to the future and advancing the grid to ensure it will continue to provide our customers benefits for many years to come. We are planning and investing in technologies to meet customer and operational needs now and in the future. This means taking a measured and thoughtful approach to maximize customer value, ensuring the fundamentals of our distribution business remain sound, and maintaining the flexibility needed as technology and our customers' expectations continue to evolve.

This Appendix discusses our grid modernization strategy that includes our Grid Modernization initiative, which is a distinct, long-term strategic plan to transform our electric distribution system to update foundational system technologies and capabilities. For the financial forecasts associated with our grid modernization plans, please see *Appendix D: Distribution Financial Framework and Information*. Overall, the Grid Modernization initiative consists of multiple elements, as shown in Figure B1-1, that work together to create a more modern and advanced distribution grid intended to meet changing customer demands, enhance transparency into the distribution and to system data, to promote efficiency and reliability, and to safely integrate more distributed energy resources (DER).

Figure B1 - 1: Elements of Grid Modernization Initiative



The elements shown above will combine with other technologies and capabilities over time to support public policies, such as the Distributed Solar Energy Standard, Community Solar Gardens, Energy Conservation & Optimization (ECO), and more, in addition to the Company's strategic objectives of leading the clean energy transition, enhancing service to customers, and at the same time, keeping customer bills affordable.

We discuss our grid modernization roadmap below. We also outline our customer strategy and roadmap related to present and future grid modernization efforts in Section V below, and the ways we intend to leverage the data for operational and planning purposes as *Appendix B2: Customer, Operational, and Planning Data Management, Security, and Information Access Plans and Policies*. Finally, we note that protective cyber security controls and protocols are built into every step and technology underlying our overall plan, and are essential to operating a secure, technologically advanced grid in today's world. We also discuss our approach to data security in Appendix B2.

I. DRIVERS OF THE GRID MODERNIZATION INITIATIVE

We have 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. We are now modernizing the grid at a more rapid pace in response to customer usage patterns, policies, and technical developments. All indications suggest our investments are coming at the right time and must continue. Drivers of our Grid Modernization strategy remain:

- 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 and future distribution system needs –in consideration of increasing integration of the grid, and
- Legislative and Commission policy and direction, and stakeholder input relative to customer offerings, performance, and technological capabilities of the grid.

We are working every day to lead the transition to a clean energy future, enhance our customers' experience with our service, and keep bills low. Our customers are our partners in an environmentally sound future. We are committed to empower them with better and more information and data to manage their energy usage and to make other energy choices. We recognize that DERs are also a key to this clean energy future, as are two-way communications connecting key elements of the distribution grid, down to the meter level. Advanced Metering Infrastructure (AMI) and the supporting Field Area Network (FAN) infrastructure, the other components of the Grid Modernization initiative, and additional technologies and capabilities that are part of our roadmap are critical to these efforts. These are necessary changes to accommodate increasing levels of DER interconnecting with the system.

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. AMI more easily and flexibly gathers detailed customer energy usage information, which can help customers better understand and manage their usage and inform other ways the Company can enhance our service to our customers. Other advanced equipment on the grid, such as Fault Location Isolation and Service Restoration (FLISR) that is also underway, can detect, communicate, and respond in real time to power outages – improving customer reliability and the tools and information available to our operators to manage the grid. These advancements form the foundation for a flexible grid environment that helps support increasing amounts of 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.

Our grid modernization strategy results in a more interactive, advanced distribution system that improves customers' overall experience by:

- Providing them with more timely and granular energy usage data,
- Creating better interfaces to better understand, control and manage their monthly bills,
- Providing them with more choices, and
- Spreading the costs over an appropriate period of time to manage the cost impact for our customers.

Finally, our strategy recognizes the importance of focusing on our customers' reliability experience – be it shorter outage durations, fewer customers that are impacted, timely communications, or accurate restoration estimates – is at the core of quality electric service.

Continued investment in the "business as usual" portion of our operations is equally as important as new technology. To support the clean energy transition, realize the efficiency gains from our advanced grid implementation, and maintain the integrity, reliability, and safety of our operations and service to customers, we are making additional strategic investments in asset health – the backbone of our operations and grid. As the operation of the distribution system becomes more complex through more integrated field devices and with the increased adoption of DER, it will be increasingly important for the Company to invest in asset health and reliability projects.

Expansion of DER and electrification generally will require that distribution equipment be designed to a modern standard when these new generation sources or loads come online. Accommodating these resources requires that our distribution equipment be robust enough to maintain proper voltage levels, have the capacity to distribute the required power, proper relay protection and equipment, and have operability with modern grid assets.

Maintaining a proper balance and continued focus on asset health and reliability projects improve the overall customer experience by supporting higher levels of DER adoption, preventing outage events, and maintaining or improving overall reliability and resiliency performance. Our customers' reliability expectations continue to increase and have been further amplified by the COVID-19 pandemic, which led to a greater acceptance of working from home. Thus, it is important that the Company continue to make necessary investments in the backbone of our system as well as new technologies to ensure that reliability is maintained on the system.

The Company has always performed well with respect to system management, reliability, and customer service – but we must make further grid and technology investments to ensure continued alignment with industry direction and customer expectations.

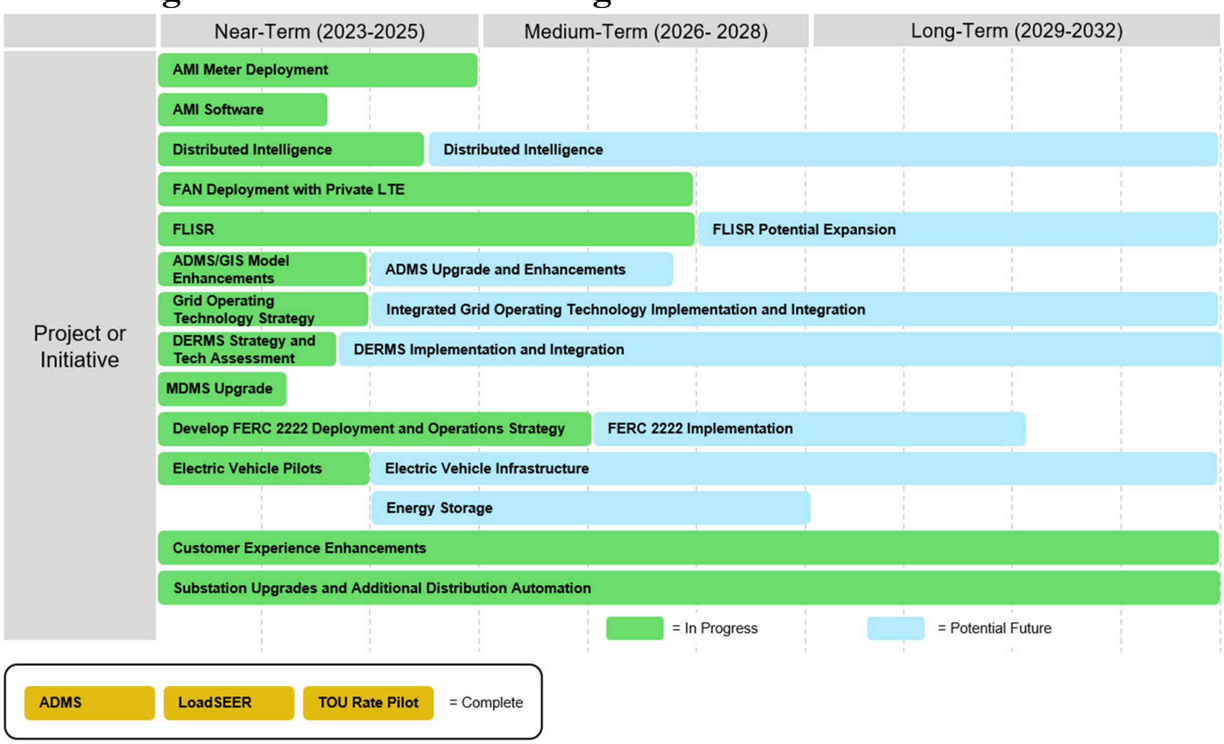
Enhanced grid management through an Advanced Distribution Management System (ADMS), meters with two-way communications that act as sensors, and greater sensing and control will all support our ability to host increasing levels of DERs.

All of these circumstances helped to drive and form the Company's Grid Modernization initiative. We will continue to evolve our plans and leverage evolving technology, platforms, and optionality as appropriate over time. We are excited to modernize our system in a measured way that addresses 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.

II. GRID MODERNIZATION ROADMAP

As we have noted, our implementation of the first foundational components of modernizing our grid is underway. Our grid modernization plans include implementing additional technologies and capabilities over the long-term – also leveraging earlier components to deliver increasing value to customers as illustrated in Figure B1-2 below.

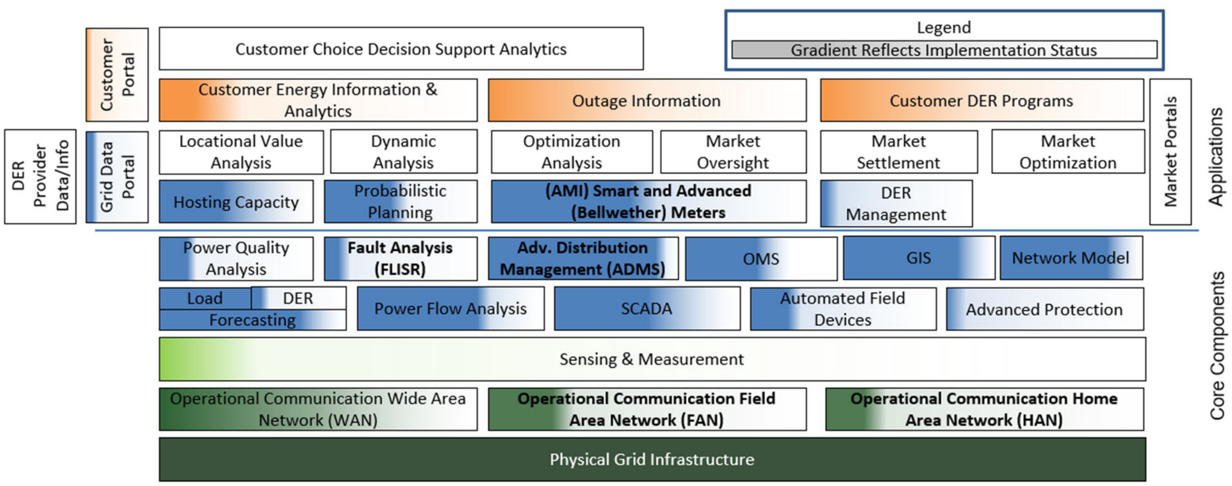
Figure B1 - 2: Illustrative Long-Term Grid Modernization Plan



IDP Requirement 3.D.2.b requires the Company to describe the 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. The U.S. Department of Energy's (DOE's) Next Generation DSPx, Volume III provides a good reference for how to consider both the elements of a modern grid and their costs.[1] The DSPx report was sponsored by the U.S. DOE's Office of Electricity Delivery and Energy Reliability. This report was developed at the request of, and with guidance from, the Minnesota Commission among others like the California Public Utilities Commission, the New York Public Service Commission, and the Hawaii Public Utilities Commission.

We portray our current state systems and processes against the DSPx framework as shown in Figure B1-3 below – developing "core components" as the foundation for our grid modernization roadmap first and subsequently building on that foundation to enable advanced applications, which is well aligned with the DSPx framework. As we discuss below, many of these core components are already in place, and others we are poised to implement in the near-term – all of which will build additional core capabilities to support grid modernization applications.

Figure B1 - 3: Estimated Status of Grid Modernization Implementation



In addition to the DSPx framework, the Company developed its own Grid Architecture – a reference that aids in development of a plan to modernize the distribution system. Our Grid Architecture depicts System Architecture of our electric power grid – from control engineering, communications and networking, to organizational structure, and power markets. We employ architectural depictions to help communicate how our systems interact. Our Grid Architecture allows us to proactively manage our grid and enterprise risk by:

- Identifying and addressing operational and functional gaps,

[1] *See Modern Distribution Grid, Volume III: Decision Guide*, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017). Available at https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf.

- Identifying and managing competing priorities, and
- Identify innovative opportunities that add to our business value and improve efficiencies.

Our Grid Modernization initiative heavily used these architectural principles in each of its programs. We have and will continue to use architectural principles in building these tools and to ensure they work efficiently and effectively with each other.

III. GRID MODERNIZATION IMPLEMENTATION SUMMARY AND STATUS

While incremental modernization efforts have taken place on the distribution system over many years and we have used these investments to provide reliable power for decades, our investments in ADMS, AMI, FAN, and sensing and control technologies such as FLISR particularly begin a more significant advancement of the grid. These foundational elements, in concert with other future investments, will provide cumulative benefits over time and transform the customer experience by providing new, innovative customer programs and service offerings, developed internally and in concert with partners.

In this section, we outline each of the grid modernization technologies and initiatives we have underway or that is in our near-term plans and discuss our customer strategy and roadmap. In Appendix B2, we discuss data security and the ways that we intend to leverage the data for operational and planning purposes.

The Grid Modernization initiative builds the foundation of our grid modernization plans and includes ADMS, AMI, the FAN, and FLISR. The Commission certified ADMS in 2016, and we completed in-servicing in 2021. The Commission certified AMI and FAN as an outcome of our 2019 IDP in Docket No. E002/M-19-666, and we began deploying AMI meters in April 2022. The Commission approved initial cost recovery of FLISR program costs in its July 17, 2023 rate case Order in Docket No. E002/GR-21-630. As of the end of August 2023, we have installed a total of approximately 34 FLISR devices and have begun integrating these devices in ADMS.

A. Implementation Snapshot

Implementation of the near-term components of our Grid Modernization plans will occur over several years and be substantially complete by 2025. We provide a snapshot of our implementation timeline in Table B1-1 below.

Table B1 - 1: Grid Modernization Technologies and Initiatives Deployment Timeline

Program	Implementation Timeline
ADMS	Our ADMS was deployed in the first two Minnesota control centers in April 2021 and deployed in the final Minnesota distribution control center in September 2021.
AMI	Meter deployment began in 2022, with anticipated completion in 2025.
FAN	The initial network and security design was completed in 2020. The first FAN device was installed and programmed in May 2021 and the installation and programming of additional FAN devices will continue through 2025. For any given geography, FAN availability will precede AMI meter deployment by approximately 6 months, to ensure that meters will have a fully operational network to use when they are installed.
FLISR	Installation of automated field devices (reclosers and switches) and substation upgrades began in 2021 on select feeders and will continue to be expanded to other feeders through 2027. The ADMS FLISR functionality will be available to the Minnesota control centers use starting in 2023 on select feeders and will be continued to be expanded to other feeders through 2027.

In addition, we have concluded two grid modernization projects: the Time of Use (TOU) Rate Pilot and LoadSEER. The TOU Pilot launched in November 2020 and concluded in late 2022. LoadSEER implementation is complete and was first used in Minnesota in September 2020. We discuss both projects briefly below; we will not include these projects in future IDPs, as they are complete.

We address our grid modernization projects in turn below, and we provide financial information for the four ongoing projects shown in Table B1-1. Additional funds included in the distribution budget shown in Appendix D include $7.6 million in capital and $4.3 million in O&M related to maintenance of installed devices. Once major grid modernization projects are completed, their ongoing costs will be reflected in other budget categories. For example, when the initial, project-based deployment of AMI meters is complete, those ongoing costs will be reflected in the distribution budget metering category.

B. Advanced Distribution Management System

ADMS is the foundational software platform for operational hardware and software applications used to operate the current and future distribution grid. ADMS is foundational because it provides situational awareness and automated capabilities that sustain and improve the performance of an increasingly complex grid. Specifically, ADMS acts as a centralized decision support system that assists the control room, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. ADMS does this by utilizing the as-operated electrical model and maintaining advanced applications, which provide the Company with greater visibility and control of an electric distribution grid that is capable of automated operations. In particular, ADMS incorporates Distribution Supervisory Control and Data Acquisition (D-SCADA) measurements and advanced application functions with an enhanced system model to provide load flow calculations everywhere on the grid, accurately adjusting the calculations with changes in grid topology and insights from devices and sensors. This allows the Company to improve the monitoring and control of power from substations to the edge of the grid, which enables multiple performance objectives to be realized over the entire grid.

The Commission certified ADMS in 2016, and we are recovering the costs of ADMS through the Transmission Cost Recovery (TCR) Rider, beginning in Docket No. E002/M-17-797.

1. Implementation

The Company completed the deployment of ADMS to all Minnesota Distribution Control Centers (DCC) in 2021. Deploying ADMS to all DCCs was the culmination of all necessary efforts to implement an operational system. Specifically, this is when our control center operators began using the ADMS system as designed – which for the first control center go-live included monitoring and control of substations, field devices, and feeders. Since the first DCC go live in April 2021, the system has performed very well and has been extremely stable. The last part of the initial ADMS deployment project is to complete the primary system asset data validation work that is necessary to support model quality as part of the implementation of ADMS, as informed by a National Renewable Energy Laboratory study.[2] We expect that to conclude in 2024.

2. Benefits

ADMS enables management of the complex interaction among outage events, distribution switching operations, FLISR and visibility to DERs and two-way power flow in the near-term, while preparing the Company to implement advanced applications like Distributed Energy Resource Management System (DERMS) in the future.

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[2] We first discussed and provided a report on this in our November 8, 2017 filing in the TCR Rider proceeding in Docket No. E002/M-17-797.

The GIS data improvement needed to enable ADMS also furthers grid modernization efforts related to DER. Specifically, this effort will help DER adoption by improving the GIS model that is used for system planning and for hosting capacity analysis. The data collection and improvements will reduce the amount of time that planning engineers spend preparing each model for analysis. The verification and population of additional data attributes will also help our designers validate capacity necessary for electric vehicles.

The current version (3.7) of the ADMS will be at end of life in mid-2026, so we are actively planning for our next phase of distribution management operating technology. As we discuss in Section IV below, we envision the convergence of operating technology across the grid in the future and are in the midst of developing a roadmap to that future.

3. *Financials*

For ADMS, we expect $900,000 in capital costs and $1.8 million in O&M costs over the five-year budget period. These amounts include Distribution and Technology Services budgeted amounts.[3]

**Table B1 - 2: ADMS Capital Expenditures Budget
Minnesota Electric Distribution (Millions)**

Project Component		2024	2025	2026	2027	2028
ADMS	Dist	$0.9	-	-	-	-
Total		**$0.9**	**-**	**-**	**-**	**-**

[3] The Distribution budget portion for ADMS is included in the budget totals presented in Appendix D.

Table B1 - 3: ADMS O&M Expenditures Budget
Minnesota Electric Distribution and Technology Services (Millions)

Project Component		2024	2025	2026	2027	2028
ADMS	Dist	$0.3	-	-	-	-
	Tech Svcs	$1.5	-	-	-	-
Total		**$1.8**	**-**	**-**	**-**	**-**

As the project aspect of this investment concludes, ongoing costs will be reflected in the Company's distribution and technology services budgets.

C. Advanced Metering Infrastructure

AMI is the Company's metering solution, consisting of an integrated system of advanced meters, communication networks, and software that enables the AMI functionality and secure two-way communication between the Company's data systems and customer meters. The AMI meters we are currently deploying, the Itron Riva 4.2, include Distributed Intelligence (DI) capabilities. This is a powerful distributed processing capability which, when integrated into the Company's broader ecosystem of customer and grid management systems, will unlock both customer and grid-facing benefits. We discuss our DI plans further in *Appendix J: Distributed Intelligence.*

The Commission certified AMI in our 2019 IDP proceeding, and we are currently recovering costs through the TCR Rider.

1. Implementation

Installation of AMI meters in Minnesota began in April 2022. As of September 30, 2023, we have installed approximately 512,250 AMI meters, and plan to complete deployment of approximately 1.4 million meters by the end of 2025.

As we have conveyed previously, the global supply chain constraints have impacted our meter supplier, Itron's, ability to supply the number of meters originally planned extending the completion of our AMI deployment into 2025. The Compan entered into an agreement with Itron, Inc. in 2019 to supply and install electric AMI meters across the Company's enterprise. Under the agreement with Itron, Itron has full responsibility to supply and install AMI meters. The Company was notified by Itron in July 2021 that a force majeure event tied to global component shortages of key meter components had occurred. After a diligent review of Itron's force majeure claim, in September 2021, the Company acknowledged a force majeure event resulting from a global shortage of integrated circuits (semiconductors). It is important to note that semiconductor shortages were widely publicized and impacted a number of industries beyond meters, including the automotive, medical supply, consumer goods, and electronics industries. It is also important to note that the component shortages impacting electric meters were industry-wide and were not limited to Itron.

Since the force majeure event, the Company has worked diligently with Itron to manage and mitigate the impacts of the meter shortages, to plan for the reduced meter availability, and to try to maintain the overall completion dates for the AMI deployment. This includes but is not limited to regular planning and forecasting meetings, supply chain meetings with Itron's operations and supply chain leadership where we assessed current market conditions and impacts on the Company's deployment, as well as other executive meetings including with Itron's CEO.

The forecasted supply chain recovery of semiconductors from Itron has shifted from an originally forecasted recovery in 2022 until July 2023, in which Itron and the Company mutually agreed and acknowledged that the force majeure was no longer active.

Table B1-4 provides the current deployment plan; we caveat, however, that we expect there will continue to be some uncertainty with regard to the specific meter volumes and installations through 2025 so the below should be viewed as estimates.

Table B1 - 4: Latest Available Meter Deployment Schedule – Minnesota

Year	Meters Deployed
2022	128,000
2023	545,000
2024	600,000
2025	127,360

2. *Benefits*

AMI is a key element of the Grid Modernization initiative because it provides a central source of information that interacts with many of the other components of a modern grid. The capabilities and data delivered by AMI provides customer benefits in reliability and ability for remote connection and disconnection, and enables greater customer offerings for rates, programs, and services. AMI also enhances utility planning and operational capabilities. Access to timely, accurate and consistent AMI data will provide insights for customers to make informed decisions about their energy sources and usage of reliable and sustainable energy. As we have noted, the AMI meters include an embedded DI platform that has the potential to further enhance the distribution grid capabilities as well as the customer experience. We discuss our DI plans further in Appendix J and discuss customer data access further in Appendix J and Appendix B2.

3. Financials

For AMI, we expect $157.9 million in capital costs and $26.6 million in O&M costs over the five-year budget period. These amounts include Distribution and Technology Services budgeted amounts, as shown in Tables B1-5 and B1-6.[4]

Table B1 - 5: AMI Capital Expenditures Budget
Minnesota Electric Distribution and Technology Services (Millions)

Project Component		2024	2025	2026	2027	2028
AMI	Dist	$94.9	$37.9	$20.2	-	-
	Tech Svcs	$4.2	$0.7	-	-	-
Total		**$99.1**	**$38.6**	**$20.2**	**-**	**-**

Table B1 - 6: AMI O&M Expenditures Budget
Minnesota Electric Distribution and Technology Services (Millions)

Project Component		2024	2025	2026	2027	2028
AMI	Dist	$0.9	$0.8	-	-	-
	Tech Svcs	$11.9	$13.0	-	-	-
Total		**$12.8**	**$13.8**	**-**	**-**	**-**

As the project aspect of this investment concludes, ongoing costs will be reflected in in the distribution budget's metering category.

[4] The Distribution budget portion for AMI is included in the budget totals presented in Appendix D.

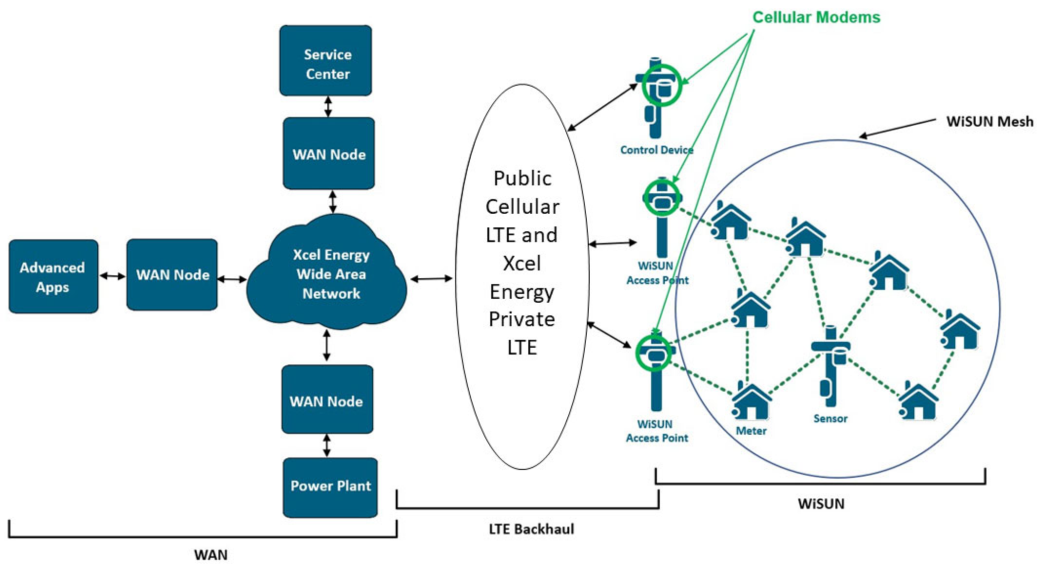
D. Field Area Network

The Field Area Network (FAN) is a secure, flexible two-way communication network that provides wireless communications to and from meters, field devices and our information systems. The Commission certified FAN in our 2019 IDP proceeding, and we are currently recovering costs through the TCR Rider.

The FAN connects to the Company's pre-existing Wide Area Network (WAN), which is a communications network primarily composed of private optical ground wire fiber and a collection of routers, switches, and private microwave communications. The private fiber and microwave technologies are supplemented by leased circuits from a variety of carriers, as well as satellite backup facilities. The WAN provides high-speed, secure, and reliable two-way communications capability between our core data centers, office locations, service centers, generating stations, and substations. The WAN also provides primary and backup communication capabilities to key facilities in the Company's areas of operation.

The FAN consists of two separate wireless technologies. The first is a lower-speed, private mesh network. The second is a high-speed network backhaul to connect the mesh network to the WAN. The relationship between the mesh, backhaul and WAN are illustrated in the diagram below.

Figure B1 - 4: Field Area Network Illustration



1. WiSUN Mesh

Wireless Smart Utility Network (WiSUN) is a wireless communication standard designed specifically to facilitate communication between smart grid devices. The WiSUN mesh network consists of three main device types: access points; repeaters; and endpoint devices. An access point is a device that will link the Company's endpoint devices with the rest of our communications network. Repeaters are range extenders and are used to fill in coverage gaps where devices would be otherwise unable to communicate. These two device types are principally located on distribution poles and other similar structures. Endpoint devices include AMI meters and can include automated field devices, such as field devices that installed as part of the FLISR project. The AMI meters are located on customer premises; the field devices are co-located with either pole-mounted or pad-mounted distribution devices.

In addition to being able to communicate with the WiSUN network infrastructure, the AMI meters are able to communicate with each other, becoming a part of a network mesh. This improves range of mesh coverage and adds redundant communication paths between the AMI meters and the WiSUN access points and repeaters.

2. *Backhaul and Private LTE*

The backhaul connects the WiSUN mesh networks to the corporate WAN. The backhaul generally consists of public or private Long-Term Evolution (LTE) cellular service, supplemented by alternatives such as microwave or fiber where LTE service may not be available. LTE cellular modems are installed on poles and are connected to the WiSUN infrastructure. Whether public or private LTE, these modems provide the backhaul connectivity from the WiSUN network to the Company's data centers.

In addition to public LTE service provided by national cellular providers, the Company is currently deploying a private LTE network for the backhaul. The Company's private LTE network will be deployed initially in 27 counties within our operating regions in Minnesota, Colorado, Wisconsin, and Texas. We will add cellular towers primarily at Company-owned and maintained locations, with the private LTE cellular headend located at the Company's data centers in Minnesota and Colorado in a redundant state. Our private LTE will backhaul the WiSUN network, similarly to Verizon, but on a cellular network that is maintained end-to-end by the Company, which increases the reliability and resiliency of the communication network. The current LTE cellular modems support dual SIM cards. As the Company's private LTE SIM cards are added, there will be a secondary, backup option for cellular communications, increasing system resilience.

3. *Implementation*

We started the initial network and security design for the FAN in 2020, and installed and programmed the first FAN device in May 2021; we will continue installing FAN devices into 2025. The FAN implementation includes the network design, the security of these networks, configuring the software and hardware components of the FAN, and the installation of FAN devices that are located primarily on distribution poles. The physical installation of FAN devices is performed by field crews. For any given geography, FAN deployment precedes AMI meter deployment by approximately six months, to ensure a fully operational network is immediately available for the meters to communicate with.

4. *Benefits*

The FAN provides two-way communication between the AMI meters (and other automated field devices, such as FLISR) and software in a safe, secure, and reliable way. As explained above, the AMI and FAN components work together to provide customers with granular information regarding energy consumption, which can help customers better manage their energy consumption and costs. This information also allows the Company to offer additional programs to customers and, for instance, enhance our ability to more quickly detect and efficiently respond to outages. The communication provided by the FAN is essential to supporting the benefits of a modern grid.

5. Financials

For FAN, we expect $27.3 million in capital costs and $.2 million in O&M costs over the five-year budget period. These amounts include Distribution and Technology Services budgeted amounts, as shown in Tables B1-7 and B1-8.[5]

Table B1 - 7: FAN Capital Expenditures Budget
Minnesota Electric Distribution and Technology Services (Millions)

Project Component		2024	2025	2026	2027	2028
FAN	Dist	$3.9	$0.7	-	-	-
	Tech Svcs	$12.1	$7.2	$1.1	$0.6	$1.7
Total		**$16.0**	**$7.9**	**$1.1**	**$0.6**	**$1.7**

Table B1 - 8: FAN O&M Expenditures Budget
Minnesota Electric Technology Services (Millions)

Project Component		2024	2025	2026	2027	2028
FAN	Tech Svcs	$0.1	$0.1	-	-	-
Total		**$0.1**	**$0.1**	**-**	**-**	**-**

E. Fault Location Isolation and Service Restoration

FLISR is an integrated technology that consists of an advanced application in ADMS, two-way communication, and automated field and substation (reclosers, switches, substation relays) equipment. FLISR improves customers' reliability experience,

[5] The Distribution budget portion for FAN is included in the budget totals presented in Appendix D.

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 with ADMS to detect issues on our system, isolate them, and automatically restore power.

The Commission approved the Company's FLISR deployment strategy, cost allocation, and recovery of 2022-2024 costs in its July 17, 2023 rate case Order in Docket No. E002/GR-21-630.

1. Implementation

The implementation of FLISR includes the deployment of automated field devices, upgrades and changes to substation relays, integration with ADMS, and finally, the use of FLISR by the DCC. As devices are installed, we go through a process to commission or integrate the devices with ADMS, which includes enabling the two-way communication to the device and a process to add the device and communication settings to ADMS prior to final commissioning in ADMS. Once a feeder has all its devices available in ADMS, we undergo a final testing to release the use of FLISR to the DCC.

We plan to deploy approximately 600 devices on 200 feeders in Minnesota from 2021-2027. The total number of feeders and devices deployed is subject to change as we are refining our plan as we go. The current plan is to reach approximately 600 devices by 2027. The FLISR plan prioritizes feeders that have had lower reliability performance when compared to our SAIDI performance in Minnesota. Each year, feeders will be re-evaluated and selected for FLISR deployment based on current topology, constructability, and historical reliability performance. This agile approach allows for feeder selection based on the most up to date analysis and can account for any other relevant load or constructability changes for prospective feeders. Based on the actual costs to deploy FLISR on each feeder, the overall program may deliver more or fewer than the expected number of approximately 200 feeders, though it is expected that there will not be a significant deviation from that figure.

2. Benefits

FLISR has both quantifiable benefits and non-quantifiable benefits. The most significant quantifiable benefit of FLISR is improved reliability for our customers.

We also expect to achieve certain non-quantifiable operational efficiencies due to the increased visibility and information provided by the FLISR field devices. One of these benefits is the reduction in field trips for our employees to effect non-outage switching, enabled by the FLISR automated devices. Additionally, all remotely operable switches will necessarily have sensors, which will provide operating data at strategic points along the feeders. This data will be useful in the refining planning models and hosting capacity analysis, allowing the planning engineer to more accurately distribute load along the feeders.

3. Financials

For FLISR, we expect $55 million in capital expenditures and $900,000 in O&M costs over the five-year budget period. These amounts include Distribution budgeted amounts, as shown in Tables B1-9 and B1-10.[6]

Table B1 - 9: FLISR Capital Expenditures Budget
Minnesota Electric Distribution (Millions)

Project Component		2024	2025	2026	2027	2028
FLISR	Dist	$11.6	$12.2	$15.6	15.6	-
Total		**$11.6**	**$12.2**	**$15.6**	**$15.6**	**-**

Table B1 - 10: FLISR O&M Expenditures Budget
Minnesota Electric Distribution (Millions)

Project Component		2024	2025	2026	2027	2028
FLISR	Dist	$0.3	$0.3	$0.2	$0.1	-
Total		**$0.3**	**$0.3**	**$0.2**	**$0.1**	**-**

Order Point 27.b of the Commission's July 17, 2023 Order in Docket No. E002/GR-21-630 states in part:

> *Xcel must report, beginning in its next IDP due November 1, 2023, on the FLISR budget approved in the present rate case.*

[6] The budget for FLISR is included in the budget totals presented in Appendix D.

Table B1-11 below shows the FLISR additions budget approved in the rate case compared to actual additions through the first half of 2023, along with our updated capital additions budget forecast. Note that Table B1-9 shows capital expenditures, while Table B1-11 shows capital additions.

Table B1 - 11: Approved FLISR Additions Budget
Minnesota Electric (Millions)

	MYRP Period			Forecast			
	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Approved FLISR Additions Budget	$3.4	$7.8	$7.8	$8.2	$20.0	15.3	-
Actual Additions	$0.1	$1.2*	-	-	-	-	-
Latest Forecasted Additions Budget	$0.1	$5.2	$11.0	$13.0	$15.5	$15.5	-

**Actual additions through June 2023.*

As shown in Table B1-11, the timing of our FLISR capital additions has shifted slightly since our initial rate case filing in November 2021. We still anticipate deploying FLISR on approximately 200 feeders by the end of 2027, as discussed above.

4. *Reliability*

Order Point 27.b of the Commission's July 17, 2023 Order in Docket No. E002/GR-21-630 states in part:

> *Xcel must report, beginning in its next IDP due November 1, 2023, on […] a summary of FLISR's reliability results in its Integrated Distribution System Plan.*

Below, we summarize FLISR reliability results.

We expect that FLISR will improve our overall reliability performance and a customer's overall outage experience. However, our performance in certain reliability metrics may decline after FLISR is installed. For instance, FLISR will help some customers avoid sustained outages. Sustained outages are tracked by the System Average Interruption Frequency Index (SAIFI) metric (annual average number of sustained service interruptions per customer served), and shorter duration outages (less than five minutes) are tracked by the Momentary Average Interruption Frequency Index (MAIFI) metric. In essence, we expect that FLISR will transform outages that would have been sustained outages into momentary outages.[7]

As a result, we expect that customers will experience fewer sustained outages, improving our SAIFI performance while our MAIFI performance will decline. We also expect that FLISR will cause our Customer Average Interruption Duration Index (CAIDI) performance to decline. CAIDI is a measure of the length of time the average customer can expect to be without power during an interruption. CAIDI performance declines when the outages are more heavily concentrated on problems that take a longer time to fix. As FLISR's automatic switching will restore power quickly to customers not along the faulted section, the result will be a sustained outage that impacts fewer customers. This will negatively impact our CAIDI performance but will be a more positive outage experience for our customers broadly because FLISR will minimize widespread extended outages on the system.

The remote and automated switching capabilities associated with FLISR supports a more resilient grid, in addition to reliability benefits. Whether storm-related or due to other unforeseen circumstances that limit employee movement (such as the COVID-19 pandemic), remote operations capabilities provide a means by which to perform critical operations when staff is otherwise limited in numbers or movement. This is a benefit to our customers that is difficult to quantify, but valuable, nonetheless.

The outright reliability benefit of FLISR feeders can be difficult to quantify with minimal years and events available for data collection and analyzing. Although, without years of system trend data for FLISR feeders, there still have been instances of reduction in sustained outages observed. As an example, a feeder level outage occurred on December 15, 2022, and was caused by a tree branch. A recloser was installed towards the middle part of the feeder as part of the FLISR project. At the time, the recloser had not been commissioned in ADMS; however, the recloser was operational in "local mode" on the feeder. When the tree branch contacted the distribution lines, the recloser opened instead of the feeder breaker, resulting in 1,079 customers that did not have an outage, totaling approximately 52,000 of avoided customer minutes out. As the Company enables the full functionality of FLISR in ADMS, it is likely it could result in even greater reliability benefits. Figure B1-5 is an illustrative representation of the benefits as we enable FLISR functionality across the different phases and as we expand the functionality to a greater number of feeders.

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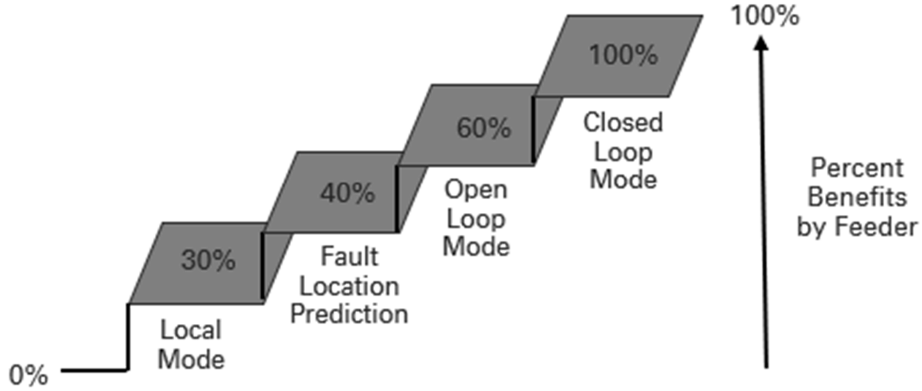
[7] With AMI meters, we will be better able to track these momentary outages for all of our customers.

Figure B1 - 5: Phases of FLISR Functionality and Benefits



F. LoadSEER – Advanced Distribution System Planning Tool

LoadSEER, or previously referenced as the Advanced Planning Tool (APT), is a spatial load forecasting tool, which combines several layers of detailed electric infrastructure, weather, economic and other data to forecast how future load and energy demands on the grid may change in the future. LoadSEER is a foundational planning tool that enhances system reliability as well as supporting modernization of our distribution system. The tool replaced our previous forecasting tool that lacked the ability to provide the data granularity and transparency necessary to keep pace with customer expectations and evolving regulatory requirements. The Commission certified LoadSEER in our 2019 IDP proceeding and approved cost recovery of LoadSEER in the 2021 TCR proceeding.

5. Implementation

LoadSEER has been the primary tool for distribution planning and load forecasting in Minnesota since 2021. With this IDP, we are presenting our DER scenario analysis completed in LoadSEER for the first time. (See *Appendix A1: System Planning*.)

6. Benefits

The LoadSEER forecasting tool provides various functionalities and benefits that make it an appropriate choice for our distribution system planning. LoadSEER enables increased forecast granularity, data to support non-wires alternatives (NWA) analysis, the ability to develop forecast scenarios, the ability to analyze distribution impacts of corporate-level load and DER forecasts, and increased ability to integrate with other planning processes.

See Appendix A1 for further discussion of LoadSEER and how we are using it in our planning process.

While we will continue to use LoadSEER in our planning process, the project deployment phase is complete; therefore, no costs remain in the Distribution budget, and we will not include LoadSEER in this Appendix in future IDPs. The complete budget information for LoadSEER is reflected in the TCR Rider filed October 31, 2023.

G. Time of Use Rate Pilot

The Company proposed a Residential Time of Use rate design pilot in 2017 (Docket No. E002/M-17-775). The Commission approved and certified the pilot in 2018.

7. Implementation

Our residential time of use rate design pilot, Flex Pricing, is now complete. Initially planned for launch in April 2020, the Company delayed the pilot start until November 2020, as the initial launch coincided with the early stages of the state's stay at home orders related to the COVID-19 pandemic. The two-year pilot focused on learning how customers respond to time of use price signals. On February 10, 2023, we reported final pilot results and conclusions in Docket No. E002/M-17-775.

8. Benefits

The Company piloted Flex Pricing in order to study customer responses to price signals, to explore and identify effective customer engagement strategies, and to understand customer impacts by sector. The pilot provided numerous benefits, including opportunities for customers to save on their utility bills. Participants received advanced meters that facilitate communication between the utility and customer, in service of driving on peak energy efficiency and load-shifting behaviors. The pilot also enabled increased communication capabilities, customer information and education, and targeted price signals. The pilot concluded in October 2022. Customers who were placed on the pilot rate can choose to remain on the TOU rate with the option to switch back to a standard residential rate at any time.

Pursuant to the Commission's July 17, 2023 Order in Docket No. E002/GR-21-630, the Company will file a proposal to transition to a residential TOU rate for all customers in our service territory by December 31, 2023. Our proposal will be based on the learnings gathered during our pilot. Because the MN TOU pilot has ended and a plan to implement the rate for all customers is being contemplated, we will not include discussion of the MN TOU pilot in future IDPs. We also note that no costs remain in the Distribution budget. The complete budget information is reflected in the TCR Rider filed October 31, 2023.

IV. ADDITIONAL GRID MODERNIZATION TECHNOLOGIES

A. Distributed Energy Resources Management System (DERMS) (*future*)

The purpose of a DERMS is to enhance the integration and utilization of DER to meet the needs of the grid, customers, the market, and regulatory entities. A DERMS would serve to enable the growing interactions between customers and the distribution grid. Our journey to utilize and manage DER will occur over the next decade. A phased implementation approach for DERMS enables the Company to meet policy, regulatory, customer, and business needs. This also balances our investment pacing with the technology launch and performance validation. We are also anticipating FERC Order 2222 to drive new business requirements, new operational dynamics between distribution and transmission, and potential market implications between retail and wholesale markets. We expect DERMS to be a part of the solution to meet FERC Order 2222.

The deployment of DERMS is an emerging approach to connect and manage DER on the utility system. As penetration levels of DER increase on our system, there is an increasing need to have more visibility and active management and coordination with DER to maintain a secure, reliable, and resilient distribution system.

Technology vendors provide DERMS software, which help provide underlying logic and or capabilities that allow utilities to manage a group of DER to better support distribution or bulk system needs. A DERMS would interact with other systems, such as ADMS and devices in the field through two-way communication including but not limited to FAN, AMI, and internet. DERMS can be viewed as a system that can aggregate and group DER in ways that provide more value to the grid and to customers who participate in programs that support the grid. Potential use cases could involve leveraging energy storage to reduce peak usage or integrating more renewables, or managed charging scenarios for electric vehicles. More sophisticated DER forecasting capabilities may help us evaluate how to integrate higher levels for DER as adoption increases, particularly for larger DER on the distribution system. Additionally, DERMS would help enable the centralized control and optimal dispatch of flexible interconnections and would aid Operations in the coordination and management of NWAs.

There is a timing balance of whether technology systems are mature enough to meet evolving and growing system needs, but the Company believes the implementation of DERMS is a necessary step to integrate higher levels of DER. Currently, we are examining DERMS capabilities in the market and will explore vendor capabilities in more detail through at least the first half of 2024. The Company is working with Electric Power Research Institute (EPRI) on a research project to gain feedback on the Company's proposed use cases, develop an overall conceptual control and communication system architecture, and determine overall system capabilities and interfaces with our planning and operational systems (such as ADMS). EPRI has been working with utilities to understand DERMS for over a decade, and we are excited to leverage their expertise to develop an overall DERMS roadmap. All of this research will help support our technology assessment and the results are also expected to expand industry knowledge on leveraging DER to serve the needs of the grid and the customer. More work also needs to be done to understand some of the new fulfillment requirements for a DERMS system, including understanding start-up requirements, resource and training needs, and ongoing operational teams needed to support DERMS once in operation.

In order to support the goals for increasing DER and electrification, balancing DERMS deployment and infrastructure investment is critical. For example, the Company anticipates using DERMS and leveraging DER flexibility to extend utilization of existing grid infrastructure. However, the ability to reach long-term goals will also depend on infrastructure investments.

B. Integrated Grid Operating Technology (*future*)

The grid is undergoing a dramatic shift with the addition of renewables and DER, which poses challenges for the grid today – and even greater challenges into the future. Some of the challenges include fluctuations in the grid's frequency and voltage, reduced inertia, and bi-directional power flow. We envision a future where these challenges will be overcome through a highly integrated technology environment. This integrated environment will allow operators to effectively collaborate to maintain safety and reliability of large-scale, dynamic systems through evolving conditions.

More specifically, the anticipated penetration of DER and advancements in grid technologies change the role of distribution operations in management of the bulk transmission system. Traditionally, distribution systems have been seen only as a connected load to transmission operators. In the future, the distribution system will have more ability to back feed generation and shift load. Additionally, resources connected to the distribution system will have an influence on market operations.

At the time of this IDP, we are in the process of determining the best path to an integrated technology environment.

C. Virtual Power Plants

Our electric grid is becoming more complex and increasingly will need to leverage DER. The use of the term "Virtual Power Plant" (VPP) has become more prominent in the energy industry over the past few years as the number of distributed and connected energy resources has increased. Today, the Company in fact operates its DR programs much like a VPP and has recently launched its Renewable Battery Connect program in Colorado, which is specifically identified as a VPP.[8] The Company is in the process of developing and deploying a similar program in Minnesota. While there is no uniform definition across the industry, the Company shares our interpretation of VPPs here. The Company considers a VPP to be:

> "An aggregation of controllable DERs managed at a scale that provides grid services or attributes, including energy and negative energy, ancillary services, and capacity. DER aggregated to create a VPP could be utility or customer owned, in-front or behind the meter. DER assets in a VPP could include, but are not limited to, photovoltaic solar, energy storage, electric vehicles, and demand-responsive devices such as water heaters, air

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[8] See SolarEdge joins Xcel Energy's virtual power plant incentive program in Colorado, PV Magazine, available at: https://pv-magazine-usa.com/2023/08/24/solaredge-joins-xcel-energys-virtual-power-plant-incentive-program-in-colorado/.

> conditioning units, thermostats, and appliances. A VPP has benefits, such as the ability to deliver peak load electricity or load-following power generation on short notice. Such a VPP could replace a conventional power plant while providing higher efficiency and more flexibility, which allows the system to react better to load fluctuations. Resources that are part of a VPP may also be able to provide local grid benefits (to the extent that the resources are in close proximity to a local constraint) such as reducing loading on a distribution feeder."

The "virtual" component of the term indicates that the resources that compose a VPP are not a singular piece of infrastructure, such as a traditional power plant. Instead, the observed and desired outcome of the VPP results from the aggregation of many heterogeneous and geographically diverse resources (typically aggregated through a software control platform). The net performance observed by the aggregation is what we consider to be the impact of the VPP. As noted in the above definition, VPPs are capable of providing different types of products and solving different system needs. Therefore, it is important that design and requirements for VPPs be tailored to specific grid use cases such as reducing bulk system peak demand or targeting locational constraints.

In the IDP, the Commission has defined DER: "For purposes of these [IDP] requirements, 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; 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, demand response, and energy efficiency."[9] The Company can contemplate VPP scenarios that could include all or some of the DER resources the Commission has defined.

The Company considers the popularity of the VPP term to be associated with emerging applications such as DERMS (described above), which are more sophisticated management systems that provide greater capabilities to enable a broader set of DER aggregation scenarios. They include but are not limited to, combining multiple technology types in an aggregation, establishing platforms and protocols that provide more interoperability and ease of execution, more beneficial groupings of DER, and more flexible settings and scheduling that that can be adjusted to reflect changing system conditions.

DER assets aggregated to create a VPP could be utility or customer-owned, or in-front of or behind the meter. Such assets could include, but are not limited to,

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[9] IDP Requirement 3.

photovoltaic solar, energy storage, electric vehicles, and demand-responsive devices, such as water heaters, air conditioning units, thermostats, and appliances. A VPP has benefits, such as delivering peak-load electricity or load-following power generation on short notice. Such a VPP could replace a conventional power plant while possibly providing higher efficiency and more flexibility, allowing the system to react more robustly and quickly to load fluctuations. Resources that are part of a VPP may also be able to provide local grid benefits (to the extent that the resources are located close to a local constraint), such as reducing loading on a distribution feeder.

The Company is excited about the application platforms that are emerging as important contributors to the enablement of flexible aggregated DER scenarios that result in VPPs. See *Appendix B3: Existing and Potential New Grid Modernization Pilots* for discussion of battery demand response pilots and programs in Colorado. An example in the Upper Midwest can be found in Minn. Stat. § 216C.379, which directs the Company to develop a battery grant program for customers with on-premises solar. Per legislation, the program will be designed to provide a one-time grant of up to $5,000 for solar PV systems with a connected battery of up to 50 kWh and will be filed with the Minnesota Department of Commerce on November 1, 2023 in Docket No. E002/M-23-459.

D. Integrated Volt-Var Optimization (IVVO)

Order Point 36 of the Commission's July 17, 2023 Order in Docket No. E002/GR-21-630 states:

> *Xcel must file an assessment and explanation in the next IDP of whether (Integrated Volt-Var Optimization) IVVO is in the public interest.*

In this section, we provide the required assessment and explanation. Ultimately, we conclude that IVVO is not in the public interest.

1. Introduction and IVVO History

IVVO is an advanced application that automates and optimizes the operation of the distribution voltage regulating devices or VAR control devices that are dispersed across distribution feeders. The concept of voltage/VAR management or control is essential to electrical utilities' ability to deliver power within appropriate voltage limits so that consumers' equipment operates properly – and to deliver power at an optimal power factor to minimize system losses. With IVVO, voltage can be monitored along the feeder and at select end points (rather than only at the substation), allowing the voltage at the substation to be lowered to achieve a variety of operational outcomes. IVVO is an application of the ADMS (deployment completed in 2021), which monitors and controls substation, field devices, a subset of AMI meters across each feeder to run a sophisticated power flow model of the distribution system. This model helps the IVVO application determine, for instance, which capacitors to turn on and how much to lower the voltage for optimal grid performance.

We have presented IVVO to the Commission and stakeholders numerous times across various dockets since 2015, culminating in the inclusion of IVVO in our certification request in our 2019 IDP.[10] As we explained in our certification request, we included an IVVO component to our certification proposal as a direct result of feedback we had received in response to our most recent grid modernization reports at the time.

In the 2019 IDP, most commenters opposed certification of all our requested investments, which included IVVO. These commenters included the Minnesota Department of Commerce, Minnesota Office of the Attorney General, Xcel Large Industrials, Citizens Utility Board, and the City of Minneapolis. Only two commenters—Fresh Energy and Innovative Power Systems (IPS) Solar—supported certification of IVVO. Notably, Fresh Energy's support was conditioned upon Xcel Energy committing to specific energy and peak demand savings.

2. *Previous IVVO Proposal and Stated Benefits*

Our proposal was for a targeted, core deployment of IVVO at 13 substations (serving approximately 224,000 customers) throughout the Minneapolis/St. Paul area where we believed the benefits would be greatest. We had confidence of achieving a 1.0 percent energy savings for this specific deployment, although the benefit-cost ratio (BCR) resulting from our cost-benefit analysis (CBA) model was less than 1 – meaning the modeled costs outweighed the modeled benefits even under the most optimistic sensitivity.

In our IVVO certification request, we identified four quantifiable benefits of IVVO:

1) Reduction of Energy Consumption. Flattening the voltage profile along a feeder and operating in the lower range of 114V to 120V reduces energy consumption for certain devices, like incandescent lighting or motors such as

[10] *See* Docket No. E002/M-19-666. We requested certification for AMI, FAN, FLISR, and IVVO – parts of what, at the time, was collectively referred to as the Advanced Grid Intelligence and Security (AGIS) Initiative.

those found in air conditioners, dryers, and refrigerators. Ensuring these types of devices are operated in the lower voltage range makes them more energy efficient. Studies have shown that the Conservation Voltage Reduction (CVR) mode benefit varies with the load type, climate zone, and feeder characteristics. The amount of energy efficiency or demand reduction that is achievable is highly dependent on a number of factors, including various attributes and the configuration of the distribution system, and customer attributes such as customer density, load characteristics, and the mix of residential and commercial customers. Of the four quantified benefits, this benefit had the highest net present value by a wide margin.

2) Reduction of Distribution Electrical Losses. IVVO models in ADMS can turn the capacitors installed along the distribution circuit on and off in an optimal manner to limit the reactive power flowing on the distribution system. This improves the efficiency of the system, reduces system losses, slightly decreases energy generation needs, and reduces carbon emissions. Power factor improvements have largely been achieved through our existing SmartVAr program in Minnesota.
3) Avoided Capacity Costs. A by-product of reduced energy consumption is the corollary reduction of demand. By reducing the demand, the benefit can be shown as a deferral of capital investments in generation, transmission, and distribution.
4) Carbon Emissions Reduction. Another by-product of reduced energy consumption is the corollary reduction in generation which in turn results in reduced CO_2 emissions. The Company valued this reduction in CO_2 emissions using Commission-approved values.

3. Changes since 2019

The energy savings we assumed at the time of our certification request did not account for declining benefits over time as customers adopt more energy efficient and constant power devices that do not have the same energy savings benefits when operating at lower voltages. The premise of IVVO realizing energy savings is dependent on the type of loads on the system. Different loads react differently to voltage reduction. For example, the classic incandescent light bulb will reduce energy consumption by 1.5 percent for a 1 percent voltage reduction, however an LED light's energy consumption would *increase* by 0.1 percent for the same voltage reduction.[11] This load and voltage relationship is defined by a ratio known as CVR factor. The current technology trend is toward household electronic devices with low to negative CVR factors. Devices with low CVR factors are known as constant power devices, whereby the internal power electronic circuits will simply draw more current to compensate for any voltage reduction below the rated voltage. In other words, devices with a lower CVR factor are less sensitive to voltage change, which means that as energy efficient devices become more prevalent – as they have since the time of our certification request – the benefit of IVVO is reduced.

Since our certification request in 2019, technology has continued to become more efficient, reducing the benefits of IVVO compared to 2019. In parallel with this dynamic, electrification is increasing, increasing load. As load increases, the proportional benefit of IVVO decreases because load from increased electrification tends to have lower CVR factors. The upward pressure on residential and commercial loads from electrification, particularly EV charging, likely negates any benefits that may have been realized from lower service voltage.

For these reasons, the benefits we estimated from IVVO are lower now than they were in 2019.

4. *Conclusion*

We did not move forward with IVVO after stakeholder opposition in the 2019 IDP and after the Commission declined to certify the project. Instead, the Company chose to move forward with more critical grid modernization investments that had better BCRs and more stakeholder support.

Since that time, we have continued to move forward with the other, valuable grid modernization investments discussed in this Appendix. Minnesota's policy goals have evolved, as evidenced by the many new distribution-related provisions passed during the 2023 legislative session, which we discuss throughout this filing. We have a long-term grid modernization vision that will continue to achieve Minnesota's ambitious policy goals, and we have prioritized investments that further this goal. In the interest of keeping bills low for our customers, we have moved forward with other investments that will result in greater value for our customers.

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[11] Source: U.S Department of Energy. Evaluation of Conservation Voltage Reduction (CVR) on a National Level http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf, T&D World https://www.tdworld.com/grid-innovations/smart-grid/article/20965787/cvr-is-here-to-stay.

IVVO had a BCR of less than 1 when we requested certification in 2019. Although CBA models are one of many tools the Commission can use in holistically assessing individual investments and to inform a public interest determination, for IVVO, we would expect the BCR to be even lower today because of changing load types, additional load from electrification (i.e., the proportional benefit of energy savings would be lower), and because we have realized benefits through other means. For these reasons, we conclude that IVVO is not in the public interest.

V. CUSTOMER STRATEGY AND ROADMAP

The Commission's IDP Planning Objectives include:

1. Enable greater customer engagement, empowerment, and options for energy services.
2. Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies.

In this section, we discuss how we are working to meet customer expectations today while preparing for the future in the spirit of the Planning Objectives listed above. 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 vehicles, 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 often 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.

Since our last full IDP filing in 2021, more than 512,250 AMI meters have been installed in Minnesota. The rollout of the new meters enables customers to view 15-minute energy usage, on-demand via the Xcel Energy web portal. Since 2021, the Company has also developed and released new products that enable customers to access the benefits of the meters to better understand how and when they use energy and take control of their bills.

Since the 2021 IDP, the Company has made strides in executing on our customer strategy, developing the foundation for future offerings. We have built a platform that will enable data to be shared with customers and customer-authorized third parties, promoting innovation and the expansion of technologies that will enable the Company to lead the clean energy transition, enhance the customer experience, and keep bills low. The following sections discusses the Company's strategy for continually improving the customer experience and leading the industry in innovating new products, rates, and services that enable customers to engage with the Company in new and more impactful ways, relaying the benefits of the AMI meters to customers.

Modernized grid infrastructure enables new developments in smart products, advanced rates, and new services. However, we recognize resources are finite and therefore, plan to take a staged approach to investing in and developing new products and services. Future investments and products will be prioritized based on the voice of the customer, cost, and benefits. In this way, we will use a building block approach, starting with the foundational systems and sequencing the investments to yield the greatest near- and long-term value, while preserving the flexibility to adapt to the evolving customer and technology landscape.

A. Expected Grid Modernization Outcomes for 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.

1. 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 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. AMI 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.

2. *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 grid modernization investments provide the platform and capabilities to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics, and automation.

3. *Facilitation of future capabilities*

The backbone of our investments will also support new developments in smart products and services. In the short term this will be accomplished 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 products.

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 grid modernization approach, we have considered the long-term potential of our ability to meet our obligations to serve 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 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 grid modernization plans 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.

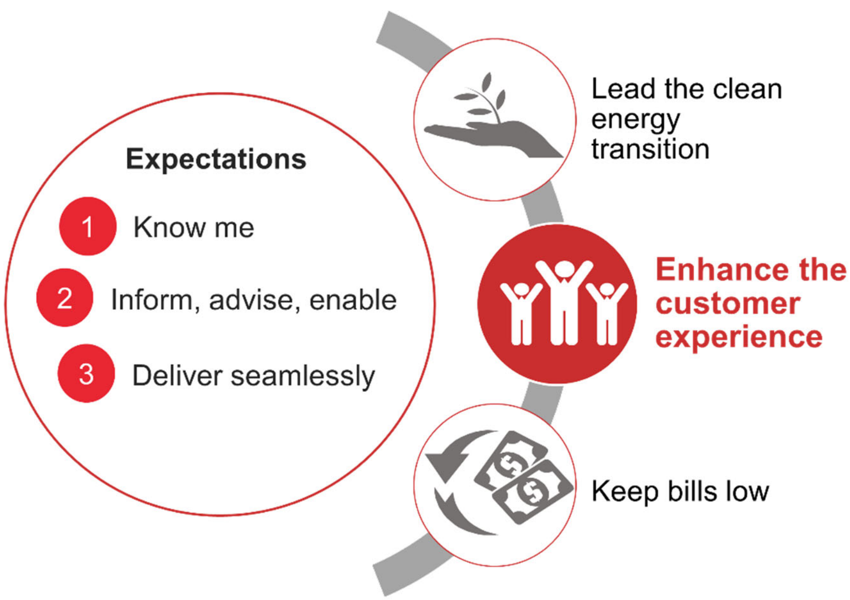
B. Customer Strategy

Our grid modernization efforts aim to transform the customer experience by implementing capabilities, technologies, and program management strategies to enable the best-in-class customer experience that our customers now expect, as shown in Figures B1-6 and B1-7.

Figure B1 - 6: Customer Strategy Informed by Customer Expectations

Today, customers expect that we know them and take a personalized approach to their relationship with us; they expect that we keep them informed and use our expertise to advise them about what to do and then empower them to take those actions; and finally, that we deliver seamless experiences for them reducing the burden on them to take action.

Figure B1 - 7: Customer Experience Priorities



In order to know our customers, inform, advise, and enable them, and deliver seamlessly, we are taking time to understand the customer's journey and experience in our program design and execution. This process starts with a commitment to understanding customers' preferences, considerations, and motivations regarding the benefits and value of an advanced grid investment from their point of view. As detailed in the following section, we conduct robust customer research and continually update that research to ensure we are reactive to our customer's perceptions. It also requires our organization to improve the skills and competencies needed to continuously evolve and iterate our programs more quickly and leverage technology to make interactions more streamlined and enjoyable.

During this transition to the grid of the future, we will take exceptional care of our customers to educate, inform, and ensure a smooth implementation. 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, as shown in Figure B1-8.

Figure B1 - 8: Customer Communications Journey Phases

Our customer communications begin pre-implementation to educate on the possibilities enabled by AMI, as well as customers' ability to opt-out of an AMI meter. As a customer's AMI installation date gets closer, each customer is informed about what to expect with the AMI meter changeover at their home or business. Finally, after the AMI installation customers receive either an email or post-card notifying them of the benefits unlocked by the AMI meters and provided with practical steps to take advantage of the customer portal or other new or enhanced services available day one.

C. 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.
- *Larger business customers have more awareness and familiarity with advanced rate designs.* Residential customers and small businesses 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.*

In our efforts to better understand customer preferences in the DI space, we've asked survey participants to answer questions about DI concepts to help inform our digital strategy. The main takeaways from that study are as follows:

- Customers want to understand and change their energy usage to save money, but they need help.
- Customers want baselines/comparisons so they know how they are doing.
- Customers want their data (cost and usage), but they want it at a glance.
- Customers want to see the current cost without having to do the math.
- Customers have a desire to know what behaviors they should implement to increase their cost savings.
- Customers don't always know the definitions to commonly used words in the utility space.

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, rates, and services as enabled by the advanced grid.

Customer feedback has informed the design of the My Energy Connection mobile application, which is in the process of being released. The mobile application uses the DI Home Area Network (HAN) capabilities to display real-time energy usage. We have also incorporated historical energy and cost graphs as a result of customer feedback. When it comes to displaying customer energy usage, preferences varied, but a majority indicated a preference for hourly usage and 15-minute interval usage. As a result, the Company incorporated graphics showing this data into the initial mobile application design. We discuss our DI plans further in *Appendix J*.

In the business space, our goal is to understand customer attitudes, opinions, and thoughts about AMI and TOU rates. We are conducting interviews focused on small and midsized organizations that are on, or will transition to, the Commercial TOU rate. Insights will be used to design future outreach and education campaigns. While this research is not fully complete, emerging themes include:

- Concerns about utility bills are prominent for many especially with inflationary pressures and rate increases.
- There tends to be general awareness of AMI, but not always if their business has it or not.
- No disruption of service or minimal downtime is expected.
- The automatic switch to AMI is much better received than an automatic switch to TOU.
- Customers would appreciate tools to help understand different rate options and the implications of each.
- Visuals and graphics are effective for explaining TOU as people do not take time to read through paragraphs of text.
- Businesses are unsure if AMI affects costs and many businesses do not see how they could benefit from TOU as they cannot realistically change operations during peak hours.
- They tend to assume these programs are more a benefit to Xcel Energy than to them.
- Communication with businesses has challenges with multiple addresses, numerous points of contact, staff turnover, and the level of junk mail they are already faced with.
- Customers are not satisfied just being told they "can" save money on TOU, they want to know "how" they can and the specifics behind this claim.

D. A Multi-Channel Experience

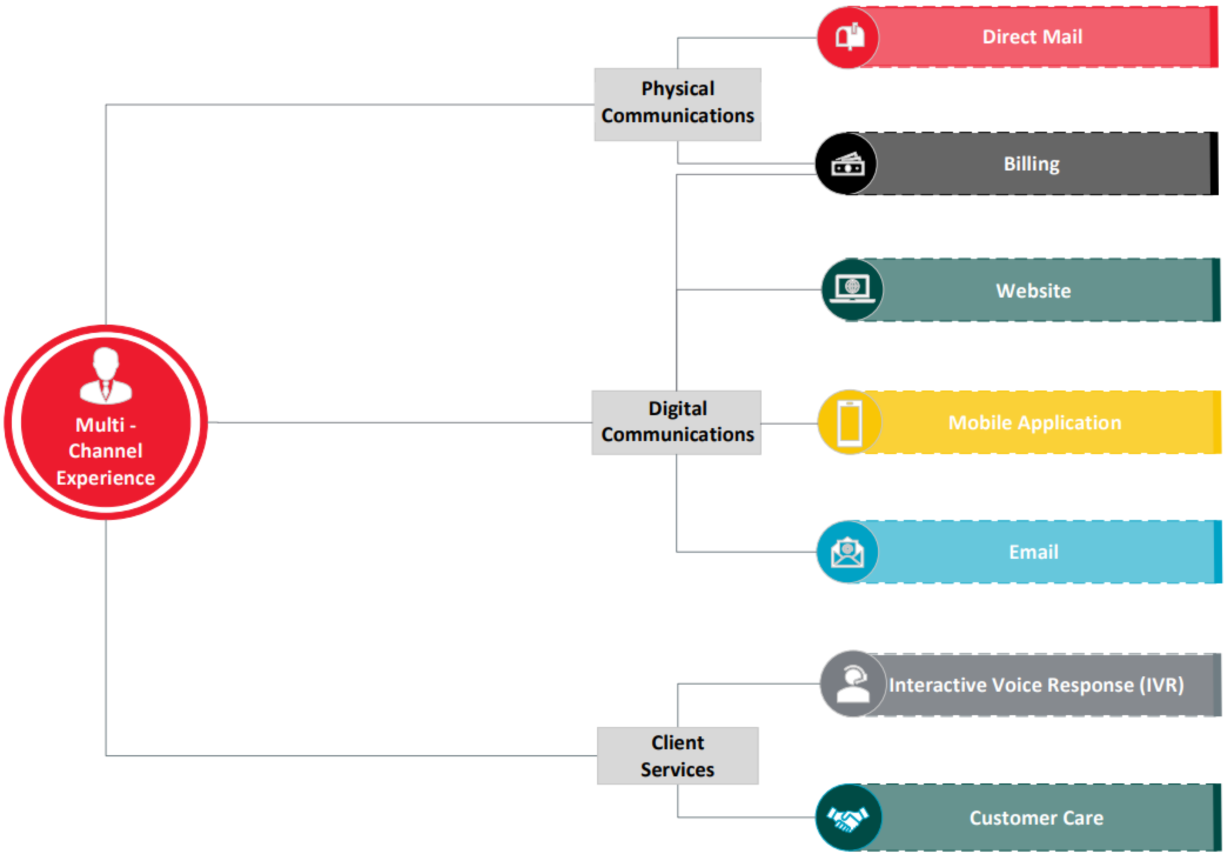
Today, Xcel Energy customers have access to numerous energy efficiency and demand management programs, renewable energy choices, electric vehicle and charging options, billing options, a mobile app, and outage notifications that include estimated restoration times. Customers also receive confirmations 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 continue integrating modern customer experience communication strategies with advanced grid platforms and technologies to enable optimized products and services for our customers.

A multi-channel approach to providing information to customers, shown in Figure B1-9, enables the Company to broaden the reach and impact of our programs while laying the foundation for future innovation. This enables the Company to continue to offer new and effortless methods for customers to engage with the utility, gain insights into how and when they use energy, and be directed to other programs that will benefit them.

The Company's communications and customer awareness strategies are continually evolving to align with customer preferences and expectations. We use a variety of methods to gather feedback from customers on their preferred communication channel and continually adapt our strategy to align with customer preferences, which often can vary within customer classes. As the grid advances, we will continue to use the latest technologies and data to inform our customers of how and when they use energy, new product and rate designs, and events that impact them such as outages.

Figure B1 - 9: Multi-Channel Communications Strategy



E. The Customer Experience Today

The Company has created a variety of products and services that leverage the AMI data and provide direct benefit to customers, the Company, and society. In the following sections, we provide more details on the types of products and services we offer today. These offerings are just the start – the Company plans to continue to build and expand our portfolio of products to take advantage of the expanded technology opportunities presented by AMI in order to more fully optimize the use of grid infrastructure.

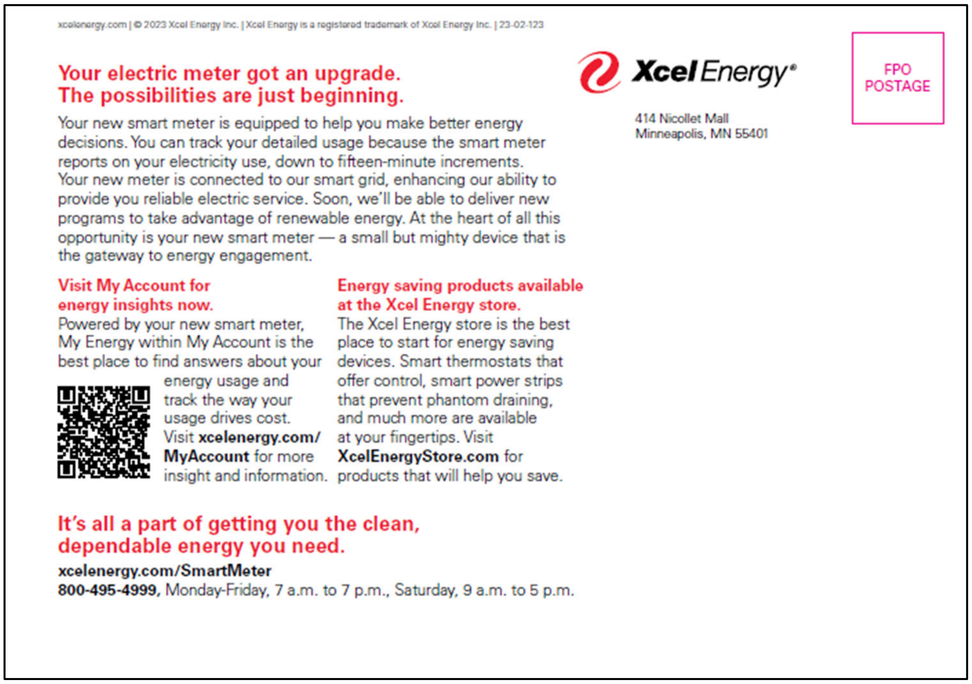
We will continually innovate and iterate these offerings and incorporate new benefits and opportunities as they become available. This may include adapting offerings to incorporate DI capabilities, transitioning traditional opportunities to DI applications, or integrating new technology that is not yet in the market.

The customer journey with their new smart meter starts with the post installation experience. The Company provides a personalized multichannel (email and direct mail) campaign after a smart meter installation to:

- Educate customers that have had advanced meters installed about online tools and resources.
- Encourage customers to view their energy use information online.
- Provide follow-up communications to customers about specific ways to use this information to manage their energy use.
- Make it easy for customers to select energy management tools and energy efficiency and conservation offerings available to them, based on their personal preferences.
- Measure consumer awareness, understanding, interest, participation and satisfaction with advanced meters and associated features.

Figure B1-10 shows an example of a postcard customers receive after their meter installation.

Figure B1 - 10: Post-Installation Postcard



As new products are developed, we will notify customers of the products through the post-installation experience as well as a variety of other channels. Table B1-12 shows the AMI- and DI-enabled products and services, approximate availability, and end-user.

Table B1 - 12: AMI and DI Products & Services

Product / Service	Available	Target End User	Available before AMI	Enabled by AMI	Enhanced or Enabled by DI
Web Portal	Current	Customer	Y	Y – Additional Information Available	Y
On Demand Meter Reads	Current	Customer	N	Y	N
Green Button Connect My Data	Current	Third Party Access (Customer and Third Party)	Y	Y – Additional Information Available	N
Green Button Download My Data	Current	Third Party Access (Customer)	Y	Y – Additional Information Available	N
Bring-Your-Own-Device / Software Development Kit	Current	Third Party Access (Third Party)	N	Y	Y
Outage Notifications to Company Systems	Current	Customer	N	Y	N

Product / Service	Availa ble	Target End User	Available before AMI	Enabled by AMI	Enhanced or Enabled by DI
Advanced Rates	TBD	Customer	Limited	Y	N
High Bill Alerts	Current	Customer	N	Y	N
Budget Alerts	Current	Customer	N	Y	N
Energy Action Days	Current	Customer	Y	Y	N
My Energy Connection Release 1	Fall '23	Customer	N	Y	Y
My Energy Connection Release 2	TBD	Customer	N	Y	Y
Xcel Energy Launchpad	Current	Third Party Access (Customer)	N	Y	Y

1. *Enhanced Digital Experience*

The features below are enhancing the customer experience and helping customers reduce their bills by providing more transparency into how their behaviors impact their energy usage and ultimately their bills.

- **AMI Energy Usage Dashboard in My Energy Portal.** Within My Energy Portal linked to My Account, customers can view their 15-minute interval, hourly, daily, monthly, and yearly usage data. For Colorado customers on TOU rates, the data is broken out by TOU peak periods (off-peak, mid-peak, and on-peak); this view will also be available for Minnesota customers when TOU rates are available. Customers can toggle between kilowatt-hour usage and cost for each view. Using this presentment tool enhances the customer experience by helping customers better understand their usage patterns.
- **On Demand Meter Reads.** The On Demand Read functionality in My Account provides customers the ability to see their 15-minute interval kilowatt-hour usage for the last eight hours. The On Demand Read functionality provides customers options to experiment with turning appliances and other equipment on and off to identify their energy usage patterns.

2. *Third-Party Access*

The Company has created several tools that allow customers to share data with customer authorized third parties. Customers must provide consent prior to sharing their data. Enabling third parties to access customer data promotes innovation and gives customer freedom of choice over how they view and use their data. Additional details about third-party access and potential terms and conditions can be found in *Appendix J*.

- **Green Button Connect my Data.** Green Button Connect (GBC) is an ongoing electronic data transfer service that allows customers to share their utility data to authorized service providers. These service providers can help customers make smarter choices about their energy usage by providing tools and applications to help them find ways to save energy. Customers can sign up for GBC in the Xcel Energy My Energy Portal and select which service providers to send their data to and how long to share their data with them. GBC sends the premises' billing and usage data down to 15-minute intervals for customers with AMI meters.
- **Green Button Download my Data.** Green Button Download is a one-time secure data download of a customer's energy usage to their computer. Customers can access Download My Data through the My Energy Portal and download their usage for personal records or in Green Button format to share with an energy services vendor. Customers with advanced meters can download 15-minute interval data; Green Button is available to all residential customers regardless of meter type, but 15-minute interval data is only available for customers with AMI.
- **Xcel Energy Launchpad.** Xcel Energy Launchpad allows customers to connect applications or devices developed by third parties to the AMI meters through the customer's home Wi-Fi network over the DI-enabled HAN. This permits the customer and third-party to directly gather 1-second energy consumption information from the meter. Customers can enroll in Xcel Energy Launchpad through their My Account. The Xcel Energy Launchpad includes a web application that walks the customer through the connection process. As part of the application process, customers are asked to provide consent to connect the meter to their Wi-Fi network. Customers must also provide consent to connect third party devices to the meter via their Wi-Fi network and the HAN.

- **Bring Your Own Device and Software Development Kit.** Bring Your Own Device (BYOD) and gateway Software Development Kits (SDKs) allows third parties to develop hardware and software products that connect to the customer's smart meter via the HAN. Devices can be energy related (thermostats, smart appliances) or non-energy related (security systems, mobile devices). The uses vary depending upon the devices and the functionality enabled.

3. More Timely Outage Communications

Outage notification alerts allow customers to be notified with important information in a timely, relevant way. These could include proactive messaging about an outage, automatic restoration, and restoration confirmation.

Prior to AMI deployment, customers would receive an initial outage communication in approximately eight to 44 minutes. AMI meters reduce the time for an initial outage communication for customers with AMI meters to approximately four to 26 minutes. As AMI deployment continues, we expect this reduction in notification time to expand to all customers, enhancing the customer experience.

4. Advanced Rates

A key aspect of the new AMI is the ability to remotely reprogram meters, rather than having to physically be connected to the meter (or replacing the meter equipment entirely). This functionality allows the Company to reprogram meters to roll out new rates in the future.

Energy consumption data for billing purposes can be recorded by AMI meters in intervals as short as five minutes, but in most cases, will be configured for 15-minute intervals. With more granular consumption data and more sophisticated meters, rate schedules can be created to better reflect the actual costs on the system at specific times of day. Customers will be able to take advantage of these price signals to manage costs. Time-of-day rate structures also encourage load shifting from peak periods to off-peak periods, resulting in emission reductions.

The Company has piloted two time-of-day rates, one for the residential sector and one for the C&I sector. The learnings from these pilots will be used to inform future rate designs and accompanying customer awareness and education campaigns to help customers align usage with the new rate structure. We discuss these pilots in more detail in Appendix B3 but note that these rate pilots do not rely on the AMI meters we are installing.

5. *Enhanced Behavioral Demand Side Management Products*

Behavioral demand side management is a mechanism to encourage customers to reduce or shift load via energy awareness. Small adjustment to customer behaviors by large numbers of customers has the potential to have a sizeable impact on the grid.

AMI meters enable the Company to create new and expand existing behavioral DSM programs. The Company is consistently looking to expand the behavioral DSM portfolio. The AMI meters as well as HAN and DI capabilities enable the company to provide personalized insights and tips to customers using the data collected by and analyzed on the meter. The Company plans on making the insights available to customers through a variety of channels including web, mobile, and email.

Each DSM program is designed with the Company's three priorities in mind: (1) lead the clean energy transition by helping customers reduce and shift energy usage from peak periods to off-peak periods with lower emissions; (2) enhance the customer experience by improving communication, insights, and customer control over their bills; (3) keep bills low by providing customers with more resources and tools to manage their energy usage.

Below we provide an overview of the behavioral DSM products created as a result of or enhanced by the AMI meters.[12]

- **High Bill Alerts.** Electric customers are automatically enrolled in the High Bill Alert program. This product notifies customers halfway through the billing cycle if their bill is trending higher than historically normal allowing the customer time to adapt their energy usage or prepare financially for the additional costs. Notifications are sent via email today. In the future alerts will also be sent via the mobile application.
- **Budget Alerts.** Budget Alerts enable customers to set a dollar threshold and be alerted if their bill is projected to exceed their set amount. Customers can sign up for Budget Alerts in the My Energy Portal and set their budget threshold. The system will check customers' bills daily between the 5th and 28th day of their billing cycle. If the projection for the current bill will be higher than their

[12] High Bill Alerts and Budget Alerts were created for AMI meters, but the functionality is also available to customers with legacy Cellnet meters through use of daily usage data.

budget amount, customers will receive an email alert notifying them. In the future alerts will also be sent via the mobile application.

- **Energy Action Days.** Energy Action Days uses digital communications and behavioral science messaging to encourage residential customers to reduce energy consumption during peak events. Participation is voluntary and there are no incentives or penalties for participation or non-participation. Customers with AMI meters receive a follow up email within a couple days of peak events, showing customers how they performed and comparing their performance to their neighbors. This feature is only available to customers with AMI meters.

F. The Customer Experience in the Near Future (2023 - 2024)

1. My Energy Connection Release 1

My Energy Connection is a mobile application that provides customers with detailed information on their energy usage. It uses the HAN to display real-time energy usage, while in their home, enabling customers take better control of their usage while providing insights to energy savings and to more Xcel Energy programs that can help them accomplish their energy goals.

See Appendix J for more information on My Energy Connection Release 1.

2. My Energy Connection Release 2

The second release of My Energy Connection will focus on providing customers with appliance-specific usage and cost breakdowns. Customers will be able to access this information through the same mobile application as release one. Having detailed usage and cost by appliance will allow customers to understand where and when they are using the most energy and will provide focus for their energy savings goals.

See Appendix J for more information on My Energy Connection Release 2.

3. Advanced Rates

The Company has concluded a residential TOU pilot, as noted above, and is currently conducting a C&I TOU pilot. We will file a proposal for a new residential TOU rate, informed by our pilot results, by the end of 2023. The results of the pilot show that the rate design used was effective. The pilot showed that the rate was close to being revenue neutral and resulted in modest demand decreases. While we are still developing the details of our permanent proposal, the effectiveness of the pilot rates leads us to anticipate only small adjustments will likely be needed to the rate design. The Company is still in the recruitment stage of our commercial TOU rate pilot, and we will use the information gathered from that pilot to inform a future proposal. Without any pilot results, it is still premature to anticipate what our permanent proposal may look like in the future. We anticipate filing a permanent proposal sometime in the next two years.[13]

G. The Customer Experience in the Future (2025 and Beyond)

The Company will continually assess, innovate, and iterate the foundational offerings made available the day customer receives their meter. As we evolve, our goal will be to prioritize and create new offerings that enable the Company to:

- **Lead the clean energy transition.** Help customers reduce load, shift from on-peak to off-peak load, and transition from high carbon to low carbon end uses such as electric vehicles.
- **Enhance the customer experience**. Deliver high quality, consistent experiences to customers that enable them to understand and control their bill and how they engage with the Company.
- **Keep bills low.** Prioritize cost-effective solutions that provide more benefits to our customers than costs, enable customers to minimize bills, and maximize low-cost energy.

The Company will continue to work with industry leaders to incorporate innovative technologies and offerings in our suite of AMI enabled customer products and services. We will continue to evaluate market trends and technical advances, ensuring we are continually passing along benefits to customers. We will continue to adapt our offerings to incorporate DI capabilities, transitioning traditional opportunities to DI applications, or integrating new technology that is not yet in the market.

The use case definitions, scope, implementation timeline, and prioritization will depend on technical capabilities available at the time of evaluation, cost-effectiveness, regulatory approval, and customer research.

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[13] Order Point 2 of the Commission's July 16, 2021 Order to Conduct Pilot Programs for General Service Time-of-use Rates, and Setting Procedural Schedule in Docket No. E002/M-20-86 requires the Company to file a permanent proposal in earliest of the following: first rate case following the substantial completion of the AMI system in Minnesota, within one year of the completion of the AMI rollout in Minnesota, or November 1, 2025.

Examples of products that are currently in our roadmap, but will continually be evaluated and iterated to ensure they are cost-effective and align with customer needs include:

- **Green Notifications and Controls.** Customers would be notified when the percentage of electricity generated by renewable services in their area exceeds a certain threshold. DI applications could be used to increase the accuracy and timeliness of these communications.
- **Enhanced DER Enablement.** Through the enhanced visibility and control of the distribution system, customers would be able to integrate distributed generation resources more seamlessly and potentially at higher levels within a given area. DI applications can assist in this aspect by providing higher levels of confidence regarding DER identification.
- **Enhanced Control Options for Behind the Meter Systems.** From the smart home to intelligent buildings, AMI meters will be able to communicate more seamlessly with devices and systems within the customer facility. Customers could use this capability to participate in demand response programs as well as to manage facility energy consumption in a more accurate and robust way.
- **Rate Advisor.** With granular usage information and analytics capabilities made possible by AMI, the Company could provide a multi-channel approach to educate customers and proactively offer ways to optimize energy usage and cost under existing and future rates.

VI. CONCLUSION

Our distribution grid is the foundation of the service we provide our customers, and modernizing the grid will be crucial to meeting the growing needs of our system and our customers over the coming decades. To that end, our grid modernization plans are 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 and future distribution system needs, and
- State policy and stakeholder input relative to customer offerings, performance, and technical capabilities of the grid.

Our grid modernization plans provide a basis on which to continue building the grid of the future – one that is resilient, reliable, safe, and affordable for all customers.

APPENDIX B2: CUSTOMER, OPERATIONAL, AND PLANNING DATA MANAGEMENT, SECURITY, AND INFORMATION ACCESS PLANS AND POLICIES

Beginning in 2016, the Company initiated a concerted effort to modernize its electric distribution system designed 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. This effort has led us to invest in new systems and field devices including an Advanced Distribution Management System, advanced infrastructure meters (AMI), a two-way field communications network (FAN), and Fault Location Isolation and Service Restoration (FLISR).

IDP Requirement 3.D.2.h requires:

> *Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)*

I. GRID MODERNIZATION TECHNOLOGIES

Below, we provide brief background information on our grid modernization technologies, which are discussed in more detail in *Appendix B1: Grid Modernization*.

A. Advanced Distribution Management System

An ADMS is the foundational software platform for operational hardware and software applications used to operate the current and future distribution grid. ADMS is foundational because it provides situational awareness and automated capabilities that sustain and improve the performance of an increasingly complex grid. Specifically, ADMS acts as a centralized decision support system that assists the control room, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. ADMS does this by utilizing the as-operated electrical model and maintaining advanced applications which provide the Company with greater visibility and control of an electric distribution grid that is capable of automated operations. In particular, ADMS incorporates Distribution Supervisory Control and Data Acquisition (D-SCADA) measurements and advanced application functions with an enhanced system model to provide load flow calculations everywhere on the grid, accurately adjusting the calculations with changes in grid topology and insights from sensors. This allows the Company to improve the monitoring and control of load flow from substations to the edge of the grid, which enables multiple performance objectives to be realized over the entire grid.

B. Advanced Metering Infrastructure and Field Area Network

AMI is the Company's metering solution, consisting of an integrated system of advanced meters, communication networks, and software that enables secure two-way communication between the Company's business and data systems and customer meters. The meters we are currently deploying, the Itron Riva 4.2, include Distributed Intelligence (DI) capabilities. This is a powerful distributed processing capability which, when integrated into the Company's broader ecosystem of customer and grid management systems, will unlock both customer and grid-facing benefits. The implementation of AMI includes the deployment of advanced meters, communication networks, and software that enables secure two-way communication between the Company's business and data systems and customer meters. The FAN is a secure, flexible two-way communication network that provides wireless communications to, from, and among field devices and our information systems.

C. Fault Location Isolation and Service Restoration

FLISR is an integrated technology that consists of an advanced application in ADMS, two-way communication, and automated field and substation (reclosers, switches, substation relays) equipment. FLISR 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 with ADMS to detect issues on our system, isolate them, and automatically restore power.

II. SECURITY AND PROTOCOLS FOR GRID MODERNIZATION

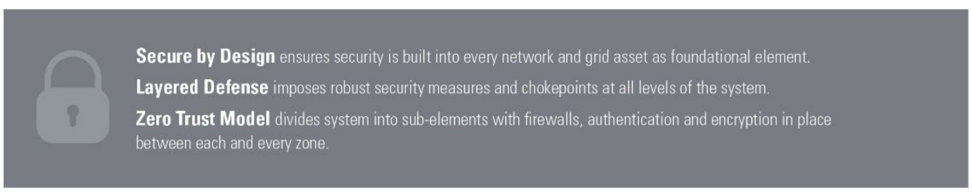
In this section, we discuss our approach to data security for our grid modernization plans. Support for protective cyber security and information technologies underlie all of these components, as they are essential to operating a secure and technologically advanced grid. Given the ongoing proceeding in the Grid Security Docket (Docket No. E999/CI-20-800), as well as continued heightened geopolitical risks and an increase in domestic threats to critical infrastructure (CI), the security of our data and customer data is paramount.

A. Overall Approach to Security

The Company has a dedicated Enterprise Security and Emergency Management (ESEM) business unit that encompasses cyber and physical security, security governance and risk management, and enterprise resilience and continuity services. This combination of services is designed to cover analysis of vendor risks, alignment of technologies with security standards, secure solution design and deployment, integration with Company solutions (including user access management, system monitoring, and incident response), as well as threat analysis and planning for continuity of business operations in the event of a disruption. The Company's security risk management program provides Company leaders with information about threats and the level of security risks, so that proportional mitigations and responses can be planned.

Generally, our security practices include a security controls governance framework, which leverages industry best practices including the National Institute of Standards and Technology (NIST) Cyber Security Framework. The Company's security policies and standards incorporate regulatory compliance requirements and security controls designed to protect the Confidentiality, Integrity, and Availability of information and systems. A rigorous vendor security risk assessment process helps to reduce supply chain risk. Figure B2-1 shows the key security components.

Figure B2 - 1: Key Security Components



We implement cyber security controls not only for systems within the enterprise data centers, but also for the intelligent devices (including meters) and communications networks outside of the company premises. Where technically feasible, these include, but are not limited to, user access controls, encryption, firewalls, intrusion detection and prevention systems (IDS/IPS), vulnerability and patch management, system change and configuration management, monitoring, and incident response planning.

Our cyber security program may best be described in terms of the five categories of controls outlined in the NIST CSF: identify, protect, detect, respond, recover. Combining these adds multiple layers of protection and detection, including defenses, at each endpoint and throughout the network. Controls within these layers include:

- *Asset management* – maintain an inventory and securely configure assets, so we know what to protect as well as what is authorized to access our networks [Identify],

- *Protection* – user access controls, encryption, digital certificates, and other controls to ensure the confidentiality, integrity and availability of data [Protect],
- *Vulnerability management* – in addition to scanning equipment for known security vulnerabilities, the Company monitors emerging threats [Detect],
- *Monitoring and alerting* – identify potentially anomalous activity so that both proactive and reactive responses are appropriate and efficient [Detect],
- *Incident response* – analyze information using playbooks and escalate to the Enterprise Command Center, the Company's 24x7 watch floor operation designed to prepare for, respond to, and recover from any potential hazard that may impact customers, Company assets, operations, or its reputation [Respond], and
- *Disaster recovery and business continuity planning* – to efficiently maintain and restore grid operations in the event of a cyber-attack [Recover].

We will apply these controls to identify and protect all components of the intelligent grid and help ensure the reliable and safe delivery of energy to our customers.

Endpoint Protection is the installation and/or enablement of protective and detective cyber security controls to thwart malware and external influences from causing unexpected, unwanted, or invalid behavior at an endpoint. These were specified as cyber security controls in the AMI vendor selection process, as they are essential to protect the devices and the data that are handled by AMI meters and headend servers.

Access Control is to confirm that only necessary and authorized users have access to the individual devices. This not only includes the devices that are installed on the consumer's premises, but also the devices that facilitate communication and control of the data flowing to the consumer. There are potentially many avenues of compromise with respect to unauthorized access to devices. This is a key consideration and will be addressed through strong authentication methods, which include multi-factor authentication methods.

Authentication is a method by which a user affirms their identity. In its simplest form, it involves a user ID and password. Where technically feasible, the Company requires multi-factor authentication so that a user must not only know their password, but they must also possess a physical or logical token. This minimizes the ability of an unauthorized user to steal passwords and access our assets and information.

Authorization is the process of determining and configuring the minimum level of access required by a user or an automated system. Granting undue permissions to devices that comprise the intelligent electric distribution system could lead to unauthorized or inadvertent changes and instability. Complying with a least-privilege principle ensures that only necessary and authorized individuals can make administrative changes.

System and Patch Management addresses the periodic manufacturer updates to software and firmware to improve performance, add features, or address security vulnerabilities. A robust system patch management process incorporates asset inventories, secure receipt of patches from the vendor, testing, and deployment to the field. The Company's threat intelligence and vulnerability management teams monitor for and inform support teams of known security vulnerabilities that require patching. Keeping current with vendor patches helps reduce the possibility that a bad actor can use a known exploit to compromise our systems or data.

Data validation is a final defensive layer between the various endpoints. As data is sent from endpoints at consumer premises, data validation at the head-end must take place. If data values received from the consumer endpoint do not fall within a range of expected values, then either the data must be assumed to be compromised and discarded, or secondary validation must take place to measure the integrity of the data received. This validation will provide yet another level of detection and protection for the intelligent electric distribution system.

B. Physical Security

Cyber security is not the only form of protection for Company assets. Physical security measures are also a strong tool to ensure the safety of our assets. Over the last eight years, the Company has focused strategic physical security efforts on assets based on their criticality to the stability of the electric grid. These have been primarily Bulk Electric System (BES) substation locations that have been identified critical to the system. While this practice has increased the protection around critical BES assets, there is an opportunity to expand those strategic efforts to substations that are critical to local load serving areas. Recent physical security events and an increase in planned and executed attacks from Domestic Violent Extremists (DVEs) across the country have highlighted the need to address the security of assets beyond the traditional BES substations. The Company is currently working to expand physical security efforts and is evaluating substation facilities to not only address their criticality to the stability of the electric grid, but their importance to our customers and communities.

The asset evaluations will result in recommendations to mitigate possible physical security risks at Company substations. Recommendations may include:

- *Physical Enhancements* – Substation hardening from physical intrusion and attack using enhancements such as enhanced security perimeters (i.e., perimeter fencing and lighting), ballistic protection, and control building ballistic protection.
- *Communication and Surveillance Infrastructure* – Increase ability for passive and active substation activity and intrusion monitoring. Equipment may include cameras, radar, and motion detection.
- *Operational Flexibility and Resilience* – Increase ability to respond and restore damaged equipment. This may include spare equipment, additional distribution feeder ties, distribution system capacity upgrade, and transmission line upgrades and additions.

C. Grid Modernization to Security Approach

Overall, while the implementation of grid modernization initiatives helps address certain existing risks, it also presents different challenges to security than a less advanced grid, and therefore requires its own comprehensive security strategy. This strategy starts with identification and protection of all components of the intelligent grid, both for the protection of customers and for the reliable and safe delivery of energy to customers. First, devices in the field must be protected. Unlike internal business technology, the distribution components are out in the field and at customers' residences; devices can only be hardened so much, and security must also rely on other controls. For example, detective controls at strategic locations to provide early notification of suspicious behavior or anomalous activity.

Additionally, although even legacy distribution systems and meters are vulnerable to physical tampering and disabling, adding a communications network that provides additional capabilities and services to our customers, as well as greater insight into our system, also enhances the potential impact of a security compromise. That said, we are designing security controls for each component and system implemented. These security risks can be organized into three primary areas: compromise of meters and devices; exploitation of the communications channels; and security lapses once data is within the corporate environment. There are also security risks related to cloud-based components including the customer web portal, as well as future customer applications and new products and services that will be enabled by the advanced grid that we are also proactively addressing prior to implementation.

We have based our controls on a security controls governance framework that leverages industry best practices including the National Institute of Standards and

Technology (NIST) and Cyber Security Framework (CSF). The Company's security policies and standards incorporate regulatory compliance requirements and security controls designed to protect against CIA (Confidentiality, Integrity and Availability) breaches. This framework serves as the basis for project security requirements as well as periodic internal security technology control assessments.

D. Cyber Security for Critical Infrastructure

In August of 2022, Governor Tim Walz signed Executive Order 22-20 (EO 22-20) directing state agencies to monitor and reduce cybersecurity risks to critical infrastructure to protect the life, safety, and property of all Minnesotans. In March of 2023, the Minnesota Department of Commerce (Department) reached out to the electric rate-regulated utilities in the state to discuss how they may meet EO 22-20 directive 3d, which Orders,

> *"By April 4, 2023, state agencies with regulatory oversight over critical infrastructure must examine their authority, and to the extent necessary and permissible under existing authority, require or encourage critical infrastructure providers to annually certify self-assessment completion and compliance with core cybersecurity best practices."*

The Department and electric utilities worked together to provide information necessary to help the Department meet its requirements. We include as Attachment P our response to the Department's Request for Information, sent on April 3 of this year. On April 11, the Commission held a Planning Meeting to better understand each electric utility's preparedness plans for protecting our critical infrastructure from cyber security threats.

The Company also participates in monthly cyber security meetings intended to help plan and information share. The Department has been a critical partner in re-engaging parties throughout the state in this effort.

E. AMI Infrastructure and Communications Overview

In this section, we discuss the controls at various points of the AMI infrastructure. These components, starting at the meter, are as follows:

- The meter sits at the customer premise, gathering metrology data to be sent to the headend for billing purposes. The meter may also employ DI agents, to gather information for electric grid optimization, or to provide the customer with additional information and capabilities for managing their energy usage.

- The meters are a part of the field area network (FAN), a communications mesh that transmits information to and from the AMI headend. FAN communications end at an Access Point which is connected to either an LTE cellular modem or fiber connection. This creates the transition from FAN to the wide area network (WAN) and the Company's internal network.
- Once on the Company's internal network, data may move between network segments as allowed by firewalls and other security controls. Ultimately, data is stored on servers that reside in the Company data centers or is securely moved to secure locations in the cloud.
- Company employs layers of security controls to protect the confidentiality, integrity, and availability of data throughout this journey.

We discuss these infrastructure components below.

1. At the Meter

Our Company's grid modernization security approach is one of "defense in depth." The advanced meters will be physically sealed and monitored to detect tampering. Customer usage data is well protected on the meter. Attempts to physically open or otherwise access a meter trigger tamper alarms. No customer-identifying data is held in the meter. When applicable, DI agent processing is primarily done in dynamic memory rather than stored on the meter. The Company has performed extensive security penetration testing in these areas, as well as to confirm the separation of metrology data and communications from that used by DI agents.

Advanced meters and other networked devices have network interface capabilities that enable them to connect to the FAN. We leverage both physical and cyber security controls to protect these network interfaces from unauthorized access. Second, a compromise of the FAN communications protocols that carry "traffic" to and from the meters and field devices could lead to disruption or alteration of information needed for grid management. Therefore, it is paramount to protect the integrity of the communication devices and channels that allow the advanced grid to perform at expected levels. It is also important to implement the correct level of monitoring and alerting, configured to identify potentially anomalous activity, so that both proactive and reactive responses are appropriate and efficient. Third, the primary risk to systems and information that reside within the Company's corporate environment is from unauthorized access – where a criminal or unqualified employee accesses sensitive data or issues commands to the grid. There are many controls in place to prevent and detect such behavior, including segmenting the AMI system from the corporate business network.

Meter communications will be encrypted to protect the privacy of our customers, as will the other communications that travel on the FAN from and between the authorized devices that have been registered onto the network. Firewalls control the information that travels in and out of the corporate network. The AMI headend will validate the integrity of the data received. We will actively monitor the communications path between the meters and the Company data centers to promptly detect and respond to any anomalous activity. Additional monitoring of the headend system will trigger alerts for investigation.

2. *On the FAN*

The equipment that makes up the FAN deploys the endpoint protections discussed above. Additional key controls for FAN include the use of firewalls to restrict which systems can interact and what ports and protocols they can use; encryption to minimize the opportunity to intercept and alter data traffic on their way to the AMI headend; monitoring and log review, as well as response to suspected security events. All member devices on the FAN have digital certificates, which prohibits rogue devices from joining the network, so traffic cannot be rerouted, or invalid information injected into the network. The mesh portion of the FAN is also Company-owned, granting Company the control to deploy and monitor security settings.

Firewalls are placed in multiple areas of the network between the customer meter and the company data center/head end. By default, all traffic through a firewall is blocked, and authorized only after a thorough review and change process. With a firewall, any unauthorized, unregistered devices that attempt to join the network or communicate to/from devices are blocked.

Encryption uses complex mathematical algorithms to obscure data prior to and during its travels through the communications network. It also prevents data from being altered. Only authorized parties to the transaction (sender and receiver) have the "keys" to encrypt and decrypt data.

3. *Company Systems and the Internal Network*

The Company systems comprising and supporting grid modernization reside in data centers with physical access protections – only authorized users are able to enter these locked facilities on Company property. Data accessed from the control centers travels from the systems in the Company data centers over the corporate network. At the control center, application users must follow the same rules for authentication, authorization, and least privilege.

Data from the intelligent electric distribution network passes through multiple defense-in-depth controls on its way back to the systems in the corporate data centers. Communications will pass through multiple firewalls to ensure that only authorized devices are communicating on authorized ports/protocols. Additionally, a protocol-aware Intrusion Detection System/Intrusion Prevention System (IDS/IPS) will inspect the traffic to ensure tampering has not been performed on the data packet. Once the data has been delivered to the systems responsible for consuming this information, only authorized processes will have the ability to act upon this information.

The Company segments its networks, so that critical operational systems and information are kept separate from business data and operations including email. This segmentation adds a significant barrier should a criminal compromise a corporate user's account. In addition to using firewalls between networks, the Company requires the use of multi-factor authentication when accessing systems from outside the control center.

After clearing firewalls, data from the FAN is routed through the internal network (and more firewalls) to the AMI headend. Meter readings are sent to other systems for processing and preparation of bills. DI data is sent to an application server in the data center which sits in a secured network segment (DMZ) where it is accessible to Company users and to Itron, which is responsible for management of that server, including patching and other security controls.

Physical access to the Company data centers is tightly controlled and periodically reviewed for business need. Data in systems controlled by the Company is protected with layers of controls, including but not limited to: access; encryption; monitoring; vulnerability and patch management; change and configuration management; and incident response planning.

4. *In the Cloud*

The Company has chosen to host some elements of the AMI solution in the Cloud. Portions of the DI solution are only available in the Cloud. The Company requires that vendors of cloud-hosted applications meet the same security standards required of systems that are on premises. Transfers of data to/from the Cloud elements are done via secure mechanisms.

In summary, we take our responsibility to protect the privacy and security of our customers, grid, and information systems seriously. We have based our controls on a security controls governance framework, which leverages industry best practices. We will take a defense-in-depth approach that will apply controls at many levels to identify and protect all components of the intelligent grid and help ensure the reliable and safe delivery of energy to our customers.

III. INFORMATION ACCESS PLANS AND POLICIES

This section summarizes our information access, privacy, and governance framework. We discuss the ways that we intend to share information from our grid modernization investments with customers and how we expect grid-facing information to benefit customers in Appendix B1 and in *Appendix J: Distributed Intelligence*.

Our customer data and information strategy enables the framework for maintaining the integrity and security of our information assets throughout its lifecycle, including the creation, storage, usage, sharing, and disposal phases. The strategy also ensures the Company's information provides business value, minimizes risk, and complies with legal and regulatory requirements.

A. Culture

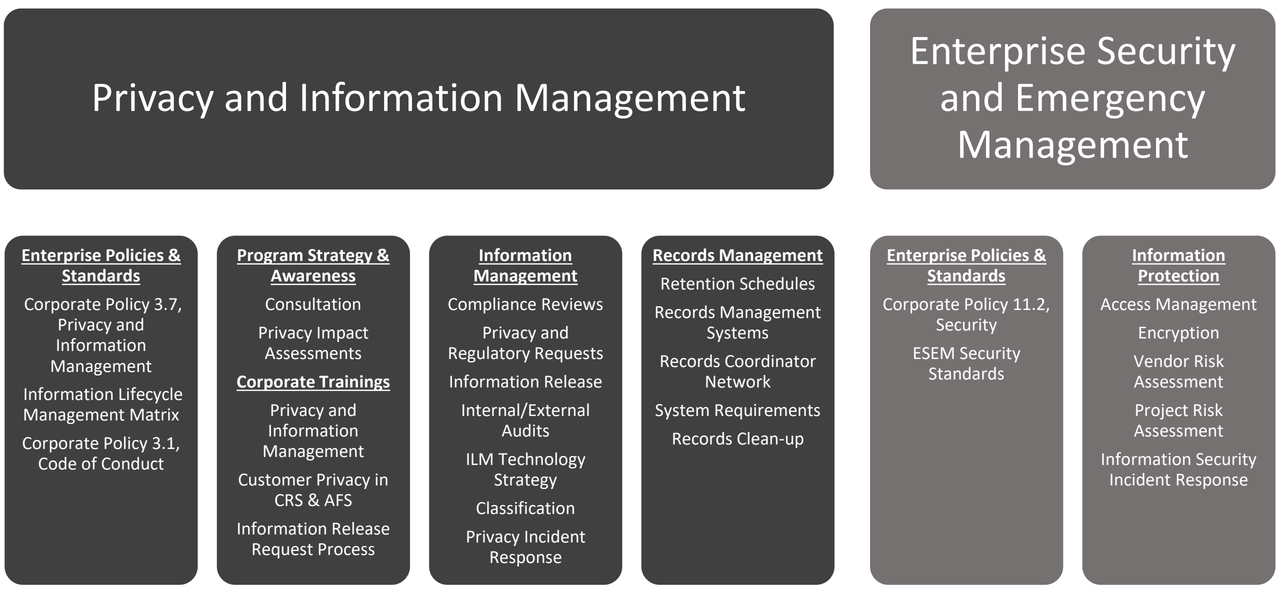
The Company's information is managed as an asset of the business. We leverage information to drive more understanding within the business about how it can be employed to improve operational performance, evaluate industry options, and help customers make better decisions. We have robust privacy and security policies that vary based on the type of information. Our customer strategy is informed by these policies, and as new products, services, and experiences are identified, they will follow these policies. Customer-specific information derived from grid modernization is treated the same way that customer-specific information is treated today. The primary difference in what data grid modernization will capture is expected to be the granularity of the data – i.e., today's monthly consumption compared to the five- and 15-minute interval data available with AMI.

The Company employees understand their responsibilities for maintaining the integrity and quality of our information assets, complying with requirements, and keeping the information safe and secure. To ensure that all employees understand the criticality and responsibility of safeguarding information, all employees are required to complete the Privacy and Information Management training annually.

B. Information Management Framework

The Company's General Counsel function oversees and provides leadership of the Privacy and Information Management policies, standards, procedures, and processes. This includes strategic oversight of the creation, collection, use, retention, and disposal of all company information in all formats. The ESEM function oversees the security requirements and protection of the Company's information assets. Compliance is a corporate and individual responsibility and is monitored and evaluated through the corporate governance framework. The Company's information management and protection framework is shown in Figure B2-2 below.

Figure B2 - 2: Xcel Energy Information Management and Protection Framework



C. Information Management and Protection

Customers trust that the information the Company creates, collects, and uses as part of its work to provide regulated utility service to customers is handled properly to avoid the potential for loss, misuse, or harm. Information Management is the policies and procedures that support data quality, data logistics and data integration covering the following lifecycle stages: (1) creation and collection; (2) use; (3) release; (4) disposition.

1. Creation and Collection

Company information is the data and content that is stored on Company resources or created, collected, or used for Company business purposes and is categorized as a Record or a Non-Record. Distinguishing between records and non-records is essential to the decision-making process regarding the creation and collection, use, release, and destruction of the information.

Records are any documentary material, regardless of format, that have been finalized and/or identified on a retention schedule. Non-records are any documentary material, regardless of format, that has not been identified as a record on retention schedule and are to be destroyed as soon as their intended purpose has been accomplished and include copies of records.

All Company information whether it is a record or non-record is classified into four information classifications based on its value or potential risk. We describe these categories and how we classify customer information below:

- *Confidential Restricted Information (CRI).* CRI includes information where unauthorized disclosure (inside or outside the Company), alteration or destruction has the potential for significant harm to the Company, its employees, shareholders or its customers, including: damage to reputation; damage to Bulk Electric System (BES); legal, regulatory, or other sanctions. Information in this classification requires the strongest level of protection. Distribution of CRI must be limited to those with a business need to know and distribution to any third party must be approved through the information release process. CRI includes Personal Information such as: Social Security Number, Driver's license or other government-issued identification numbers, financial account number, any individually identifiable information received directly from a financial institution, biometric identifiers (including, fingerprints, voice print, retina or iris image), first name (or initial) and last name (whether in print or signature) in combination with any one of the following: Date of birth, Mother's maiden name, Digitized or other electronic signature, or DNA profile.
- *Confidential Information (CI).* CI includes information where unauthorized disclosure (inside or outside the Company), alteration or destruction has the potential for harm to the Company, its employees, and customers including: damage to reputation; material productivity loss; impede the organization's operations to the BES; legal, regulatory, or other sanctions. Information in this classification requires protection and may only be distributed to those with a business need to know and distribution to any third party must be approved

through the information release process. CI includes customer personal information, such as: details regarding a customer's account or other Xcel Energy-assigned numbers, energy usage, current charges, and billing records.

- *Internal Information (II)*. Internal information includes information where unauthorized disclosure (inside or outside the Company), alteration or destruction is unlikely to cause harm to the Company, its employees, and customers, such as: damage to reputation; significant inconvenience or productivity loss; damage to BES; legal, regulatory, or other sanctions. Information in this classification may not be shared outside the company without prior approval from the information owner. II includes aggregated customer energy usage data (CEUD) or aggregated whole building CEUD to the 4/50 threshold.
- *Unsecured Information (UI)*. Information that may or must be available to the public and includes the Company's website, and the following documents once published and made available to the general public: Securities and Exchange Commission filings and Federal Energy Regulatory Commission filings, brochures, advertisements, press releases, annual reports, billboard advertising, current billing rates. In terms of customer information, once aggregated CEUD is authorized, it becomes unsecured information (example: the Community Energy Reports on xcelenergy.com).

2. Use

Our Privacy Notice outlines the ways that we may use the information we obtain about our customers, as follows:[1]

- Providing service, establish and maintain account, run our business, communicate and provide customer support.
- Setup new service, confirm identify, protect against fraud and collect on past-due accounts.
- Enroll in energy assistance programs.
- Gauge interest in energy efficiency programs and market those programs and services.
- Facilitate participation in energy efficiency programs.
- Process payments for services.
- Provide access to and maintain the security of My Account.

[1] The Xcel Energy Privacy Notice in its entirety can be found at: https://www.xcelenergy.com/staticfiles/xe-responsive/Working%20With%20Us/23-06-635%20English%20language%20privacy%20notice_P3%20-%20Accessible.pdf.

- Operate, evaluate and improve our business and the products and services we offer such as developing new and analyzing exiting products and services, optimizing customer experience, managing our energy distribution system, reduce costs and improve service accuracy and reliability, manage risk exposure, perform accounting, auditing and other internal functions).

Internally, we base our use parameters on the information classification assigned to the type of information. Employee access to customer CRI or CI is limited to only those employees and contract workers with approved access to our customer system (Customer Resource System or CRS).

Employees with access to customer CRI and/or CI are prohibited from accessing viewing for a non-business reason; accessing or transferring it for personal gain, advantage, or any other personal reason; giving access to or transferring it without first obtaining appropriate approvals; downloading, uploading, or saving it on a personally owned computing device; and accessing it from a public computer.

3. Release

The Company will only release customer information pertaining to an individual to that individual once the identity of the individual has been validated. We will release customer information to the customer of record upon validating the customer's identity, or to a third party upon receiving a documented and verified consent from the customer of record. We may also disclose customer information as required or permitted by law or applicable regulations, including to a federal, state, or local governmental agency with the power to compel such disclosure, or in response to a subpoena or court order.

We also release customer information to our contracted agents, when it is necessary for our agent to perform the service(s) specified in an Agreement.[2] All of our contracted agents go through a security vendor risk assessment (SVRA) screening process intended to provide transparency into security-related risk(s) that could potentially be introduced to the Company as a direct result of utilizing a third-party vendor's product, service, application, etc. All newly proposed vendor arrangements are subject to the SVRA process before a contract is signed. Suppliers are assessed by multiple ESEM teams to ensure security risk is addressed holistically. We prohibit these service providers from using or disclosing the information we provide them,

[2] Contracted Agents are entities with whom we have a contractual relationship to support our provision of regulated utility service, or that directly provide regulated utility service to our customers on our behalf.

except as necessary to perform specific services on our behalf or to comply with legal requirements.

For information about the Company's policies, practices, and protocols regarding the release of customer information to customers or third parties upon request the request of a customer, please see our most recent Annual Report.[3]

4. Disposition

The disposition phase of the information management lifecycle consists of disposal requirements as defined in a retention schedule. Customer account information is retained for the duration of the customer relationship plus seven years. Billing information and data from our meters are retained for current year plus seven years.

[3] Xcel Energy Compliance Filing – Annual Report on Privacy Policies and Open Data Access Standards, Docket Nos. E,G999/CI-12-1344 and E,G999/M-19-505 (March 1, 2023).

APPENDIX B3: EXISTING AND POTENTIAL NEW GRID MODERNIZATION PILOTS

In this section, we discuss existing pilot projects, as well as potential new pilot programs and demonstration projects.

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.*

I. LOAD FLEXIBILITY AND ELECTRIC VEHICLE PILOTS AND DEMONSTRATIONS

The Company filed a Load Flexibility proposal on February 1, 2021,[1] and received approval of three pilots on March 15, 2022, including EV Optimize Your Charge (Commercial and Residential), Peak Flex Credit, and Thermal Energy Storage. Additionally, there were two demonstrations allowed as part of the proposal including Excess Supply Partners and School Bus Vehicle to Grid (V2G). Cost recovery of these expenses was approved by the Commission's July 17, 2023 Order in Docket No. E002/GR-21-630. The pilot programs launched in late 2022 and are summarized below, along with the demonstration projects. In addition, we discuss our Public Fast Charging Network proposal previously approved by the Commission.

A. EV Optimization Pilot

The EV Optimization Pilot was launched in December 2022 for both residential and commercial customers under the name Optimize Your Charge. As a part of this pilot, the Company aims to manage potential grid impacts of EVs by incentivizing customers to charge their EVs during off-peak hours. The management of the grid impacts of electric vehicles is done by working with customers to provide schedule options for their daily EV charging, with participating customers receiving a bill credit. The schedule options ensure charging occurs outside the Company's system peak and are designed to stagger charging times to avoid demand spikes during the off-peak period. Participants must conduct at least 25 percent of their charging within the schedule to receive an annual $50 bill credit incentive.

[1] Docket No. E002/M-21-101.

B. Excess Supply Demonstration

This demonstration was to test active load-shifting mechanisms and evaluate their value to customers and the grid. Under the proposed demonstration project, a small group of commercial customers with interval meters would be invited to enroll in an active demand-response program. The Company would provide consulting services to guide the customers in receiving signals and shifting usage to times that are beneficial to the system.

C. Dynamic Thermal Storage Pilot

The pilot, renamed from Commercial Thermal Storage, will study incentives provided to commercial customers for the installation and operation of thermal storage solutions, as well as ongoing credits for the associated daily load shifting.

D. Peak Flex Credit Rider Pilot

This pilot will study a dispatchable, load-shedding program for commercial customers that provides additional flexibility and optionality to customers who want to design program parameters to work within their operational and business needs. This pilot provides pricing for both peak control events as well as buy-through options for economic control events. In approving this pilot, the Commission required the Company to create a second tranche of participation dedicated to testing the ability of aggregators to provide retail demand response in Minnesota using the Peak Flex Credit product design.

E. School Bus V2G Demonstration

The goal of a School Bus Demonstration is to study the value of V2G applications for the distribution grid. Initially approved within the Load Flexibility docket, the Commission subsequently ordered the Company to modify the demonstration plan with an additional proposal.[2] That proposal was initially included in our Clean Transportation Portfolio proposal in Docket No. E002/M-22-432. However, that proposal was subsequently withdrawn.[3] As a condition of that withdrawal, the

[2] *See* Order Accepting 2021 Transportation Electrification Plans and Adopting Additional Information Requirements (May 17, 2022), Docket No. E999/CI-17-879, Order Point 3.
[3] *See* Order Accepting Withdrawal of Clean Transportation Portfolio Subject to Conditions (August 23, 2023), Docket No. E002/M-22-432.

Company is required to include a new proposal to support electric school buses with our 2023 Transportation Electrification Plan (TEP), which is included with this filing.[4]

The proposal included within our TEP will study and address barriers to school bus electrification, school bus bi-directional connection to the grid, and to better understand the costs and benefits of electric school buses as grid resources. Through this demonstration, the Company proposes to partner with the Department on its Electric School Bus Deployment Program, to support two V2G capable installations on sites of entities, school districts or school bus owners and operators, willing to participate in the demonstration to inform pathways of using V2G electric school buses in the future as demand response, distributed energy resources for grid resiliency and reliability resources.

V2G refers to the ability of EVs enabled with bi-directional charging capabilities to be used as a source of power, potentially exporting power directly to the grid to help manage system needs. This demonstration will focus on using electric school buses, which, due to their large battery capacity and regular driving schedules, have seen more rapid adoption of V2G than other types of electric vehicles. Through the demonstration, the Company will provide EVSI and rebates for bi-directional EV chargers to school districts and/or other electric school bus operators. By agreeing to be a part of the demonstration, the school district/electric school bus operator will agree to allow the Company to discharge power from the vehicle in response to grid conditions. Testing V2G for various events along with monitoring performance and evaluating impacts to the participants and the buses will continue for two years.

F. Public Fast Charging Network Program

The Company has been approved to install, own, and operate DC fast charging (DCFC) stations in Minnesota.[5] This pilot focuses on addressing range anxiety, a primary barrier to EV adoption. The pilot also helps address the current public charging infrastructure gap in the Company's service territory, provide access to charging for those who cannot charge at home or at their business, and enable inter- and intra-community electric transportation. The Company is placing DCFC stations in locations not currently served by the existing market, mostly in the rural parts of the state outside of the Minneapolis-St. Paul area. As discussed in previous filings, the Company has recently decided to focus only on the signed agreements we currently

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[4] See Appendix H
[5] *See* ORDER APPROVING PUBLIC CHARGING STATION PROPOSAL (April 27, 2022), Docket No. E002/M-20-745, Order Point 1

have at seven individually owned sites.[6] This decision was made due to higher forecasted costs caused by inflationary pressure along with recent market announcements on changes in technology.

II. PREVIOUS RESIDENTIAL BATTERY DEMAND RESPONSE PILOT AND RENEWABLE BATTERY CONNECT PRODUCT

The Company managed an 18-month Virtual Power Plant (VPP) pilot for Residential Battery Demand Response Pilot (marketed as "Battery Connect") in our Colorado service territory in 2021 as part of our 2019/2020 Demand Side Management (DSM) Plan. The VPP pilot tested how batteries could provide energy during peak hours, perform solar time shifting, execute controlled charging, and absorb excess energy during morning hours around low-cost production times. The Company had contracted with both Tesla and SolarEdge for managing the performance of residential batteries installed inside customer homes. Participating customers received an upfront incentive in exchange for letting the Company control the battery up to 100 times for both charge and discharge events. At the end of the pilot, the Measurement & Verification report provided several takeaways and learnings from all the battery data the Company provided including timing of the battery charge.

The Colorado pilot successfully evaluated various energy storage concepts related to residential battery use. Renewable Battery Connect, which is a VPP, represents the next version of this product and was filed in the 2022-25 Renewable Energy Plan and approved by the Colorado Public Utilities Commission in September 2022. The primary product design changes from the pilot are the increased upfront incentive amount and the requirement for the battery to be 100 percent charged by an on-site solar system which enables the battery to qualify as a renewable energy resource. The product launched in June 2023.

We also note that – while not a pilot program – we are proposing an Energy Storage Incentive Program. In 2023, the Minnesota Legislature passed Minn. Stat. § 216C.379 Energy Storage Incentive Program, which directs the Company to develop a battery grant program for customers with on-premises solar. Per legislation, the program will be designed to provide a one-time grant of up to $5,000 for solar PV systems with a connected battery of up to 50 kWh and will be filed with the Minnesota Department of Commerce on November 1, 2023 in Docket No. E002/M-23-459.

In conjunction with the battery grant program, the Company is developing, in parallel,

[6] *See* our June 30, 2023 Supplement in Docket Nos. E002/M-15-111, et. al.

a demand response program. While this is not a pilot program, we note it because it will build upon the Renewable Battery Connect Program offered in Colorado described above. The Company intends to propose this demand response battery program as part of our 2024-2026 Energy Conservation and Optimization (ECO) Triennial via a modification sometime in 2024. We will propose flexibility with the ECO program to include existing installed battery storage systems and to allow customers without on-premise solar to participate in the program. The battery grant program will encourage participation in the demand response program.

III. RATE PILOTS

A. General Service Time of Use (TOU) Pilot

The Company is currently piloting a General Service Time of Use rate that encourages C&I customers with demand equal to or greater than 50 kW over the preceding 12 months to shift load from on- to off-peak times.[7] One rate design, the TOU Rate, features two time-varying rate components—an energy rate component and a demand charge component. Each of the two components have charges that vary based on three time periods. The Demand charge is further differentiated by time of year. The three time periods are: peak (3-8 p.m. non-holiday weekdays), off peak (12-6 a.m. everyday), and base period (all other hours).

The other rate design, the critical peak pricing (CPP) rate, will feature volumetric pricing that combines energy and demand charges into one per kWh charge. The charge will vary by time of day, using the same time periods as the TOU Rate. This rate will also feature a CPP component that allows the Company to call events for up to 75 hours per year with a much higher per kWh charge during these events.

At a high level, the pilot aims to measure commercial customer response to pricing signal and inform future rate design that can leverage advanced metering infrastructure (AMI) and eventually replace the current Time-of-Day structure. We expect a permanent rate, if approved, would be launched after AMI is fully deployed and operational. We note that the pilot does not rely on AMI meters but will utilize them for participating customers who have already received new meters.

[7] Pilot approved in Docket No. E002/M-20-86.

B. Residential Time of Use Rate Pilot

As discussed in previous IDPs and in *Appendix B1: Grid Modernization*, the Commission certified and approved a residential TOU rate pilot that involves two-way communication field area network (FAN) infrastructure and advanced meters.[8] The pilot was initially scheduled to start in April 2020. However, due to the COVID-19 pandemic, the formal launch of the pilot was delayed until November 2020. The pilot concluded in late 2022.

As a part of the pilot, selected residential customers were switched to a rate design with variable pricing based on the time of day that energy is used. We provided participants with new metering technology, increased energy usage information, education, and support. The pilot was designed to encourage shifting energy usage to daily periods when system load conditions are normally lower. Strategies that shift load away from peak times may reduce or avoid the need for system investments in fossil fuel plants that serve peak electric load.

For the pilot, we deployed advanced meters to approximately 17,000 residential customers. The customers were 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. The pilot has now concluded, and participating customers can choose to remain on the TOU rate or transition to a standard residential rate at any time. On February 10, 2023, we reported final pilot results and conclusions in Docket No. E002/M-17-775.

Pursuant to the Commission's July 17, 2023 Order in Docket No. E002/GR-21-630, the Company will file a proposal for a permanent residential TOU rate by December 31, 2023. Because the MN TOU pilot has ended and a permanent rate is being contemplated, we will not include discussion of the MN TOU pilot in future IDPs.

IV. RESILIENCE AND NON-WIRES PILOTS

A. Resilient Minneapolis Project

We requested certification in our 2021 IDP for the Resilient Minneapolis Project (RMP). In pursuit of the Commission's September 21, 2023 Order in Docket No. E002/M-21-694, we are continuing discussions with the host communities and will

[8] *See* Docket Nos. E002/M-17-776 and E002/M-17-775.

file a revised RMP proposal on or before March 19, 2024 (180 days from the date the Order was received). The Company will be receiving a U.S. Department of Energy (DOE) funding award for resilience that includes our request for $9 million in federal funds to complement RMP. We will work with DOE as well as our RMP partners to determine next steps and how this funding can be used. We will keep the Commission updated in our December 1, 2023 Annual Report, and as needed.

Order Point 10 of the Commission's July 26, 2022 Order in Docket No. E002/M-21-694 states:

> *Xcel shall include a discussion of the RMP program in comparison to battery and microgrid programs/projects in Xcel's service territories in other states, lessons learned from these programs as they move through construction and into operation, and specific details how these lessons are informing RMP project decisions, reducing costs, and/or improving efficacy.*
>
> *a. Xcel shall include this information in Xcel's 2023 IDP filing.*
>
> *b. Xcel shall include this information in each of Xcel's annual reports filed in Docket No. E-002/M-21-694.*

We note we provided this information with our December 1, 2022 RMP Annual Report. We are currently working with community partners to develop a revised RMP proposal, which will consider lessons learned from other battery and microgrid programs/projects, where applicable.

Below we provide updates of the Company's resilience microgrid initiatives in Colorado and Wisconsin, including relevant lessons learned.

1. Community Resilience Initiative (Colorado)

The Community Resilience Initiative (CRI) project seeks to support communities in Xcel Energy's Colorado service area by providing BESS-enabled microgrids in community center locations. As with RMP, the Company-owned BESS will provide back-up power to critical infrastructure during outage events while allowing for the energy storage asset to provide grid services during non-emergency operation. The BESS were sized to meet each facility's load and to provide grid value at the interconnection point. Working with our partner communities, the Company selected six sites for deployment of the CRI microgrids: the Alamosa Recreation Center, the Arvada Center for Arts and Humanities, Denver International Airport, the Denver Rescue Mission, the National Western Center, and the Nederland Community Center. CRI is currently commissioning two sites building a third and working through permitting with the last three sites.

During this process several important lessons were learned and incorporated into the initial RMP RFP and how this team is carrying out the work:

- *Developing relationships and technical understanding with hosts*. We learned from CRI that multiple site visits and virtual meetings can help clarify host organization goals. Based on this learning, we have met repeatedly with the RMP hosts to understand how their facilities are used and their goals as a resilience hub. Additionally, we have worked on the physical site location with the hosts to ensure understanding of what the microgrid will look like and how it will work.
- *Choosing an Engineering, Procurement, and Construction (EPC) contract setup*. Based on our CRI experience, we chose an EPC approach for the initial RMP. This is to reduce the number of handoffs between parties, help to streamline work and reduce costs.
- *Extended manufacturing lead times driven by utility demand*. Timelines for both technical (e.g., BESS and electrical equipment) and non-technical project components (e.g., BESS enclosures) can be affected by supply chain challenges and labor shortages.
- *Evolving fire safety codes for BESS*. Proximity of BESS sites to other infrastructure or underground utilities can slow the siting and permitting process. In addition, the Company has been meeting regularly with a fire safety consultant to discuss site layouts and configurations, equipment clearances, vendor equipment specifications, fire safety plans, and points of egress. RMP planning will benefit substantially from these learnings.
- *Permitting requirements and review times*. These projects are relatively unfamiliar to City permitting departments, and the process to answer questions and complete administrative reviews will be longer than anticipated.[9]
- *Increased focus on material procurement*. We asked potential RMP bidders to verify where their equipment is made, how much is on hand, and which protocols and method they are proposing for site communications. These factors are critical to keeping the project moving forward and reducing costs due to delays.

[9] For further details, see *Community Resiliency Initiative Compliance Report*. June 15, 2022. Filed in Colorado Public Utilities Commission Proceeding No. 19A-0225E.

2. *Empower Resiliency (Wisconsin)*

Empower Resiliency is a pilot project approved by the Wisconsin Public Service Commission (PSC) in July 2021.[10] The project provides a new option, oriented primarily to commercial, government, and industrial customers seeking increased energy resiliency and very high reliability levels. The Company provides a turnkey resiliency service, tailored to the customer and including analysis, design, construction, maintenance, and financing if desired. Equipment is owned and maintained by the Company but operated according to customer requirements. The customer pays for the resiliency improvements on their bill over an agreed-upon period, 10, 15, or 20 years, at the conclusion of which ownership of assets transfers to the customer. The program is technology-agnostic, providing funding for any technology that enhances resiliency including standby generators (natural gas, diesel, or other), BESS, solar PV (ground-, roof- or carport-mounted), microgrid controls, and electrical distribution equipment.

The PSC Order approving Empower Resiliency requires the Company to report annually on the number of customers participating, each customer's contribution in aid of construction, any received construction allowances, and a list of resiliency projects in development along with estimated costs. As of October 2023, there are no customers with in-service resiliency assets as yet, but there are several projects in various stages of development. [11]

Implementation of Empower Resiliency remains in early stages. We have received strong interest in the program, and a wide variety of customers have signed up to undergo scoping studies. The Company has conducted a design and engineering study for one customer that has moved into final negotiations on the construction contract and has signed a Customer Service Agreement in late September 2023 to design, build, and construct a microgrid with a second customer. As Empower Resiliency moves forward, we expect to gain additional insights on microgrid technologies and system configurations, different use cases of interest to customers, procurement approaches, delivery timelines, permitting, and other aspects of implementation. While the customers are different, the technologies and some of the desired applications could be similar to a revised RMP. We will continue to report as Empower Resiliency grows.

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[10] PSC Docket 4220-TE-106 (PSC REF# 416900).

[11] Northern States Power Company, a Wisconsin Corporation. July 25, 2022 Annual Report Compliance Filing in Docket No. 4220-TE-106, *Request for Approval of a Resiliency Services Pilot.*

B. Future Non-Wires Alternative Pilot

As discussed in *Appendix F: Non-Wires Alternatives Analysis*, our non-wires alternatives (NWA) analysis this year shows three potentially viable and cost-effective projects, which could be candidates for an NWA pilot project. The three potentially viable projects have in-service dates in 2028. Given that timeline, we will have another opportunity to run our NWA analysis next year as part of our annual NWA analysis update before additional steps are taken.

APPENDIX C: ACTION PLANS

In this section, we provide a five-year action plan as part of a long-term plan for the distribution system, as required by filing requirement 3.D.2.

> *Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan 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:*
>
> *a. Overview of investment plan: scope, timing, and cost recovery mechanism*
> *b. 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.*
> *c. 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.*
> *d. System interoperability and communications strategy*
> *e. 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.)*
> *f. Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)*
> *g. Customer anticipated benefit and cost*
> *h. Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)*
> *i. Plans to manage rate or bill impacts, if any*
> *j. Impacts to net present value of system costs (in NPV RR/MWh or MW)*
> *k. For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel shall provide all information used to support its analysis.*
> *l. Status of any existing pilots or potential for new opportunities for grid modernization pilots.*

m. *The results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology.*
n. *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 in future IDPs.*
o. *Long-range distribution studies conducted since the last IDP.*

We summarize our five-year and long-term action plans for distribution system developments and investments in grid modernization and associated customer impacts below. However, rather than attempt to summarize our fulfillment of each of the above requirements in this section, we provide this information in our Compliance Matrix provided as Attachment B.

I. NEAR-TERM ACTION PLAN

The first five years of our action plan will be focused on providing customers with safe, reliable electric service and continuing to make investments to modernize the distribution grid with foundational capabilities including AMI, FAN, ADMS, and FLISR, which we have discussed in depth in this and prior IDPs.

Throughout this IDP, we also discuss other near-term focus areas and priorities and our plans to invest in our system to ensure that we are able to continue to provide reliable electric service today and in the future. We outline how we intend to prepare for the future, enable the clean energy transition, maintain and enhance resilience and reliability, and modernize the grid. We are also taking near-term actions to improve the way that we are integrating Distributed Energy Resources (DER) and planning for longer-term implications and benefits of increased penetration levels. We discuss these in *Appendix E: Distributed Energy Resources, System Interconnection, and Hosting Capacity.*

In the balance of this Appendix, we summarize near-term actions by subject. We also use this section to comply with the portions of IDP Requirement 3.D.2 and other filing requirements that we have not yet addressed elsewhere in this IDP.

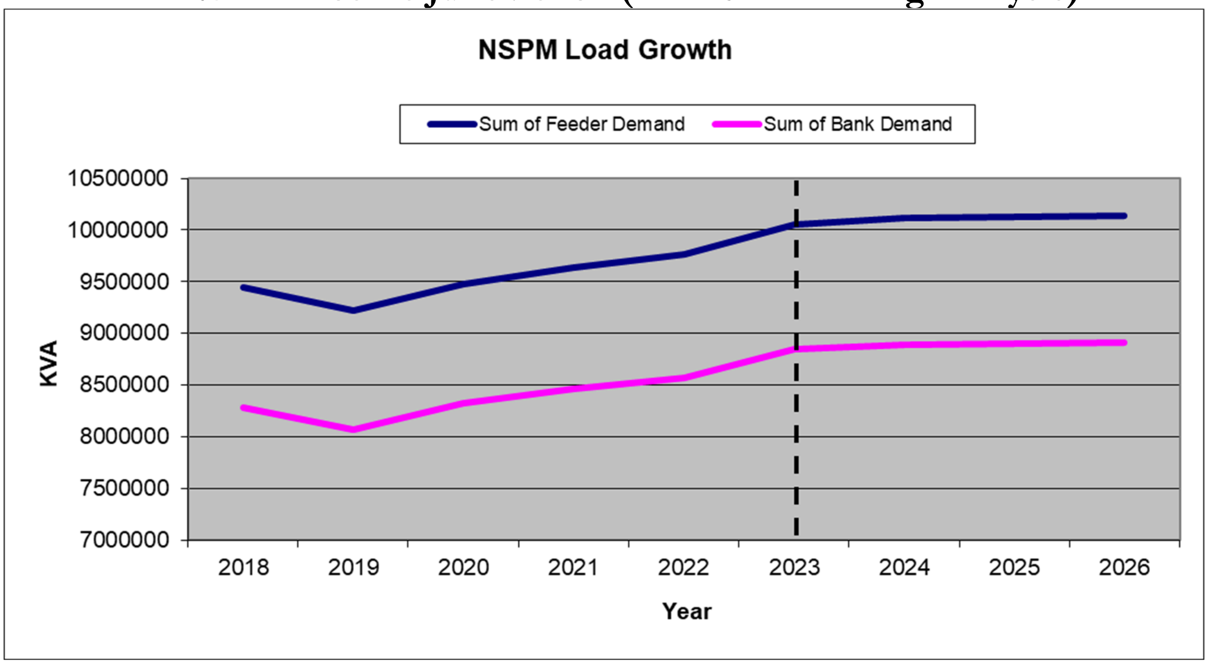
A. Load Growth Assumptions

IDP Requirement 3.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 C-1 below provides the load growth assumption stemming from our Fall 2022 system planning analysis, as described in detail in *Appendix A1: System Planning.*

Figure C - 1: Distribution System Planning Load Growth Assumptions NSPM Electric Jurisdiction (Fall 2022 Planning Analysis)



We additionally provide load growth assumptions for smaller portions of the NSPM geography in Minnesota that stemmed from this same analysis as Attachment F to this IDP. Please also see the capital projects list for the current five-year budget cycle sorted into the IDP financial categories, provided as Attachment H.

B. Grid Modernization Plan

See *Appendix B1: Grid Modernization* and related appendices and attachments as referenced for discussion regarding our grid modernization and related customer, data, and cost recovery plans.

1. *Current Initiatives Underway*

Table C-1 below provides a summary of the implementation timeline for current grid modernization investments. We also discuss cost recovery mechanisms for each of these initiatives.

Table C - 1: Grid Modernization Implementation Timeline

Program	Implementation Timeline
ADMS	Our ADMS was deployed in the first two Minnesota control centers in April 2021 and deployed in the final Minnesota distribution control center in September 2021.
AMI	Meter deployment began in 2022, with anticipated completion in 2025.
FAN	The initial network and security design was completed in 2020. The first FAN device was installed and programmed in May 2021 and the installation and programming of additional FAN devices will continue through 2025. For any given geography, FAN availability will precede AMI meter deployment by approximately 6 months, to ensure that meters will have a fully operational network to use when they are installed.
FLISR	Installation of automated field devices (reclosers and switches) and substation upgrades began in 2021 on select feeders and will continue to be expanded to other feeders through 2027. The ADMS FLISR functionality will be available to the Minnesota control centers use starting in 2023 on select feeders and will be continued to be expanded to other feeders through 2027.

Note: The Time of Use (TOU) rate pilot and LoadSEER are not reflected in the table above because the projects are complete. See Appendix B1 for further details on those two projects.

We are currently recovering costs for these investments through:

- **The Transmission Cost Recovery (TCR) Rider.** We included ADMS costs in the TCR beginning in 2019 (Docket No. E002/M-19-721). In 2021, we added first sets of revenue requirements (through 2022) associated with other certified grid modernization initiatives: the TOU Rate Pilot, AMI, FAN, and LoadSEER (Docket No. E002/M-21-814). On October 31, 2023, we submitted our 2023 TCR Petition, which includes ADMS, the TOU Pilot, AMI, FAN, and LoadSEER costs.

- **Base Rates**. The Commission approved recovery of 2022-2024 FLISR program costs as part of our most recent rate case (Docket No. E002/GR-21-630).

With respect to the IDP requirement to discuss plans to manage rate or bill impacts for grid modernization investments, if any, we emphasize that keeping bills low is a strategic priority of the Company, and our building block approach to grid modernization helps mitigate rate and bill impacts. At the same time, grid modernization investments create new opportunities for programs and tools that can help customers take control of their energy usage and potentially lower their bills, and create efficiencies in Company operations that will lead to a lower the cost of service over time, compared to what it would have been in the absence of these investments. The TCR Rider petition filed on October 31, 2023 includes the actual 2023-2024 revenue requirements and resulting TCR Rider Adjustment Factors. We note that the proposed TCR Rider Adjustment Factors include primarily revenue requirements associated with grid modernization-related projects, as transmission project costs previously recovered through the TCR Rider would move to base rates starting in 2024.

2. Near-Term Grid Modernization Initiatives

We are not proposing certification of any grid modernization investments with this IDP. We provide an update on our plans for Distributed Intelligence (DI) in *Appendix J: Distributed Intelligence*, in compliance with the Commission's Order in our most recent electric rate case. The analytics made possible through DI can provide additional insights to help customers make more informed decisions about their energy usage, increase the ability to connect customers to demand-side management programs, and increase the efficacy of time-differentiated rates. In addition, DI allows the Company to create new, innovative demand side management and demand response offerings. As we take an enterprise-wide approach to our DI plans, Minnesota customers will be able to access and benefit from new apps and tools that become available. Due to the current timing of our revised DI plans, we anticipate seeking seek cost recovery as part of a future rate case and through the Conservation Improvement Plan Rider as appropriate.

While we have not incorporated additional grid modernization investments into a specific timeline, budget, or proposal, in Appendix B1 we discuss potential future projects and technologies, including Distributed Energy Resources Management System (DERMS) and an integrated grid operating technology. A phased implementation approach for DERMS enables the Company to meet policy, regulatory, customer, and business needs. We also expect DERMS to be a part of the solution to meet FERC Order 2222, which we anticipate will drive new business requirements, new operational dynamics between distribution and transmission, and potential market implications between retail and wholesale markets. Currently, we are examining DERMS capabilities in the market and will explore vendor capabilities in more detail through at least the first half of 2024. At the same time, we are in the process of determining the best path to an integrated technology environment.

C. Impacts to Net Present Value of System Costs

IDP Requirement 3.D.2 requires the Company to provide:

> …*Impacts to net present value of system costs (in NPV RR/MWh or MW)*

See *Attachment G: Distribution Function NPV 2023*.

D. Demand Side Management

The five-year action plan for Demand Side Management, which includes energy efficiency, demand response, and efficient fuel switching, will be largely determined through a combination of the Minnesota Energy Conservation and Optimization (ECO) Triennial (both current and future) filings and the next Integrated Resource Plan (IRP), which is due February 1, 2024.

The Company's 2024-2026 ECO Triennial Plan was submitted to the Department of Commerce for approval on June 29, 2023.[1] This Triennial Plan continues the Company's long-standing commitment to energy efficiency. The programming and proposals detailed in this Plan build on the Company's established record of successful energy efficiency and demand response programming. In addition, they represent an exciting new chapter in utility-delivered programming in Minnesota, enabled by the landmark Energy Conservation and Optimization Act of 2021 (ECO Act). In combination, the various components of this ambitious Plan will achieve energy savings well above the minimum savings targets established in Minnesota Statutes and generate over $1.7 billion in net benefits.[2]

[1] Docket No. E,G002/CIP-23-92.

[2] Net benefits based on the Minnesota Test, adopted as the primary test for cost-effectiveness. See Decision, In the Matter of 2024-2026 Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities, Docket No. E, G999/CIP-23-46, March 31, 2023.

1. *Energy Efficiency*

As outlined in the 2024-2026 ECO Triennial Plan, the Company proposed to exceed the requirements outlined in Minn. Stat. § 216B.241 aiming savings targets over two percent of savings as a percent of retail sales equaling 1,869 GWh over the three-year period. The proposed electric savings targets aligns with the Company's DSM commitments in our most recent Upper Midwest Integrated Resource Plan (Docket No. E002/RP-19-368). Our ECO Triennial Plan includes the savings we can justifiably claim based on technical requirements approved by the Deputy Commissioner of Commerce. There are a portion of customer savings that are no longer or never claimed under the ECO umbrella – these include lighting technologies and cooling equipment that are efficient, but no longer over Minnesota State Energy code—or many energy-efficient appliances that are not rebated by the Company. We believe that our ECO Plan achievements plus "naturally occurring" savings will continue to meet our regulatory commitments to achieve an average of 780 GWh per year and help us continue to lower our carbon footprint. This is consistent with the discussion of program-driven and naturally occurring energy conservation found in Appendix G1 of the Company's 2020-2034 Integrated Resource Plan (pp. 34-35).

2. *Efficient Fuel Switching*

The 2024-2026 ECO Triennial Plan is the first plan under ECO Act allowing the Company to provide customers with incentives for customer's switching from one fuel type to another to serve the same end use. As Minnesota's only investor-owned combination natural gas and electric utility, the Company is uniquely situated with respect to energy efficient fuel switching (EFS). The Company believes that EFS measures will have a key role in achieving its aggressive emission-reduction goals for both its electric and natural gas businesses. At the same time, the market for many EFS measures is nascent and their long-term impact on both the gas and electric systems is not yet certain.

The Company proposed several new EFS measures as part of the Triennial and included two dedicated programs. Only natural gas savings are allowed to be claimed as part of the EFS program, however, we anticipate a small reduction in overall electric load along with more efficient equipment.

3. Demand Response

Demand Response (DR) will continue to be heavily influenced by our efforts to achieve the incremental 400 MW by 2023, a requirement that stemmed from our 2015 IRP in Docket No. E002/RP-15-21. In addition, the ECO Act created further opportunities for the Company to include demand response options specific to load shifting. Our 2024-2026 ECO Triennial Plan includes measures aimed to focus on load shifting for businesses and includes our Critical Peak Pricing pilot. Our forthcoming IRP, due February 1, 2024, also includes incremental demand response as a selectable resource option.

E. Incremental Hosting Capacity and Beneficial Electrification

Order Point 133 of the Commission's July 17, 2023 rate case Order in Docket No. E002/GR-21-630 states:

> *Xcel must quantify, in its next IDP, the incremental hosting capacity and beneficial electrification that will be accommodated by its planned distribution system investments.*

Through our planned distribution system investments, referencing *Attachment E: Risk Scored Project Details*, we estimate an overall increase of 936 MW in substation transformer and 746 MW in feeder hosting capacity. This estimated increase in hosting capacity is based on the expected nameplate ratings and factors in the Technical Planning Standard.

However, true locational hosting capacity is calculated based on a variety of factors beyond the continuous thermal rating, including voltage deviation, under/over-voltage, and more. These more thorough hosting capacity calculations are currently performed by the Company using the EPRI DRIVE tool. Due to the time and level of effort required, we were not able to analyze each of the planned distribution system investments in DRIVE for this IDP. Therefore, the estimated increases in substation and feeder hosting capacity provided above are not necessarily reflective of the increase in hosting capacity that would be seen in the Company's HCA after the completion of these investments.

Relatedly, we have included a placeholder estimate in the five-year budget for proactive system upgrades to increase DER hosting capacity. We have heard from the state legislature, the Commission, and stakeholders that increased hosting capacity is a growing priority for the State of Minnesota. That said, we have not yet identified specific uses for this funding so we look forward to Commission and stakeholder feedback on how we should prioritize these funds.

F. Transportation Electrification

The Company is making significant investments in EV-related programs intended to encourage greater adoption of electrified transportation options and to enable options that can lessen the burden EV charging can have on system resources. As EV adoption is rapidly increasing in Minnesota, the demand impact of EV charging will only continue to grow. The Company is attempting to combat that through our EV charging options for both residential and commercial programs. That includes options for residential customers (EV Accelerate at Home, EV Subscription Service, Optimize Your Charge) that offer incentives to charge vehicles during off-peak, overnight hours when system demand is lower and renewable energy generation tend to be higher. Options for commercial customers include Optimize Your Charge, a Fleet EV Service Pilot, and a Public Charging Infrastructure Pilot.

The Company has proposed a new demonstration project in our Transportation Electrification Plan (*Appendix H*) that will study and address barriers to school bus electrification, school bus bi-directional connection to the grid, and to better understand the costs and benefits of electric school buses as grid resources. Through this demonstration, the Company proposes to partner with the Department on its Electric School Bus Deployment Program, to support two V2G capable installations on sites of entities, school districts, or school bus owners and operators, willing to participate in the demonstration to inform pathways of using V2G electric school buses in the future as demand response, distributed energy resources for grid resiliency, and reliability resources.

II. 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 and providing a long-term load forecast.

IDP Requirement 3.D.3 requires the following:

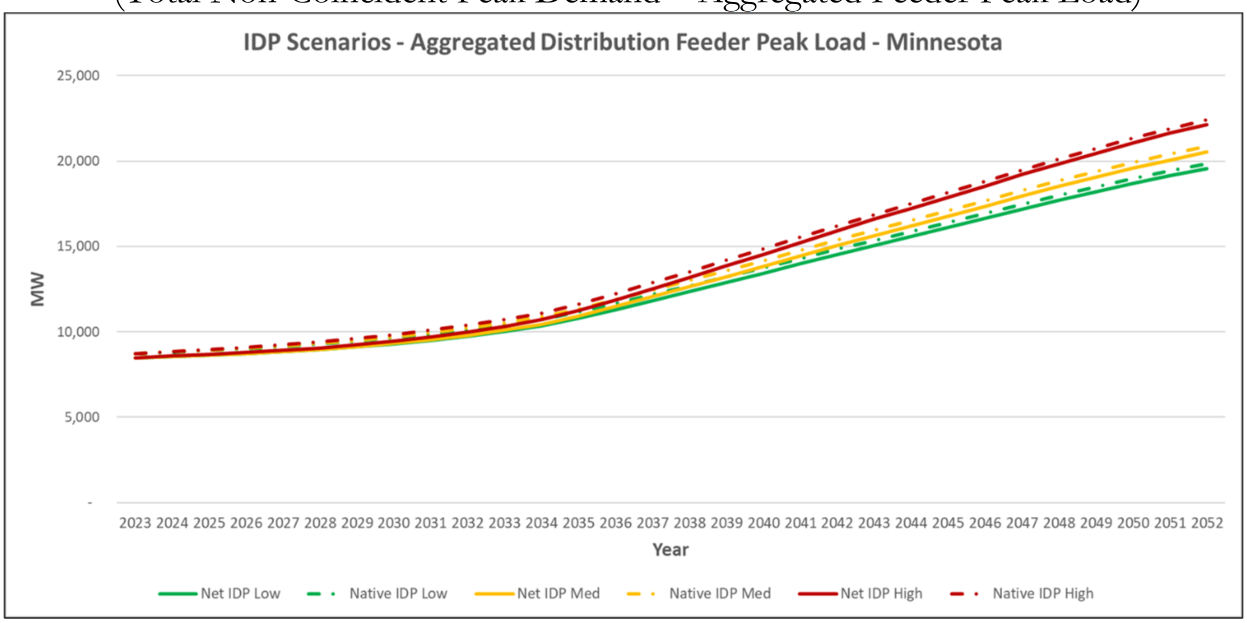
> *In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term plan discussion should address the long-term assumptions (including load growth assumptions), the long-term 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.

A. Long-Term Load Growth Assumptions

As we have discussed in this IDP, distribution system planning is performed for a five-year planning horizon. In the case of this IDP, that period is 2024-2028. In Section I above, we provided our load growth forecast from Fall 2022, which informed the five-year plan and budget presented in this IDP.[3] For load growth assumptions beyond the distribution budget planning period, we provide our 30-year distribution forecast of aggregated feeder peak load in Figure C-2 below. Overall, we estimate that the distribution system will need to *triple in size* over the next 30 years to accommodate new loads and distributed generation. We discuss our distribution forecast further in Appendix A1.

Figure C - 2: 30-Year Distribution Peak Demand Forecast
(Total Non-Coincident Peak Demand – Aggregated Feeder Peak Load)



[3] We note that the five-year budget reflects the energy and peak demand forecasts, not speculative DER adoption scenarios discussed in Appendix A1.

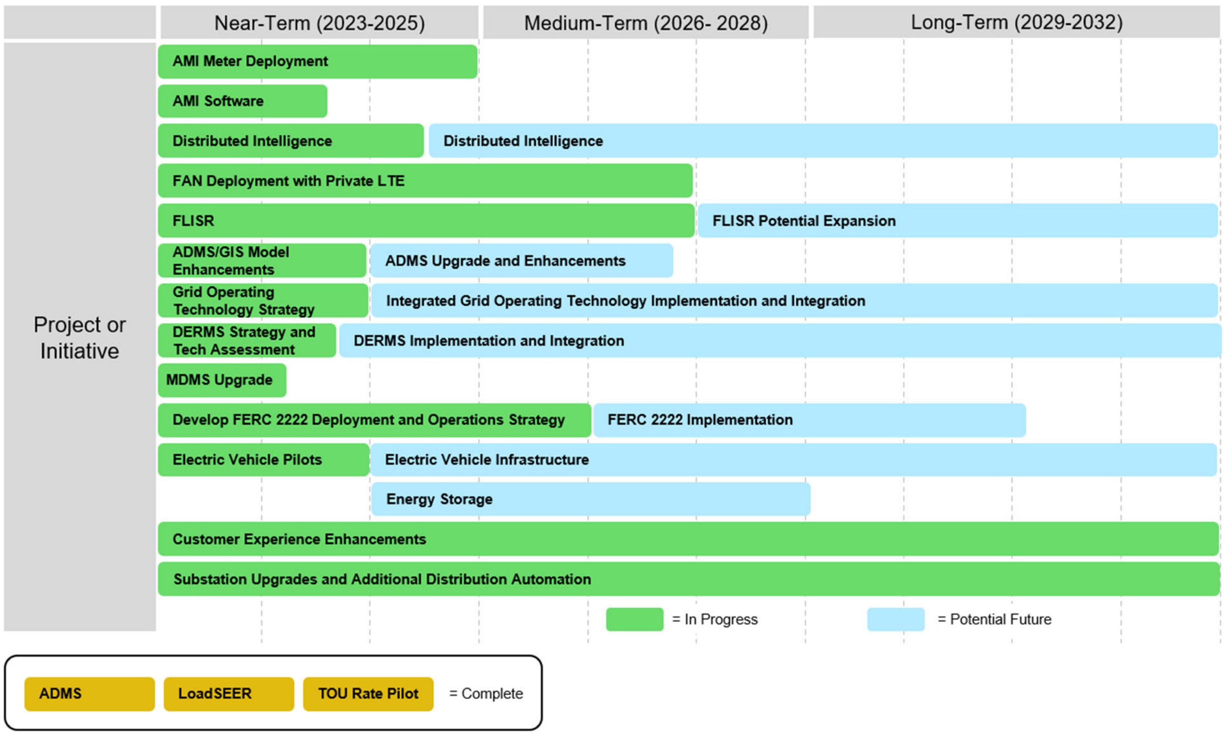
B. Long-Term Grid, Tools, and Capabilities Focus

The health of our distribution system is critical to ensuring that we are able to continue to provide reliable electric service today and in the future. Our long-term strategy incorporates not only the necessary work to maintain poles and wires, but also the work needed to prepare for the future, enable the clean energy transition, maintain and enhance reliability and resilience, and modernize our customers' interactions with the distribution grid.

Characteristics of anticipated load growth shown in Figure C-1 above represent a paradigm shift from historical ways of planning and operating the grid. In the past, we have generally seen gradual, localized load growth with longer lead times often tied to large construction projects leading to more predictable patterns for required upgrades. Our new paradigm involves rapid, system-wide load growth that can be difficult to predict, and requires preparation now for a future with high loads and increased DER. We will need more resources of all types – digital tools and automation as well as human resources – to ensure we can fully realize the opportunities of this paradigm shift while maintaining reliable service.

With respect to grid modernization, for easy reference, we provide a 10-year view of the sequencing of planned and potential advanced grid investments in Figure C-3 below.

Figure C - 3: Illustrative Long-Term Grid Modernization Plan



Our plans include implementing additional technologies and capabilities over the long-term – also leveraging earlier components to deliver increasing value to customers as illustrated in Figure C-3.

As we note in other areas of this IDP, as DER penetration continues to increase on the distribution system, we recognize that we will need to continually update our interconnection processes. Today, we study DER interconnections by analyzing each project's impacts on a case-by-case basis. As available generating capacity on the distribution system tightens, the industry and other stakeholders are evaluating different scenarios which could provide higher DER penetration in a given area. One such scenario could involve more control and management of both existing and new interconnections.

Although we and the industry are in the early stages of the progression toward more advanced interconnection and DER management, we are studying the technology requirements and the timing of their implementation that would be needed to enable the progression toward active management of DER interconnections. Some of these technologies include the analysis and planning tools and future systems such as

DERMS. We are also remaining attentive to new developments across the industry to ensure that our plans are aligned with industry practices.

In addition to discrete grid modernizations investments, increased system resilience will be a crucial component of maintaining reliability. 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 to lay the groundwork for the grid of tomorrow. At the same time, we must protect the physical and cybersecurity of our system.

In conclusion, we fully expect the technology, policy interests, and customer expectations to continue to inform our strategy in several significant ways in the next 10 years and beyond. The continued adoption of DER, electric vehicles, and other beneficial electrification technologies will require changes in the way we plan for and operate our grid. These changes further have the potential to challenge the current capabilities and resource requirements; we must ensure that our teams continue to have the appropriate skillsets, knowledge, and experience that will be necessary as the grid of the future takes shape. With the tools and strategies discussed in this IDP, 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.

APPENDIX D: DISTRIBUTION FINANCIAL FRAMEWORK AND INFORMATION

This Appendix discusses the Company's distribution financial information. This includes the overall budget development, as well as the Distribution organization's specific budget development processes.

This year's IDP is the first with electric vehicle programs as its own financial category. In this Appendix, we also address new requirements from Docket Nos. E,G999/CI-22-624 and E002/GR-21-630.

FINANCIAL CATEGORIES CROSS REFERENCE

The IDP Filing Requirements specify that the Company should provide historical and planned financial data in IDP-specific categories:

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
i. Electric Vehicle Programs
    1) Capital Costs
    2) O&M Costs
    3) Marketing and Communications
    4) Other (provide explanation of what is in "other")

IDP Requirement 3.A.27 notes another category, which we refer to as "non-investment":[1]

> *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 note that this IDP represents the first with the Electric Vehicle (EV) Programs financial category. In prior IDPs, EV Program costs were included in the Grid Modernization and Pilot Projects IDP category.

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[1] We address IDP Requirement 3.A.27 specifically in *Appendix E: Distributed Energy Resources, System Interconnection, and Hosting Capacity*.

This Appendix reflects the information for Distribution budget only. Additional information specific to EV programs is provided in *Appendix H: Transportation Electrification Plan*. *Appendix B1: Grid Modernization* provides further information on project-specific costs.

The IDP categories overlap with, but do not perfectly match, the Company's budget categories that we present in other filings such as rate cases and riders. To facilitate review of budgets between multiple filings, Table D-1 provides a cross-reference of the IDP categories to our own capital budget categories.

Table D - 1: Financial Categories Cross-Reference

IDP Category	**Xcel Energy Capital Budget Category/Categories** (if more than one, categories are separated by a semicolon)
Age-Related Replacements and Asset Renewal	Asset Health & Reliability
New Customer Projects and New Revenue	New Business; Capacity
System Expansion or Upgrades for Capacity	Capacity
Projects related to Local (or other) Government-Requirements	Mandates
System Expansion or Upgrades for Reliability and Power Quality	Asset Health & Reliability
Other	Fleet, Tools & Comm
Metering	New Business*
Grid Modernization and Pilot Projects	Grid Modernization
Non-Investment	Capacity; Fleet, Tools & Comm; New Business
Electric Vehicle Programs	Electric Vehicles

* The Major Category of "New Business" includes transformer purchases while transformer purchases are captured under the IDP category of "Other"

As evidenced by Table D-1, there is not a one-to-one relationship between the Company's budget categories and those required in the IDP. As discussed in the IDP Main Report, we propose that the IDP Requirements for the Company be revised to remove the requirement that financial information be reported in IDP-specific categories. This refinement would allow the Company to report financials in the same budget categories across dockets. Reporting financials in this manner could facilitate easier comparisons of financial information across dockets – including IDPs and rate cases – and vintages and eliminate the significant manual work required to re-categorize our budget forecasts.

I. OVERALL BUDGET DEVELOPMENT FRAMEWORK

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 NSPM.

To a large extent, the O&M and capital budgeting processes are the same. The capital budget process, however, requires additional steps and internal approvals for capital projects with expenditures over $15 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.[2]

II. DISTRIBUTION BUDGET FRAMEWORK

Historically, the overwhelming majority of the 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.

Now, our budget framework incorporates not only the necessary work to maintain poles and wires, but also the work needed to prepare for the future, facilitate the clean energy transition, maintain and enhance reliability and resilience, and modernize our customers' interactions with the distribution grid. The health of our distribution system is critical to ensuring that we can continue to provide reliable electric service today and in the future. Each year when a five-year budget is created and approved,

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[2] For further discussion on our budget development framework, see Appendix D of our 2021 IDP, filed November 1, 2021 in Docket No. E002/M-21-694.

the first-year budget is essentially "locked in." However, budgets for the subsequent two to five years are reevaluated in the next budgeting cycle and will necessarily change in response to new developments and changing policy priorities, 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.

A. Maximizing Inflation Reduction Act (IRA) Benefits

Order Point 1 of the Commission's September 12, 2023 Order in Docket No. E,G999/CI-22-624 states in part:

> *The utilities shall maximize the benefits of the Inflation Reduction Act in […] integrated distribution plans […]. In such filings, utilities shall discuss how they plan to capture and maximize the benefits from the Act, and how the Act has impacted planning assumptions including (but not limited to) the predicted cost of assets and projects and the adoption rates of electric vehicles, distributed energy resources, and other electrification measures.*

In *Appendix A1: System Planning*, we discuss how the IRA has impacted overall distribution planning assumptions. In *Appendix F: Non-Wires Alternatives Analysis*, we describe how IRA tax credits are incorporated into our analysis assumptions.

Regarding capturing and maximizing benefits of the IRA, with respect to the standard distribution system investments included in our five-year budget forecast, none of these projects are eligible for IRA tax credits, which are focused on renewable and carbon-free energy investment and production. We note that investments in hosting capacity upgrades, such as those for which we have included placeholder amounts in the five-year budget, may be eligible for IRA tax credits if paired with a specific renewable energy project.

The IRA includes provisions related to transportation electrification. Those provisions include federal tax credits for consumers for the purchase of new (IRC 30D) and used (IRC 25E) electric vehicles of up to $7,500 and $4,000 respectively. Commercial clean vehicle purchases are also eligible for tax credits of up to $40,000 depending on the vehicle weight under IRC 45W. A tax credit under the Federal Alternative Fuel Vehicle Refueling Property Credit (IRC 30C) remains and can provide a 30 percent tax credit per station up to $100,000 for businesses and up to $1,000 in other cases. The eligibility and applicability provisions of the IRA are specific and have detailed requirements to apply these tax credits. In general the Company will take advantage of Federal funding and tax credits where we are eligible and where we have an applicable scope of work or a project. As discussed in Appendix A1, the IRA provisions have resulted in an increase in our EV forecast.

While not related to the IRA, we further note that we have been seeking other federal funding opportunities to complement our distribution system investments and keep bills low for customers. We recently received news that NSPM will receive up to $28 million in funding from the U.S. Department of Energy's (DOE's) Grid Resilience and Innovation Partnership (GRIP) program, funded through the Bipartisan Infrastructure Law. While the details remain to be worked out with DOE, we will keep the Commission and parties updated as we make progress on the GRIP award.

III. CAPITAL BUDGET DEVELOPMENT

Our distribution system is the portion of our electric system that is closest to our customers and consists of overhead feeder lines, poles, and underground cable that connect individual customers to the larger electric grid. Distribution also operates and maintains area substations comprised of transformers, switches, breakers, and relays that step-down the high voltage power from transmission lines to serve our customers. Each of these many assets must be maintained in good working order for our distribution system to be able to work as it is intended. The health of our distribution system is critical to ensuring that we are able to continue to provide reliable electric service today and in the future. To that end, our near-term investments in our distribution system are focused on achieving four primary objectives: (1) preparing for the future; (2) enabling the clean energy transition; (3) maintaining and enhancing reliability and resilience; and (4) modernizing the grid.

A. Preparing for the Future

In the five-year budget, starting in 2025, we have included a placeholder estimate, totaling $190 million, for proactive system upgrades to increase distributed energy resources (DER) hosting capacity. We have heard from the state legislature, the Commission, and stakeholders that increased hosting capacity is a growing priority for the State of Minnesota. That said, we have not yet identified specific uses for this funding – it is intended solely as a placeholder at this time, subject to change based on stakeholder and Commission feedback and additional analysis such as that presented in *Appendix I: Distribution System Upgrades*. We are interested in hearing stakeholders' and the Commission's feedback on whether and how we should prioritize system upgrades for hosting capacity – potentially over other upgrades or investments in support of resilience, grid modernization, or reliability improvement.

B. Enabling the Clean Energy Transition

Our LoadSEER analysis discussed in Appendix A1 shows a need for the distribution system to triple in size over the next 30 years to accommodate increased load. The electric sector is uniquely positioned not only to lead the decarbonization of the sector itself but also to contribute significantly to a net-zero economy, and our five-year budget includes investments to enable the clean energy transition.

In the near term, our ability to accommodate electrification will require investments in areas where the existing primary distribution system capacity may be exceeded, requiring the addition of new substations and feeders to serve the increased load density. Adding new feeders and substations in already developed areas makes siting and construction of new projects more expensive and subject to scheduling delays. Through the Grid Reinforcements Program, proactive planning and installation of substations and feeders, particularly in congested metropolitan areas, can help enable electrification. The distribution system includes a large volume of existing low voltage (120 V to 600 V) shared secondary equipment that serve multiple customers which will be impacted by increasing electrification for transportation and other end uses. The Grid Reinforcements Program also includes replacement of lower capacity service-level transformers exhibiting existing overloads for multiple consecutive hours during peak day events and other equipment to prevent outages and help maintain standard voltage ranges, improving customer experience, which could in turn help accelerate beneficial electrification. Planning for replacements of service level equipment that has become overloaded over time due to increasing loads with new higher capacity service-level equipment tends to be less costly than reactive replacements. In addition, while not the primary purpose of the program, the reinforcement of this lower capacity, service-level equipment may also provide associated increases in the ability of the secondary systems to host distributed generation. The Grid Reinforcements Program budget is included in the "System Expansion or Upgrades for Capacity" IDP category.

In addition, this IDP represents the first with the Electric Vehicle Programs financial category. In prior IDPs, EV Program costs were included in the Grid Modernization and Pilot Projects IDP category. See Appendix H for further discussion of the EV Program budget. The Company has also established goals for the electrification of its own fleet vehicles which may include the need to budget not only for the vehicles and charging infrastructure, but also a need to further upgrade the distribution grid serving company properties to accommodate an increase in loads due to charging of zero emission vehicles.

As discussed in Appendix A1, we strive to load feeders to approximately 75 percent of maximum capacity, which provides operational capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions. As discussed in our 2022 IDP annual update filing, in practice, historical budget limitations have often allowed feeder loading to exceed the 75 percent planning criteria. Our latest five-year budget – largely in 2026 and 2027 – reflects the necessary funding level to start to enable upgrades that will start to bring all Minnesota feeders within our established guideline of a 75 percent loading level. We expect that ramping up and maintaining this funding over the next 10 years will be necessary to address all feeders based on our budget forecast scenario; additional load growth due to DER and electrification adoption trends will also increase the funding requirements. Aligning our budget to our planning guidelines will reduce overall system risk; produce operational flexibility; maintain reliability as electrification accelerates; increase hosting capacity; reduce premature asset failure; and enable quicker accommodation of new load. This overall budget is included in the "System Expansion or Upgrades for Capacity" IDP category; however, not all specific mitigations to reduce feeders to less than 75 percent loading have been identified.

C. Maintaining and Enhancing Reliability and Resilience

Since the early 2000s, our assets have continued to age and now many more of these assets are beyond their expected service life. To address the condition and age correlated degradation of these assets, Distribution has placed greater focus on its Asset Health and Reliability budget category to ensure that we continue to meet our long-standing priority of providing safe and reliable service to our customers. In addition to funding for established programs within the Asset Health and Reliability category, we have additional programs within our Asset Health and Reliability to address specific assets that are, in some cases, having a pronounced impact on reliability. Many crucial substation assets are reaching end-of-life, including transformers, metalclad switchgear, circuit breakers, and relays. Failures in any of these assets can result in outages affecting thousands of customers. As the substation equipment fleet ages, the possibility of a failure poses significant, increased reliability risk. In addition, reliability is hampered by aging line infrastructure. Funds for replacement of aging line equipment – reclosers, voltage regulators, capacitor banks – as well as rebuilding poor-performing lines will ensure we continue to meet our customers' reliability expectations.

In addition, a changing climate creates new and greater reliability and resiliency risks to our distribution system – a modernized grid includes investments to mitigate such risks. Budget for system hardening is included in the "System Expansion or Upgrades for Reliability and Power Quality" IDP category; again, we note that specific mitigations have not yet been identified in the outer years of the budget.

D. Modernizing the Grid

Investments supporting this priority include the Distribution investments for the major projects we have underway, including our Advanced Metering Infrastructure (AMI), Field Area Network (FAN), Advanced Distribution Management System (ADMS), and Fault Location Isolation and Service Restoration (FLISR) implementations. Appendix B1 provides additional details on the status of these major projects and project-specific budget forecast information; the budgets reflected in this Appendix include only grid modernization costs within the Distribution budget. The detailed budget and forecast for these projects are included in the appropriate cost recovery proceedings. The "Grid Modernization and Pilots" IDP budget category through 2027 also includes FLISR, which was approved in the most recently concluded multi-year rate case in Docket No. E002/GR-21-630. We are continuing to expand our Supervisory Control and Data Acquisition (SCADA) capabilities, preparing for FERC Order 2222, and taking further steps to examine Distributed Energy Resources Management System (DERMS) capabilities in the market and developing an overall DERMS roadmap. As also noted in Appendix B1, we are planning for a future convergence of grid operating technology – and what that roadmap means for the current ADMS, which will reach end of life in mid-2026.

IV. XCEL ENERGY CAPITAL BUDGET CATEGORIES

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. The IDP requires that we report our capital expenditures in specific categories that differ somewhat from our internal categories; as discussed above and in the IDP Main Report, we propose to remove these IDP-specific budget categories from the IDP filing requirements and instead provide budget forecast information within our own budget groupings. This change will help streamline comparisons between dockets such as IDPs and cost recovery proceedings, although we note that cost recovery proceedings provide different types of cost information such as capital additions and revenue requirements that are not reflected in the IDP. This change will also eliminate the significant manual work required to re-categorize our budget forecast. See the IDP Main Report for our suggested redlines to the IDP filing requirements.

In this section, we outline our internal categories, then present our budgets in the IDP categories.

A. Capital Budget Categories

We outline the Xcel Energy budget categories and how they correlate to the IDP financial categories below.

1. *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 service reliability and increasing O&M expenditures needed to repair the 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 useful life. This category also captures replacements due to storms and public damage.

2. *Grid Modernization (IDP Category: Grid Modernization and Pilots)*

Traditionally, our investments to modernize our grid were budgeted in the Asset Health category. Beginning in 2019, we created a separate budget category for our planned major investments in an ADMS, AMI, FAN, and FLISR. These grid modernization investments will improve power reliability, reduce power outages, help integrate increasing amounts of DER onto the grid, and empower customers to track and manage their energy usage. To the extent we propose or implement other major grid modernization projects, those too would be reflected in this budget category. Once major grid modernization projects are completed, their ongoing costs will be reflected in other budget categories. For example, when the initial, project-based deployment of AMI meters is complete, the ongoing costs of the AMI meters will be reflected in the Metering budget category. We provide project-specific budget forecasts in Appendix B1.

3. New Business (IDP Categories: New Customer Projects, New Revenue and Metering)

This work includes 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.

This category also includes steady-state electric meter and transformer purchases.

4. 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, due to new customers or existing customers increasing their load, and to continue 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 sometimes span multiple years and are necessitated by increased load from either existing or new customers. This category includes capacity programs such as the grid reinforcement program and feeder load monitoring. As noted above, in this category this year we have included a placeholder estimated budget for potential proactive system upgrades to increase DER hosting capacity.

5. Mandates (IDP Category: Projects related to Local (or other) Government-Requirements)

This category covers projects to relocate utility infrastructure in public rights-of-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.

6. Tools and Communications (IDP Category: Other)

This category includes tools, communication equipment and various other items that do not fit within the other budget categories. Communication equipment includes the communication components of projects or programs including the Feeder Load Monitoring program, Network Monitoring program, Fiber Buildout program, Cyber

Security program, capital associated with locating costs, and the ongoing, post-project/initial deployment costs of assets such as the FAN implemented as part of our grid modernization efforts.

7. Solar (IDP Category: Non-Investment)

This category includes the distribution costs associated with interconnecting community 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.

8. Electric Vehicle Programs (IDP Category: Electric Vehicle Programs)

This category includes the capital costs associated with EV pilots and programs that were previously approved by the Commission – the Residential EV Charging Tariff, Residential EV Accelerate at Home, Fleet Charging Pilot, Public Charging Infrastructure Pilot, Residential Subscription Service Pilot, and Multi-Dwelling Unit Charging Pilot.[3] As a part of the Minnesota Transportation Electrification Plan (TEP) being filed concurrently with this IDP, the Company is making several proposals, including an expansion of the existing Residential EV Subscription Service Pilot, a new electric school bus pilot, and rebates for home wiring for vehicle charging. In addition, we are requesting additional funding to continue our fleet and public charging programs and our EV advisory services. See Appendix H for further detail on our EV plans and investments.

B. IDP Capital Financial Information

IDP Requirement 3.A.26[4] 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*

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[3] *See* Docket No. E002/M-17-817; Docket No. E002/M-18-643; Docket No. E002/M-19-186; Docket No. E002/M-19-559.

[4] 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.

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
i. Electric Vehicle Programs
1) Capital Costs
2) O&M Costs
3) Marketing & Communications
4) Other (provide explanation of what is in "other")

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

1. *Category Descriptions*

a. Age-Related Replacements and Asset Renewal

This category includes a comprehensive suite of programs and projects aimed at replacing aging infrastructure, as generally outlined below.

Reactive Asset Health	• Pole Replacement Program: Criteria-based pole replacements • Restoration/Failure Reserves: Storm restoration, equipment failures, and reserve transformers • Routine Rebuilds/Conversions: Small rebuild or conversion projects to address reactive, in-year system issues or customer requests • Reactive Line Programs: Asset renewal programs with minimal flexibility • SE Region Reliability Initiative Reactive Discrete Projects: Discrete projects driven by internal or external customers

Proactive Asset Health	• Substation Renewal Programs: Proactive replacement of substation equipment
	  o Transformers, Breakers, Switches, Regulators, Relays, etc.
	• Line Renewal Programs: Proactive replacement of line equipment/infrastructure
	  o Network Renewal: Transformers, Protectors and Vault Tops
	  o Line Equipment Renewal: Porcelain Cutouts, Arrestors, Reclosers, etc.
	  o Pole Related Renewal: Pole Fire Mitigation, Multi-Feeder Pole Mitigation
	  o High Customer Count Taps
	• Discrete Projects: Discrete rebuild projects targeting aging equipment or infrastructure including substation rebuilds and 4kV conversions.

b. System Expansion or Upgrades for Capacity

This category includes projects that increase the capacity of the system to adequately serve present and forecasted customer loads, as generally outlined below.

Capacity	• Discrete Projects
	  ○ Load Growth: Projects driven by existing or forecasted load growth in the area and risk minimization including overloads and contingencies
	  ○ Customer Driven: Projects driven by a new customer load or the expansion of existing load
	• Routines: Small reinforcement projects to address reactive, in-year system issues or customer requests
	• Programs
	  ○ Feeder Load Monitoring – Program to install SCADA on existing substations
	  ○ Grid Reinforcements – Program to upgrade to our distribution system to enable the system to handle increased load associated with increased electrification.
	  ○ As noted above, in this category this year we have included a placeholder estimated budget for potential proactive system upgrades to increase DER hosting capacity.

c. System Expansion or Upgrades for Reliability and Power Quality

This category focuses on replacing infrastructure that is experiencing high failure rates and, as a result, negatively impacting service reliability and increasing O&M expenditures needed to repair the equipment, as generally outlined below.

Reliability	• Cable Replacement: Criteria based program to replace tap and mainline cable
	• Reliability Programs: Criteria based programs aimed in improving reliability
	  ○ Feeder Performance Improvement Program (FPIP)
	  ○ Reliability Monitoring System (REMS)
	  ○ Viper Reclosers CSG

d. New Customer Projects and New Revenue

This category includes new overhead and underground extensions and services associated with extending service to new customers, as generally outlined below.

New Service	• Routine Extensions/Services: Small extension projects to address reactive, in-year customer requests • Discrete Projects: Larger customer driven extension projects
Streetlights	• Routine Streetlights: New streetlight installations

e. Grid Modernization and Pilot Projects

This category includes major grid transformation projects.

Grid Modernization Projects	• Major projects including AMI, FAN, ADMS, and FLISR

f. Projects Related to Local (or other) Government Requirements

This category includes projects driven by local governmental entities to accommodate public works projects such as road widening or other initiatives that require the Company to relocate its facilities in public rights-of-way, as generally outlined below.

Mandates	• Discrete Projects: Large discrete relocation projects involving the relocation of overhead and underground infrastructure including wire, cable, manholes and ductline. • Routine Relocations: Small relocation projects and service conversions to address reactive, in-year government driven projects or customer requests.

g. Metering

This category includes 'business-as-usual' meter purchases, not metering expenditures associated with our AMI plans.

Meter Purchases	• Meter Purchases: Routine meter purchases associated with base business.

h. Other

This category includes fleet, tools, communication equipment, and locate costs associated with modifications or additions to the distribution system or supporting assets, and transformer purchases. This category also includes placeholders for new strategic programs to increase cyber security, privatizing the substation communication infrastructure and add monitoring equipment to our downtown networks, as generally outlined below.

Other	• Fleet Purchases
	• Communication Equipment
	    o Discrete Projects
	    o Feeder Load Monitoring Program
	    o Network Monitoring
	• Corporate Initiatives
	    o Fiber Buildout
	    o Cyber Security
	• Tools & Equipment

Transformer Purchases	• Routine transformer purchases associated with new business (new service and capacity work) and reconstruction work (rebuilds, relocations and restoration).

i. Electric Vehicle Programs

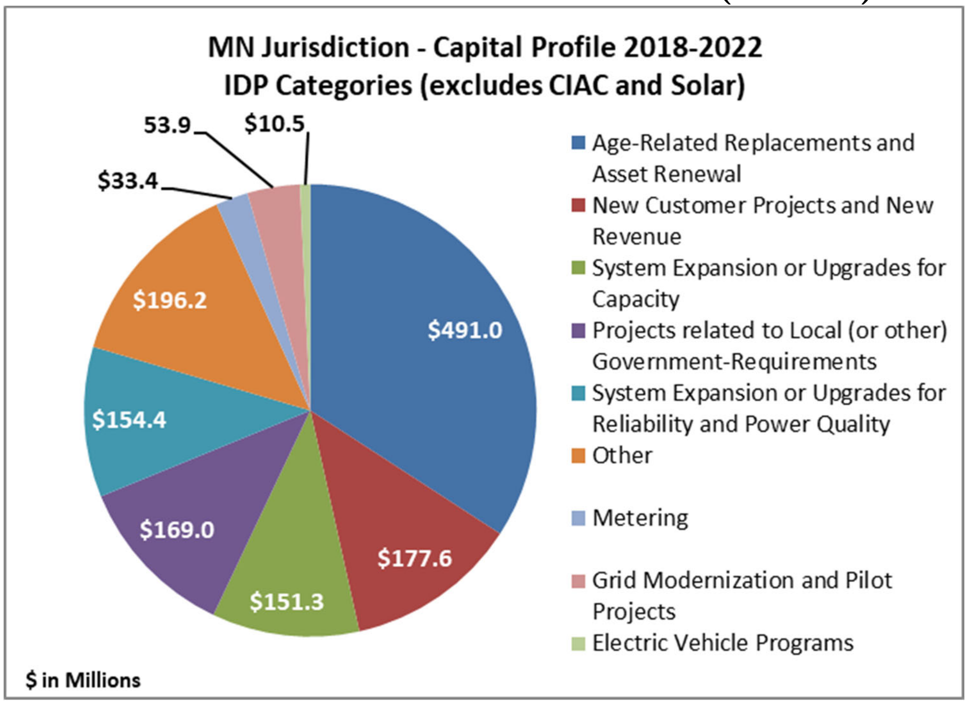
This category includes the capital costs associated with EV pilots and programs that were previously approved by the Commission – the Residential EV Charging Tariff, Residential EV Accelerate at Home, Fleet Charging Pilot, Public Charging Infrastructure Pilot, Residential Subscription Service Pilot, and Multi-Dwelling Unit Charging Pilot, and reflect some previously assumed growth for long term planning purposes in those programs and pilots.[5] As a part of the Transportation Electrification Plan (TEP) being filed concurrently with this IDP, the Company is making several proposals, including an expansion of the existing Residential EV Subscription Service Pilot, funding to support an electric school bus demonstration, and rebates for home wiring for vehicle charging. In addition, we are requesting additional funding to continue our fleet and public charging pilots and our EV advisory services. For the most up to date costs and forecasts that reflect the proposals in the TEP, please see *Appendix H: Transportation Electrification Plan* for further detail on our EV plans and investments.

2. *Historical Actual Expenditures*

Figure D-1 below provides a summary of historical actual capital expenditures in the IDP categories.

[5] *See* Docket No. E002/M-17-817; Docket No. E002/M-18-643; Docket No. E002/M-19-186; Docket No. E002/M-19-559.

Figure D - 1: Actual Historical Distribution Capital Profile by IDP Category State of Minnesota – Electric 2018-2022 (Millions)



Note: Non-investment items (Contributions In Aid of Construction (CIAC), 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).

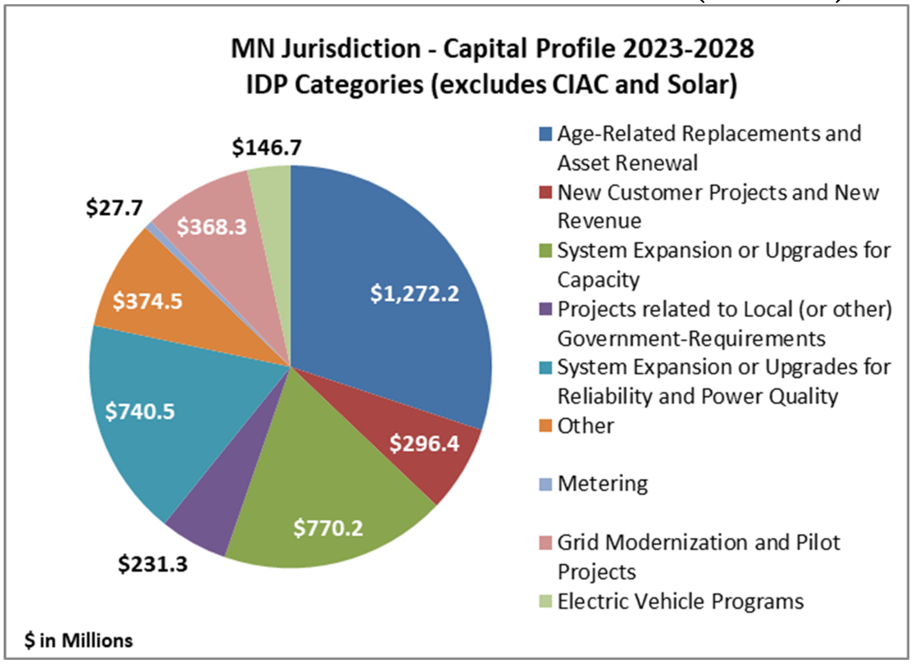
3. *Budgeted Capital Expenditures*

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.*

Figure D-2 below provides an overview of our 5-year capital budget in the IDP categories. We clarify that we do not have any specific non-traditional distribution projects in our five-year budget as we interpret "non-traditional distribution projects" in the context of the IDP Requirements to mean non-wires alternatives projects. However, for projects in the Grid Modernization and Pilot Projects category that could be considered "non-traditional;" see Appendix B1 for an itemization of those projects.

Figure D - 2: Budgeted Distribution Capital Profile by IDP Category State of Minnesota – Electric 2023-2028 (Millions)



Note: Excludes Non-investment items (Contributions In Aid of Construction (CIAC), 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).

Table D - 2: Distribution Capital Expenditures Budget – State of Minnesota – Electric 2023-2028 (Millions)

	Bridge Year			Budget			Budget Avg
IDP Category	2023	2024	2025	2026	2027	2028	2024-2028
Age-Related Replacements and Asset Renewal	$136.9	$179.4	$199.6	$231.2	$252.7	$272.4	$227.1
New Customer Projects and New Revenue	$50.1	$44.9	$47.6	$49.2	$51.1	$53.5	$49.3
System Expansion or Upgrades for Capacity	$35.8	$61.8	$93.2	$159.0	$193.3	$227.1	$146.9
Projects related to Local (or other) Government-Requirements	$29.2	$37.2	$39.6	$40.6	$41.6	$43.3	$40.4
System Expansion or Upgrades for Reliability and Power Quality	$40.9	$38.7	$55.4	$76.4	$201.2	$328.0	$139.9
Other	$70.8	$74.1	$55.1	$54.8	$56.4	$63.4	$60.7
Metering	$5.3	$4.1	$4.4	$4.7	$4.6	$4.5	$4.5
Grid Modernization and Pilot Projects	$115.4	$111.3	$56.3	$40.9	$33.5	$10.8	$50.6
Non-Investment	($2.1)	($4.0)	($4.0)	($4.0)	($4.0)	($4.0)	($4.0)
Electric Vehicle Programs	$9.3	$8.9	$1.4	$18.4	$36.9	$71.8	$27.5
TOTAL	$491.7	$556.5	$548.5	$671.2	$867.2	$1,070.7	$742.8

In Table D-2 above, Grid Modernization and Pilot Projects includes the Distribution component of grid modernization projects such as AMI, FAN, ADMS, FLISR, etc. Similarly, the Electric Vehicle Programs category include the Distribution component of program investments. Other includes Fleet, Tools, Communication Equipment, Locating, and Transformer Purchases. Non-investment includes Contributions In Aid of Construction (CIAC), which partially offset total project costs and third-party reimbursements for system upgrades due to interconnections and solar, which are 100 percent reimbursable by the developers; annual totals will vary based on payment and project timing.

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 anticipated changes in historical spending – with the driver categories aligning with the IDP distribution spending categories. We provide this information as Attachments H and I to this filing. Tabular data in live Excel format for the financial information in this Appendix below is provided as Attachment N.

Significant investments in the Distribution five-year budget include our grid reinforcements program to prepare the grid for increasing electrification; grid modernization initiatives, primarily in the first three years of the budget as we complete AMI deployment; and potential proactive investments in system upgrades to increase hosting capacity, discussed above. However, recent inflation and supply chain challenges have decreased the amount of investments that can be completed with existing budgets. Therefore, budgets may need to further increase to achieve the investment plans identified in the five-year budget and achieve state policy goals.

5. Reactive/Proactive Cable Replacements

Order Point 31 of the Commission's July 17, 2023 Order in Docket No. E002/GR-21-630 states:

> *Xcel must track its planned and actual spending on reactive and proactive cable replacements and include the information as part of its IDP budget filing.*

We note that cable replacements are included in the "System Expansion or Upgrades for Reliability and Power Quality" IDP budget category.

Cable failures are a main contributor to outages for customers who are served by underground facilities and accounted for approximately 65 percent of customer minutes out (CMO) from 2016 to 2020. The focus of the Company's cable replacement program is to respond to outages caused by cable failures and to replace cable that is either damaged beyond repair or that has failed more than once in a two-year period to avoid future outages.

Table D-3 shows the breakdown of actual spending on proactive versus reactive cable replacements in 2022 and the first half of 2023.

Table D - 3: Cable Replacement Capital Spend

January 1, 2022 through June 30, 2023

	Actual Capital Spend (Millions)	Actual Capital as a %
Reactive	$ 25.9	50.5%
Proactive	$ 25.4	49.5%
Total	$ 51.2	100.0%

Table D-4 shows projected spend for the five-year budget period. Planned spending shown in Table D-4 is based on historical actuals and is subject to change; the cable replacements program encompasses both proactive and reactive replacements. This budget flexibility is an important necessary component of the program due to the significant seasonal and year-to-year variability in the cable failure rates that drive the reactive replacements. The primary purpose of the cable replacement program is to make reactive replacements of cable that have failed. If these reactive failures are lower than anticipated in a given year, the Company plans to make proactive replacements of cables. with a history of poor reliability. Predicting the amount of reactive replacements that will occur each year is difficult as there is variability in the number of cable failures each year. As the Company cannot predict the exact number of reactive cable replacements that will be needed in a given year, budgeting for reactive and proactive replacements in a single budget provides Company the necessary flexibility to fund proactive replacements as the budget allows. If the Company created separate budgets for reactive and proactive cable replacements, the Company would be required to move dollars from one budget to another each year depending on the number of reactive replacements in those years. The current method of budgeting with a single category is a more efficient way to manage the budget for this program.

Table D - 4: Cable Replacement Capital Budget Forecast (Millions)
2024-2028

	2024	2025	2026	2027	2028	2024-2028
MN tap level cable replacement Budget	$ 28.7	$ 29.6	$ 30.5	$ 31.4	$ 33.0	$ 153.2
MN feeder level cable replacement Budget	$ 6.5	$ 8.0	$ 10.0	$ 12.0	$ 12.6	$ 49.1
Total cable replacement budget	$ 35.2	$ 37.6	$ 40.5	$ 43.4	$ 45.6	$ 202.3

	2024	2025	2026	2027	2028	2024-2028
Forecasted reactive cable Replacements	$ 17.8	$ 19.0	$ 20.5	$ 21.9	$ 23.0	$ 102.2
Forecasted proactive cable Replacements	$ 17.4	$ 18.6	$ 20.1	$ 21.5	$ 22.6	$ 100.2
Total forecasted cable replacements	$ 35.2	$ 37.6	$ 40.6	$ 43.4	$ 45.6	$ 202.4

V. O&M BUDGET DEVELOPMENT AND MANAGEMENT

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 capital and 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, 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. Table D-5 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 2018 to 2022.

Table D - 5: 2018-2022 Annual NSPM O&M Storm Restoration Expenses (Millions)

2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	5-Year Average
$1.90	**$6.90**	**$3.70**	**$7.10**	**$7.50**	**$5.42**

As shown in this table, we experienced a marked increase in O&M expenses related to storm restoration due to severe weather in 2019 through 2022, as compared to 2018 and prior years due to a steady increase the frequency of storms as well as more severe storms in some years. Thus far in 2023, we are forecasting storm O&M expenses of over $8 million – or approximately $2.6 million higher than the average of the previous five 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 reallocation, such as in years where we have had significant storm activities driving larger deviations 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 Company's Finance Council.

A. O&M Financial Information

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.

IDP Requirement 3.A.26[6] requires the following:

[6] 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.

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
i. Electric Vehicle Programs
1) Capital Costs
2) O&M costs
3) Marketing and Communications
4) Other (provide explanation of what is in "other")

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

Unlike our capital budgets, where it was possible to undertake a manual process to assign projects from our internal categories to the IDP 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 an 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 that cannot be aggregated in the required categories. For this reason and others discussed in the IDP Main Report, we propose to eliminate the IDP financial categories from the Company'ss IDP filing requirements.

That said, we have however been able to create a partial "functional" view of both historical actuals and five-year budgeted amounts.

B. Category Descriptions

Labor and Labor (overtime/other). This category includes the labor and labor overtime associated with the Company's employees to operate 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 any grid modernization O&M for ADMS, AMI, FAN, and FLISR 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. We note that there is no EV program-specific O&M budget within the Distribution budget; see Appendix H for O&M information specific to EV programs.

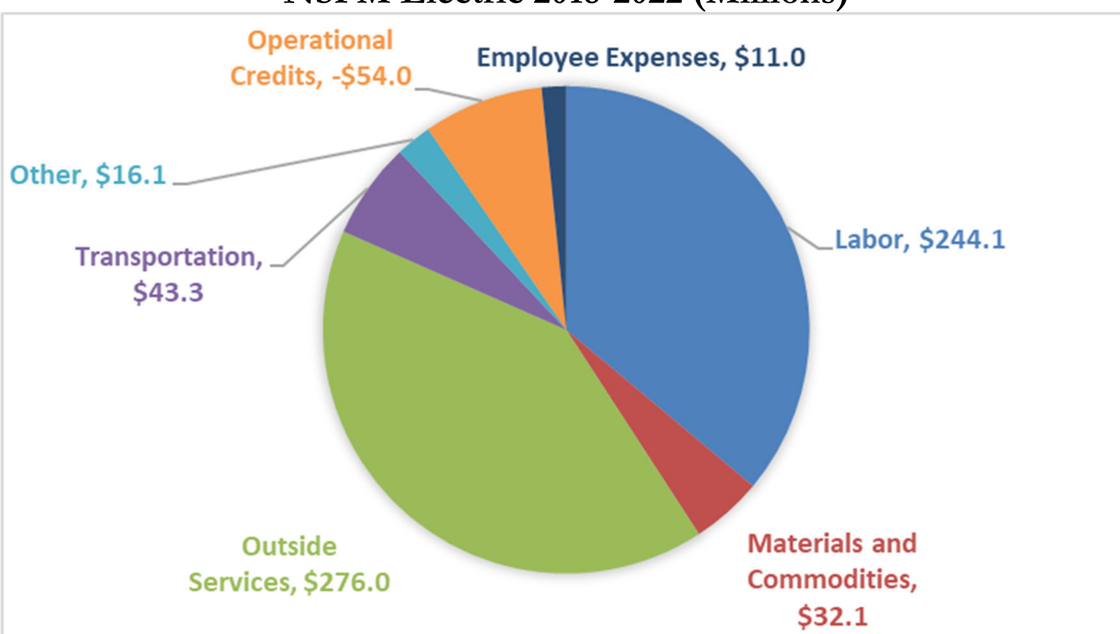
Miscellaneous Other. This category represents the O&M expenditures that include office supplies, janitorial costs, dues, donations, permits, electric use costs, electric safety clothing for the crews, permits and other various items minor costs.

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 and replacement of existing units.

C. Historic and Budgeted Information

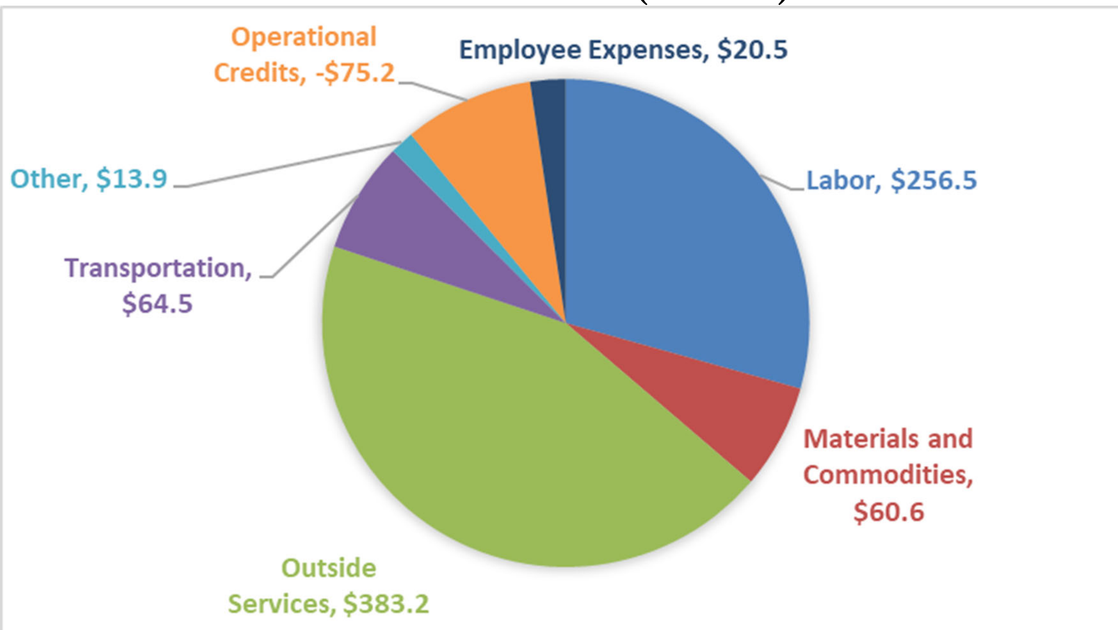
Figures D-3 and D-4 below provide a summary of historical actual and budgeted O&M costs in the most descriptive way that we were able to portray them given the reasons we have discussed.

Figure D - 3: Actual Historical Distribution O&M Costs by Cost Element – NSPM Electric 2018-2022 (Millions)



See Appendix H for O&M expenditures associated with electric vehicle programs . The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are $32.4M and $9.3M, respectively; Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Figure D - 4: Budgeted Distribution O&M Costs by Cost Element – NSPM Electric 2024-2028 (Millions)



See Appendix H for O&M budgets specific to electric vehicle programs; there is no EV program-specific O&M budget within Distribution. See Appendix B1 for a project-specific view of grid modernization O&M. The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are $38.5M and $14.8M, respectively; Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Table D-6 below provides a snapshot of our NSPM Operating Company O&M Distribution budget.

Table D - 6: Distribution O&M Expenditures Budget – NSPM Electric 2023 – 2028 (Millions)

Expenditure Category	Bridge 2023	Budget 2024	Budget 2025	Budget 2026	Budget 2027	Budget 2028	Budget Avg 2024-2028
Labor	$47.8	$45.4	$47.0	$48.6	$50.2	$52.0	$48.6
Cont. Outside Vendor/Contract Labor	$20.1	$17.2	$20.4	$24.5	$22.8	$22.4	$21.5
Vegetation Management	$27.8	$38.3	$37.8	$39.0	$39.9	$42.8	$39.6
Damage Prevention Locates	$12.7	$13.8	$14.3	$18.0	$18.7	$19.3	$16.8
Grid Modernization Projects	$1.3	$2.6	$2.6	$1.7	$1.4	$1.5	$2.0
Other (Materials, Transp, First Set Credits)	$0.3	$10.8	$16.0	$17.4	$18.7	$19.0	$16.4
TOTAL	**$110.0**	**$128.1**	**$138.1**	**$149.2**	**$151.7**	**$157.0**	**$144.8**

See Appendix H for O&M budgets specific to electric vehicle programs; there is no EV program-specific O&M budget within Distribution. See Appendix B1 for a project-specific view of grid modernization O&M. Other includes bad debt, First Set Credits, use costs, office supplies, janitorial, dues, donations, permits, etc.

As compared to 2022 actuals, our next five-year forecasted O&M budget increases by approximately $6 million annually from 2024 through 2028. Two primary areas drive the increase. First, we expect an average of an $12 million annual increase in Vegetation Management due to the new contract rates which took effect beginning in 2023 with primary providers. Second, we expect an increase of $2 million additional annual Damage Prevention budget by 2025 driven by higher contractor labor rates that took effect in 2022. We then anticipate an additional increase by $4 million as the current contract with our Damage Prevention vendors expires at the end of 2025 and a new contract will need to be implemented starting in 2026. We are anticipating another large increase due to inflationary factors for the next contract with our vendors.

Finally, although only required for capital under IDP Requirement 3.A.29, we provide a similar trend view of our O&M costs over time as Attachment J to this IDP.

APPENDIX E: DISTRIBUTED ENERGY RESOURCES, SYSTEM INTERCONNECTION, AND HOSTING CAPACITY

In this Appendix, we outline considerations regarding distributed energy resources (DER), including our strategy roadmap. We also summarize our hosting capacity analysis (HCA) and overall interconnection processes, and provide current levels of DERs and discuss integration considerations. Finally, we discuss advanced inverter functionality, changes associated with IEEE 1547, and happenings at the federal level that implicate DER and the distribution system.

I. PLANNING LANDSCAPE FOR DER

As DER penetration continues to increase on the distribution system, we recognize that we will need to continually update our interconnection processes. Today we study DER interconnections by analyzing each project's impacts on a case-by-case basis. This means that the earliest interconnections on a feeder may have the most favorable study results, because available capacity to host DER on the feeder is most plentiful. As the amount of interconnected DER on a feeder increases, the available capacity for additional DER decreases. Eventually, the cumulative DER capacity on a feeder approaches the feeder's ultimate rated capacity, and further interconnections are ultimately constrained by thermal, voltage, or other physical limits of the distribution system infrastructure. This may lead to significant infrastructure upgrades in order to safely interconnect the DER with the system.

As available generating capacity on the distribution system tightens, the industry and other stakeholders are evaluating different processes and technologies which may be able to integrate higher DER penetration in a given area. One such scenario could involve more control and management of both existing and new interconnections.

Although we and the industry are in the early stages of the progression toward more advanced interconnection management, we are studying the process and technology requirements and the timing of their implementation that would be needed to enable the progression toward active management of DER interconnections. Some of these technologies include the analysis and planning tools and future systems such as Distributed Energy Resource Management Systems (DERMS) that are discussed in this Appendix and parts of this IDP. We are also remaining attentive to new developments across the industry to ensure that our plans are aligned with industry practices.

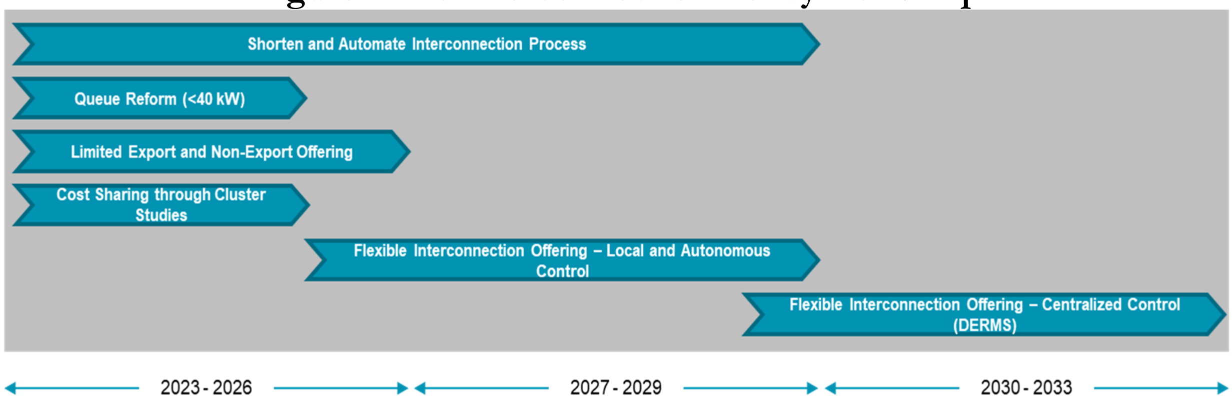
As shown in the DER forecasts in *Appendix A1: System Planning*, we are anticipating significant rates of DER adoption and growth on the distribution system between now and 2050. To keep up with this demand and ensure continued safe, reliable, resilient, and affordable service for our customers, we must begin evolving our planning and interconnection processes towards a clear vision of the future. This vision must cross multiple functional areas of the distribution system, including planning, operations, technology, and policy, and must coordinate multiple interdependent efforts including coordination with the transmission system. As we also discuss in other parts of this IDP, we are in the midst of planning for the future convergence of grid operating technology, which we believe is necessitated by the expected significant increase in DER and renewable generators along with increased security and resilience requirements in a changing risk and threat environment, and the need for advanced communications and information available for operators and customers.

II. DER STRATEGY ROADMAP

In this section we present our conceptual DER strategy roadmap. The roadmap is broken into 10 categories: Interconnection Policy; Flexible Interconnections; DERMS, non-wires alternatives (NWA), and Market Participation; Dynamic Hosting Capacity; Data and Automation; Reducing Costs; Maintaining Customer Choice; Equity Metrics in Planning; Cyber and Physical Security; and Integrated System Planning. For each category, we provide a conceptual timeline, with key activities spread across three time periods: short term (2023-2026), mid-term (2027-2029), and long term (2030-2033). Unless otherwise stated, the timing of the beginning and completion of each timeline activity are not rigidly defined here and are subject to change; this roadmap is intended to be generally indicative of the timing, order, and interdependency of each activity relative to the other activities in the group, but we emphasize that the specific timing is illustrative. In addition, resources such as planning and engineering staff will be required to implement these strategies.

A. Interconnection Policy

Figure E - 1: Interconnection Policy Roadmap



The roadmap for evolving interconnection policy, shown in Figure E-1 above, focuses on two main objectives: making the existing DER interconnection process more efficient and examining lower cost alternatives to traditional, static interconnections when capacity constraints would require costly upgrades. We continue to investigate opportunities to streamline or potentially automate the various stages of the interconnection process, with a goal of meeting timelines and/or reducing the overall time to interconnect from the submission of an application to receiving permission to operate. Additionally, Minnesota Session Laws 2023, Ch. 60, Art. 12, Sec. 75 requires the establishment of a queue prioritization process for smaller distributed generator interconnections less than 40 kW AC in size,[1] and the Minnesota Legislature has indicated a policy objective that DER projects up to 40 kW be reviewed and approved more quickly.[2] Queue reform will likely help streamline the interconnection process for smaller, lower-impact distributed generators, and we are investigating other opportunities to streamline the process for these projects.

With existing interconnections, if capacity constraints cannot be resolved by power factor or other inverter setting adjustments, then upgrades must be pursued. System upgrades are identified when the proposed DER may impact the reliability and safety of the system; in some cases, this may occur a limited number of hours per year or year-round. To reduce upgrade costs to customers, we have been offering the ability for DER systems to adjust inverter power factors, share costs through a cluster study

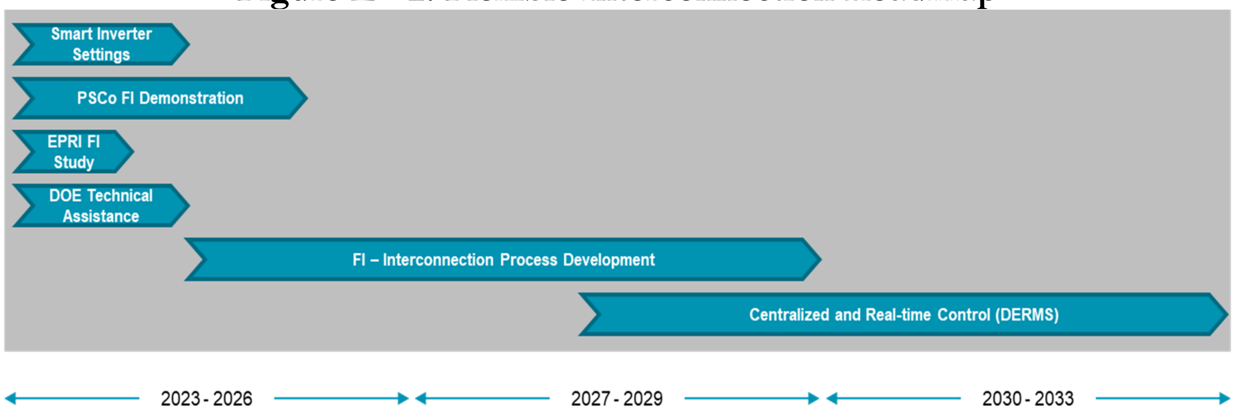
[1] This is the subject of the Commission's Notice of Comment Period issued on September 1, 2023 in Docket No. E999/CI-16-521.
[2] *See* Minn. Stat. § 216C.378 Subd. 2(2), as added by Minnesota Session Laws 2023, Chapter 60, Article 12, Section 38.

process, or – in the case of projects up to 40 kW AC – participate in our cost sharing program. The next phase of alternatives could include offerings for limited-export and non-export interconnections, in which energy storage or other technology can be used to minimize or avoid the reverse power flow that causes constraints.

Flexible interconnections (FI), which are described further below, are an emerging DER control strategy used to defer or avoid system upgrades necessary for interconnection and increase DER integration. This means that DER may experience temporary curtailment of generation during times of grid constraint, but full generation during times without grid constraint. FI could be an additional interconnection offering that helps customers decrease interconnection time or costs. However, FI is not currently available as an interconnection offering, and needs further study and demonstration prior to being made available. The first phase of FI offerings will be likely be based on local and autonomous control, in which the inverter for the DER would operate on settings specified for that specific inverter. However, for broader, more programmatic (e.g., multiple flexible interconnections on a substation or feeder) deployment, FI would require centralized control software to dynamically manage these generators. DERMS is one type of control software capable of providing this coordinated control. For example, DERMS would calculate the optimal curtailment of multiple FI-participating DER on a feeder or substation based on a load flow model and would automatically dispatch curtailment signals as appropriate. However, additional interconnection policy factors, such as the inclusion of Daytime Minimum Load (DML) in the Technical Planning Standard (TPS) for DER interconnections, may need to be re-addressed by the Company as we look toward FI. An in-depth review of interconnection policies and processes will be needed to identify issues and enable solutions.

B. Flexible Interconnections

Figure E - 2: Flexible Interconnection Roadmap



FI are still in the early stages of implementation in the utility industry. There are many questions that still need to be answered regarding the technology, economics, and policy before FIs can be deployed as a standard offering for interconnection customers. We have taken and plan to continue taking steps towards answering these questions and develop an FI framework that meets the needs of interconnecting customers while maintaining the safety and reliability of the distribution system. Specifically, we have developed compliance standards for smart inverter settings that we will begin implementing in early 2024 – the enablement of smart inverters is foundational to flexible interconnection capabilities.

Additionally, we have been working with the Electric Power Research Institute (EPRI) on the techno-economic study of flexible interconnection with utility scale solar PV systems. This project sets out to investigate the economic and technical feasibility of actively managing solar resources to enhance energy production and use of available feeder capacity, with the consideration of grid constraints. We also applied and have been awarded technical assistance from the U.S. Department of Energy (DOE) on flexible interconnections through the Interconnection e-Xchange (i2X) Technical Assistance Opportunity. We are working with Pacific Northwest National Lab and leading a project team with Commonwealth Edison, an Illinois utility. This project is creating an end-to-end process and best practices guide to implementing flexible interconnection, including a generic template of key interconnection and operational agreements between utilities and customers, to enable FI. This is part of a broader i2X initiative to support efforts in flexible interconnection standards and implementation.

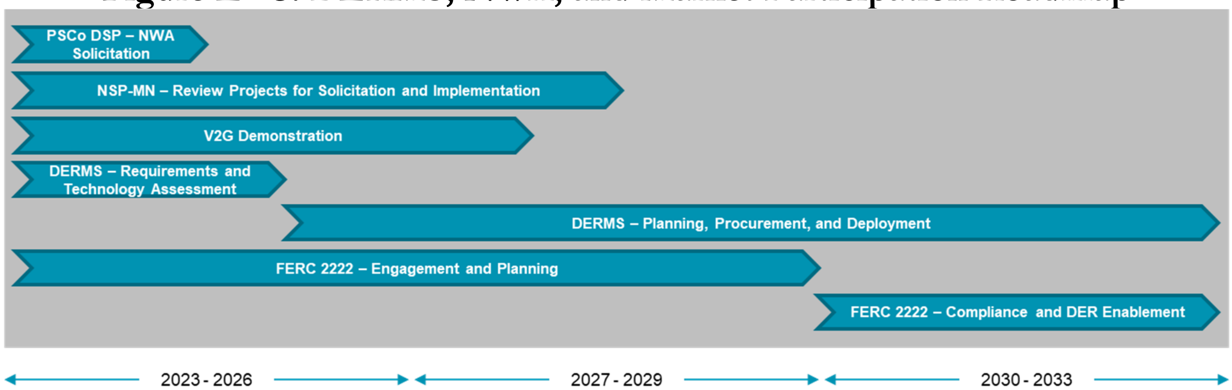
Our first demonstration of flexible interconnection capabilities will be in our Colorado operating company. The scope of these demonstrations is still being developed with stakeholders; however, the Company intends to test and demonstrate local and autonomous smart inverter settings combined with scheduled curtailments based on historic and forecasted power flow. The demonstrations stemmed from the Colorado Distribution System Planning filing Joint Stipulation Agreement, where the Company agreed to implement at least two FI pilots before the end of 2024.[3] We will then take the learnings from that demonstration and apply them across our operating companies, including in Minnesota, using the lessons to inform development of FI processes, standards, and requirements over the coming years. Finally, after a local and autonomously controlled flexible interconnection offering is made available in the mid-term, we will work to develop the process and requirements for using a DERMS to actively manage flexible interconnections.

Active grid management of DER using a DERMS represents a significant paradigm shift from the current distribution grid operation practices, which necessitates execution of pilot projects and demonstrations to rigorously test and validate the new technology, ensure its seamless integration with grid operations, and adhere to pertinent industry standards. Moreover, successful implementation requires integrating a future DERMS platform with the existing enterprise systems and establishing secure two-way communication links with different types of DER from various manufacturers. Careful considerations during implementation are imperative due to the emerging industry standards for DER communications and cybersecurity. As with major technology shifts, extensive analysis and training is needed to understand new technical capabilities, identify potential risks, establish cybersecurity specifications, develop new processes, understand integration requirements with existing systems, and evaluate resources and associated skill sets needed for successful implementation.

[3] Colorado Public Utilities Commission Proceeding No. 22A-0189E.

C. DERMS, NWA, and Market Participation

Figure E - 3: DERMS, NWA, and Market Participation Roadmap



In addition to FI, NWAs and participation of DER in energy markets will be dependent on a DERMS product for their coordination in the long term. We are currently assessing the capabilities available with existing emerging DERMS platforms on the market and will also be establishing technical requirements for a DERMS in the short term. These requirements will then be used to plan, procure, and ultimately deploy a DERMS solution; we expect this to be an initiative with multiple phases of deployment.

A key capability of DERMS is providing enhanced visibility and active management of DER on the distribution system. In order to gain this benefit, two-way communication is required, either directly with DER or through an aggregator platform. The Field Area Network (FAN) could be an important conduit of this overall platform. Also, we have a strategic advantage with our Advanced Metering Infrastructure (AMI) meters having a Wi-fi network card utilizing the IEEE 2030.5 communications standard, and in the future could be an important channel to communicate with DER and DERMS.

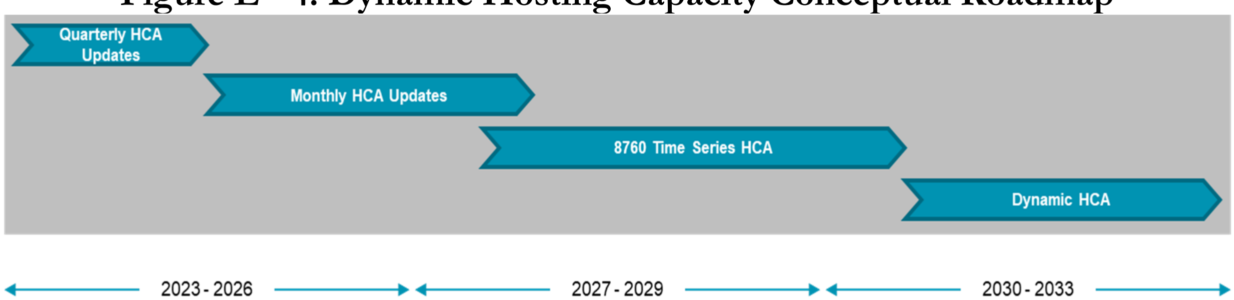
While a DERMS is not required for the implementation of an individual NWA project or pilot, it will significantly aid our ability to monitor, control, and coordinate NWA solutions safely and reliably. This will be especially important in a future distribution system to help with economies of scale in managing multiple flexible load strategies and generation technologies that contribute to dynamic, two-way power flows.

While we work to identify a DERMS solution that can meet this need, we will be pursuing a vehicle-to-grid (V2G) demonstration project. This demonstration will use electric school buses as a form of demand response, calling upon the electric school buses to discharge their batteries into the distribution system through V2G capable chargers, thereby reducing the effective system loading. While this project was not identified through our NWA analysis process to address specific distribution capacity risks, it will be a demonstration of our ability to integrate V2G technology for use in future NWA applications. We provide more information on the V2G demonstration project in *Appendix H: Transportation Electrification Plan*.

We believe that DERMS will play an important and crucial role in supporting FERC Order 2222 efforts. FERC Order 2222 DERMS capabilities vary from vendor to vendor and are still evolving. We intend to examine these capabilities as part of our requirements and technological assessment of these systems; we discuss FERC Order 2222 further in Section VII below.

D. Dynamic Hosting Capacity

Figure E - 4: Dynamic Hosting Capacity Conceptual Roadmap



HCA is one of several valuable resources available for guiding customer and DER developer interconnection decisions. However, for it to remain a useful tool, the pace and needs of DER interconnections on the distribution system should also be considered in the future. We have already taken steps in this direction as we have been updating the HCA map on our website on a quarterly basis and are now in the process of moving to implement the Monthly Updates use case.

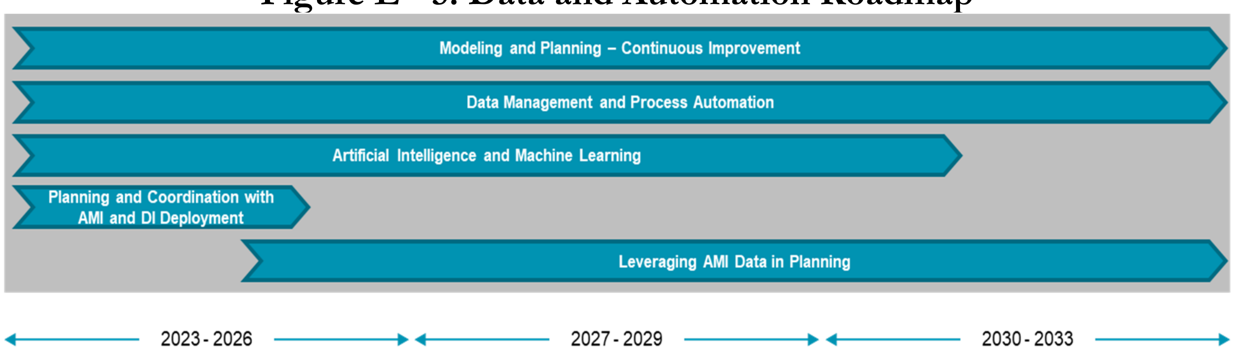
The next step in the HCA progression will be to explore how to potentially incorporate 8,760 time-series analysis in the HCA. The inclusion of 8,760 data can provide additional insight into both hosting capacity constraints as well as how much of the year those constraints are present. The modeling functionality for performing 8,760 time series analysis in the HCA is still nascent and conceptual, but the work we are currently doing with Foundational Improvements and moving to Monthly Updates would support this effort.

Our long-term vision for the HCA is to move toward dynamic analysis, in which HCA updates for individual feeders are queued, processed, and results posted to the map on a near real-time basis when update triggers are indicated in our source systems. This will require continued improvement of input data, as well as significant improvement and automation of modeling processes. However, this aspirational goal would eliminate most process lag and ensure that the data shown on the hosting capacity map is as up to date as possible.

The Company notes that while we are exploring this potential progression of the Hosting Capacity Program, we are not aware of any utility that has implemented or is pursuing or exploring real-time HCA updates, as the technologies to accomplish this are unknown. Therefore, we have no examples we can draw-upon for guidance on how to achieve this aspiration, nor do we have any indication of what it may cost in terms of time and money, even if real time updates do prove to be technically feasible.

E. Data and Automation

Figure E - 5: Data and Automation Roadmap

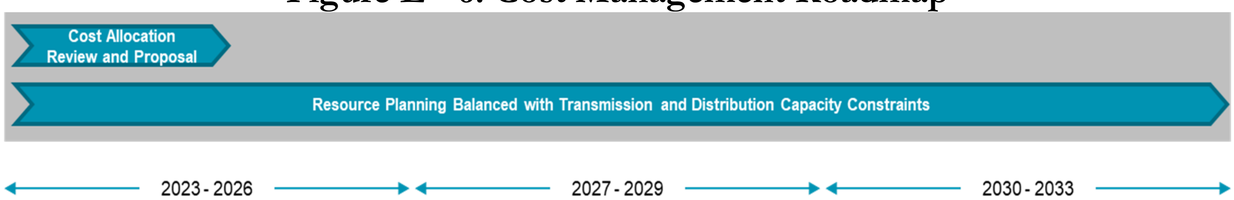


Access to detailed and accurate system data is critical to our distribution planning process. The volume of data required for modeling the distribution system is increasing, and we need continued focus on data management, process automation, and continuous improvement of system modeling. Additionally, we anticipate that advancements in artificial intelligence and machine learning will open up new ways to utilize our system data, and we will remain engaged with the industry to identify these opportunities.

In addition, leveraging AMI data in our planning process will open up new ways to study and understand the demand on the distribution system, and we anticipate that it will drive efficiencies in our planning work. Specifically, we intend to use aggregated AMI data as an input into the load forecasting process when it becomes available for the entire system. This will help build a better understanding of the existing customer loads and load patterns on the distribution system. That said, it will take time to implement AMI data into our planning processes and understand the full benefits of its use.

F. Managing Costs

Figure E - 6: Cost Management Roadmap



Enabling DER adoption is a key component of Xcel Energy's plan to achieve 100 percent carbon-free electricity for all customers by 2050, and this is reflected in the rapid rate of DER adoption in our forecasts. This level of adoption will require new infrastructure and upgrades to the distribution and transmission systems..

In *Appendix I: Distribution System Improvements*, we offer a forecast of these infrastructure costs and a review of alternatives to the cost causation principle that currently guides cost allocation. The transmission and distribution costs to interconnect DER also need to be incorporated in the Integrated Resource Plan (IRP) to ensure optimal plan selection. We have begun the process of identifying appropriate distribution and transmission costs for our next IRP (due February 1, 2024), and this will continue to be an area of focus for future IRPs.

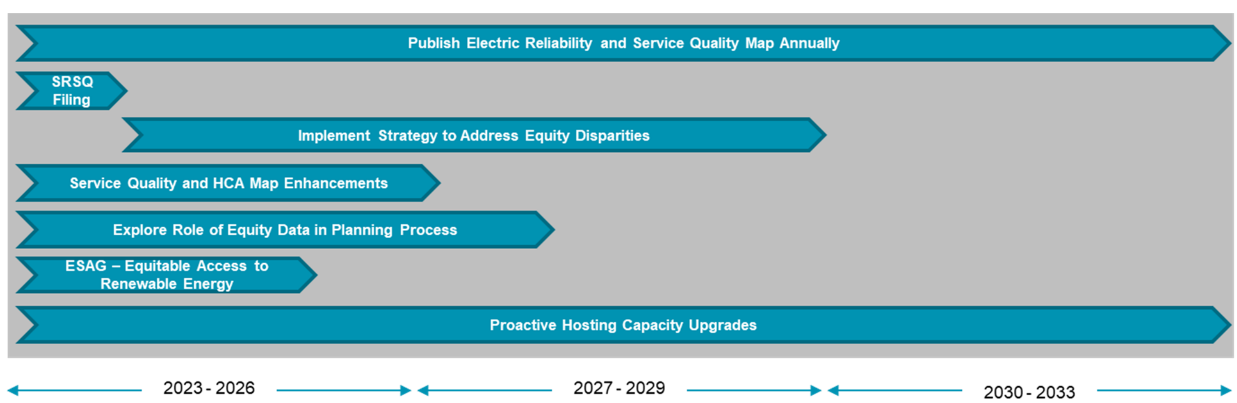
G. Maintaining Customer Choice

Figure E - 7: Maintaining Customer Choice Roadmap

We believe that all our retail customers should have equitable and fair access to siting DER and pursuing electrification. Given the rate of adoption of these technologies that we are expecting over the next 30 years, it is important that we establish a planning philosophy and framework that enables this goal. The first area of focus is on our planning limits for DER. The DER planning limit that is currently used in Minnesota is the TPS, which states the maximum allowable penetration of nameplate distributed generation on a feeder or substation transformer is 80 percent of the device continuous rating plus the DML. One of the issues that we have identified with the TPS in practice is that all distributed generation is measured against the TPS whether it is a large, front of the meter generator or a small generator that is behind the meter, paired with load (e.g., a rooftop solar system). This has led to several areas of our distribution system where the TPS has been reached or exceeded entirely due to large front of the meter generation, restricting the ability of our retail customers to host DER generation without incurring significant capacity upgrade costs. Today, we are making two filings in which we discuss prioritizing small interconnections through technical adjustments that we believe would improve the utilization and operational flexibility of the distribution system while also providing consideration for retail customers to have access to siting DER in the long term.[4]

H. Equity Metrics in Planning

Figure E - 8: Equity in Planning Roadmap



[4] *See* our November 1, 2023 Comments in Docket No. E999/CI-16-521 regarding procedures for projects up to 40 kW to receive queue priority over larger projects, and our November 1, 2023 filing to the Department of Commerce (Docket No. E002/M-23-458) regarding the Distribution System Upgrade Program created by Minn. Stat. § 216C.378 as added by Minnesota Session Laws 2023, Chapter 60, Article 12, Section 38.

We provide annual updates in our Service Reliability Service Quality to the Service Quality Interactive Map, which shows, in part, electric system reliability and demographic data for the communities we serve. Additionally, in our next electric Service Reliability Service Quality filing on April 1, 2024 we will provide the results of an external study that analyzed reliability and service quality metrics and trends as they relate to equity. Should we identify equity disparities from that analysis, we will develop and implement a strategy to address those disparities over the short- and mid-term. We will also continue to explore how these equity metrics could be incorporated in our overall distribution planning process.

Through our engagement with the Equity Stakeholder Advisory Group (ESAG) we are identifying ways to improve our ability to provide equitable access to renewable energy. Through their respective dockets, we will continue to work with stakeholders on ways to enhance our Service Quality Interactive Map, that includes electric reliability data, as well as our Hosting Capacity map to make it easier for interested parties to access relevant metrics about our distribution system. However, one of the most significant limitations in access to renewable energy is a lack of available hosting capacity. For this reason, we are taking two important steps toward investing in proactive hosting capacity upgrades in Minnesota. First, we are filing a plan today with the Department of Commerce (Docket No. E002/M-23-458) proposing a plan for hosting capacity upgrade projects using the $10 million of funding, per state legislation. Second, we have included capital funds for proactive hosting capacity upgrades in our five-year budget; we discuss this budget in further detail in *Appendix D: Distribution Financial Framework and Information*.

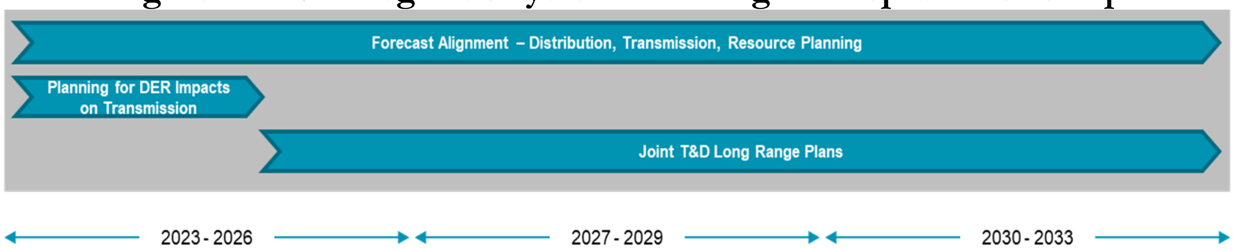
I. Cyber and Physical Security

Figure E - 9: Security Roadmap

The grid security landscape is rapidly evolving. As we continue to make investments in distribution infrastructure and grid modernization, we must also remain in alignment with industry standards and security regulations. This will help ensure that we are able to quickly deploy mitigations to newly identified safety and security risks. We discuss cybersecurity and physical security further in *Appendix B2: Customer, Operational, and Planning Data Management, Security, and Information Access Plans and Policies.*

J. Integrated System Planning

Figure E - 10: Integrated System Planning Conceptual Roadmap



As discussed in Appendix A1, we have taken steps towards ensuring alignment between the forecasts used for planning. We will continue to look for further ways to align these forecasts in the long term, as new data, modeling tools, and processes may change the way in which forecasts are generated.

Organizationally, as noted in Appendix A1, we have also made changes aimed at improving the integration of our planning process. Namely, we have created an Integrated System Planning (ISP) organization, which is an entirely new business unit outside of Operations that brings the planning functions for Distribution, Transmission, Gas, and Energy Supply together.

Our next step in integrating our distribution planning process with transmission planning will be to identify the impacts of forecasted DER adoption on the transmission system. The estimated distribution costs to integrate the forecasted DER shown in Appendix I are extensive, but there will also be costs for the transmission system that have not yet been identified. We need to study and understand these impacts and iterate on that analysis as forecasts continue to be refined in the future. Once those transmission system impacts are identified, we will be able to start developing joint transmission and distribution long range studies to determine what investments could be required to meet the needs of both the transmission and distribution systems in 2050.

III. PROCESSES AND TOOLS

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, and we anticipate that it has the potential to further enable DER integration by guiding future installations and identifying constrained areas. In compliance with Minn. Stat. § 216B.2425, and by order of the Commission, beginning in 2016, we have conducted and submitted an annual Hosting Capacity Program Report. We submitted our most recent Hosting Capacity Program Report on October 31, 2023 (2023 Hosting Capacity Program Report). These studies show hosting capacity results at the feeder and sub-feeder level, provide an indication of distribution feeder capacity for DER, and streamline interconnection studies by helping to guide projects to places on the distribution system where there may be available capacity.

In its July 30, 2020 Order in Docket No. E002/M-19-685, the Commission directed the Company to explore several potential future Use Cases for the HCA, including various ways to integrate the HCA with the interconnection process, which in turn advances customer-sited DER. Our November 1, 2020 HCA Report in Docket No. E002/M-20-812 outlined how HCA information could be used in certain parts of the Minnesota DER Interconnection Process (MN DIP) and the associated investments to go in that direction. At the September 30, 2021 hearing in that docket, the Commission decided this work should continue.

In the Company's 2022 Hosting Capacity Program Summary filed in Docket No. E002/M-22-574, we continued this work in conjunction with stakeholders to further outline a development plan for the Hosting Capacity Program. This development plan included a review of current software used along with the implementation of several Foundational Improvements, which will improve the quality of the hosting capacity results once completed. Additionally, we also provided preliminary timelines for implementing the Monthly Updates and the Fast Track Supplemental Review Screen (FTSRS) use cases. The Company is moving forward with the Foundational Improvements and, per Commission Order, the Monthly Updates, which will provide users with fresher data and, in combination with the Foundational Improvements, increase confidence in the ability of the HCA to identify interconnection points on the distribution system and to inform the interconnection process.

Also included in the Company's 2022 Hosting Capacity Program Summary was the results of the Company's first ever Load-HCA. The Load-HCA indicates the capacity available for siting new or additional load on the distribution system, such as a new or expanding customer load, batteries (charging only), or electric vehicle (EV) fast charging stations. This differs from the Generation HCA (Gen-HCA) analysis we have done in the past, which is an analysis performed specifically for siting new generation-based DERs, such as photovoltaic (PV) or wind resources or batteries (discharging only). As indicated in our 2023 Hosting Capacity Program Report, the Company has not been further ordered to continue these updates. Therefore, we intend the 2023 Load-HCA to be the Company's final Load-HCA.

In its September 15, 2023 Order in Docket No. E002/M-22-574, the Commission further ordered the Company to continue working with stakeholders to conduct a full cost-benefit analysis of the FTSRS use case. More details about this process can be found in our 2023 Hosting Capacity Program Report.

1. HCA Tools

The two primary tools currently used to conduct the HCA are Det Norske Veritas' (DNV's) Synergi Electric modeling software, and EPRI's Distribution Resource Integration and Value Estimation (DRIVE) analysis software.

Models are created for distribution feeders subject to the hosting capacity program using Synergi based on several data sources including GIS, customer billing data, forecasted peak load demand, historic daytime minimum loading ratio, and more. Engineers use this data to create and validate the model before processing it via DRIVE.

DRIVE was developed by EPRI to automate and streamline the HCA process and has been used by the Company since we began performing the HCA in 2016. The DRIVE tool incorporates years of knowledge from HCAs conducted by EPRI to screen for voltage, thermal, and protection impacts from potential DER or load additions. DRIVE is used by utilities across the country, and a group of utilities and planning tool vendors work together to apply and evolve HCA as the DRIVE User Group. As DRIVE has expanded its reach, industry and stakeholder collaboration has been beneficial in creating consistency with the DRIVE application and methodologies, and EPRI's ongoing engagement with the DRIVE Users Group has resulted in DRIVE evolving to be more streamlined and produce more efficient, accurate results.

Recent versions of the DRIVE tool have added the capability to also analyze the load characteristics of newer forms of DER, including battery storage and EVs. These capabilities could be used to identify areas with greater potential for siting EV charging stations, new buildings that are heated electrically, or other loads associated with beneficial electrification.

The Company continues to use DRIVE's Centralized methodology, which assesses DER at specific locations along each feeder by adding incremental DER at each node to determine the amount of DER that specific location can accommodate before encountering limiting criteria thresholds. The results of this nodal analysis are often rolled-up to sections that reflect a range of hosting capacity that can be accommodated between the nodal points that were studied. When an HCA uses the Centralized methodology, the results show location-specific hosting capacity values/amounts of DER that can be accommodated at each location (node or sub-feeder section).[5] The Company and stakeholders agreed that the Centralized method was the best choice during the Company's June 2020 Workshop series.[6]

Use of the Centralized method affects the hosting capacity results by generally showing a larger maximum hosting capacity and smaller minimum hosting capacity than the Distributed method. The Centralized method considers all DER installations assuming interconnection on three-phase lines, which generally have more capacity and better align with the types of DER installations we experience on our system. The smaller minimum hosting capacity that results from this method is due to the concentration at specific locations, which has the tendency to affect the overvoltage and thermal violation thresholds a little more than distributing the load across the feeder. Consequently, that concentration also unmasks the potential to add more generation at ideal locations on the feeder (maximum hosting capacity).

The Company uses seven criteria for the Gen-HCA and four criteria for the Load-HCA as indicated in Table E-1. The limiting criteria are categorized into voltage, power-flow, protection, and power quality & reliability. Voltage is checked at each location on the feeder. Power-flow is checked at the breaker, regulator, and feeder head. Protection is checked at the breaker, recloser, sectionalizer, and feeder head. The power quality and reliability criteria are not used for either HCA type, as they are

[5] DRIVE considers potential DER in increments of 100 kW on three-phase sections, which means that even if a feeder shows zero hosting capacity, the actual available hosting capacity may be something between zero and 100 kW. Therefore, additional small-scale DER may not be prohibitive.
[6] Xcel Energy, Renewable Developers Interconnection, Hosting Capacity Workshop Materials, https://mn.my.xcelenergy.com/s/renewable/developers/interconnection.

not part of our interconnection process. As a general principle, the Company attempts to align the thresholds used in DRIVE with those used in the interconnection studies.

Table E - 1: Limiting Criteria Used for Each HCA Type

Criteria	Gen-HCA	Load-HCA
Primary Over-Voltage	✓	
Primary Under-Voltage		✓
Primary Voltage Deviation	✓	✓
Regulator Voltage Deviation	✓	✓
Thermal Discharging	✓	
Thermal Charging		✓
Additional Element Fault Current	✓	
Breaker Relay Reduction of Reach	✓	
Unintentional Islanding[13]	✓	

The Company does not include any forecasted or queued DER generation in the HCA. Generally, it is challenging to fully predict where potential future DERs will be located – even with an interconnection queue. For instance, a large PV system in the interconnection queue (with a signed interconnection agreement) may be required to make some line upgrades to accommodate the proposed generation. The interconnection of that PV system and the line upgrades required for that interconnection are not reflected in our GIS until the design and construction phases are complete. This is to ensure we are modeling the system as-is, in case there are delays or changes to the final construction. 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. The HCA results cannot replace the detailed system impact study used to determine required system upgrades in the interconnection process, nor are they a guarantee of available hosting capacity without further detailed system impact studies being performed. The risks of trying to forecast available hosting capacity based on too many variables would inevitably lead to confusion or even misguide users who submit applications. We believe that our efforts are best spent on producing increasingly accurate and reliable results for the current system configuration, with only guaranteed near-future grid infrastructure projects, for developers to reference.

2. *We Continue to Improve the HCA*

For several years, the Company has engaged with stakeholders who are interested in either monitoring the development of, or informing interconnections with, the results from the Hosting Capacity Program. In 2019 and 2020, the Company organized a series of stakeholder workshops to discuss the methodology, process steps, assumptions, and limiting criteria for generation HCA. The stakeholders provided helpful suggestions regarding the HCA process and the presentation of results, many of which have been incorporated into the Hosting Capacity Program. These improvements over the past four years include the following:

- Quarterly update cadence,
- Establish criteria for updating feeder models on the quarterly cadence,
- Nodal tabular results by feeder segment (Feeder Nodal Results),
- Adding a unique identifier for each feeder segment,
- Pop-up feature on the heat map with additional details and results for each feeder segment,
- Notes field on the tabular results,
- All criteria violations listed on tabular results and heat map,
- Listing the data cutoff date (most recent data when the data was updated),
- New data in results (e.g., transformer name, feeder and transformer minimum loading, presence of Load Tap Changer, network or radial feeder),
- Lowering the DER generation threshold that triggers a feeder model update from 500 kW to 100 kW,
- Noting if voltage supervisory reclosing (VSR) is installed on each feeder,
- Noting if the actual DML value is used in the analysis for each feeder,
- Noting if the feeder or substation is constrained,
- Noting if the substation is owned by another utility than Xcel Energy.

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. There are several ongoing projects that will assist with advancing customer-sited DER, identify interconnection points on the distribution system and necessary distribution upgrades to support continued DER development, and generally improve our hosting capacity program for our customers.

Per the Commission's September 2023 Order, the Company is pursuing the Monthly Updates use case discussed in our Hosting Capacity Program Report. Increasing the HCA update cadence form quarterly to monthly will provide developers with fresher data and increase confidence in the ability of the HCA to inform the interconnection process of customer-sited DER by working to close the delay between the data cutoff date and the publication of results. More information about the timeline for implementation and prerequisite software upgrades can be found in our 2023 Hosting Capacity Program Report filed October 31, 2023. Furthermore, the implementation of the Advanced Distribution Management System (ADMS) and the ongoing implementation of AMI will provide enhanced system visibility to improve the data inputs and the analytical tools to further refine the HCA output.

In addition to these projects, as discussed in our 2023 Hosting Capacity Program Report, we have made changes to our methodology that improve the tool's usefulness for identifying interconnection points on the distribution system and places where upgrades to support DER development are needed. These improvements include adding the TPS Capacity Utilization and adding a feeder update criterion. The TPS Capacity Utilization accounts for the remaining capacity on a feeder based on the TPS and will reduce instances where the HCA map shows more capacity than is otherwise available. The updated feeder criterion will cause feeders to be updated when their normal rated capacity has been modified. Both changes, and the other changes discussed in our 2023 HCA filing, will increase the accuracy of the HCA and help engineers more accurately identify where there is room on the system and where upgrades are needed.

3. HCA in Relation to Other Processes

HCA 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 respond more efficiently 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 as amended in IEEE-1547a-2020, 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).

In compliance with Order Point 7 from the Commission's July 31, 2020, Order in our 2019 HCA Report proceeding in Docket No. E002/M-19-685, we examined the use cases, methodology and presentation of data associated with a "Load-HCA". This analysis could be insightful for where EV chargers, battery installations, or other forms of beneficial electrification may be able to be accommodated on the primary system. However, we note that the load analysis is only applicable to the charging capabilities of EVs and batteries and does not include analysis surrounding discharging load-based DERs.

It is also important to note that the analysis of loads on the distribution system is complex. While a specific location may be able to support a given amount of load, the individual characteristics (motor starts, charging ramp rates, power factor, etc.) of the load would require additional analysis prior to interconnection to the grid.

The Commission's November 9, 2021 Order in Docket No. E002/M-20-812 required the Company to produce a Load-HCA by November 1, 2022. To this end, we produced the initial set of results and included them with our 2022 Hosting Capacity Program Report. We aligned the two analyses where possible, including using the same models used in the Gen-HCA and the use of DRIVE. As with the Gen-HCA, the Load-HCA provides only preliminary information regarding the available hosting capacity of a feeder circuit. Utilizing the suite of interconnection tools and resources available to developers is necessary for determining if interconnection is possible at a specific location. The Load-HCA results were provided at a summary level for each feeder circuit included in the Gen-HCA in the form of a tabular report in 2022, and have again been provided in our 2023 report. However, as previously stated in this filing – and in our 2023 Hosting Capacity Program Report – the Company does not plan to continue these updates.

The tabular report showing the summary level results for each feeder is enough for interested parties to pursue load-based interconnections such as EV chargers, grid-scale batteries, or other beneficial electrification projects. Parties can use the Gen-HCA heat map to identify the feeder circuit near their proposed interconnection and then reference the available hosting capacity of the feeder circuit to inform their decision to proceed in the interconnection process.

We recognize that the primary benefit to the Gen-HCA heat map is to allow users to identify sites that are most likely to allow interconnection without having to upgrade infrastructure. This is largely driven by the fact that developers must bear the costs of upgrades for those types of interconnections. Infrastructure upgrades are often required when interconnecting new load to the system as well, however many customers are not required to pay for those upgrades (or pay significantly less than the actual cost) due to existing tariffs surrounding revenue justification; where the expected revenue from the additional load on the system is deducted from the upgrade costs charged to the interconnecting customer. We believe that the revenue justification for interconnecting load reduces the need to see if capacity deficiencies exist on a specific part of the feeder circuit, as the solutions to these limitations are generally cheaper than those at the substation level.

Additionally, we believe that providing a Load-HCA heat map would present several security issues which must be addressed. The Load-HCA results, when provided at a granular, sub-feeder level, are more indicative of actual loading on the system and can highlight system vulnerabilities. We further refer this topic to the ongoing Docket No. E999/CI-20-800.

4. HCA Investments

As previously mentioned, Company is currently working on the Foundational Improvements and Modeling Software Review as was laid out in our 2022 Hosting Capacity Program Report.[7] These Foundational Improvements will allow for a more automated feeder modeling process, which is essential for providing monthly updates, as well as more reliable results for further integration with the MN DIP. The Foundational Improvements will be implemented simultaneously in our Minnesota and Colorado service territories. Once the Foundational Improvements have been implemented, they will be available Company-wide. These improvements include developing a feeder model database, utilizing the Common Information Model (CIM) extracts of GIS data that are used for ADMS (closing the gap between processes), and further data enhancements and automation. The Foundational Improvements have an estimated cost of $2,895,000 (with 50 percent contingency) and will provide an estimated savings of 1,431 hours and $136,000 in labor for performing a full HCA of all distribution feeders. The Foundational Improvements are expected to complete in 2024.

As previously mentioned, the Commission's September 2023 Order directed the Company to pursue the implementation of the Monthly Updates use case. Following the implementation of the Foundational Improvements and vetting the new process, we plan to move to implement Monthly Updates as early as Q1 2025. Additionally, we have completed the modeling software request for proposals (RFP) that we sought in

[7] Docket No. E002/M-22-574.

mid-2023. Per Order Point 5 from the Commission's September 15, 2023, Order,[8] the Company provided details about this RFP in our most recent TCR Rider petition filed October 31, 2023. More information can be found in our 2023 Hosting Capacity Program Report.

B. 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 review screens in the MN DIP process.

The now-quarterly HCA available on our website may be useful as a step to assist developers in choosing sites and help others assess whether areas are constrained. In accordance with E002/M-22-574 Order Point 3 from the Commission's September 15, 2023 Order, we are proceeding with our planned implementation of the Monthly Updates use case for hosting capacity. Further integration between the Hosting Capacity Program and the MN DIP would occur with the FTSRS use case that the Commission is still reviewing, and for which we provide a further cost-benefit analysis in conjunction with our 2023 Hosting Capacity Program Report.

In addition, the Company provides a monthly Public DER Queue on our interconnection website. The public queue, a requirement of the MN DIP, provides a look at how many projects are being reviewed at any given feeder and, in the case of community solar gardens (CSGs), indicates whether or not upgrades are required for DER to interconnect. The Public DER Queue in conjunction with the Hosting Capacity Site provides interested parties with an idea of what interconnection may look like in any given area.

Figure E-11 below shows how the different components of our interconnection process currently work. Interconnection screenings and studies require in-depth analysis by engineers to help assess whether a project can be connected to the distribution system reliably and safely. Hosting capacity and pre-application data provide information to developers that can be used 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.

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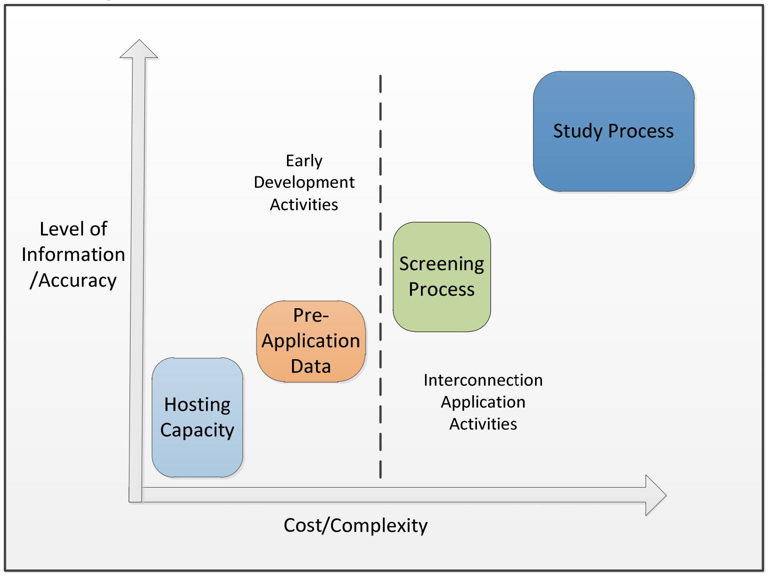
[8] *Id.*

Figure E - 11: Interconnection Processes



IDP Requirement 3.B.2 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 can proceed without further analysis being needed to study the potential for grid impacts. Each application's site and electrical characteristics are compared with feeder primary, feeder secondary, and/or substation data (i.e., DML, thermal capacity, aggregate DER) to determine whether a project can be expedited or should receive further analysis on voltage, thermal, or protection impacts.

Any initial review screen(s) that fail generally lead to analysis for the specific impact (i.e., voltage constraints, feeder loading). 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. The initial review screens use system data and load characteristics available through several of the Company's systems. We use our GIS to determine if the interconnection is within the Company's service area and site-specific details for secondary-connected DER. The aggregate amount of active and in-queue generation is collected from the DER interconnection applications in our Salesforce system, which has a connection to GIS to automatically update the feeder to which the premise is connected. Feeder maps or GIS can be used to determine the presence of a voltage regulator, which is a relevant factor in one screen. We retrieve peak load information via Supervisory Control and Data Acquisition (SCADA) telemetry and reported via LoadSEER, which we also use for system planning. Fault current can be retrieved by the Outage Management System (OMS) or a spreadsheet analysis tool.

C. 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 CSGs, 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 MN DIP as approved by the Minnesota Public Utilities Commission (Docket No. E999/CI-16-521). This process requires the Company to track DER installation costs for all DER customers. We began collecting this data in 2019. We do not have data prior to this time. However, we have calculated costs at a substation and distribution level for all CSGs (Docket No. E002/M-13-867) and can report on the DER costs for CSGs projects as shown in bills sent in a calendar year. In 2022, the Company billed CSG projects $3.1 million in substation costs and $8.3 million in distribution costs for an approximate total of $11.5 million. For onsite solar, projects typically move directly into a Facilities Study under MN DIP 3.2.2.2 and 3.4.5.2, and therefore do not receive a detailed engineering cost. In 2022, there were 38 projects that fell into this category over 20 kW. The cost of these upgrades averages approximately $7,500 each.

In addition to this, we separately charge an engineering study fee for all DER interconnections based on the requirements of MN DIP. There are several categories of fees defined in the MN DIP including a pre-application report, review screens and engineering analysis. In 2022, these fees totaled $1,980,000. The breakdown of this total consists of fees for Engineering Process ($465,100), Facility Study ($744,100), System Impact Study ($630,100), Supplemental Review ($104,700), and Pre-Application fees ($36,000). Administrative fees are only collected for CSGs. 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.[9]

We provide further details regarding our other programs and the compliance filings completed yearly below. Additionally, we acknowledge that these programs were adjusted by 2023 Legislation in H.F. 2310. Final changes are pending at the Commission in their respective dockets.

Solar*Rewards Community – Docket No. E002/M-13-867

- Annual Report filed by April 1 every year (2022 Annual Report filed on March 31, 2023).

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[9] *See*, for example, Docket No. E999/PR-23-10, available at this link: https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={A0E0B487-0000-C917-9986-F4D6E808C8DD}&documentTitle=20234-195095-02.

- *Deposits*: In 2022, we received $8 million for new projects into our deposit accounts, including any deposit that the Company was holding that the Garden Operator moved to escrow. These deposits will be refunded with interest back to the Garden Operator upon a fully executed interconnection application or if the application is withdrawn.
- *Application Fees*: The Company collected a total of $51,600 in application fees.
- *Participation Fees*: Annual participation fees were $451,000.
- *Metering Fees:* The Company administers metering charges as defined in our Section 10 Tariff based on the applicant's desire for upfront or ancillary meeting charges.

Solar*Rewards – Docket No. E002/M-13-1015

- Annual Report filed by June 1 every year (2022 Annual Report filed on June 1, 2023).
- Engineering Fees are no longer administered for Solar*Rewards projects, applicants pay all applicable fees as defined in the MN DIP.
- *Metering Fees*: The Company administers metering charges as defined in our Section 10 Tariff based on the applicant's desire for upfront or ancillary meeting charges.

IV. 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.

A. Current and In-Queue DER Volumes

In Tables E-2 and E-3 below, we present the DER volumes on our Minnesota distribution system in compliance with IDP Requirement Nos. 3.A.17, 3.A.18, 3.A.19, 3.A.20, 3.A.23, 3.A.24, and 3.A.25.

Table E - 2: Distribution-Connected Distributed Energy Resources – State of Minnesota

(As of March 2023 – as provided in Docket No. E999/PR-23-10)

	Completed Projects		Queued Projects	
	MW/DC	# of Projects	MW/DC	# of Projects
Small Scale Solar PV				
Rooftop Solar	162	10,283	93	3,939
RDF Projects	35	25	1	1
Wind	9	58	<1	5
Storage/Batteries[10]	<1	25	<1	48

	Completed Projects		Queued Projects	
	MW/AC	# of Projects	MW/AC	# of Projects
Large Scale Solar PV				
Community Solar	864	463	304	330
Grid Scale (Aurora)	100	13	0	0

Table E - 3: Minnesota Distributed Energy Resources – Demand Side Management and EVs

	Completed Projects		Queued Projects	
	Gen. MW	# of Projects	Gen. MW	# of Projects
Energy Efficiency*	2,433	N/A	N/A	N/A
Demand Response	820	421,000	N/A	N/A
Electric Vehicles	N/A	34,532[11]	N/A	N/A

*Cumulative since 2005.

For reference, below are the IDP Requirements fulfilled in Tables E-2 and E-3 above:

IDP Requirement 3.A.17 requires the following:

[10] 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.
[11] We do not have information that ties our customer accounts to EV users outside of our customer programs. We estimate that there are approximately 34,532 EVs on the road in our service territory. *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 2022, these details were provided in Docket No. E999/PR-23-10. 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) and Solar*Rewards Annual Report (Docket No. E002/M-13-1015), and Solar Energy Standard Annual Report (most recently in Docket No. E999/PR-23-12). We note that each of these reporting dockets have different reporting requirements and timing and therefore may differ slightly. Additionally, the Company provides quarterly reports regarding interconnection under the MN DIP in Docket No. E999/CI-16-521.

For purposes of this IDP requirement, we provide the information in Tables E-2 and E-3 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 2022, these details were provided in Docket No. E999/PR-23-10. 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), Solar Energy Standard Compliance (Docket No. E999/PR-23-12), and the Quarterly Compliance Reporting under MN DIP (Docket No. E999/CI-16-521) to name a few.

For purposes of this IDP requirement, we provide the information in Tables E-2 and E-3.

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 as well as in our Quarterly Compliance Filings in Docket No. E999/CI-16-521. In 2023, with data as of end-of-year 2022, this information was provided in Docket No. E999/PR-23-10. 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 and operation 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 E-2 and E-3 above.

IDP Requirement 3.A.23 requires the following:

> *Number of units and MW/MWh ratings of battery storage.*

See Table E-2 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 as well as in our Quarterly Compliance Filings in Docket No. E999/CI-16-521. In 2023, with data as of end-of-year 2022, this information was provided in Docket No. E999/PR-23-10.

IDP Requirement 3.A.24 requires the following:

> *MWh saving and peak demand reductions from EE program spending in previous year.*

In 2022, the Company's EE programs saved 647,797 MWh including a demand reduction of 183,922 kW.[12] Table E-2 above provides the cumulative savings since 2005. In addition, we note an overlap between the Energy Efficiency and Demand

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[12] See 2022 Status Report and Associated Compliance Filings, Docket No. E,G002/CIP-20-473, March 31, 2023.

Response lines. Minn. Statute § 216B.241 defines energy efficiency as a reduction in energy for which certain demand response products qualify; therefore, we have included the total cumulative savings for our portfolio in Table E-3.

IDP Requirement 3.A.25 requires the following:

Amount of controllable demand (in both MW and as a percentage of system peak).

In 2022, the Company's controllable demand in Minnesota was 820 MW which is 12 percent of the system load. See Table E-3 above.

B. Electric Vehicles and Charging Stations in Service Area

IDP Requirement 3.A.21 requires the following:

*Total n*umber of electric vehicles in service territory, by type where possible (e.g. light duty, transit, medium duty, heavy duty)

Customers are not required to inform the Company when they purchase an EV, and we do not maintain this information outside of our approved EV customer program participation. Therefore, we estimate that there are 34,532 registered EVs in our service area as of June 2023.[13] Compared to the Company's estimates in our 2021 TEP Filing, there has been an increase from 14,233 to 34,532, demonstrating a growth rate of roughly 140 percent within the Company's service area. Table E-4 below shows the number of EVs broken down by vehicle type.

Table E - 4: Registered EVs in Service Territory by Vehicle Type

Vehicle-type	Estimated Number
Light-duty	34,512
Medium-duty	9
Heavy-duty	11
Total	**34,532**

Battery electric vehicles (BEVs) now make up most of the light-duty EVs in our service territory, accounting for approximately 23,800 of all vehicles. The remaining portion (~10,800) are plug-in hybrid electric vehicles (PHEVs). The Tesla Model 3 is the most common EV in operation in the Company's service territory, followed by the Tesla Model Y and Nissan Leaf. Electric sedans are still the most prevalent EVs in

[13] Based on internal Company analysis.

use but as auto manufacturers introduce new EVs into the market, there continues to be growth in the number of electric cross-over utility vehicles, sport utility vehicles, and trucks, like the Chevrolet Bolt EUV and the Ford F-150 Lightning.

IDP Requirement 3.A.22 requires the following:

> *Total* number and capacity of public access electric vehicle charging stations, broken out by:
> a. *Number and capacity of known public access Level 2 Charging Stations*
> b. *Number and capacity of Level 2 Charging Stations enrolled in a utility EV program broken out by program*
> c. *Number and capacity of known public access direct current fast charging (DCFC) stations*
> d. *Number and capacity of DCFC installed through a utility EV program, broken out by program*
> e. *All other known EV charging stations (by type, ex DCFC, Level 2)*

According to DOE's Alternative Fuels Data Center, there are approximately 512 public EV charging station locations in Minnesota, with 1,273 charging ports.[14] We estimate that there are 446 Level 2 charging stations in our service territory, representing about 1,031 charging ports and a total estimated capacity of around 7.4 MW. We also estimate that there are about 57 DCFC stations in our service territory, representing 214 charging ports and an estimated total capacity of 42.1 MW. Table E-5 below provides a breakdown of publicly accessible charging stations by type and respective enrollment in a utility program.

Table E - 5: Publicly Accessible Charging Stations

	L2 Charging Ports[15]	**L2 Ports in a Utility Program[16]**	**DCFC Ports[17]**	**DCFC Ports in a Utility Program[18]**
Number of Ports	1,031	218	214	16
Capacity (MW)	7.6	1.6	42.1	1.4

[14] *See* public online portal at https://afdc.energy.gov/stations/states (Accessed August 26, 2023).
[15] Data as of August 26, 2023.
[16] Participation data as of 2023 Annual EV Reporting.
[17] Data as of August 26, 2023.
[18] Participation data as of 2023 Annual EV Reporting.

C. 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. 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 and as well as in our Quarterly Compliance Filings in Docket No. E999/CI-16-521. In 2023, with data as of end-of-year 2022, this information was provided in Docket No. E002/PR-23-10. We also publish a Public DER Queue, which can be used to track DER installations and applications by feeder, DER type, system size and status. This information is published monthly in the Interconnection Developer Resources portion of our website at https://mn.my.xcelenergy.com/s/renewable/developers/interconnection.

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.*

The Company has made significant improvements in the forecasting process using LoadSEER in the past two years. As described in Appendix A1, we have been working collaboratively with Integral Analytics, the LoadSEER vendor, to introduce speculative adoption points into the LoadSEER model to tune the Spatial Allocation. These points represent specific locations on the distribution system where there is a higher likelihood of adoption of the specific technology or load type being studied. For example, speculative points can be added where undeveloped land of a specific minimum acreage is located within our service territory to represent areas that could be targeted by developers to install CSGs or other front of the meter solar. We then applied this methodology to the state-wide DER adoption forecast scenarios in LoadSEER for the purposes of creating location-specific load forecast scenarios. The results of the solar portions of those location-specific allocations show the geographic areas of the distribution system that are expected to have higher and lower levels of solar adoption. See Appendix A1 for further detail.

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 and may also depend on the particular issue or scenario being discussed. We believe one way to define high

DER penetration is when the connected DER output exceeds feeder load, resulting in reverse power flow. Feeders that exceed the DML and result in reverse power flow are listed in the Public DER Queue. When backward flow occurs, mitigations become necessary.[19] 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 configuration, and the feeder voltage and other attributes.

Another way to define high DER penetration would be setting the high threshold where existing capacity on a particular feeder can no longer be transferred to an adjacent feeder during abnormal conditions due to the high level of DER. Yet another way to define high DER penetration would be to specify the high level at the planning limits for a feeder or substation – i.e., the TPS, defined as 80 percent of device continuous rating plus the DML.

V. 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.*

A. DER Treatment in the Distribution Planning Load Forecast

We do not currently factor the impact of DER generation 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 the impacts of energy efficiency and load management.

However, our newly implemented LoadSEER forecasting tool allows us to simulate the impact that our corporate load and DER forecasts might have on the distribution system. This will allow us to better understand how loading on the distribution system might change into the future with and without the impact of each type of DER. We note however that LoadSEER cannot identify any voltage constraints associated with DER, so there are limitations. LoadSEER primarily provides insight into the impact

[19] Mitigations may be required for other conditions below this level, such as potential voltage issues or line capacity.

that forecasted DER growth might have on system loading, and does not consider whether DER can actually be hosted at the forecasted locations; that level of analysis still requires detailed modeling using a load flow tool such as Synergi Electric. While we currently plan the distribution system based on native loading (the system loading without the load-masking impact of DER generation), understanding both net loading and native loading will help us to anticipate the range of possible loads that may manifest on the system in various conditions. This probabilistic assessment will help better inform distribution planning when conducting risk analysis and developing project plans. It is also the basis for the initial Planned Net Loading (PNL) methodology for including the load-reducing impact of distributed generation in the distribution planning process, which is discussed further in Appendix A1.

LoadSEER allows us to integrate forecasts for DER into the distribution system planning forecast to help our planners understand the impacts that continued DER growth might have on distribution system loading in the future. We do note that the impact of DER is very locational, meaning that local conditions such as distance from the feeder, size of the conductor, feeder loading, amount of other DER present, and the size of projects will all influence how well DER can be accommodated without additional impacts. The Company cannot fully predict where developers will place solar gardens or other larger DER projects, and therefore more granular forecasts are only able to provide an indication of where DER are likely to be interconnected based on available land and adoption propensity. LoadSEER can provide directional insights, but further studies are needed during the interconnection process to fully understand whether DER can be connected in a certain location.

B. 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. 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 a 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 grid modernization 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 DER levels, interconnection reviews become increasingly complex and, without changes, overly burdensome and costly. The current spreadsheet analysis tool has been improved with basic automation to populate information from customer applications and streamline some reviews depending on the type of interconnection. This automation reduced review timelines and increased bandwidth for other process improvements. More advanced automation, processes, and tools will be needed to make any significant improvement to reviews going forward. The capability to access on demand and interval voltage data from AMI will assist in the voltage analysis of the review process. However, AMI is not yet fully deployed, so there has been limited opportunity to utilize and gain experience using that capability. For future improvements, the service voltage data from AMI could be used with the primary voltage, load, and generation production data, from ADMS or other tools, to estimate the impedance of the secondary system which, depending on the quality of the data, provides the capability to perform more advanced screening of DER interconnections to secondary systems and could help validate secondary equipment data in GIS. The use of ADMS in interconnection reviews continues to be explored. Experience with the tool continues to grow, and strengths and weaknesses are being identified compared to current modeling software used for interconnection studies. We plan to continue to refine the process and results from ADMS and assess the time savings and accuracy with the other tools and processes.

We note that interconnection queue reform is underway as a result of new legislation. We discuss these efforts in Section V.D below.

Hosting Capacity Analysis. HCA serves as an early indicator of available hosting capacity on the distribution system which can help guide customers' or developers' decision on whether to pursue an interconnection. We continue to improve the HCA through recent feature additions such as the service territory map overlay available for our heat map, which will allow users to see if their proposed location is within Xcel Energy's service territory or not. A full list of improvements can be found in our 2023 Hosting Capacity Program Report. In that report, we also provide an update on our progress with the Modeling Software RFP as well as an updated roadmap to Foundational Improvements and Monthly Updates. These updates will provide fresher data and increase the ability of the HCA to inform the interconnection process. They are also necessary for the potential implementation of the FTSRS use case, which is still under Commission consideration.

Planning Tools. As discussed in this IDP, our advanced planning tool, LoadSEER, allows 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.

LoadSEER provides us with the ability to disaggregate DER adoption forecasts into the distribution load forecast, and conduct scenario analysis against those forecasts. Our baseline DER adoption forecasts are 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 also makes it easier to develop DER scenario analysis over time that can be applied at this more granular level, and allows us to gain insight around different adoption scenarios within the tool. The DER adoption scenarios studied for this IDP are described in further detail in Appendix A1.

In providing distribution planning with an hourly-level load forecast that includes the impact of forecasted DER adoption, distribution planning has the data that is necessary to adequately perform risk analysis based on equipment thermal limits and inform the capital budgeting process. The LoadSEER assessment of DER impacts is probabilistic in nature and thus unable to replace the need for the interconnection review process due to the requirement for a deterministic approach to identify the cost causer of a system impact from DER interconnection. However, it works in conjunction with HCA to give Distribution Planning a better understanding of where on the distribution system, both at present and in the future, the ability to accommodate additional DER is constrained, and what it may cost to alleviate those constraints. This cost estimation is described in further detail in Appendix I.

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 and its advanced applications are well situated to fill much of that need in the near-term. We note that we expect a DERMS will become essential, as will a further integration of grid operating technologies. As discussed earlier in this Appendix, as we research and prepare for flexible interconnection solutions, a DERMS will be critical to enable a flexible interconnection option for customers, as well as the need for quality monitoring and control equipment while maintaining safety and reliability. The implementation of

FERC Order 2222 also highlights the need for both a DERMS and the monitoring of and communication to and from those DERs participating in the wholesale market. Along with the monitoring and control benefits of ADMS, an additional benefit of improved asset data will help with the integration of DER. We have previously discussed the necessity for asset data improvements as part of our initial implementation of an ADMS, and note that, in addition to supporting our core distribution operations, these data improvements also improve the accuracy and efficiency of our interconnection review modeling and planning analysis efforts.

We also note the necessity to continue deploying SCADA to the substations that are not so equipped. We describe our SCADA deployment plans in further detail in Appendix A4. AMI, along with the enabling FAN, are tools that are also essential to enabling higher DER levels. AMI will provide insights into DER presence, transformer loading, and voltage levels, something that previously was not possible. And the initial grid-facing Distributed Intelligence capabilities of Locational Awareness and EV Detection will provide deeper insights into both our own secondary system and the operation of EVs. (See *Appendix J: Distributed Intelligence* for further discussion.) We plan to expand upon these initial capabilities in the future and believe that our meter positions us well to support DERs through the future use of WiFi and 2030.5 capabilities.

C. System Impacts that May Arise from Increased DER Adoption

DER has the potential to impact the system both positively and negatively. We address potential system benefits and negative impacts below.

1. Potential System Benefits

Potential benefits of DER 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 not 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.

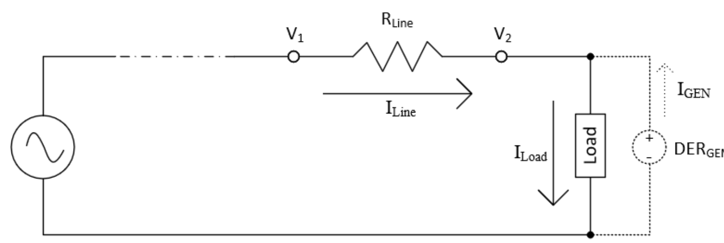
- *Manage local capacity constraints.* Typically, PV does not have a perfect coincidence with demand and is a variable source of power, but it may be able to offset load in the earlier hours of the peak. However, left unmanaged, PV can create a new capacity constraint due to high solar production during low-load periods. Energy storage can help modify this pattern by charging and discharging during certain times of the day to shift the generation output and increase system utilization. Each feeder is somewhat unique – and we study how DER can provide benefits as part of our NWA analysis process. Additionally, we further assess the value that DER provides to reducing overload risks during distribution system peak load conditions in our initial PNL methodology described in Appendix A1.
- *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.
- *Source of renewable energy.* Any interconnected PV or wind generation adds to the percent of delivered energy that comes from carbon-free or renewable energy resources.

We will continue to study these benefits as we conduct our NWA analysis processes and work to incorporate DER impacts into the distribution planning process. As DER costs come down and technology software platforms mature, we expect the opportunities in this area to continue to grow.

2. *Potential Negative Impacts of DER*

Table E-6 summarizes some of the potential negative impacts of higher penetration of distributed generation. Note that there may be other impacts from distributed generation under unique situations. Impacts to the transmission system are also not covered in the summary below.

Table E - 6: Potential Distribution System Impacts from Distributed Generation

Distribution Impact	Impact Description	Cause
Over-Voltage	Steady-state voltage exceeds the American National Standards Institute (ANSI) C84.1 Range A for Service Voltage of 60HZ AC systems >100V[20]. The Range A Maximum Utilization and Service Voltages on a 120V base is 126V (1.05 per unit) and is applicable to sustained voltage levels and not to momentary voltage excursions, such as from motor starting currents. ANSI is the industry standard for utility voltage operating range.	In the line segments where generation exceeds the load and reverse power flow is present, voltage rise is possible. At a high level, the voltage change calculation is ($V_2 = V_1 - I*R$). However, the current injected by the DER, **in excess of load**, travels in the opposite direction and mathematically is represented as a negative number. This makes the equation ($V_2 = V_1 - (-I)*R = V_1 + I*R$). From this equation we can see how the power injected by the DER results in a higher voltage. At a more granular level, the voltage change depends both on the power injected by the DER and the impedance it flows through between the site and the load it serves. This impact is usually largest during seasons and times of low load and peak generation, on conductors with high impedances, and locations with large distances to the substation. 
Voltage Fluctuation	A change or multiple changes in voltage that result in noticeable change in illumination of lights significant enough to cause a visible irritation.[21]	A change in power flow from individual or aggregate increases or decreases in generation or load, which results in a change in current through line segments and a change in voltage. Such events include switching operations, responses to market services, and automatic control of or protection device operation that cause DER or large loads to cease operation. This impact is usually largest during seasons and times of high load and peak generation, where generation is providing voltage support, or when storage or EV devices transition from full charging to full discharging.
Voltage Regulator Operations	A change or multiple changes in voltage that result in an increased number of operations of a voltage regulator or load tap changer.	Voltage fluctuations from the passage of clouds or fluctuations in wind speed, responses to market services, and automatic control of DER, causing the voltage at a regulating device to be out of band. Multiple voltage fluctuations per day can substantially increase the number of operations increasing both voltage fluctuation seen on the feeder and the wear-and-tear on the regulating device.

[20] Electric Power Systems and Equipment – Voltage Ratings (60 Hertz), ANSI C84.1-2011.
[21] IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems, IEEE Std 1453-2015.

Distribution Impact	Impact Description	Cause
Thermal Loading of Utility Equipment	The current (Amps) or power flow (kVA) through a specific conductor or device exceeds its continuous/normal rating which results in a reduction of asset health and potential failure increasing the risk to reliability and public safety.	All equipment connected to the electric power system has a thermal limit. This limit can be provided in a variety of different ways, including ampacity, apparent power capacity in Volt-Amperes (kVA), or degrees C rise above ambient. This limit is impacted by a number of factors including but not limited to the standards, initial design, power quality, altitude, burial depth, expected air flow, cool-down time, and asset health. A violation occurs anytime the power flowing (in either the forward or reverse direction) through the device exceeds its limit. Standard transformer cores are designed with an assumed electromagnetic field (EMF) in one direction, from the high side to the low side. Reversing the EMF direction increases the core losses in the transformer, which leads to additional heating and a reduction in asset health.[22] Devices most commonly at risk include but are not limited to; conductors, cables, transformers, voltage regulators, fuses, reclosers, switches, and switch cabinets.
Desensitizing Protective Device Relays	The fault current (Amps) contribution from DER reduces the fault current that flows through the upstream protective device. This condition can be enough to result in a failure of one or more protective devices to detect a fault condition, which is a risk to reliability and public safety.	A fault occurs when an energized conductor or device comes into contact with other phases, systems, or ground. DER, including non-exporting generation and storage systems, supply current towards that fault location. Since power travels the path of least resistance, the amount of fault current flowing through the upstream device is reduced. The reduction in fault current depends on the size and location of generators as well as the impedance between each source and the fault location. This impact is usually largest on long feeders with high DER penetration.
Additional Element Fault Current	Increased fault current (Amps) from the DER or upgrades required to accommodate the interconnection of DER exceeds the interrupt capability of the protective device and can result in device failure and increased risk to reliability and public safety.	Common upgrades required to interconnect DER, such as larger conductors/cables and transformers, increase fault current to locations downstream of the upgrades. DER, including non-exporting generation and storage systems, also supply additional current towards the fault location. This risk is most common for hydraulic recloser or trip saver with low interrupt capabilities. Operating these devices to interrupt current above the interrupt rating significantly increases the probability of catastrophic failure and reliability and public safety concerns.

[22] Cigre Science & Engineering, ABB, Upadhyay, P., Kern, J., Vadlamani, V. (October 2020). Distributed Energy Resources (DERs): Impact of Reverse Power Flow on Transformers.

Distribution Impact	Impact Description	Cause
Coordination of Protective Devices	Fault current contributed from the DER impacts the coordination of time overcurrent protective schemes increasing the risk of miss-operation of protective devices which reduces reliability and complicates troubleshooting and patrols to locate the fault.	The fault current provided by DER can increase the fault current through series protective devices. The additional fault current can reduce the Coordination Time Interval (CTI) between devices, increasing the risk of miscoordination and mis-operation of devices.
Reverse Power Flow	Changes in power flow direction through devices that can affect the control, operation, or protective settings resulting in regulator runaway or nuisance tripping.	Without generation, power flow from the source (substation) to the load (feeder), referred to as the "forward" direction. Reverse power flow occurs when generation in a given area exceeds the load downstream. This excess power flows from the generator in the "reverse" direction towards the substation. The reverse power flow can cause voltage regulator controls to runaway and fully boost or fully buck resulting in voltage issues. Protective devices with low trip settings can see reverse current greater than its trip rating causing the device to miss-operate. Network systems that utilize network protectors will trip with any reverse power flow.
Unintentional Islanding	When DER keeps a portion of the utility grid energized after removal of the utility source and is not designed to do so.	If the amount of generation closely matches the amount of load on a portion of the system when it is disconnected and isolated from the utility source (substation/grid), then the system is operating within a non-detection zone (NDZ) such that the anti-islanding functions of the DER may not sense the island[23]. This risk of unintentional islanding is increased if the island includes grid forming inverters, load following schemes, or a rotating mass, such as a synchronous generator or motor. Because the island is unintentional, it does not have the ability to synch with the bulk electric system (BES). Attempting to reconnect an island that is out of sync with the BES can result in significant utility and customer equipment damage.

[23] Electric Power Research Institute, Key, T., Huque, A. (2021). Taxonomy for Inverter Island Detection Methods.

Distribution Impact	Impact Description	Cause
Transient Over-Voltage (TOV)	An overvoltage of significant magnitude for relatively short durations, which could result in failure of surge arrestors, transformer bushings, insulators, and/or customer equipment. Magnitudes of TOV can be on the scale of 150% to 300% of the nominal or regulated voltage. Duration of TOV could be as short as a few cycles to as long as 2 seconds.[24]	The presence of DER specifically increases concerns of Ground fault over-voltage (GFOV) and load rejection over-voltage (LROV). In an effectively grounded system, the neutral reference in a voltage phasor diagram has little to no shift from center when there is a current unbalance, such as during a SLG fault.[25] In a system that is not effectively grounded, the neutral reference shifts away from center when there is a current unbalance. The neutral reference shifts towards the faulted phase and causes the line-to-neutral voltage (VLN) in the un-faulted phases to grow to as large as the line-to-line voltage (VLL). The strongest ground source in the grounded wye distribution system is at the substation transformer. During SLG faults, a protective device trips, removing the substation ground source from the line downstream from the protective device. If the DER is downstream of the isolation point, this creates an island for a short duration before DER detects the island and trips. During this time, the island may no longer be effectively grounded and the SLG fault may cause GFOV. LROV can occur during any island scenario. When the island is disconnected from the grid, the excess generation has no outlet and results in an increase to system voltage directly correlated to the amount of excess generation. While LROV is generally smaller in magnitude than GFOV, it is possible for them to occur at the same time resulting in greater voltages on the system.
Current and Voltage Unbalance	Unbalanced currents means more current is flowing through one phase than the other two. Unbalanced currents due to the installation of single-phase DER causes unbalanced voltages. These system imbalances can cause miss-operation of protective devices, unexpected overloads, excessive heating, and damage to customer 3-phase equipment.	The installation of single-phase DER can cause system imbalances by offsetting load, reducing the current flowing on a single phase, or in extreme cases reversing power flow on a single phase. This most commonly occurs with three-phase customers interconnecting single-phase DER and in rural areas where only one phase is available for interconnection.

[24] Assumes all DER trip within 2 seconds in compliance with IEEE 1547. Note: IEEE 1547-2018 Subclause 7.4 requires DER to limit their cumulative duration to voltages exceeding 138% to one cycle.
[25] Voltage Disturbance (2018). Neutral Inversion and Neutral Displacement. https://voltage-disturbance.com/power-engineering/neutral-inversion-and-neutral-displacement/.

Distribution Impact	Impact Description	Cause
Load Masking	Generation from DER reduces the amount of power fed from the substation. This effectively hides a portion of load being served on the feeder from metering equipment and can impact planning or operational functions, such as load transfers, which could result in equipment overloads or voltage issues.	Distributed generation can reduce demand and hide reliability risks on a feeder if the planner or operator does not account for the generation on the feeder. This can lead to switching error where more load or generation is transferred than expected during peak times. This impact or risk is highest on feeders with a high aggregation of small DER, or large DER without real-time telemetry.
Arc Flash Energy	An increase in the incident energy, which could impact the ability to perform hot-line work.	Changes in fault current through protective devices caused by DER may increase available fault current or clearing times for protective devices, which will increase the incident energy of an arc flash.
Harmonics	Distortions in voltage and current waveforms that could cause equipment heating, noise, overloads, or shortened equipment life.	Harmonic current distortions can be injected from the DER by power electronic based switching devices, such as inverters, and can impact the harmonic voltage distortion on the utility system. The type and severity of the harmonic contributions depend on the inverter technology, harmonic filters, and configuration of the interconnection.

Electric Vehicle Impacts – EV charging forecasts continue to show rising growth in the coming years as shown in Appendix A1. EV charging impacts the grid predominately at the service transformer and feeder system levels, where chargers can increase the load on a transformer and/or feeder and change the load shape on that system equipment.

EV charging impacts tend to emerge in three distinctive categories based on charging use case: (1) Residential charging, (2) Fleet charging, and (3) Public, Commercial, and Workplace charging. Each use case has direct and distinct impacts to system load and load shape on a feeder. For instance, Residential charging impacts the grid at the service transformer level and consists of mostly Level 1 and Level 2 charging levels. Service transformers, which are typically heavily loaded due to the significant number of electric services they support, can be at risk of overload with the addition of Level 2 chargers at services served by these transformers. Fleet charging, involving Level 2 and 3 charging, generally impacts the grid at the feeder level. Fleet charging can often exceed 1 MW of capacity with some sites even exceeding 10 MW. As Class 6, 7, and 8 vehicles and buses continue to be produced and deployed in our service territory, Level 3 and Megawatt charging can be expected. And lastly, Public and Workplace charging typically impacts the grid at the feeder level and like fleet charging, consists of mostly Level 2 and 3 chargers. Public charging station sites typically range between 450 kilowatts (kW) to 1.5 MWs of connected charging capacity per site. As EV adoption progresses, the utilization of these charging stations will grow, realizing a higher average demand with utilization likely to occur during the day when transportation fuel is commonly needed.

Unmanaged EV charging load can potentially result in increased system load at various times throughout the day and night and lead to overloading risks on local distribution equipment, such as service transformers. Managed charging pilots and programs administered by utilities can help to mitigate this risk to the grid and yield potential benefits, by shifting EV charging to times of day that are outside of system peak. The Company currently offers a portfolio of Clean Transportation customer programs that aim to manage Residential, Fleet, and Public and Workplace EV charging through EV-specific Time-of-Use (TOU) rates and charging optimization incentives. Specifically, we have observed success in our Residential program portfolio where more than 90 percent of all EV charging takes place during off-peak system hours, demonstrating that customers respond to TOU rate price signals and other managed charging incentives. For more information about managed charging, our customer programs, and practices and technologies such as vehicle-to-grid (V2G), please see our 2023 Transportation Electrification Plan, included with this IDP as Appendix H.

Energy Efficiency and Demand Response – It is expected that demand response programs would be able to alleviate a portion of the NSP system peak loads. There is potential that the reduction of load resulting from energy efficiency and demand response programs could also negatively impact feeders with high amounts of distributed generation capacity. DER Interconnection System Impact Studies consider the net power flow of a circuit, calculated by the load (in kVA) minus the generation (kVA) where a positive net power flow indicates forward power flow from the source (substation) towards the load or customers and a negative net power flow indicates reverse power flow from the load towards the source. Prior to the interconnection of the DER, the interconnection is studied considering a specific amount of load on the circuit. If load decreases after the system impact study, the net reverse power flow caused by distributed generation would increase, which could result in new system impacts as described in Table E-6. This is one of the reasons why technical planning standards were applied to DER interconnections, to provide a safety margin in the event of a decrease in load on the feeder or transformer. However, that margin only reduces the risk of overloads, not over-voltage, thus system upgrades resulting from energy efficiency or demand response are possible unless a margin for voltage levels is added to the Company's practice. Flexible interconnection practices, as described below, could reduce this risk.

Distribution-Sized Energy Storage Systems – Energy storage systems are a valuable asset to grid reliability when they are deployed to do so; but today, most installations in our Minnesota service territory are driven by the customer's interest in having back-up power available. 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 operation and location of the energy storage systems. Long term, Company programs that better facilitate the use of energy storage to provide value to the grid should be considered. The Company started a Renewable Battery Connect program in Colorado, which provides incentives to customers for installing eligible battery equipment, charged 100 percent by renewable energy, in exchange for allowing the Company to dispatch the battery during periods of peak demand; see our November 1, 2023 Petition in Docket No. E002/M-23-459 for more information on our battery incentive program. Other possible use cases include charging batteries during times of high renewable generation, and other ways of reducing grid usage over the entire day. The ability for energy storage systems to provide wholesale market services through an aggregation is another possible method for customers to expand the capabilities of their energy storage systems in the future. Stacking the benefits of energy storage systems can improve their cost-effectiveness, however, adding multiple services to an energy storage system increases the complexity of the system and could potentially impact its availability to provide those services. For example, an energy storage system may no longer have the energy capacity (kWh) to provide back-up service for the outage duration it was originally designed for if the energy was recently discharged to provide other services. Therefore, larger storage installations may be required to provide additional services and fulfill the customers' design request, which impacts the cost-benefit analysis.

Similar to the PV interconnection review, customer-connected energy storage systems are 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.

Today, it appears customers choosing to install residential energy storage systems do so for back-up power, but these systems also have the potential to address local congestion issues at larger aggregate levels that could potentially defer an upgrade to distribution equipment, such as an NWA application.

See *Appendix B3: Existing and Potential New Grid Modernization Pilots* for further discussion of the Renewable Battery Connect program in Colorado and our plans for potential future pilots and programs regarding energy storage.

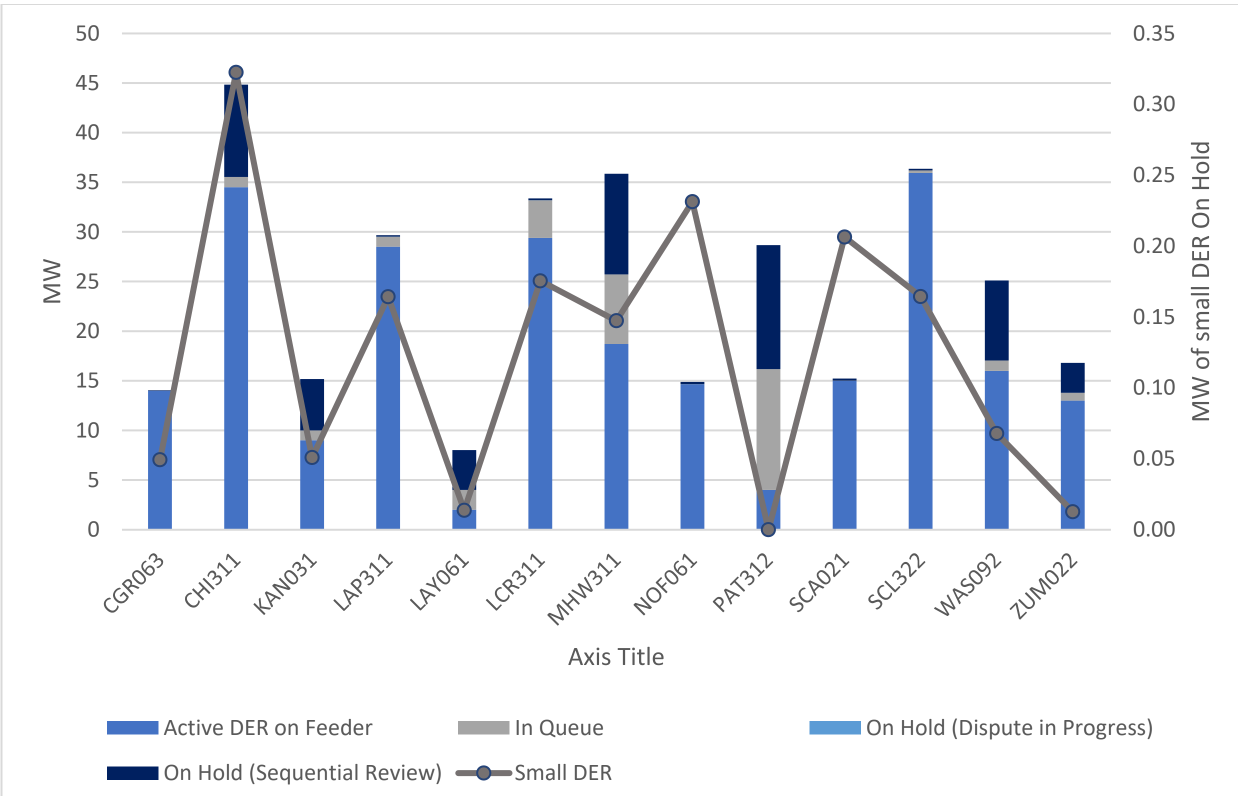
D. Potential Barriers to DER Integration

Minnesota has a cost-causation regulatory construct for DER, which requires the "cost causer" to pay 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 without causing impacts to the distribution system. In some cases, the developer or customer chooses not to pursue the modification and the project does not move forward due to costs. Therefore, system modifications costs are a barrier to DER integration. We highlight forecasted system upgrade costs for DER integration and discuss alternative cost allocation strategies in Appendix I.

Another barrier to DER integration occurs when a customer with a small DER system is 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 reconductoring a feeder, if they seek to install a DER system after other larger systems (e.g., CSGs) have done so on the same feeder. The cost-causation approach to addressing system upgrade costs for DER interconnections is simple and cost-effective in the short term when there is existing capacity available. However, as observed in recent years, when there is no more existing capacity available, the system upgrade costs to interconnect are typically too large for any one residential or smaller customer to pay.

Lengthy interconnection queues in highly congested areas where the conditions are ideal to site CSGs have been a consistent issue since the 2019 filing of the IDP. This congestion has led to several projects being on hold, either due to the time required for projects to be reviewed sequentially, because there is currently no capacity and significant upgrades, such as a new feeder, transformer, or substation, are required for interconnection, or because there is an open dispute that has a material issue with the rest of the projects in the queue. A parallel review process was established early on to allow DER projects 40 kW and below to proceed through the process in parallel with the large DER projects that required more detailed review and study if there was not a material issue. However, the number of large DER projects and material issues was still significant and the study time for these congested and constrained locations has been a barrier for developers and installers who are waiting for the results of those studies. Below is a summary of DER capacity projects on hold, based on our October queue report.

Figure E - 12: Capacity Constrained Feeders (over 5 projects on hold)



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 reconductoring or other changes to avoid adverse reliability impacts for the customers connected to that feeder. This could require additional investments that take time to plan, obtain permits, and build.

We have proposed several changes in Docket Nos. E999/CI-16-521 and E999/CI-01-1023 to address the barriers described above. The Commission's March 31, 2022 Order (1) expanded the Company's parallel review process to include projects of all sizes up until the system impact study phase where the study of the next project in queue is now initiated when the ahead-in-queue project begins the facilities study, instead of execution of the interconnection agreement; (2) allowed the Company to pilot mandatory group studies for capacity constrained feeders or substations with three or more applications greater than 40 kW; and (3) allowed the Company to use a cost-sharing mechanism for DER projects 40 kW and under, funded from a one-time fee by all applications of that size.

Since the March 31, 2022 Order, the total number of capacity constrained feeders decreased from 58 to 48 (as of June 1, 2023). Removal of a feeder from the capacity constrained list could be due to a combination of capacity upgrades, changes in load, and withdrawals from the queue. The total number of on-hold projects was not significantly impacted (decreased from 299 to 261), however 138 new projects applied to capacity constrained feeders since the Order.

To illustrate the impact of these changes, we provide examples of specific feeders. In March of 2022, there were 26 projects in the queue on one of the most congested feeders, CHI311, and as of October 1, 2023, there were 40 projects in that queue. In other words, despite the resources we provide to communicate the lack of capacity on these feeders, new projects are added to the queues as fast or faster than we can sequentially process them due to the number of large DER in the queue that require a full study.

Recent state-level efforts toward queue reform will likely help streamline the interconnection process for smaller, lower-impact distributed generators, and investigating other ways in which existing queue processes can be reformed to streamline interconnections would be appropriate. For example, Minnesota Session Laws 2023, Ch. 60, Art. 12, Sec. 75. requires the establishment of a queue prioritization process for smaller distributed generator interconnections less than 40 kW AC in size,[26] and the Minnesota Legislature has indicated a policy objective that DER projects up to 40 kW be reviewed and approved more quickly.[27] Some of the funding appropriated for the Distributed Energy Resources System Upgrade Program is required to be used to implement the small interconnection cost-sharing program ordered by the Commission in Docket No. E002/M-18-714.[28]

We are still hopeful that group/cluster studies can assist in decreasing queue times by studying multiple projects at once and to share upgrade costs among the cluster study

[26] This is the subject of the Commission's Notice of Comment Period issued on September 1, 2023 in Docket No. E999/CI-16-521.
[27] *See* Minn. Stat. § 216C.378 Subd. 2(2), as added by Minnesota Session Laws 2023, Chapter 60, Article 12, Section 38.
[28] Minnesota Session Laws 2023, Chapter 60, Article 11, Section 2, Subd. 10.

participants. Our pilot of mandatory cluster studies has had mixed results. While the total duration of the cluster studies was longer than typical studies of individual interconnections, the study time per project was lower. There are also administrative efficiencies gained by combining the applicant steps in the cluster study, such as the 20-day, 15-day, and 30-day steps for the applicant to sign the System Impact Study Agreement, Facilities Study Agreement, and Interconnection Agreement, respectively. Those steps would be done at the same time for all participants in the cluster study, rather than sequentially for the individual projects. This is good for projects waiting for ahead in queue projects to be studied, albeit a delay for the first project in that queue. There have been a wide range of interconnection costs in each study, ranging from roughly $222,000 to $2,111,500 per project. As of June 22, 2023, one out of 14 completed cluster studies resulted in signed interconnection agreements, three resulted in signed facilities study agreements, and ten resulted in withdrawals. The average cost per project of the withdrawn projects was roughly $1,374,000. Some of those interconnection costs involved substation upgrades, but some were only reconductor upgrades to mitigate significant over voltages. It is unclear if the costs of any of those withdrawn projects would have been low enough to be economically viable if studied individually. The cluster studies were structured such that we limited the number of participating projects to the point when significant upgrades were known to be required, such as a transformer upgrade. One lesson learned is that when significant upgrades are known to be required, there may be a "minimum participant" requirement for a cluster study for the cost sharing to be effective in making the interconnections economically viable. As of June 22, 2023, there are 13 more cluster studies to be performed. Five of those will require a new transformer or new feeder, so we will see how feasible it is for cluster studies to overcome high interconnection costs for thermal limitations. From this pilot we will learn best practices for cluster studies.

Longer term, we are monitoring the developments with flexible interconnection strategies, described in more detail below and in Section II.B above.

E. Types of System Upgrades that Might be Necessary to Accommodate DER at the Listed Penetration Levels

While we are confident the proposed process changes discussed above will help support the higher levels of DER adoption noted in our forecast, there is still interest among the Company, developers, and the Commission alike to find ways to integrate more DER easily.

Long term, we will be monitoring flexible interconnection capabilities and identifying associated gaps. Flexible interconnection could allow more DER to be connected without system upgrades, but the tradeoff would be that not all DER could generate or discharge during periods of distribution system constraint. While some utilities have demonstrated flexible interconnection solutions without a DERMS platform, they have been narrow in scope, primarily focused on a single large front-of-the-meter DER and preventing impacts on a specific device. With the increase in service transformer replacements required to interconnect additional small rooftop PV to shared secondary systems and the increase in transformer lead-times, we expect there will also be appetite in small rooftop PV wanting a flexible interconnection option to reduce their interconnection costs and timelines. We identify our planned next steps and long-term vision for Flexible Interconnections in Section II above.

We also know that the implementation of FERC Order 2222 will require significant changes to our interconnection process in the latter part of the decade and may also require new tools for aggregated DER registration as well as monitoring and control capabilities. We discuss Order 2222 in Section VII below.

As we have outlined in other areas of this IDP, we expect that grid modernization investments 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 E-7 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.

Table E - 7: Potential Mitigations for Common Impacts

Category	Impacts	Mitigation
Voltage	Overvoltage	Adjust DER power factor setting, reconductor
	Voltage Fluctuation	Adjust DER power factor setting, reconductor
	Voltage Regulator Operations	Adjust DER power factor setting, reconductor
Loading	Thermal Limits	Reconductor, replace equipment
	Load Masking	Real-Time generation output communicated over SCADA
Unbalance	Current and Voltage Unbalance	Swap phases on single phase taps, conversion from single phase tap to a three phase tap
Protection	Additional Element Fault Current	Replace protective equipment
	Protective Device Reduction of Reach	Adjust relay settings, replace relays, move or replace protective equipment
	Coordination of Protective Devices	Adjust relay settings, replace relays, move or replace protective equipment
	Reverse Power Flow	Update controls on regulation devices, install Power Control System on DER to control power output/export
	TOV	Provide a ground reference, implement fast tripping on DER, installation of Direct Transfer Trip (DTT)
	Unintentional Islanding	Implementation of Voltage Supervisory Reclosing (VSR), installation of DTT, delay reclosing[29]

VI. 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.

[29] Delaying reclosing impacts reliability and reduces the customer experience. It does not eliminate the risk, only reduces the risk.

Finally, we discuss our view of the impact of IEEE Std. 1547-2018 on interconnection standards/processes.

As an initial matter, we note that IEEE 1547-2018 has been amended to IEEE 1547a-2020.

A. Inverter Advancements

Advancements in inverters and their functionality can be utilized as one measure to reduce system impacts from PV and other inverter-based DER. A revision to the industry standard governing of the interconnection of DER with electric power systems (IEEE 1547) was published in April 2018[30] and modified in April 2020.[31] 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 and reactive power, and regulating voltage. Furthermore, the latest revision of the standard specifies interoperability requirements, a design consideration in all our advanced grid investments.

Currently, smart inverters that are compliant with and certified to the newest IEEE 1547 standards are becoming available with wide market availability expected later in the year. Availability had been limited as specific manufacturers and the models continue to receive certification. The standard for test and conformance procedures necessary to certify inverters, IEEE 1547.1-2020 was completed in February 2020 and implementation of those procedures is underway. Underwriters Laboratory is in the process of updating their testing certification standards (UL 1741) to the latest information and as these updates are approved, they are distributed to the Nationally Recognized Testing Laboratories (NRTLs) for testing implementation and certification. While the timeframe for standard DERMS development activities is fluid, we anticipate compliant and certified equipment will become more widely available later in 2023.

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[30] 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

[31] See IEEE Publishes Standard Revision for Interconnection and Interoperabil.ity of Distributed Energy Resources (DER) with Associated Electric Power Systems Interfaces, Piscataway, NJ (April 2020) https://standards.ieee.org/ieee/1547a/7696/.

B. Planning Considerations Associated with IEEE 1547-2018 (as amended to IEEE 1547a-2020)

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).*

The standard IEEE 1547-2018 as amended to IEEE 1547a-2020 scope is focused on the interconnection and interoperability requirements for DER. 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.

Distribution system planning considerations including integrating DER into capacity expansion plans and grid support functions required by IEEE 1547-2018 as amended to IEEE 1547a-2020 is expected to 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. This provides a necessary tool for mitigating future 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, 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. The Company is currently performing studies on an interim basis on request utilizing the Volt-VAR functionality in place of fixed power factor.

The Company participated in an EPRI two-year research project with other utilities that evaluated different advanced DER functions to help identify "best fit" or "universal" DER functions to meet system objectives. EPRI modeled multiple inverter functions and settings across a wide variety of feeder models supplied by participating utilities. While the impact of various inverter settings on a particular feeder has been studied, less was known about applying universal settings across a wide variety of feeder conditions. The benefits of the project included identifying feeder types were "best fit" common inverter settings would work effectively and also identify situations where more locational analysis is needed. EPRI also intends to build more capabilities into its DRIVE hosting capacity tool so that these inverter settings can be more easily modeled. The project was completed at the end of 2022 and non-proprietary results are available to the public for purchase or otherwise.

We prepared our roadmap for the deployment of smart inverters and shared it third quarter 2022.[32] We shared using a stepped approach. Inverters will inherently have "ride-through" capabilities that in aggregate will prevent contributing to grid instability during a short-term transmission or generation event. The first step involved would be standardizing autonomous or unattended functions where appropriate, as well as harmonization with the bulk electric system various settings for protection and other considerations.

The interoperability capabilities required by IEEE 1547-2018 as amended to IEEE 1547a-2020 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 something that will be evaluated as we move forward. Using the DER interoperability interface, DER advanced functions required could 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.

[32] Docket No. E002/M-21-694, 2021 Integrated Distribution Plan Annual Update (November 1, 2022).

C. 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.*

Abnormal voltage and frequency issues can manifest due to distribution conditions, transmission conditions, or a combination of the two. Distribution system circumstances that can lead to abnormal conditions can include (not limited to) high DER penetration, high source impedance, and highly variable loads. These circumstances exist today and create areas within the distribution system that experience abnormal conditions. As discussed above, there are multiple efforts being pursued to determine how advanced inverter technology could be leveraged to address these conditions.

Abnormal conditions on the transmission system can occur during scenarios such as tripping or loss of generation and transmission line faults. A driving factor for modifying national interconnection standard IEEE 1547-2018 as amended to IEEE 1547a-2020 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 as amended to IEEE 1547a-2020 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 possible differing technical objectives of these stakeholders. Midcontinent Independent System Operator (MISO) has initiated a process to collect stakeholder input and provide guidance on preferred DER settings associated with response to abnormal grid conditions.

Abnormal conditions, whether related to distribution or transmission events or circumstances are difficult to forecast. At this time, we do not have a method for forecasting where abnormal conditions may manifest and their effect on the system. As industry knowledge and experience on advanced inverter settings grows, there may be an opportunity to develop methods for high-level prediction of potential areas with abnormal conditions and how they can be address with new functionality. The Company views Minnesota statewide DER Technical Interconnection and

Interoperability Requirements being developed in Phase II of Docket No. E999/CI-16-521 as the proper place to address DER abnormal response functions.

D. Impact of IEEE 1547-2018 on Statewide Interconnection Standards

As we have discussed, IEEE 1547-2018 as amended to IEEE 1547a-2020 is the current published DER interconnection and interoperability standard. As also noted, we developed a roadmap for adopting the standard and determining implementation pathways for the numerous options it offers. The roadmap covers near- and long-term perspectives.

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 Docket No. E999/CI-16-521, especially in Phase II, which considers statewide technical standards, and other details are expected to be associated with Company business practice decisions. The Company along with other utilities within the state have updated the statewide Technical Interconnection and Interoperability Requirements (TIIR) to address the IEEE 1547-2018 as amended to IEEE 1547a-2020 standard.

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 Docket No. E999/CI-16-521. 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.

VII. CHANGES OCCURRING AT THE FEDERAL AND REGIONAL 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 2021 IDP, we discussed FERC Order No. 841, which addresses two different levels of participation of storage resources in wholesale markets and FERC Order No. 2222, which removes barriers for DER aggregations to participate in wholesale markets. We discuss these Orders largely in the context of Order 2222, which deals with all both storage and non-storage DER aggregations participating in wholesale markets.

We provide a discussion of the FERC Orders in this section and specifically, the potential impacts of the Orders in part C below.

A. FERC Order Nos. 841 and 2222

FERC Order No. 841, adopted in February 2018, requires that RTOs and ISOs accommodate the various types of services that electric storage resources can provide, regardless of whether they are interconnected at transmission voltage or to the distribution system. In September 2020, FERC expanded the requirements applicable to participation of resources interconnected to the distribution system in wholesale markets with issuance of Order No. 2222 in Docket No. RM18-9-000, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators.[33]

We see minimal challenges associated with implementing Order 841 as it relates to storage resources interconnected to the transmission system, as it does not pose any material additional burdens on utilities. RTOs/ISOs have revised their market rules and systems to accommodate such storage resources.

FERC's Order 841, to the extent it addresses wholesale market participation by DER storage resources, and FERC's Order 2222, left many key details regarding implementation to resolution by RTOs/ISOs and distribution utilities. We continue to work to understand the implications of the order from both the wholesale market level, and more importantly the distribution system level. Our primary focus in these

[33] A copy of XES's comments in FERC Docket No. RM18-9-000 is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14682284. 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.

efforts is to ensure the continued integrity of wholesale markets and the safety and reliability of the distribution system while also trying to work through the business processes, information systems, and personnel requirements that will be required to implement and administer the rule from a distribution utility standpoint. Under the rule, FERC has jurisdiction over the manner in which DER storage resources and DER aggregations participate in wholesale markets while FERC has deferred to the Relevant Electric Retail Regulatory Authority (RERRA), the responsibility for regulatory requirements needed to maintain the safety and reliability of the distribution system and allocation of costs associated with accommodating market participation by DER storage resources and DER aggregations.

Even at low penetration levels of DER, FERC's expectation that electric storage resources and DER aggregations be enabled to participate in wholesale RTO or ISO markets poses challenges. The implications of these challenges become more significant at higher penetration levels. For example:

- *Distribution System Usage.* 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 DER. In addition to the technical considerations, issues such as cost assignment will need to be addressed. Costs of such upgrades at the distribution level are currently directly assigned to the DER causing such costs to be incurred. We discuss cost allocation considerations further in Appendix I. Further, Order 2222 contemplates application of distribution system access charges to transmit DER services to the MISO Market.

- *Aggregation Reviews.* As part of the RTO/ISO process for registering proposed aggregations, distribution utilities will be afforded the opportunity to evaluate whether the concerted actions of the DERs participating in the aggregation will have potential adverse impacts on the safety and reliability of the distribution system. The performance of aggregations in the wholesale market will differ from the impacts studied at the time of interconnection and will likely be much more dynamic than the impacts of the typical DER, resulting in fairly complex studies. Additional staff resources and tools may be needed to perform aggregation reviews.

- *Distribution Operations.* Electric distribution companies (EDCs) 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 safe and reliable distribution system operations. The need for such capabilities will increase as DER penetration increases. The mechanisms to manage these operations will likely require enhanced communications systems between the EDC, DER, and market operator; software that can monitor distribution system impacts and identify reliability issues and solutions; DER and aggregation tracking systems; and additional operations personnel to effectively manage the impacts of DER participation in markets.
- *Metering.* Participation of DER aggregations raises questions about the capability to use metering to distinguish between wholesale activities and retail activities in the case of dual-use facilities. For storage resources, 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 and discharging 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 avoiding payment of full retail rates when it is charging a storage resource for what will ultimately be used for a retail purpose.
- *Wholesale market issues.* In addition to the direct distribution-level impacts of DER aggregations participating in markets, there are a variety of other issues that must be addressed at the wholesale market level. These issues include applicable wholesale market metering and telemetry requirements; operational coordination among the RTO/ISO, EDC, and DER aggregator; and whether market software can effectively be deployed to manage large numbers of relatively small resources. Through their stakeholder processes, RTOs and ISOs undertook to work through these issues in the context of developing proposed revisions to their wholesale tariffs. Such revisions are subject to FERC approval; as discussed further below, MISO's tariff revisions are pending at FERC.

Given the broad scope of RERRA responsibilities associated with implementation of Order 2222, we expect that distribution utilities will need to develop statejurisdictional tariffs and agreements that address the rights and responsibilities of both distribution utilities as well as DER storage assets and DERs and their aggregators in terms of utilization of the distribution system to enable their participation in the wholesale markets. In addition, RERRAs will need to consider requests for funding of additional personnel and systems to accommodate such wholesale market participation, and the appropriate assignment or allocation of such costs.

Xcel Energy is committed to supporting DER aggregations and storage resource participation in wholesale markets. In an effort to work through solutions/ recommendations to some of the issues discussed above, Xcel Energy joined a collaboration initiative led by Advanced Energy Economy (AEE)[34] and GridLab to bring together DER developers/aggregators and EDCs to discuss common challenges associated with the implementation of Order No. 2222.
The primary purpose of this effort was to provide RERRAs insight into areas of agreement among EDCs and DER developers with respect to Order No. 2222 implementation.[35]

B. MISO

In Order No. 2222, FERC established a compliance filing deadline date for the RTOs/ISOs of July 19, 2021. MISO filed a request to extend that date until April 18, 2022 and FERC granted MISO's request. In January 2021, MISO held the first meeting of its DER Task Force (DERTF).[36] The DERTF met on a regular basis prior to MISO's compliance filing until MISO made its Order No. 2222 compliance filing on April 14, 2022. MISO also held workshops to coordinate Order No. 2222 implementation with the RERRAs.[37]

MISO's compliance filing proposes an effective date for its implementation of Order 2222 of October 2029. On August 12, 2022, FERC asked MISO for more information about its compliance filing, and MISO responded to that request on October 11, 2022. As of this date, MISO's compliance filing remains pending at FERC.

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[34] Advanced Energy Economy is now known as Advanced Energy United.
[35] *FERC Order 2222 Implementation: Preparing the Distribution System for DER Participation in Wholesale Markets,* January, 2022, AEE-GridLab-FERC-O.2222-Campaign-Final-Report.pdf.
[36] *See* MISO's DERTF webpage at: https://www.misoenergy.org/stakeholder-engagement/committees/DERTF/. Last accessed October 19, 2021.
[37] Access the recording of this DERTF meeting at: https://cdn.misoenergy.org/20210728%20RERRA%20O2222%20Coordination%20Workshop%20Recording578273.mp4. Last accessed October 19, 2021.

C. Potential Impact of FERC Orders

There are a number of issues associated with Order No. 2222 implementation that will not be addressed by the RTOs/ISOs and will fall to the RERRA to resolve. These include:

- *DER Interconnections.* In Order No. 2222 and again in Order No. 2222-A, FERC declined to exercise jurisdiction over the interconnection of individual DERs that interconnect to the distribution system for the purpose of participating in wholesale markets. The details of how these interconnections are facilitated, what studies are performed, and allocation of costs for any system upgrades will fall to RERRAs. While Minnesota already has a standard distribution interconnection process (the Minnesota Distributed Energy Resource Interconnection Process or MN DIP) and the Company has interconnection tariffs in place, these were not developed with wholesale participation in mind. As more DER interconnect to participate in wholesale markets, and more DER use the distribution system as a vehicle to access the transmission system, these interconnection studies and processes may need to be re-evaluated to ensure the ongoing safety and reliability of the distribution system and to prevent cost shifts for the use of the distribution system by DER developers/aggregators to retail customers.
- *DER Aggregation Review.* FERC Order No. 2222 provided for a process by which the RTO/ISO would provide for the EDC to perform a review of any proposed DER aggregations prior to their participation in the wholesale market in order to ensure the DER aggregation has no adverse effects on the safety or reliability of the distribution system. While the process for implementing the review falls under FERC jurisdiction and will be outlined by the RTO/ISO, the details of how the EDC will perform the review and what will be studied intersects with the RERRA's authority over distribution system reliability.
- *Dual Participation.* Order No. 2222 allows for DER in aggregations to participate in both wholesale markets and retail programs as long as the DER is not double compensated for the same service in both markets. In multi-state RTOs/ISOs, such as MISO, the RTO/ISO will need to rely to a large degree on RERRAs to determine which state retail programs are compatible with dual participation in wholesale markets and which are not. Failure to adequately identify and prevent inappropriate dual participation could result in higher costs to retail customers, as customers would pay once for the service as part of

a retail program and then pay again for the same service as part of wholesale rates.

- *Distribution Asset/Operations Management Systems/Software.* As the number of DER participating in wholesale aggregations increases, EDCs will increasingly need more sophisticated processes, procedures, and tools – not to mention human resources – to efficiently process interconnection requests, perform aggregation reviews, track individual DERs and DER aggregations, and safely and reliably operate a distribution system that will increasingly be used to facilitate DER access to wholesale markets. These management systems are in the nascent stages of development and will require significant customization in order to integrate into existing distribution provider infrastructure. Order No. 2222 did not address how the costs of these systems would be allocated. As a result, these decisions will fall to RERRAs to determine how best to balance the increased costs between retail customers, DER developers interconnecting to the distribution system for retail purposes, and DER developers/aggregators to access wholesale markets.
- Should the Commission reopen consideration of non-utility aggregators of retail customers (ARC) participation in wholesale markets as contemplated in E999/CI-22-600, the Company recommends the Commission consult with The Organization of MISO States (OMS) to ensure that MISO has appropriate processes in place to manage DER through ARCs. In addition, the OMS should have a dialogue with MISO about the effectiveness of its existing DR performance measurement and verification.[38]
- The Commission should also consider whether measures such as certification, data privacy, and truth-in-advertising requirements should apply to ARCs. Additionally, considerations for customer protections should be established through rules and procedures to ensure that customers are fairly compensated by the ARCs representing them in wholesale markets. The Commission should also consider setting up processes to regulate the sharing of customer information with ARCs.[39]

Finally, we note that we expect issues regarding data security and privacy will also need to be addressed.

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[38] The Company also raised this issue in comments filed in the Commission's Docket No. E999/CI-22-600, *In the Matter of a Commission Investigation into the Potential Role of Third-Party Aggregation of Retail Customers.*

[39] *Id.*

APPENDIX F: NON-WIRES ALTERNATIVES ANALYSIS

The discussion in this Appendix responds to IDP Requirements 3.E.1, 3.E.2, and 3.A.5.d., and Integrated Resource Plan (IRP) Order Point 9.D.[1]

IDP Requirement 3.E.1 and 3.E.2 require:

> *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.*

IDP Requirement 3.A.5.d requires:

> *5. 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, including:
>
> > *d. Improving non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources to address discrete distribution system costs.*

IRP Order Point 9.D states:

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[1] Order Approving Plan with Modifications and Establishing Requirements for Future Filings (April 15, 2022), Docket No. E002/RP-19-368.

*9. Xcel shall stake steps to better align distribution and resource p*lanning, including:

D. Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources to address discrete distribution system costs.

Regarding IDP Requirement 3.A.5.d and IRP Order Point 9.D, this Appendix discusses improvements to our NWA analysis overall. See *Appendix A1: System Planning* for more detailed discussion on coordination between the IRP and IDP regarding NWA analysis.

We note that in past IDPs, we have provided a separate Attachment with the full results of our NWA analysis. This year, this Appendix includes all NWA analysis information, including the full results and load curves. We have also streamlined the format of the NWA analysis results section.

I. INTRODUCTION

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. States with high Distributed Energy Resource (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 non-traditional 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, we are continuing to see NWA solutions 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 an NWA a custom, one-off solution that requires extensive oversight and management. However, as technology advances and manufacturing evolves – and with the potential availability of new tax credits – DERs have the potential to quickly become a more common option. Further, there are additional values and revenue streams that DERs can provide beyond just the deferral of a traditional distribution project, and these can be assessed to reduce the overall cost impact of an NWA solution. As such, we are 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.

The below sections note the Commission's requirements and the corresponding aspects of our NWA analysis. This year, the results of our NWA analysis show that three projects are viable and potentially cost-beneficial.

II. NWA ANALYSIS IN THE PLANNING PROCESS

IDP Requirement 3.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.

Table F-1 below shows the traditional projects analyzed for this year's NWA analysis. These projects have a total cost greater than $2 million and meet the criteria detailed below.

Table F - 1: Projects Analyzed

	Budgeted Cost per Year				
Project Title	**2024-2025**	**2026**	**2027**	**2028**	**2024-2028 Total**
Reinforce Basset Creek BCR TR1	-	-	$200,000	$2,200,000	$2,400,000
Install Lone Oak LOK Feeder	-	$200,000	$6,800,000	-	$7,000,000
Install Osseo OSS TR3	-	-	$200,000	$4,400,000	$4,600,000
Reinforce Medicine Lake MEL089	-	-	$2,160,000	-	$2,160,000
Reinforce Elm Creek TR1 to 50 MVA	-	-	$100,000	$2,300,000	$2,400,000

	Budgeted Cost per Year				
Project Title	**2024-2025**	**2026**	**2027**	**2028**	**2024-2028 Total**
Install Lone Oak LOK TR3	-	-	$200,000	$3,680,000	$3,880,000
Install West Coon Rapids WCR TR	-	-	$200,000	$3,400,000	$3,600,000
Blue Lake reinforce banks to 50MVA and add feeder	-	-	$200,000	$5,547,000	$5,747,000
Reinforce Afton AFT321	-	$200,000	$7,800,000	-	$8,000,000
Reinforce SLP85 Feeder	-	-	$2,710,000	-	$2,710,000
Reinforce Saint Louis Park SLP092	-	-	$4,050,000	-	$4,050,000
Install New Midtown MDT072	-	-	-	$5,320,000	$5,320,000
Install Chemolite CHE TR03	-	$200,000	$5,786,000	-	$5,986,000
Reinforce Parkers Lake PKL065	-	-	-	$3,700,000	$3,700,000
Reinforce Twin Lakes TWL065	-	-	-	$2,500,000	$2,500,000
Reinforce Twin Lakes TWL078	-	-	-	$3,500,000	$3,500,000

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 LoadSEER. Those curves are then blended together, where applicable, for contingency situations that are unique for each. We then tailor and add in demand response (DR), 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. As our NWA analysis process continues to evolve and we contemplate solicitation processes and the attendant requirements, it is likely we will need to add staff to continue to maintain and advance our analysis and future implementation of NWAs.

Many capacity projects budgeted at greater than $2 million address 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 more streamlined. While the majority of the process will still be fairly manual for the foreseeable future, we are working within the industry to help affect change and improvement and are also reviewing existing tools that could be used to automate complex but repeatable NWA analyses.

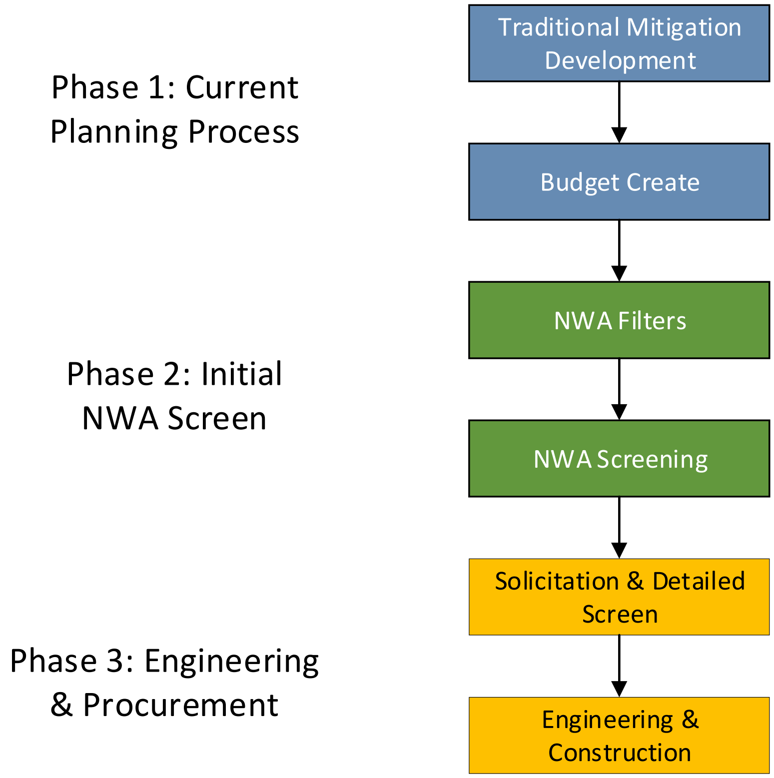
For each of these projects, we focused on the peak load curve for each feeder or transformer risk involved, forecasted to five years after the in-service date of the traditional project. This forecasted load was used due to the five-year deferral window assumed in the analysis. We then applied focused DR in an effort to reduce the load – and followed that with energy storage and/or solar generation to address the remainder of the deficiency. In some instances, we had existing solar on particular feeders that we could utilize in the analysis as well.

IDP Requirement 3.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.*

The NWA process fits into the overall distribution planning process and can be broken down into three main phases:

Figure F - 1: NWA Analysis Process Phases Appended to Existing Planning Process

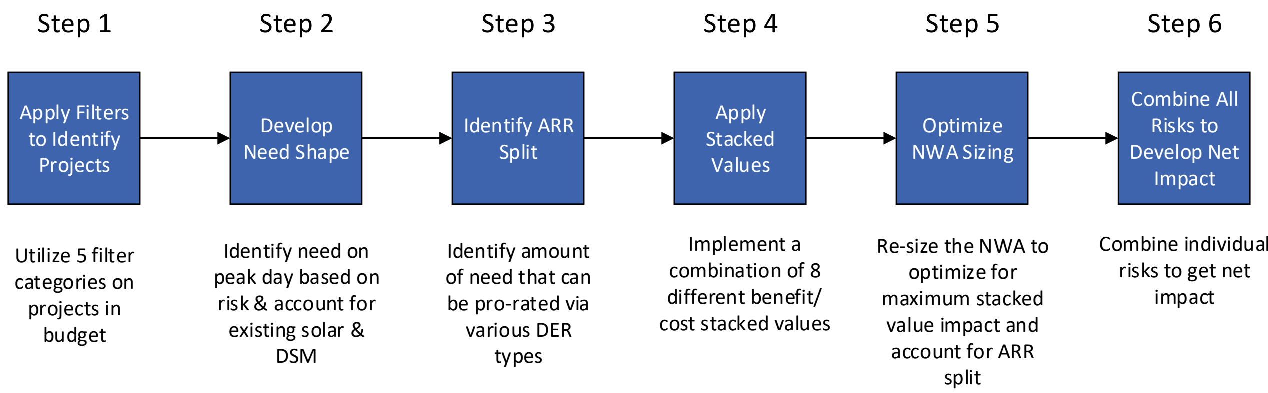


In Phase 1, the current planning process, traditional mitigations are developed and put into the budget create process, as discussed in Appendix A1. After this process has completed, Phase 2 can begin. In this phase, projects in the budget go through a set of NWA filters and a screening tool. For projects that pass the filter and screening process, the project continues to Phase 3, the engineering and procurement phase. At this stage, the project goes out for solicitation and a detailed screen. If the project bids received are demonstrated to be cost beneficial in the detailed screen, the project will then continue to final engineering, construction, and in-servicing.

A. Initial NWA Steps

In conducting NWA analysis, we are primarily focused on the steps within Phase 2 of Figure F-1, which comprises the Initial NWA Screen. The methodology for this process can be further broken down into six key steps, as seen in Figure F-2 below:

Figure F - 2: The Six Steps of the Initial NWA Screen



The first step in NWA analysis comprises applying filters to identify projects. After a project list is identified, a need shape, also known as a load reduction requirement, reflects the amount of risk that would need to be solved in the context of a power purchase agreement (PPA) with an NWA developer. As part of this, the load-reducing impact of existing solar and demand response programs are accounted for in the need shape.

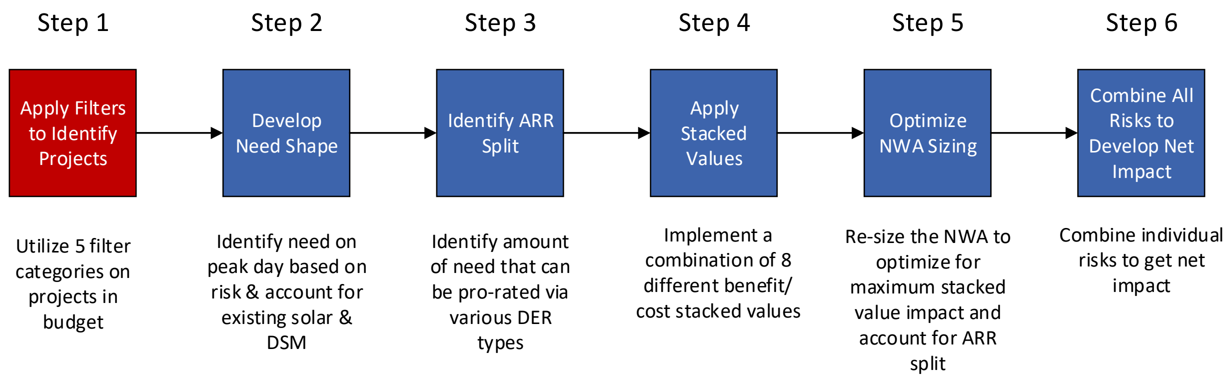
After the amount of risk is identified in a need shape, we then identify the Avoided Revenue Requirement (ARR) split. This identifies the percentage of total solar and battery storage technology that would be required to solve the need shape. This percentage is applied at a later step 5, during the optimization and economic cost calculation for the NWA.

After the ARR split is identified, stacked values are estimated. In this stage, a combination of eight different benefit and cost stacked values are considered; these eight represent the most impactful benefits and costs that can be reasonably estimated during an initial screen. If the project passes the initial screen, during the detailed engineering screen more stacked values would be considered based on the details provided in the received bids.

At this point, the combination of technologies required to mitigate the risk is optimized for maximum stacked value impact and to account for ARR split. Finally, the optimal NWA solutions for each of the individual risks are combined to produce a total net impact for the project. This net impact is used to indicate whether a project could be cost beneficial.

Discussing each of the steps in detail, there are unique considerations for each.

Step 1: Apply Filters to Identify Projects



In the initial screen and consistent with our 2022 analysis, we apply a set of filters to traditional projects in the budget to identify which projects are appropriate to consider for NWA analysis. Projects must meet the following criteria to pass these filters and move to NWA analysis:

- **Project Type**: Capacity
- **Timeline**: Year 3+
- **Project Cost**: >$2 million
- **Risk Type**: Non-Network Substation and Non-Single Bank Substation
- **Risk Size**: Annual Hours at Risk < 5,840
- **Risk Quantity**: ≤5 Risks

III. PROJECT TYPE

IDP Requirement 3.E.2 requires, in part, that the Company provide

> *…information on …Project types that would lend themselves to non-traditional solutions (i.e. Load relief or reliability)*

In this section, we discuss the three project types (mandates, asset health and reliability, and capacity) we consider in our NWA analysis. We also discuss the reasons we believe capacity projects best lend themselves to a non-traditional solution.

A. 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. If we chose to not 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 for operational efficiency and reliability. The grid offers many benefits, such as affordable reliability, and removing customers from the grid is not a viable solution for either the Company 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 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 and impracticable to accomplish within such a short period of time given the complexities of analyzing and developing a unique and new solution that an NWA would offer.

B. Asset Health and Reliability Projects

Asset Health and Reliability projects are projects required to replace equipment that is reaching the end of life or has 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 continually replace 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. Because asset health affects every part of the distribution system and is essential to maintaining reliability, an NWA is not workable.

C. Capacity Projects

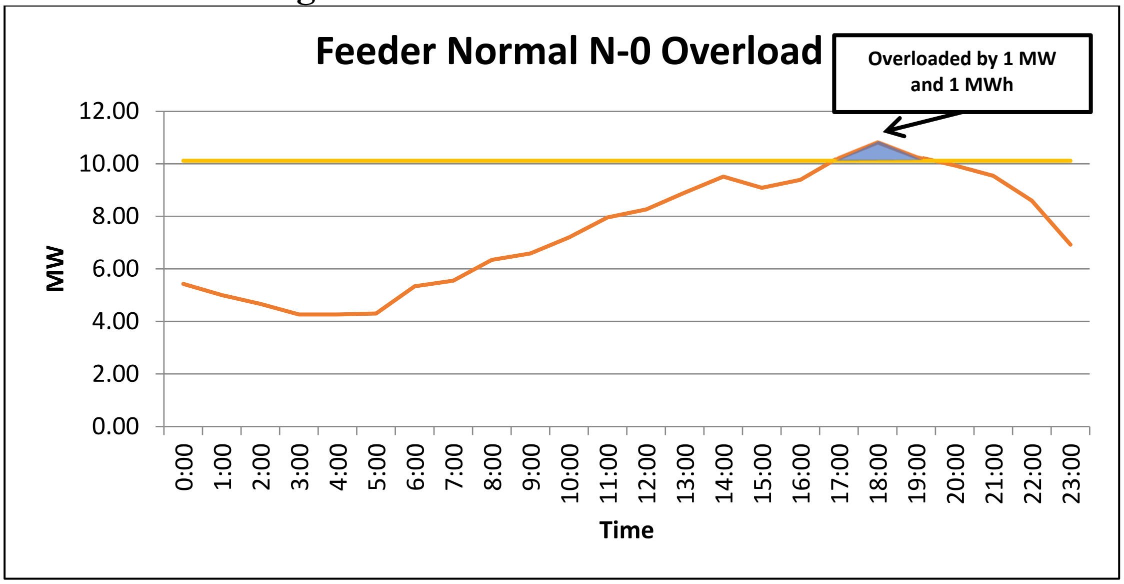
Capacity projects are better suited for NWAs as they are driven by a capacity deficiency that can be offset or otherwise deferred by strategically sited DER. DER that can generate, discharge, or reduce the consumption of electricity downstream on a feeder can decrease the amount of load that is drawn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

Because capacity projects do not have external requirements to build capacity, each project is given a priority score based on a general assessment of costs and benefits, 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, which supports our strategic priority to keep bills low while balancing competing system needs.

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 75 percent loaded, and all N-1 risks. 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 75 percent loading capacity threshold. We provide an illustrative example of an N-0 overload that exceeds the 100 percent feeder limit below.

Figure F - 3: Illustrative N-0 Overload

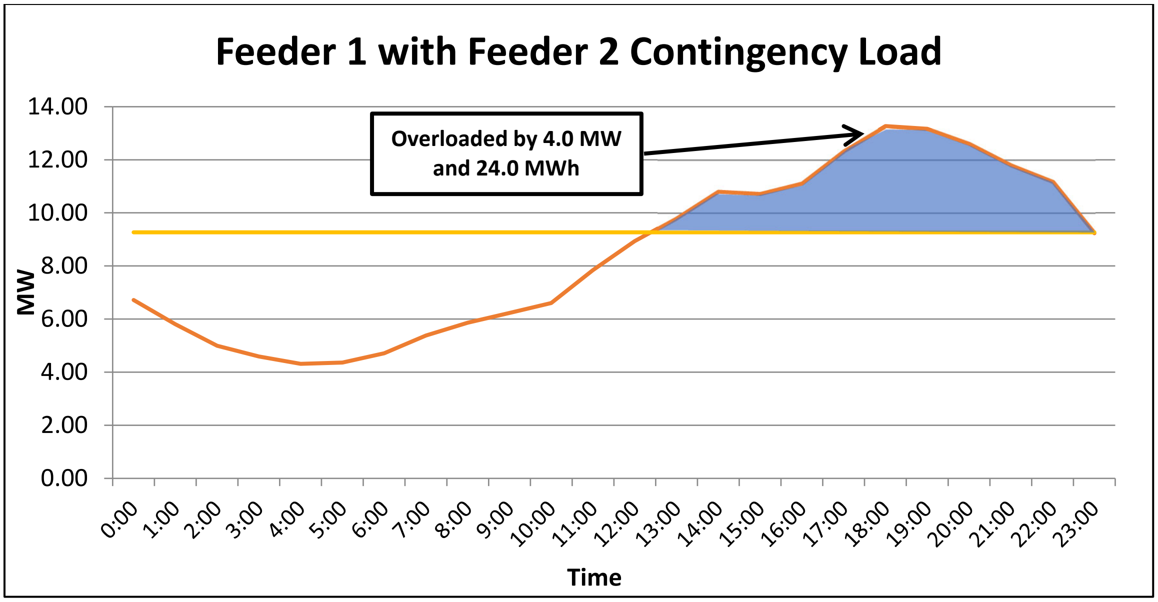


In Figure F-3 above, the overload is relatively small with a peak magnitude of 1 MW. Additionally, due to the small magnitude, the total duration of the overload is brief as well, yielding a total of approximately 1 MWh overloaded.

N-1 overloads occur when, for loss of a feeder, feeder load is transferred away to adjacent feeders, causing an overload. If an N-1 overload risk is created by transferring an entire section of a feeder to an adjacent feeder, the magnitude and duration of the overload is generally much more larger than is seen in N-0 overload risks. This comparative increase in the magnitude and duration of the risk tends to make N-1 risks less viable for NWA solutions.

We show an illustrative example of an N-1 overload below in Figure F-4. 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 and third sections 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 F - 4: Peak Day Load Curve for Feeder 1 after Feeder 2 Second Section Load has been Transferred



The magnitude of the illustrative N-1 overload shown above is relatively normal for N-1 risks tied to a project at 4.0 MW at risk. However, just 4.0 MW of load at risk causes the duration of the overload to extend to 10 hours. In this case, both the magnitude and duration of the risk are significantly greater than was seen in the N-0 example shown in Figure F-3. Therefore, N-1 risk-driven projects are not considered viable for NWAs.

IV. TIMELINE

IDP Requirement 3.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 analysis, we assumed we need about three years to appropriately consider and incorporate most NWA solutions. Due to recent increases in lead times for procuring substation transformers, however, we have determined that traditional projects that require substation transformers would need a minimum of four years to appropriately consider and incorporate an NWA solution. These timelines account for our internal time for analysis as well as all the steps surrounding a request for proposals (RFP) to actually procure an NWA solution. This includes issuing an RFP, obtaining response, screening the responses, technical and sourcing reviews, and then contract negotiations, regulatory approval, and construction. In the event a solution ultimately proves infeasible (or no RFP bids are received), these timelines would allow us to still construct the traditional project (including ordering a substation transformer, if needed) and still meet the original in-service date required to address the identified capacity risk. It is our understanding that this timeline is consistent with the approach other utilities have used in similar analyses. That said, since we first implemented these timing assumptions, supply chain constraints have increased, affecting not only substation transformers but other critical materials. In future analyses, we may need to adjust our timing assumptions and only consider projects that would not require a traditional solution within five years.

V. PROJECT COST

IDP Requirement 3.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.*

Per IDP Requirement 3.E.1, the Company has only considered traditional projects greater than $2 million in cost.

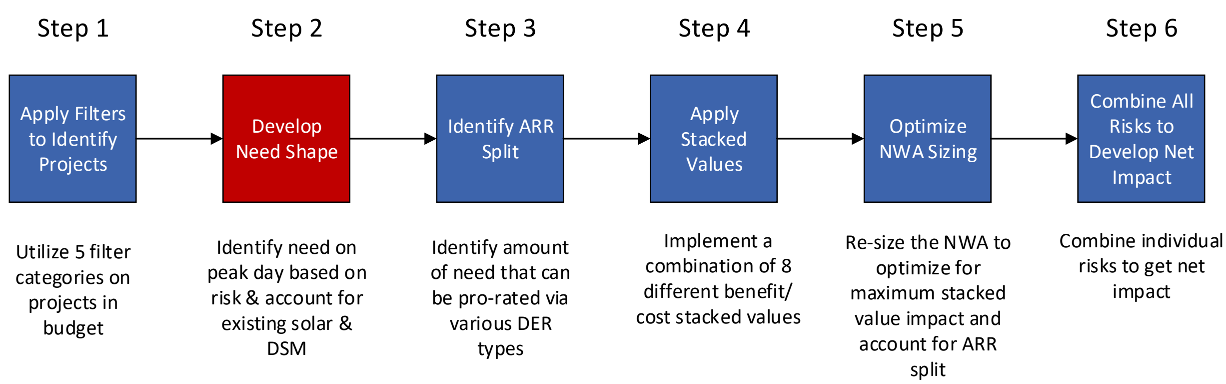
VI. RISK TYPE, SIZE, QUANTITY

Since we began conducting NWA analysis in 2019, we observed that some traditional projects were being included in the analysis that were not actually feasible. These infeasible projects were either mitigating excessive quantities of risks (greater than five risks), mitigating risks that existed for over 2/3 of the year (or 5,840 hours), or mitigating risks that were in substations that only had one substation transformer.

For these infeasible cases, there was so much risk on the system that no combination of demand response, solar and batteries could address the risk. These risks existed during hours when solar would not be generating and batteries could not have enough hours or capacity to charge between 24-hour load cycles. For these reasons, we do not look at projects with single bank substations or annual hours at risk greater than 2/3 of the year.

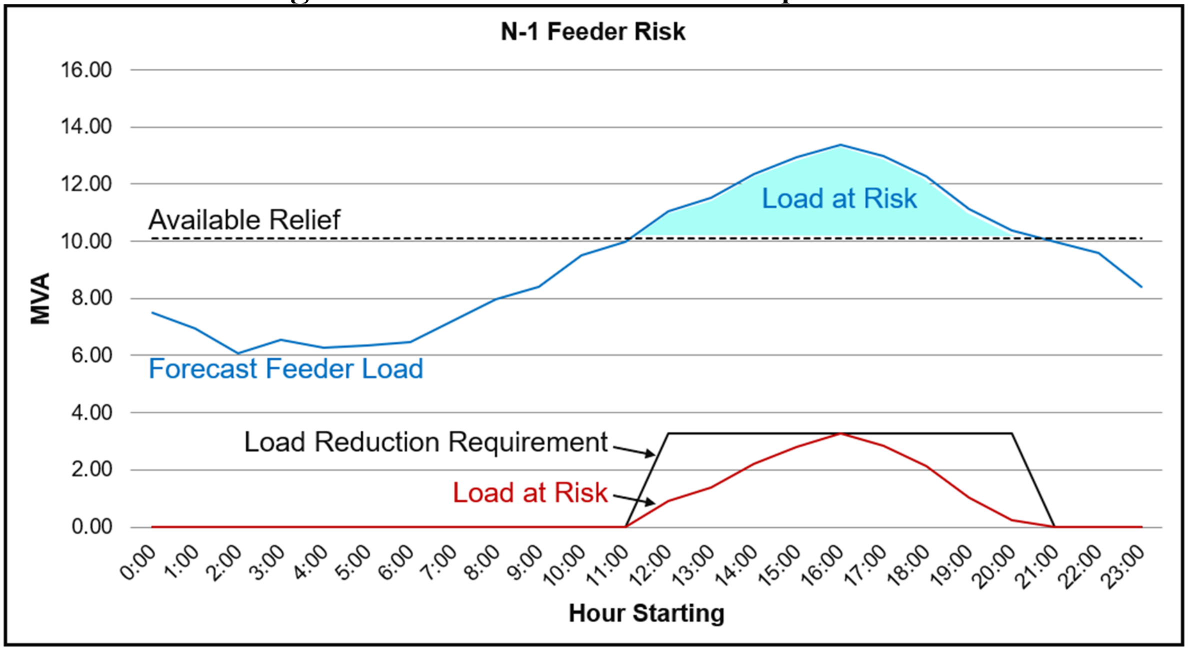
Additionally, we do not consider projects impacting downtown mesh networks due to the difficulty of installing DER in networks as well as the general complexities of analyzing an NWA in a non-radial distribution system. Also, due to NWAs being an emerging technology for which we are still developing expertise, we also want to ensure that large customers that are sensitive to outages like hospitals or nursing homes are not dependent on NWAs to maintain service reliability.

Step 2: Develop Need Shape



After a project list has been identified, the initial NWA screening can begin. The first component of this involves developing a need shape. Figure F-5 below reflects a simplified example of a need shape for a N-0 normal overload.

Figure F - 5: Load Reduction Requirement

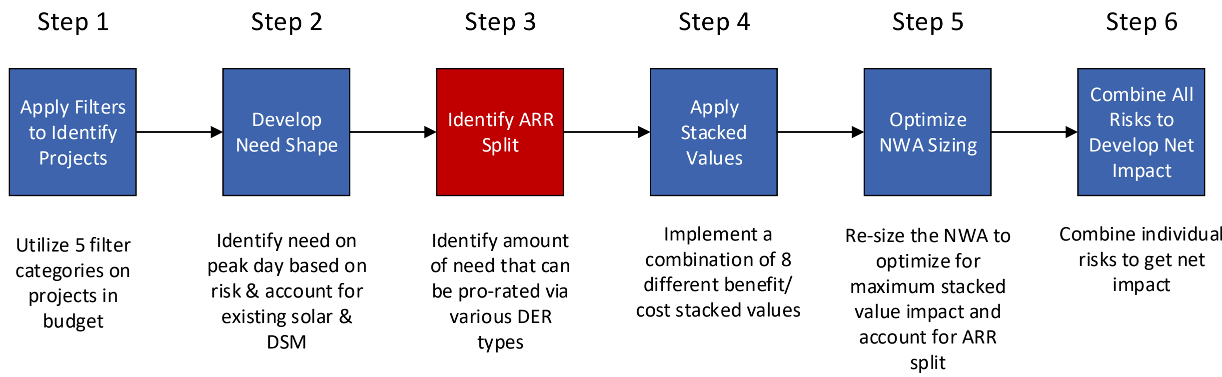


The need shape for NWA risks is described as the required peak contribution for the duration of the risk. This enables the Company to account for uncertainties in the forecasted load shape. This approach to load reduction is consistent with NWA load reduction contract structures seen in the industry. Figure F-5 illustrates the need shape as the "Load Reduction Requirement" at the bottom.

In the figure above, the forecasted feeder load exceeds the capacity which indicates an overload. The need shape, which is also known as the load reduction requirement, is sized based on the peak of the load at risk and extends across all hours for which the load at risk exists. This reflects the general format for how the Company anticipates an NWA project will be structured in the context of a PPA with an NWA developer.

There are some additional assumptions baked into the need shape, namely that it is assumed that the load reduction requirement is only needed during weekdays and only for the summer from June through September. An NWA solution could potentially be used by an NWA developer for other use cases during times when there is no load reduction requirement. While not reflected in the figure above, in this step, existing solar and demand response are considered in the need shape.

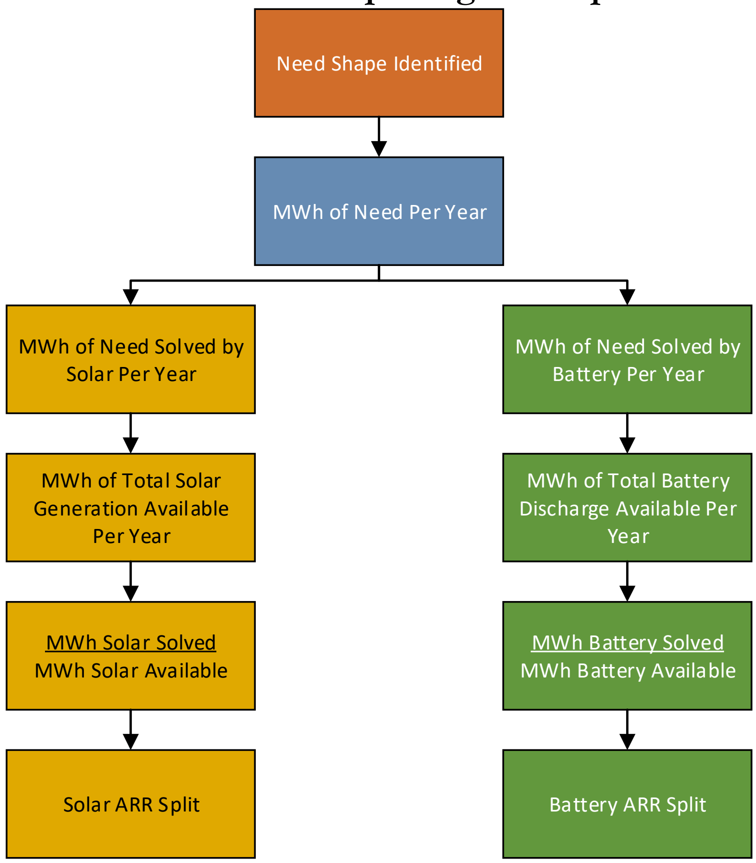
Step 3: Identify ARR Split



At this point, the MW and MWh of need is known for the risk. In Step 3, figuring out how much of the cost could be pro-rated for each DER type helps define the ARR split.

The ARR split represents the pro-rated NWA costs and stacked values that are proportional to the contribution of the DER to solving the risks. Figure F-6 below reflects a flow chart of how ARR split is calculated:

Figure F - 6: Flow Chart Depicting ARR Split Calculation



The ARR split calculation begins with identifying the need shape. The need shape is identified using a 24-hour peak-day curve found in the LoadSEER forecasted 8760-hour demand curve. Utilizing the need shape, the MWh of need per year is extrapolated. At this point, the process falls into two categories: the amount of need per year that can be addressed by solar and the amount that can be addressed by battery storage.

Considering that the NWA is assumed to be only needed for the summer months, the MWh of need that could be solved by solar and battery storage is identified. Then, for solar, the total MWh of solar generation per year is estimated using a generic, location-specific solar curve from NREL PVWatts. In parallel, the total MWh of battery discharge available per year is estimated.

To calculate the ARR Split for solar and battery storage, respectively, the following formulas are applied:

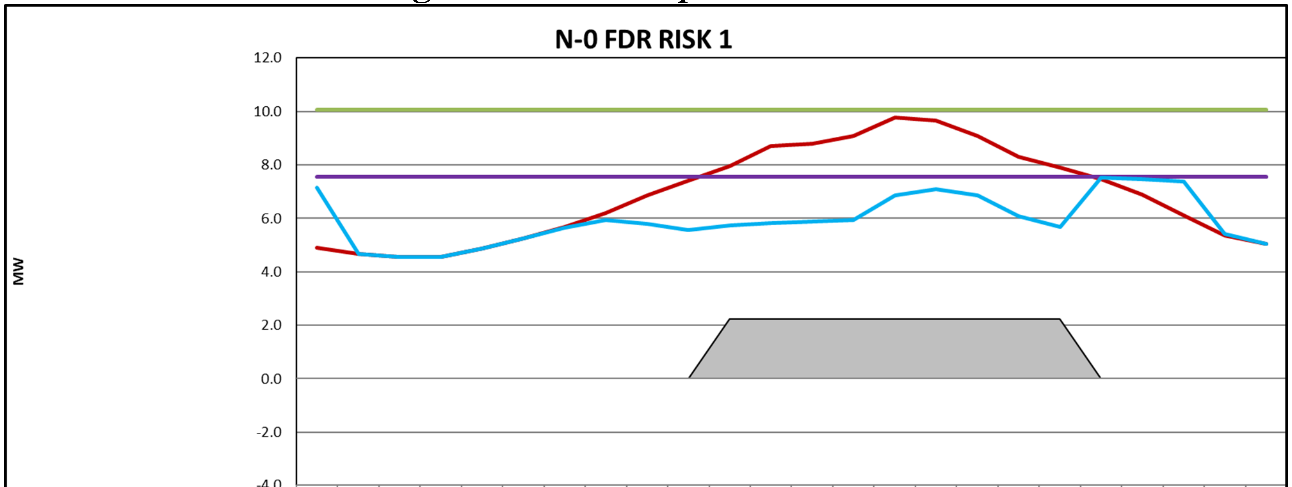
$$ARR\ Split_{Solar} = \frac{MWh\ Solar\ Used\ for\ NWA}{MWh\ Solar\ Available}$$

$$ARR\ Split_{Battery} = \frac{MWh\ Battery\ Used\ for\ NWA}{MWh\ Battery\ Available}$$

The resultant value comprises the ARR Split percentage for the solar and battery components.

Bringing the need shape and ARR split concepts together, Figure F-7 below reflects an example of an N-0 risk.

Figure F - 7: Example N-0 Risk



	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Need Shape (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	0.0	0.0	0.0	0.0	0.0
Feeder Limit (MW)	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Feeder Load (MW)	4.9	4.7	4.6	4.6	4.9	5.2	5.7	6.2	6.9	7.4	8.0	8.7	8.8	9.1	9.8	9.7	9.1	8.3	7.9	7.5	6.9	6.1	5.3	5.0
Forecast Uncertainty Margin (MW)	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Feeder Load With NWA (MW)	7.2	4.7	4.6	4.6	4.9	5.2	5.6	5.9	5.8	5.6	5.7	5.8	5.9	5.9	6.9	7.1	6.9	6.1	5.7	7.5	7.5	7.4	5.4	5.0
Solar Generation (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.3	-1.1	-1.8	-2.2	-2.9	-2.9	-3.1	-2.9	-2.6	-2.1	-1.5	-0.9	-0.2	0.0	0.0	0.0	0.0
Battery State of Charge (MWh)	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.2	2.3	2.3	2.3	2.3	2.3	2.1	1.4	0.0	0.3	0.9	2.2	2.3	2.3

In this example, at hour 10, the feeder load begins to exceed the forecast uncertainty margin and we begin to get an N-0 overload condition. This overload continues through hour 18 (6 p.m.).

The need shape reflects the peak of the overload across all hours when we have a load at risk condition. This general format of need shape is reflective of the PPA structure for an NWA project. From hours 10 to 18, the NWA accumulates approximately 2.2 MW and 20 MWh of total need required.

With the need shape going out to 6 p.m., the solar generation alone cannot meet the need shape, so battery storage is required to supplement. For battery storage, there needs to be enough hours with available grid capacity to first charge before it can then discharge when solar is not available for each 24-hour load cycle.

For the solar ARR split, the amount of total MWh of solar generation available per year from the required solar (estimated using the solar curve) is 15,403 MWh. However, not all the annual solar generation can be used for the NWA because of the hours of the day when the risk exists, and because it is required only during summer months. The amount that is available and required for the NWA throughout a given year is 4,056 MWh of solar. Dividing the amount of annual solar generation that is required to address the need (4,056 MWh) by the total annual solar generation available (15,403 MWh), produces an ARR split of 26 percent.

For the battery storage ARR split, the amount of battery that could be available to discharge is dependent on having enough hours to charge it and ensuring that the grid can handle charging the battery during those hours. Based on the size of battery storage required in this case, 825 MWh of battery discharge would be available per year. Considering that solar provides part of the need shape and battery storage provides the remainder, the battery would provide 196 MWh of the need per year. Taking the division of the two results in an ARR split of 24 percent.

The final ARR splits for the solar and battery storage required for the NWA solution are 26 percent and 24 percent, respectively. The results are summarized in Table F-2 below.

Table F - 2: ARR Split Example

Component	**Solar**	**Battery Storage**
MWh Generation or Discharge Available Per Year	15,403	825
MWh Need Provided Per Year	4,056	196
Final ARR Split	26%	24%

a. ARR Split Impacts

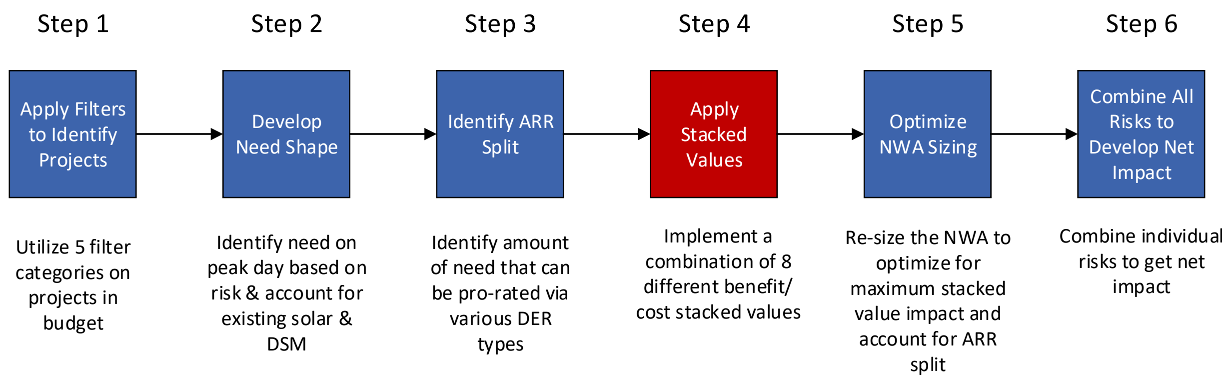
The ARR split ultimately impacts the project cost allocation of the NWA analysis. NWA providers would pay the full cost to design, build, and install the DER, and the Company would compensate the NWA provider for the prorated portion of those costs, as calculated by the ARR split. This payment to the NWA providers is assumed to be capitalized and recovered through rates.

The ARR split concept can be described as prorating NWA costs and stacked values proportional to the fraction of NWA output that solves the system risk. For example, consider a 1 MW solar installation that produces 2,000 MWh annually, but only 400 MWh throughout the year are during the needed load reduction period. In this case, costs and benefits would prorate to 20 percent of the total to reflect the portion of the NWA necessary to solve the risk and defer the traditional solution. Further, the costs of energy storage are additionally prorated based on the percentage of the energy storage system's useful life that is needed for the deferral period. For example, consider a battery storage system that has a useful life of 15 years, of which it will only be needed for the five years of the NWA deferral period. In this case, the cost of the battery storage would prorate to one-third of the total battery storage cost to reflect the portion of the battery's life that is needed for the NWA. This structure reflects NWA approaches at other utilities and allows potential NWA providers (including the Company) to own the DERs and leverage their projects for other needs or uses cases outside of the load reduction period.

In previous NWA screenings, the full lifetime of the NWA was considered. This assumed utility ownership, maintenance, and operation of the NWA solution. In the current methodology, we mitigate the risk for a five-year deferral period and perform the cost-benefit screening based on this five-year deferral period – not the full useful life of the NWA technology. This aligns the cost-benefit screening process with how we may structure potential NWA load reduction contracts in the future. This also has the effect of improving the cost-benefit screening performance of potential NWA projects. Within this framework, we assume a contracted load reduction level, with the possibility to work with either a third-party or utility ownership.

The ARR split and stacked values are critical components of the incremental net impact calculation for an NWA.

Step 4: Apply Stacked Values



As we have noted, we engaged with stakeholders to explore ways to advance our NWA analysis, including screening criteria, analysis methodology and assumptions, and evaluation parameters.[2] We also explored how we might include a broader set of costs and benefits in future NWA analyses, which is sometimes referred to as "stacked values."

Within the initial cost-benefit screening, we conduct a comprehensive assessment, in which we analyze market inputs and develop stacked values with the resulting data. During Phase 2, the initial NWA screen, a set of discrete stacked values are considered as defined in the National Standards Practice Manual. The methodology used for calculating each of these stacked values is reflected in the Assumptions and Calculations section.

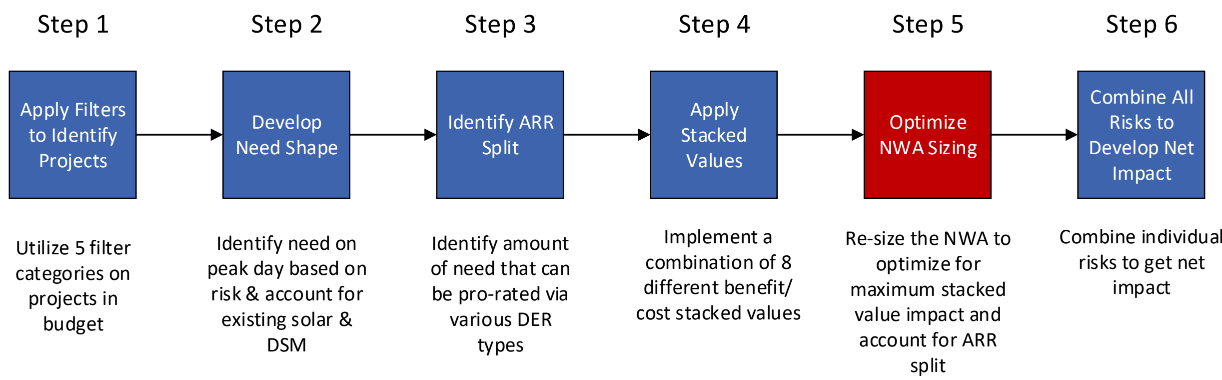
Viable projects that move to solicitation would undergo additional stacked value screening based on specific bids received.

We note that while stacked values are considered for the NWA solution, our NWA analysis considers only the cost of the traditional project and no additional value associated with a traditional mitigation. Therefore, although the analysis may show that an NWA solution has a positive incremental net impact, that result does not necessarily support a conclusion that the NWA is more beneficial than the traditional solution. In this sense, the stacked values methodology is asymmetrical – an issue that is worthy of further consideration.

[2] See Appendices F and I of our 2021 IDP (Docket No. E002/M-21-694) for further background on the NWA stakeholder workshops held in 2021, which informed our methodology.

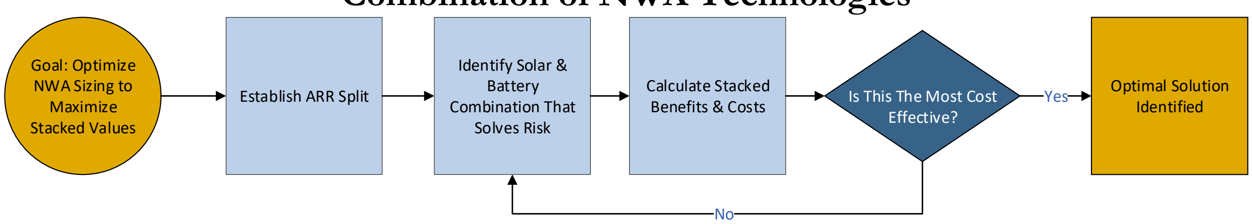
Viable projects that move to solicitation would undergo additional stacked value screening based on specific bids received.

Step 5: Optimize NWA Sizing



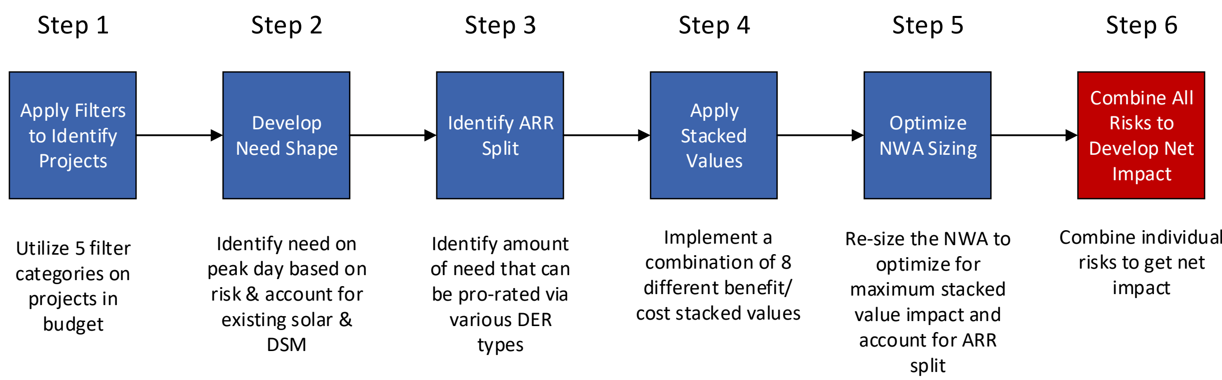
After the stacked values are calculated and applied in the NWA analysis, NWA sizing is optimized to maximize the stacked value impact. Figure F-8 below reflects a flow chart of the logic behind the optimization algorithm:

Figure F - 8: Simplified Algorithm for Calculating the Most Cost-Effective Combination of NWA Technologies



The optimization begins with establishing the ARR split. Then, a specific combination of solar and battery that would solve the risk is identified. The stacked benefits and costs are calculated using this specific NWA technology combination, with a resulting net impact being output. Comparing to all other NWA sizing combinations, if that combination is not the most cost-effective, then a different combination of solar & battery is used, and the stacked benefits and costs are recalculated. This process is re-iterated until all combinations possible are exhausted and an optimal solution is identified. This provides the individual NWA risk sizing.

Step 6: Combine All Risks to Develop Net Impact



After the combination of NWA technologies is optimized for cost-effectiveness for each risk, the results are combined to produce a total net impact for the NWA project. The total net impact is calculated using the following formula:

$$Net\ Impact\ =\ Total\ Benefit - Total\ Cost$$

With this formula, if the resultant value is positive, then there is more benefit than cost and the project would be considered cost beneficial. If the value is negative, then the costs exceed the benefits and would not be considered cost beneficial. Because this net impact is based on the results of the initial screen, it does not consider all possible costs and benefits associated with the NWA project. Rather, it represents the most impactful costs and benefits that can reasonably be calculated at an early stage of project development. Therefore, a positive or negative net impact does not absolutely determine whether a project would be cost-beneficial but instead, provides an indication of whether a project would be worth investigating further for an NWA in a market solicitation.

In the example shown in Figure F-9 below, the traditional project has five different risks with different feeder sections contributing to these risks. The optimal NWA solution for each risk is identified and combined to develop a total benefit, total cost, and resulting net impact.

Figure F - 9: Example Project with Optimal NWA Solution and Stacked Values Identified for Each Risk

Capacity Risk	Need Shape			Optimal DER Solution						Stacked Values Cost Split
				DSM	Solar			Battery Total		
Anonymized Name	MW Overload	Duration	MWh Overload Annual	MWh	Existing MW	New MW	Acres	MW	MWh	
N-1 FDR RISK 1, SECTION 1	0.14	2	24	0.0	0.00	11.5	80	0.00	0.00	$64,233
N-1 FDR RISK 1, SECTION 2	0.16	1	14	0.0	0.00	10.2	71	0.00	0.00	$17,895
N-1 FDR RISK 4, SECTION 1	2.07	13	2,340	0.0	0.00	11.4	80	2.25	20.32	$326,696
N-1 FDR RISK 5, SECTION 1	2.73	10	2,373	0.0	0.00	10.2	71	2.96	21.04	$910,257
N-1 FDR RISK 6, SECTION 1	2.35	8	1,633	0.0	0.00	13.5	94	2.55	15.50	$775,223
N-1 FDR RISK 7, SECTION 3	0.09	1	8	0.0	0.00	9.0	63	0.00	0.00	$37,620
TOTAL	**61.60**	**83**	**62,772**	**0.00**	**0.00**	**65.80**	**461**	**7.76**	**56.85**	**$2,131,925**

For each risk, the need shape is identified as well as the optimal DER solution, which can comprise demand response, solar, and battery storage. The stacked values cost split represents how much each risk contributes to the total net impact. Adding up each of these stacked value cost splits comprises the cost and benefits summary shown in Figure F-10. In this case, the total benefit exceeds the total cost, resulting in a positive net impact.

Figure F - 10: Individual Cost and Benefit Calculations for an Example Project, Used to Calculate the Net Impact

Cost and Benefits Summary	
Energy Generation	$1,544,526
Generation Capacity + MISO Reserves	$473,600
Transmission Capacity	$20,332
Deferral Benefit	$800,717
GHG Emissions + Other Environmental	$2,112,750
Solar Cost	$(2,177,637)
Battery Cost	$(438,363)
Interconnection Fees	$(204,000)
Total Benefit	**$4,951,924**
Total Cost	**$(2,819,999)**
Net Impact	**$2,131,925**

One key contributor to the cost effectiveness of this project is the impact of the ARR split pro-rating the cost for the DER in the NWA solution. The actual, total cost to install the DER would be considerably higher than reflected in the stacked values –

the costs shown in the stacked values represent only the prorated portion of the total DER costs that would be allocated to the NWA and paid for by the Company. As a result of this, the actual capital costs would be higher than is represented in the stacked values, and it is assumed that the owner of the DER asset would be willing to install the DER at their own cost with the Company contributing only the pro-rated amount itemized in the stacked values.

Additionally, the results shown above represent the "optimal" NWA solution as determined in the NWA analysis methodology. The NWA methodology determines the optimal solution by selecting the unique combination of solar and energy storage that mitigates the risks but also maximizes the incremental net impact. However, this optimization naturally leads the model to maximize the amount of solar incorporated in the NWA solution due to the higher rate of benefit accrual for solar compared to energy storage. While the maximum amount of solar that can be accommodated in the solution was constrained by the feeder Technical Planning Standard (TPS), it was not constrained by other factors such as land availability for hosting solar PV. Therefore, the optimal solution may not be a realistic solution based on what can actually be built; the most realistically buildable solution may be sub-optimal and would yield a lower incremental net impact.

At this point, the initial NWA screen is completed for this project. If the project passes the screen with a positive cost-benefit then Phase 3, the Engineering and Procurement stage, would be the next step for the NWA project.

VII. 2023 NWA ENHANCEMENTS

In this year's NWA analysis, several key enhancements to the process have been implemented. These enhancements comprise streamlining discount rate calculation, implementing a forecast uncertainty margin, and advancing project feasibility metrics.

A. Discount Rates and Cost-Effectiveness Ranges

Order Point 3 of the Commission's July 26, 2022 Order in Docket No. E002/M-21-694 requires the Company to use both weighted average cost of capital (WACC) and societal discount rate in its NWA analysis and discuss the results of the two approaches in a future IDP stakeholder meeting. This year, we have continued the practice we employed in our last NWA analysis in our November 1, 2022 IDP baseline compliance filing. In compliance with the Order, we calculated two Incremental Net Impact values for each project analyzed; one using WACC and one using a societal discount rate.

The approach we have taken in this analysis, while compliant with the Commission's Order, is imperfect and provides limited value in assessing which, if any, projects to move forward to a solicitation phase. For all of the projects evaluated in 2023, the incremental net impact of the optimal solution was very similar under both discount rates, differing by less than $100,000 in all three cases.

At our June 12, 2023 stakeholder workshop, we discussed the results of our 2022 analysis with stakeholders. Using a poll, we asked stakeholders if we should continue to conduct NWA analysis using both the WACC and societal discount rates. Only 8 out of 26 attendees responded to the poll, with five respondents indicating "both" and three indicating "not sure."

Given the low rate of stakeholder input and the results of our NWA analysis using both discount rates in 2022 and 2023, going forward, we propose to use only WACC as the discount rate in our NWA analysis. With the exception of some specific instances when the Commission has determined another rate should be used for particular analyses, we generally use WACC as the discount rate for analyzing proposed projects of all types. Notably, as we move to more integrated planning, WACC is what we use in resource planning, including in numerous resource plans that have been accepted over the years by the Commission and stakeholders.[3] WACC is the appropriate rate to use in evaluating the cost-effectiveness of proposed investments because it is the Company, not individual customers, or society as a whole, that may be making these potential investments, and we use our capital to do so. That capital is either debt or equity and WACC represents the average cost we pay for that capital. WACC is thus an opportunity cost and, as such, is commonly used by companies to evaluate potential investments.

For each project we analyzed this year, as shown below in Section IX, the potential range in NWA net impact is shown in two different ways. First, a range was made from least cost effective to most cost-effective. The most cost-effective solution is optimized to have the greatest net impact possible as calculated from the stacked values. In many cases, this means that the most cost-effective NWA solution has a

[3] We note that while the WACC used in our NWA analysis is typically consistent with the WACC used in the resource plan modeling, due to the timing of the NWA analysis this year, we are using the WACC from the last approved resource plan (Docket No. E002/RP-19-368). The forthcoming resource plan filing on February 1, 2024 will use the latest capital structure approved by the Commission in its July 17, 2023 rate case Order in Docket No. E002/GR-21-630. The difference between the two WACC discount rates is small and would not materially affect the outcome of our analysis. In future NWA analyses, we will align the discount rate with the resource plan whenever possible.

significant amount of solar. However, the amount of solar in some of these solutions is extremely high and may be infeasible.

For example, in one most cost effectives solution for a project studied in our 2022 baseline compliance filing, just the solar component of the NWA required installing 24 MW of solar in St. Louis Park, which could take 165 acres of land. In this case, the project had a positive incremental net impact, but the project requires a large amount of solar in a densely populated suburb.

On the other side of the range, the least cost-effective solution addresses a situation where the NWA has a much larger battery component, resulting in a lower incremental net benefit. However, this solution may be a more realistic scenario for projects in dense metro areas where installing very large quantities of solar is not possible, but installing a large battery that takes up less land may be more feasible. However, the least cost-effective solution could have a minimally positive or even negative incremental net impact.

This illustrates not only how big of an impact stacked values have towards projects but also how much solar in particular impacts the modeled cost effectiveness of the project.

The second component of these tables is shown on the rows under the discount rates. Generally speaking, WACC represents the cost for the Company to acquire capital for investments. In the context of an NWA, this is typically used for costs and benefits that are related to utility function, like building assets and the cost of producing energy.

Societal discount rate represents the relative value of costs and benefits from projects that benefit society or the broader public. Thinking about this in terms of NWAs, this is typically used for carbon avoidance and societal benefits from solar.

Keeping these definitions and applications in mind, notice the WACC and societal rows in the Incremental Net Impact Summary tables for each project studied below. Each of these rows represent using only WACC discount rates for all stacked values and societal discount rates for all stacked values, respectively. As noted above, the different discount rates did not result in demonstrably different results.

B. Forecast Uncertainty Margin

In this year's NWA analysis, a new metric titled the forecast uncertainty margin was added to the NWA initial screen. This margin reflects the fact that forecasts are just that – forecasts – and cannot be perfectly accurate. Since the NWA solutions are sized based on forecasted peaks, accounting for inaccuracies in potential load growth is important. Forecasts can have relatively high accuracy when observed at the system-wide level, but at the granularity of an individual feeder circuit or substation discrete changes, such as one large customer connecting to the grid, can introduce significant variance in the forecast. Even if load growth was anticipated in an area and included in the forecast, if the actual customers that ultimately interconnect in the area happen to have a higher or lower load density than was assumed then the forecast will not have been accurate. If an NWA is sized to precisely meet the need identified in the forecast, then such a forecast variance could cause the NWA to no longer be able to meet the need that actually develops based on how the NWA technology was sized. Therefore, NWAs need to be sized accordingly to account for uncertainty in the forecast.

In the N-0 risk case, the forecast uncertainty margin reflects 75 percent of the feeder limit, which aligns with our planning criteria. In the N-1 risk case, we scale the peak of the N-1 overload load curve up by 25 percent and assess the overload against 100 percent of the feeder limit, which aligns with our planning criteria.

For both use cases, the need shape is developed using the forecast uncertainty margin, resulting in a larger need shape, which is important to ensure the NWA is sized appropriately to be able to maintain reliability under futures with higher loads.

VIII. Project Feasibility

Our 2023 NWA analysis included a more in-depth scrutiny of project feasibility. Specifically, for a project to be feasible, if a battery is required in the NWA solution, the battery must be at a full state of charge by the first hour of the need shape. This ensures that the battery, which is charged from the grid, can discharge when needed. If the battery does not have a full state of charge by the first hour of the need shape, it cannot discharge enough MW or MWh required to meet the entirety of the need shape. Thus, if a project contained a risk that proved to be infeasible, the project as a whole is rendered infeasible. Project feasibility does not consider constructability components of projects. Construction elements of projects are considered during final engineering and design stages of an NWA and not during the initial screen.

IX. NWA PROJECT RESULTS OVERVIEW

In this section, we outline the results of our 2023 NWA analysis, which examined the 16 projects that fit our NWA criteria, as outlined in Table F-3 below. For each of these projects, we focused on the peak load curve for each feeder or transformer risk involved, forecasted to the end of the deferral period (five years after the planned in-service date). We then applied focused DR 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 included in the analysis as well. We provide the results of the analysis, along with the load curves and assumptions used in the Assumptions and Calculations section (Section XI below).

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 F-3 below summarizes the outcome of our NWA analysis for the projects that advanced to the initial NWA analysis screen. Note that a positive Incremental Net Impact indicates that the modeled benefits outweigh the modeled costs in the stacked values model.

Table F - 3: 2023 NWA Candidate Projects – Results Summary

Project Title	Feasibility	Incremental Net Impact	Traditional Project Cost
Reinforce Basset Creek BCR TR1	N	-	$2,400,000
Install Lone Oak LOK Feeder	N	-	$7,000,000
Install Osseo OSS TR3	N	-	$4,600,000
Reinforce Medicine Lake MEL089	N	-	$2,160,000
Reinforce Elm Creek TR1 to 50 MVA	N	-	$2,400,000
Install Lone Oak LOK TR3	N	-	$3,880,000

Install West Coon Rapids WCR TR	N	-	$3,600,000
Blue Lake reinforce banks to 50MVA and add feeder	N	-	$5,747,000
Reinforce Afton AFT321	N	-	$8,000,000
Reinforce SLP85 Feeder	N	-	$2,710,000
Reinforce Saint Louis Park SLP092	N	-	$4,050,000
Install New Midtown MDT072	N	-	$5,320,000
Install Chemolite CHE TR03	N	-	$5,986,000
Reinforce Parkers Lake PKL065	Y	$3,700,000	$3,700,000
Reinforce Twin Lakes TWL065	Y	$2,500,000	$2,500,000
Reinforce Twin Lakes TWL078	Y	$3,500,000	$3,500,000

Table F-4 below summarizes the outcome of our NWA analysis for the projects that advanced to the initial NWA analysis screen and resulted in feasible solutions. The Incremental Net Impact indicates that the modeled benefits outweigh the costs if the value is positive, and that the costs outweigh the benefits if the value is negative. As Table F-4 shows, all three projects analyzed have a positive Incremental Net Impact.

The incremental net impact is one initial indication that a potential project may be cost effective, but – like any model – the analysis has limitations, which we discuss further below. As we have discussed, any potential NWA project would require additional analysis before determining true cost-effectiveness and feasibility.

Table F - 4: 2023 Feasible NWA Candidate Projects – Results Summary

Project Title	# of Risks	Most Cost-Effective Incremental Net Impact (WACC)	Cost of Traditional Project
Reinforce Parkers Lake PKL065	1	$1,123,876	$3,700,000
Reinforce Twin Lakes TWL065	1	$1,065,072	$2,500,000
Reinforce Twin Lakes TWL078	1	$1,326,783	$3,500,000

We discuss each of these project analyses in Section IX below.

X. PROJECT DETAILS

This section contains a summary of each of our NWA project analyses, including one chart for each project to illustrate the risk assessment process. We also provide a more-detailed assessment of the costs and benefits from each of the value and revenue streams considered for the project. Also, we provide the Incremental Net Impact for the range of viable NWA solutions, including a comparison of the resulting value when the WACC is used for the discount rate, or the societal discount rate is used. For the 2023 IDP, we have updated the format of this section to streamline the information. This year, we are presenting most project details in list or table form instead of the narrative form we have used in past years.

We note that while the solutions summarized here represent the most cost-effective solution with WACC discount rate for the NWA, the optimal solutions may not be feasible due to procurement and siting challenges. A functional NWA can still be achieved with a suboptimal mix of technologies, but with a more costly incremental net impact.

To aid in understanding this range of possible net impact values, for each project we provide a table comparing the overall incremental net impact of the most cost-effective NWA solution and the least cost-effective NWA solution. Further, this table also includes the incremental net impact when the WACC is used for the discount rate, as well as an alternative in which the societal discount rate is used. Collectively, these four values provide a range of possible net impact values that could be achieved depending on the NWA solution that is ultimately implementable, and the discount rate that is used in the economic calculations.

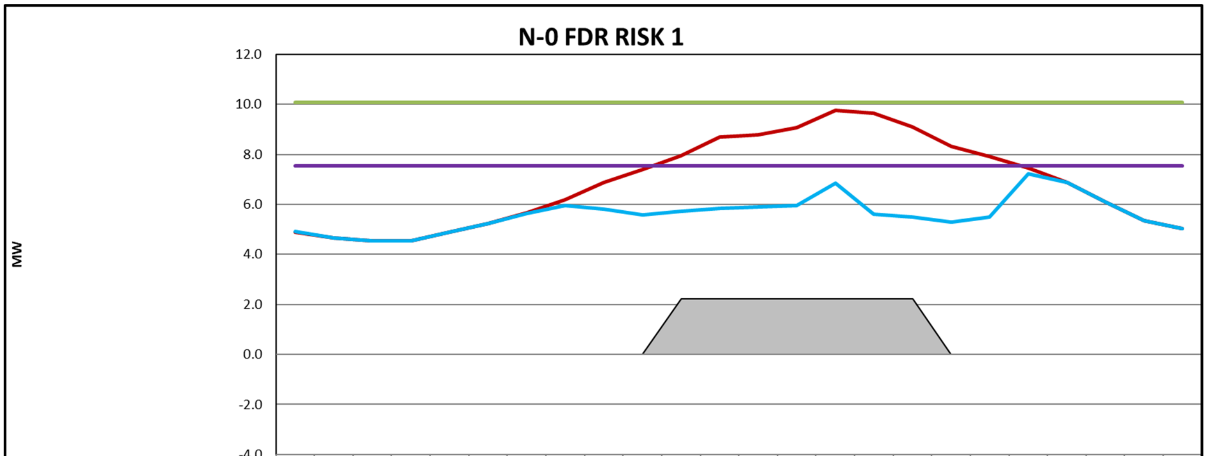
A. Reinforce Twin Lakes TWL065 Feeder

Overview

Capacity risks addressed:	1
Feeder normal overloads:	1
Feeder contingency risks:	0
Transformer normal overloads:	0
Transformer contingencies:	0
Traditional solution:	Upgrade feeder capacity by installing parallel cables in duct
NWA solution:	New energy storage and new solar PV systems at strategic locations to mitigate risks

Figure F-11 shows the amount of load at risk from the normal overload of the feeder associated with the project.

Figure F - 11: Feeder Overload Risk



	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Need Shape (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Feeder Limit (MW)	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Feeder Load (MW)	4.9	4.7	4.6	4.6	4.9	5.2	5.7	6.2	6.9	7.4	8.0	8.7	8.8	9.1	9.8	9.7	9.1	8.3	7.9	7.5	6.9	6.1	5.3	5.0
Forecast Uncertainty Margin (MW)	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
Feeder Load With NWA (MW)	4.9	4.7	4.6	4.6	4.9	5.2	5.6	5.9	5.8	5.6	5.7	5.8	5.9	5.9	6.9	5.6	5.5	5.3	5.5	7.2	6.9	6.1	5.3	5.0
Solar Generation (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.3	-1.1	-1.8	-2.2	-2.9	-2.9	-3.1	-2.9	-2.6	-2.1	-1.5	-0.9	-0.2	0.0	0.0	0.0	0.0
Battery State of Charge (MWh)	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03

Existing solar on feeder (MW): 0

Available relief from DSM (MWh): 6.1

Most Cost-Effective Solution[4]

Technology or Technologies:	Solar and Storage
Incremental Solar Capacity (MW):	8.6
Incremental Storage Capacity (MW/MWh):	0.17/0.29
Risk mitigated:	Feeder N-0

Table F-5 summarizes the most cost-effective DER solution (using the WACC discount rate) for each of the risks associated with this mitigation.

[4] Using the WACC discount rate.

Table F - 5: Reinforce TWL065 Feeder – Summary of DER Solutions

Capacity Risk	Need Shape			Most Cost-Effective Solution		
	Overload (MW)	Duration (Hours)	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)
N-0 FDR RISK 1:	2.22	9.00	6.1	0.00	8.6	0.17/0.29

Table F-6 summarizes the overall incremental net impact of the most cost-effective NWA solution (using the WACC discount rate), including a detailed view of the incremental impact of each cost/benefit category.

Table F - 6: Reinforce TWL065 Feeder – Costs and Benefits Summary

Cost/Benefit Category	Incremental Impact
Energy Generation	$ 420,212
Generation Capacity + MISO Reserves	$ 150,039
Transmission Capacity	$ 7,134
Deferral Benefit	$ 424,281
GHG Emissions + Other Environmental	$ 658,574
ARR Split - Solar Cost	$ (532,518)
ARR Split - Battery Cost	$ (28,649)
Interconnection Fees	$ (34,000)
Total Benefit	**$ 1,660,240**
Total Cost	**$ (595,167)**
Net Impact	**$ 1,065,072**

Table F-7 below reflects the range of NWA solutions for both societal and WACC discount rates. It also illustrates the spectrum of net impact values from least cost-effective to most cost-effective.

Table F - 7: Reinforce TWL065 Feeder – Incremental Net Impact Summary

Incremental Net Impact		NWA Solution	
		Least Cost-Effective Solution	**Most Cost-Effective Solution**
Discount Rate	**WACC**	$57,818	$1,065,072
	Societal	$65,000	$1,158,156

B. Reinforce Twin Lakes TWL078 Feeder

Overview

Capacity risks addressed: 1

Feeder normal overloads: 1

Feeder contingency risks: 0

Transformer normal overloads: 0

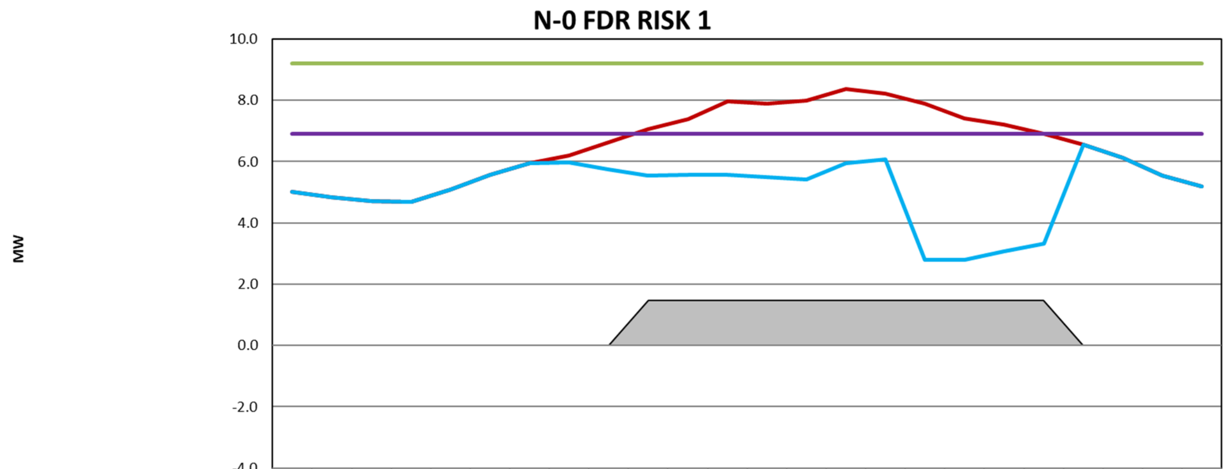
Transformer contingencies: 0

Traditional solution: Upgrade feeder capacity by installing parallel cables in duct

NWA solution: New solar PV systems at strategic locations to mitigate risks

Figure F-12 shows the amount of load at risk from the normal overload of the feeder associated with the project.

Figure F - 12: Feeder N-0 Contingency Load Risk



	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Need Shape (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	0.0	0.0	0.0	0.0
Feeder Limit (MW)	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2	9.2
Feeder Load (MW)	5.0	4.8	4.7	4.7	5.1	5.6	6.0	6.2	6.6	7.0	7.4	8.0	7.9	8.0	8.4	8.2	7.9	7.4	7.2	6.9	6.6	6.1	5.5	5.2
Forecast Uncertainty Margin (MW)	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
Feeder Load With NWA (MW)	5.0	4.8	4.7	4.7	5.1	5.6	5.9	6.0	5.7	5.5	5.6	5.6	5.5	5.4	6.0	6.1	2.8	2.8	3.1	3.3	6.6	6.1	5.5	5.2
Solar Generation (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	-0.9	-1.5	-1.8	-2.4	-2.4	-2.6	-2.4	-2.1	-1.7	-1.2	-0.7	-0.2	0.0	0.0	0.0	0.0
Battery State of Charge (MWh)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Existing solar on feeder (MW): 0.07

Available relief from DSM (MWh): 13.6

Most Cost-Effective Solution[5]

Technology or Technologies: Solar

Incremental Solar Capacity (MW): 7.1

Incremental Storage Capacity (MW/MWh): 0.00/0.00

Risk mitigated: Feeder N-0

Table F-8 summarizes the most cost-effective DER solution (using the WACC discount rate) for each of the risks associated with this mitigation.

[5] Using the WACC discount rate.

Table F - 8: Reinforce TWL078 Feeder – Summary of DER Solutions

Capacity Risk	Need Shape			Most Cost-Effective Solution		
	Overload (MW)	**Duration (Hours)**	**Demand Response (MWh)**	**Existing Solar PV (MW)**	**Incremental Solar PV (MW)**	**Battery Storage (MW/MWh)**
N-0 FDR RISK 1	1.46	11.00	13.6	0.07	7.10	0.00/0.00

Table F-9 summarizes the overall incremental net impact of the most cost-effective NWA solution (using the WACC discount rate), including a detailed view of the incremental impact of each cost/benefit category.

Table F - 9: Reinforce TWL078 Feeder – Costs and Benefits Summary

Cost/Benefit Category	**Incremental Impact**
Energy Generation	$ 510,308
Generation Capacity + MISO Reserves	$ 102,960
Transmission Capacity	$ 4,896
Deferral Benefit	$ 620,024
GHG Emissions + Other Environmental	$ 760,966
ARR Split - Solar Cost	$ (638,370)
ARR Split - Battery Cost	$ -
Interconnection Fees	$ (34,000)
Total Benefit	**$ 1,999,154**
Total Cost	**$ (672,370)**
Net Impact	**$ 1,326,783**

Table F-10 below reflects the range of NWA solutions for both societal and WACC discount rates. It also illustrates the spectrum of net impact values from least cost-effective to most cost-effective.

Table F - 10: Reinforce TWL078 Feeder – Incremental Net Impact Summary

Incremental Net Impact		NWA Solution	
		Least Cost-Effective Solution	Most Cost-Effective Solution
Discount Rate	WACC	$243,945.36	$1,326,783.43
	Societal	$249,780.50	$1,418,556.16

C. Reinforce PKL065 Feeder

Overview

Capacity risks addressed: 1

Feeder normal overloads: 1

Feeder contingency risks: 0

Transformer normal overloads: 0

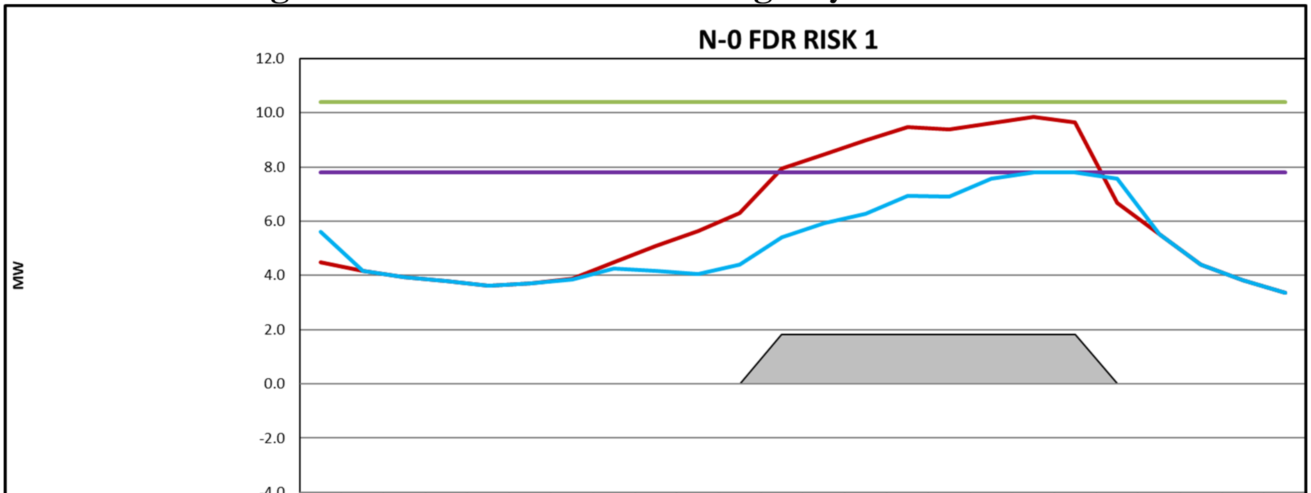
Transformer contingencies: 0

Traditional solution: Upgrade feeder capacity by installing parallel cables in duct

NWA solution: New energy storage and new solar PV systems at strategic locations to mitigate risks

Figure F-13 shows the amount of load at risk from the normal overload of the feeder associated with the project.

Figure F - 13: Feeder N-0 Contingency Load Risk



	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Need Shape (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	0.0	0.0	0.0	0.0	0.0
Feeder Limit (MW)	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Feeder Load (MW)	4.5	4.2	3.9	3.8	3.6	3.7	3.9	4.5	5.1	5.6	6.3	7.9	8.5	9.0	9.5	9.4	9.6	9.8	9.6	6.7	5.5	4.4	3.8	3.4
Forecast Uncertainty Margin (MW)	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Feeder Load With NWA (MW)	5.6	4.2	3.9	3.8	3.6	3.7	3.9	4.3	4.2	4.1	4.4	5.4	5.9	6.3	6.9	6.9	7.6	7.8	7.8	7.6	5.5	4.4	3.8	3.4
Solar Generation (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.2	-0.9	-1.6	-1.9	-2.5	-2.5	-2.7	-2.5	-2.2	-1.8	-1.3	-0.8	-0.2	0.0	0.0	0.0	0.0
Battery State of Charge (MWh)	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	0.8	0.0	1.1	1.1	1.1	1.1	1.1

Existing solar on feeder (MW): 0.9

Available relief from DSM (MWh): 0.9

Most Cost-Effective Solution[6]

Technology or Technologies: Solar and Storage

Incremental Solar Capacity (MW): 8.6

Incremental Storage Capacity (MW/MWh): 1.13/2.45

Risk mitigated: Feeder N-1

Table F-11 summarizes the most cost-effective DER solution (using the WACC discount rate) for each of the risks associated with this mitigation.

[6] Using the WACC discount rate.

Table F - 11: Reinforce PKL065 Feeder – Summary of DER Solutions

Capacity Risk	Need Shape			Most Cost-Effective Solution		
	Overload (MW)	Duration (Hours)	Demand Response (MWh)	Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)
N-0 FDR RISK 1	1.81	8.00	0.9	0.9	7.50	1.13/2.45

Table F-12 summarizes the overall incremental net impact of the most cost-effective NWA solution (using the WACC discount rate), including a detailed view of the incremental impact of each cost/benefit category.

Table F - 12: Reinforce PKL065 Feeder – Costs and Benefits Summary

Cost/Benefit Category	Incremental Impact
Energy Generation	$ 400,266
Generation Capacity + MISO Reserves	$ 122,602
Transmission Capacity	$ 5,830
Deferral Benefit	$ 627,936
GHG Emissions + Other Environmental	$ 623,658
Solar Cost	$ (504,285)
Battery Cost	$ (118,130)
Interconnection Fees	$ (34,000)
Total Benefit	**$ 1,780,292**
Total Cost	**$ (656,415)**
Net Impact	**$ 1,123,876**

Table F-13 below reflects the range of NWA solutions for both societal and WACC discount rates. It also illustrates the spectrum of net impact values from least cost-effective to most cost-effective.

Table F - 13: Reinforce PKL065 Feeder – Incremental Net Impact Summary

Incremental Net Impact		NWA Solution	
		Least Cost-Effective Solution	Most Cost-Effective Solution
Discount Rate	WACC	$281,051.61	$1,123,876.26
	Societal	$287,577.24	$1,212,331.83

XI. FUTURE NWA PILOT

We are excited that we have continued to advance our NWA analysis and incorporate stakeholder feedback. In our 2022 IDP Annual Update filed November 1, 2022, we noted that we were exploring potential NWA pilot projects and would provide an update in this IDP. Over the past year, given the numerous competing priorities facing our Distribution Planning and Engineering teams, we determined that waiting for the results of our 2023 NWA analysis would provide a better basis on which to continue exploring potential pilots or solicitations for NWAs. Indeed, this year's NWA analysis shows three potentially viable and cost-effective projects.

All three of these potentially viable projects have in-service dates in 2028. Given that timeline, we will have another opportunity to run our NWA analysis next year as part of our annual NWA analysis update before additional steps are taken. If any of the projects remain potentially viable and cost-effective, we would then determine next steps in the next IDP Annual Update filing in 2024.

If we were to issue a solicitation process for an NWA project, viable projects would undergo additional stacked value screening based on specific bids received. Additional factors also need to be considered- like locations, community priorities, equity and environmental justice, and cost recovery. We would also need to consider the internal resources required to execute a solicitation process and move a pilot through the engineering, design, construction, and management phases.

It is important to note that although three projects were feasible and showed a positive incremental net impact in this year's analysis, NWAs as a technology are a nascent mitigation option within the utility industry. In order for NWAs to be integrated effectively and safely into the system, a Distributed Energy Resources Management System application may be required, and internal operational expertise must mature due to the operational complexity. The practicalities of operating NWAs to solve risks on the system are not yet fully understood. Additionally, the distribution system is continually changing, and the results of this year's NWA analysis could look different next year.

XII. ASSUMPTIONS AND CALCULATIONS

For all NWA studies, we made reasonable assumptions toward streamlining the process. Our goal in these studies is to reduce overloads down to 75 percent of the capacity rating and contingencies with a 25 percent forecast uncertainty margin down to 100 percent of the capacity rating based on the forecasted loading at the end of the deferral period. Therefore, there is no "spare" capacity in these solutions and any additional load growth not planned for in the load forecast or the forecast uncertainty margin could cause additional risk; it would ultimately require an additional risk analysis, associated mitigation, and potentially another NWA analysis to address this incremental risk. The introduction of the forecast uncertainty margin reduces the risk of needing "spare" capacity during the deferral period, but it is not completely eliminated.

When conducting an NWA analysis, we assumed that peak day conditions contain the highest magnitude of risk. Therefore, rather than doing the analysis for potentially multiple overload events during the year, NWA studies are done utilizing available SCADA data containing peak day conditions. If SCADA data was not available, we used LoadSEER to generate peak day load curves. We selected a recent historical peak day for each risk and scaled the load curve to peak loads forecasted to the end of the deferral period.

Calculating various costs and benefits requires an assessment of how many times per year the NWA will be needed to reduce system demand, but this assumption is difficult to accurately estimate because peak load is primarily driven by weather conditions on weekdays during the summer. Therefore, the NWA needs to be able to reduce the effective system loading during any weekday during the summer months (June through September). In the future, as parts of the system electrify, areas could become winter peaking. In these cases, NWA solutions will need to provide relief in the winter months as well, possibly over the nighttime hours.

When approaching feeder and transformer risks, load that was not able to be offset by solar or DR resulted in energy storage solutions. To appropriately account for the various cost and benefits, we considered both the charging and discharging of the battery storage system throughout the peak day.

The minimum solar output curve we used ranges from 24-36 percent of nameplate output from 10:00 a.m. to 4:00 p.m., and to percentages less than that outside of that timeframe. We obtained this solar curve from the NREL PV Watts tool.

The DR curves we applied assumed peak at 6:00 p.m. on associated feeders, with a maximum of four-hour duration. Load reduction curves from DR were applied to risks that had N-0 overloads. Risks containing N-1 contingencies were generally not considered for DR 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.

Energy efficiency is already included in our load forecasts. It is common to both the traditional projects as well as the NWAs and therefore not considered as an NWA component. As noted previously, we explored use of a broader set of values and revenue streams for future NWA analyses with stakeholders in 2021 and have included those value and revenue streams in this analysis.

The analysis methodology calculates the optimal mix of solar PV and energy storage needed to address the remaining risk while maximizing the incremental net impact, which is calculated as the net benefits minus the net costs. However, the maximum quantity of solar PV that can be accommodated in the NWA analysis was constrained by the affected feeder's Technical Planning Standard (TPS). The TPS is defined as 80 percent of the feeder's continuous rating plus the daytime minimum load. This constraint was added to prevent the model from violating the planning limit for maximum distributed generation on the affected feeders. In reality, upgrades could nonetheless be required in order to interconnect the calculated amount of incremental solar on the affected feeders, but these costs were not considered in the NWA analysis. Additionally, there were no constraints applied based on land availability or other factors that could prevent the optimal solution from being realistic. Therefore, the most realistic solution may differ from the optimal solution and would result in a different, lower incremental net impact. To characterize this range of possible solutions, the incremental net impact for both the optimal solution and the least cost-effective solution is provided in the NWA analysis results for each project below.

Regarding cost assumptions, previously we utilized a flat battery storage unit cost based solely on energy capacity (MWh) using existing available industry costs. Since the 2022 NWA analysis, we have been using battery storage costs based on both the energy (MWh) and power (MW) components of battery storage systems. We obtained the formula we used to calculate these costs from the 2023 NREL Annual

Technology Baseline (ATB).[7] Table F-14 below shows the cost and benefit assumptions used in the NWA analysis.

Like battery storage, solar PV costs were obtained from the NREL ATB, which uses estimated PPA costs per MWh of annual production. Both battery storage and solar PV costs were pro-rated in the analysis based on the percentage of the annual production that coincides with the load reduction period. Because the battery storage cost estimates reflect the actual costs to install the battery storage system, these costs were further pro-rated based on the percentage of the battery's useful life that is needed for the NWA deferral period. These pro-rated components of the analysis are described as the ARR Split.

We did not include O&M costs related to maintaining solar or battery storage systems. DSM Program Administration Costs as well as End-of-Life Replacement costs were not included. Additionally, we assumed that land would be available at key locations on feeders/transformers/substations that would enable the NWA solution and did not include any potential land lease or purchase costs in our analysis.

Table F - 14: Cost and Benefit Assumptions in NWA Analysis

Assumption Category	Assumption	Value	Source/Basis
Economic	Deferral Period	5 years from project in-service date	Currently expected structure of potential future NWA load reduction contracts
	Need Shape - Days Per Week	5 (weekdays)	
	Need Shape – Months Per Year	4 (June through September)	
	General Cost Escalation Rate (Inflation)	2%	2020-2034 Integrated Resource Plan (Docket No. E002/RP-19-368)

[7] Available at https://atb.nrel.gov/electricity/2023/data.

Assumption Category	Assumption	Value	Source/Basis
	Discount Rate (Weighted Average Cost of Capital (WACC)	6.47%	2020-2034 Integrated Resource Plan
	Societal Discount Rate	3.00%	2024-2026 Minnesota CIP Triennial Plan (Docket No. E002/CIP-23-92)
	Year 1	2027	
Energy Supply	Year 1 Annual Average On-Peak Marginal Energy Cost	$33.35/MWh	2020-2034 Integrated Resource Plan
	Year 1 Annual Average Off-Peak Marginal Energy Cost	$26.71/MWh	2020-2034 Integrated Resource Plan
	Year 1 Surplus Capacity Credit	$54,600/MW	2020-2034 Integrated Resource Plan
	Levelized Avoided Emissions Benefit	$39.8/MWh	Value of Solar
	MISO Reserve Margin	7.4%	MISO Loss of Load Expectation Study
Transmission	Year 1 Transmission Capacity Credit	$3,346/MW	2024-2026 Minnesota CIP Triennial Plan, '24-'26 Avoided Costs
	Transmission Capacity Cost Escalation Rate	2.00%	2024-2026 Minnesota CIP Triennial Plan, '24-'26 Avoided Costs
	Transmission System Losses	96%	2020-2034 Integrated Resource Plan

Assumption Category	Assumption	Value	Source/Basis
DER	Total Battery Cost	Total System Cost ($) = Battery Storage Capacity (MWh) * Battery Energy Cost ($/MWh) + Battery Power Capacity (MW) * Battery Power Cost ($/MW) + Battery Power Constant ($)	2023 NREL ATB[8]
	Battery Energy Cost	$186,850/MWh	2023 NREL ATB
	Battery Power Cost	$755,877/MW	2023 NREL ATB
	Battery Power Constant	$175,840	2023 NREL ATB
	Battery Useful Lifetime	15 years	2023 NREL ATB
	Battery Roundtrip Efficiency	85%	2023 NREL ATB
	Battery Depth of Cycle	70%	2023 NREL ATB
	DER Planning Limit	80% Feeder/TR Capacity + Fixed Daytime Minimum Load – Existing Solar	Technical Planning Standard
	Solar PPA Cost	Ranges from $38.56 - $45.85/MWh	2023 NREL ATB[9]
	Solar Annual Rating	1791 MWh/MW	NREL PVWatts
	Average DER Interconnection Study Cost	$34,000	Sum of Fees for System Impact Study, Facility Study, and Processing Fees

[8] The 2023 NREL ATB cost assumptions for battery energy storage systems does not include Inflation Reduction Act (IRA) tax credits. Although we are making an adjustment for our forthcoming Resource Plan modeling, we did not have time to incorporate that adjustment into this year's NWA analysis.
[9] Reflects IRA tax credits.

Assumption Category	Assumption	Value	Source/Basis
Exclusions	O&M Costs	Not included in analysis	
	DSM Program Administration Costs	Not included in analysis	
	Land Costs and Availability	Not included in analysis	
	End of Life Replacement Costs	Not included in analysis	

A. Stacked Values Formulas

Calculation – Avoided Energy Generation (Benefit)

$$Avoided\ Energy\ Generation\ [\$] = PV\ Avoided\ Energy\ Generation\ [\$] + Battery\ Avoided\ Energy\ Generation\ [\$]$$

Calculation – PV Avoided Energy Generation (Benefit)

$$PV\ Avoided\ Energy\ Generation\ [\$] = \sum_{y=1}^{Deferral\ Period} PV\ Annual\ Output\ During\ Load\ Reduction\ Period\ [MWh] * Year\ 1\ Annual\ Average\ On\ Peak\ Marginal\ Energy\ Cost\ [\$/MWh] / \text{Transmission System Losses } [\%] * \left(\frac{1 + Inflation\ Rate}{1 + Discount\ Rate}\right)^{y}$$

Calculation – Battery Avoided Energy Generation (Benefit)

$$Battery\ Avoided\ Energy\ Generation\ [\$] = \sum_{y=1}^{Deferral\ Period} Battery\ Annual\ Output\ During\ Load\ Reduction\ Period\ [MWh] * \left(Year\ 1\ Annual\ Average\ On\ Peak\ Marginal\ Energy\ Cost\ [\$/MWh] - \frac{Year\ 1\ Annual\ Average\ Off\ Peak\ Marginal\ Energy\ Cost\ [\$/MWh]}{Battery\ Roundtrip\ Efficiency\ [\%]}\right) / \text{Transmission System Losses } [\%] * \left(\frac{1 + Inflation\ Rate}{1 + Discount\ Rate}\right)^{y}$$

Calculation – Avoided Generation Capacity and MISO Reserves (Benefit)

$$\begin{aligned} &\mathit{Avoided\ Generation\ Capacity\ and\ MISO\ Reserves}\ [\$] \\ &= \sum_{y=1}^{\mathit{Deferral\ Period}} \mathit{NWA\ Demand\ Rating}\ [MW] \\ &* \mathit{Year\ 1\ Surplus\ Capacity\ Credit}\ [\$/MW] / \text{Transmission System Losses [\%]} \\ &* \frac{\mathit{NWA\ Annual\ Output\ During\ Load\ Reduction\ Period}\ [MWh]}{\mathit{NWA\ Annual\ Output}\ [MWh]} \\ &* \left(\frac{1 + \mathit{Inflation\ Rate}}{1 + \mathit{Discount\ Rate}}\right)^{y} \end{aligned}$$

Calculation – Avoided Transmission Capacity (Benefit)

$$\begin{aligned} &\mathit{Avoided\ Transmission\ Capacity}\ [\$] \\ &= \sum_{y=1}^{\mathit{Deferral\ Period}} \mathit{NWA\ Demand\ Rating}\ [MW] \\ &* \mathit{Year\ 1\ Transmission\ Capacity\ Credit}\ [\$/MW] \\ &/ \text{ Transmission System Losses [\%]} \\ &* \frac{\mathit{NWA\ Output\ During\ Load\ Reduction\ Period}\ [MWh]}{\mathit{NWA\ Annual\ Output}\ [MWh]} * \left(\frac{1 + \mathit{Inflation\ Rate}}{1 + \mathit{Discount\ Rate}}\right)^{y} \end{aligned}$$

Calculation – Deferral Benefit (Benefit)

$$\mathit{Deferral\ Benefit}\ [\$] = \mathit{Year\ 1\ Traditional\ Solution\ Cost}[\$] * \left(1 - \left(\frac{1 + \mathit{Inflation\ Rate}}{1 + \mathit{Discount\ Rate}}\right)^{10}\right)$$

Calculation – Solar Cost (Cost)

$$\begin{aligned} \mathit{Solar\ Cost}\ [\$] = &\sum_{y=1}^{\mathit{Deferral\ Period}\ [years]} \mathit{PV\ Annual\ Output\ During\ Load\ Reduction\ Period}\ [MWh] \\ &* \mathit{Year\ 1\ PPA\ Cost}\ [\$/MWh] * \left(\frac{1 + \mathit{Inflation\ Rate}}{1 + \mathit{Discount\ Rate}}\right)^{y} \end{aligned}$$

Calculation – Battery Cost (Cost)

$$
\begin{aligned}
\mathit{Battery\ Cost}\ [\$] \\
&= (\mathit{Battery\ Storage\ Capacity}\ [MWh] * \mathit{Battery\ Energy\ Cost}\ [\$/MWh] \\
&+ \mathit{Battery\ Power\ Capacity}\ [MW] * \mathit{Battery\ Power\ Cost}\ [\$/MWh] \\
&+ \mathit{Battery\ Power\ Constant}\ [\$]) \\
&* \frac{\mathit{Battery\ Annual\ Output\ During\ Load\ Reduction\ Period}\ [MWh]}{\mathit{Battery\ Annual\ Output}\ [MWh]} \\
&* \frac{\mathit{Load\ Deferral\ Timeframe}\ [years]}{\mathit{Battery\ Useful\ Lifetime}\ [years]}
\end{aligned}
$$

Calculation – Interconnection Fees (Cost)

$$
\begin{aligned}
\mathit{Interconnection\ Fees}\ [\$] \\
&= \mathit{Number\ of\ Interconnection\ Points} * \mathit{Average\ Interconnection\ Study\ Cost}\ [\$]
\end{aligned}
$$

Calculation – Avoided GHG and Other Avoided Environmental Impacts (Benefit)

$$
\begin{aligned}
\mathit{Avoided\ Greenhouse\ Gas\ Emissions\ and\ Other\ Avoided\ Environmental\ Impacts}\ [\$] \\
&= \mathit{PV\ Annual\ Output\ During\ Load\ Reduction\ Period}\ [MWh] \\
&* \mathit{Levelized\ Avoided\ Emissions\ Benefit}\ [\$/MWh] * \mathit{Deferral\ Period}\ [years]
\end{aligned}
$$

APPENDIX G: STAKEHOLDER ENGAGEMENT

In this Appendix, we discuss our stakeholder engagement leading up to this IDP.

In summary, we held six workshops and the IDP Preview between September 2022 and September 2023 covering those areas of highest interest for IDP stakeholders. Over 250 stakeholders participated in the six workshops and preview- with many of those participating in more than one event. As required by IDP Order Point 6 of the Commission's July 26, 2022 Order in Docket No. E002/M-21-694 (the 2021 IDP Order), we made a compliance filing on August 1, 2023, in Docket No. E002/M-21-694 that provided a summary of the stakeholder series and engagement process. This Appendix provides supplementary information to that compliance filing and includes details about the IDP Preview. All workshops provided the opportunity for our stakeholders to ask questions and to provide us feedback on our IDP. We listened to, and reflected upon, our stakeholders input and incorporated it into our plans where appropriate and will continue to evaluate where that feedback can be incorporated as we go forward. For example, we incorporated feedback regarding forecasting and the initial planned net loading methodology, which is discussed in *Appendix A1. System Planning*.

To get into the details further, IDP Order Point 6 of the 2021 IDP Order requires the following:

> *Xcel shall hold a series of stakeholder meetings to collaborate with interested parties, obtain input, and generate new ideas around a shared vision of the distribution grid of the future. This stakeholder series is intended to provide transparency into the Company's distribution planning process and explore how Minnesota's public policy goals will be realized on the distribution system and impact the Company's future plans.*
> *This stakeholder series should be timed such that stakeholder input can be incorporated into the Company's next IDP filing and next IRP filing and include at least four meetings. The topics will include, but not be limited to, the following:*
>
> > *a. Integrated Distribution Planning 101*
> > *b. Identify the public policy goals that are changing the expectations of the distribution grid and how each public policy is expected to be realized on the grid in the near- and long-term. [For example, examine transportation, building and industrial electrification forecasts and the effects on load profiles in the near-term and long-term.]*
> > *c. How energy efficiency, demand response, and other DER might impact Xcel's planning processes.*
> > *d. How Xcel should consider and incorporate local clean energy goals in its planning processes.*

e. What investments are necessary to achieve the distribution grid of the future, and the criteria Xcel should use to plan and prioritize those investments.
f. Prioritizing the use of "net load" in its load forecasts and system planning, including developing a methodology for incorporating the load reducing impact of distributed generation into its load forecasts and system planning processes.
g. Develop a methodology for valuing the load-modifying impacts of demand response in load forecasts and present a load forecast that includes demand response contributions.
h. Identify appropriate transportation, building, and industrial end use electrification scenarios for inclusion in the 2023 IDP load forecasts.
i. How Xcel anticipates proactively planning for grid investments to allow distributed generation and EV additions consistent with the DER forecast.
j. Estimate the potential synergies between interconnection upgrades and planned distribution capital investments, and discuss the anticipated overlap between planned investments and capacity constrained locations on Xcel's distribution system.

Xcel shall make a compliance filing with a summary of the stakeholder process and a list of next steps by August 1, 2023. Xcel shall include a summary of the stakeholder series in its next IDP and relevant summary in its next IRP, including how it considered and incorporated stakeholder input.

The Commission's 2021 IDP Order required the Company to hold at least four meetings in its stakeholder series. Based on the amount of material we wanted to share with stakeholders, the Company held six workshops, which included presentations from the Company's staff, questions and input from attendees, and time for open discussion. The workshop series were held beginning September 2022 and ran through September 2023, with workshops being held virtually, in-person, or as hybrid meetings. The overall duration of all the workshops combined was more than 16 hours. We recognize that this was a significant amount of time for stakeholders, and we appreciate their time and input. Table 1 below provides a matrix of the Order Points, the required topics covered, and the corresponding workshop detail(s).

Table G-1: IDP Order Points 3 and 6 Stakeholder Outreach Efforts

IDP Order Point 3	Addressed in Workshop:
Xcel shall use both the WACC and societal discount rate in its NWA analysis and discuss the results of the two approaches in a future IDP stakeholder meeting.	Planning the Grid of the Future Part 2 Workshop: June 12, 2023

IDP Order Point 6: Xcel shall hold a series of stakeholder meetings to collaborate with interested parties, obtain input, and generate new ideas around a shared vision of the distribution grid of the future. This stakeholder series is intended to provide transparency into the Company's distribution planning process and explore how Minnesota's public policy goals will be realized on the distribution system and impact the Company's future plans. This stakeholder series should be timed such that stakeholder input can be incorporated into the Company's next IDP filing and next IRP filing and include at least four meetings.	
	Addressed in Workshop:
(a) Integrated Distribution Planning 101	IRP/IDP 101 Workshop: September 26 and 27, 2022
(b) Identify the public policy goals that are changing the expectations of the distribution grid and how each public policy is expected to be realized on the grid in the near- and long-term. [For example, examine transportation, building and industrial electrification forecasts and the effects on load profiles in the near-term and long-term.]	Policy, Technology and Planning Workshop: November 15, 2022 Forecasting: Electrification and DER Workshop: February 13, 2023
(c) How energy efficiency, demand response, and other DER might impact Xcel's planning processes.	Planning the Grid of the Future Part 1 Workshop: May 22, 2023
(d) How Xcel should consider and incorporate local clean energy goals in its planning processes.	Policy, Technology and Planning Workshop: November 15, 2022
(e) What investments are necessary to achieve the distribution grid of the future, and the criteria Xcel should use to plan and prioritize those investments.	Envisioning the Grid of the Future: April 20, 2023
(f) Prioritizing the use of "net load" in its load forecasts and system planning, including developing a methodology for incorporating the load reducing impact of distributed generation into its load forecasts and system planning processes.	Planning the Grid of the Future Part 1 Workshop: May 22, 2023
(g) Develop a methodology for valuing the load-modifying impacts of demand response in load forecasts and present a load forecast that includes demand response contributions.	Planning the Grid of the Future Part 1 Workshop: May 22, 2023
(h) Identify appropriate transportation, building, and industrial end use electrification scenarios for inclusion in the 2023 IDP load forecasts.	Planning the Grid of the Future Part 1 Workshop: May 22, 2023
(i) How Xcel anticipates proactively planning for grid investments to allow distributed generation and EV additions consistent with the DER forecast.	Envisioning the Grid of the Future: April 20, 2023
(j) Estimate the potential synergies between interconnection upgrades and planned distribution capital investments, and discuss the anticipated overlap between planned investments and capacity constrained locations on Xcel's distribution system.	Envisioning the Grid of the Future: April 20, 2023 Planning the Grid of the Future Part 2 Workshop: June 12, 2023 60

To better accommodate stakeholders' schedules and increase participation rates, a survey was sent to stakeholders to solicit information pertaining to their preferred format. The survey was sent to approximately 500 individuals on our Interested Parties List with 35 responses or a seven percent response rate. Of those that responded, 66 percent preferred meetings held virtually, yet 66 percent also indicated that meetings held in-person were more effective. As a result, a variety of meeting workshop options were held over the series, with all in-person workshops later in the series being offered as hybrid workshops.

Invitations were filed in Docket No. E002/M-21-694 and emailed to those who have requested to be on our "Interested Parties List." As discussed below, three workshops covered topics related to both the IDP and the Integrated Resource Plan (IRP). At every workshop, we referenced the "Interested Parties List" and provided direction on how stakeholders could be added to the list. Approximately 500 stakeholders on our Interested Parties List received email invitations for each workshop. Based on the number of direct email invitations alone, which does not include attendees that may have been alerted to the workshop via docket submissions, participation rates ranged from five percent to 11 percent, or approximately 25-50 participants. Participants could submit questions during the registration process and were also provided ample opportunity to ask questions and provide feedback and input during each workshop. Consistent with the Commission's July 23, 2020 Order in Docket No. E002/M-19-666, workshops were open to any interested person.[1] After each workshop, we filed the Company's presentation in Docket No. E002/M-21-694.

We estimate that the Company's employees dedicated over 700 labor hours to the development and delivery of these workshops. These hours include time spent in meetings to develop agendas and topics to be addressed in the workshop; identify areas of stakeholder input; administrative activities including registration tracking; preparation of workshop presentations including editing, review, and dry run throughs of the presentation; workshop participation; and follow up as necessary. We recognize the benefit and the importance of connecting with our stakeholders and receiving their input and feedback on our planning processes. The in-person and virtual workshops each held their own benefits. The in-person workshops allowed the Company to connect one-on-one with our stakeholders, while the virtual sessions provided participants easier access to the workshops and minimized travel requirements.

The workshop series began with a general overview on the IDP process, and each following workshop became more detailed and technical in nature. We found that once the information became more specific, the number of stakeholders attending each consecutive workshop decreased, but the feedback we received and questions that were asked also became more specific.

As required by IDP Order Point 6, we made a compliance filing on August 1, 2023, in Docket No. E002/M-21-694 that provided a summary of the stakeholder series and engagement process. The filing included an overview of each workshop, a summary of questions and input received, and poll input results, where applicable, for each of the workshops held prior to August 1, 2023. Below, we provide an overview of the stakeholder workshop held after the compliance filing, on September 19, 2023.

[1] Order Point 5 states, "Xcel must allow any interested person to participate in stakeholder engagement meetings regarding its IDP and HCA."

IDP Preview Summary
Logistics: Virtual: September 19, 2023
Attendance: 27
IDP Order Point: IDP Requirement 2 as provided in the Commission's December 8, 2022 Order in Docket Nos. E002/M-21-694 and E999/CI-17-879 and Order Point 6 of the Commission's July 26, 2022 Order in Docket No. E002/M-21-694.

1. *IDP Preview Overview*

The intent of this virtual workshop was to share a preview of this IDP with stakeholders. The preview included preliminary distribution system budgets and investment plans and distributed energy resources (DER) forecasts.

The presentation began with a brief overview of the IDP including objectives, regulatory requirements, and the distribution planning process. This was followed by a discussion on the forecasting process, scenarios considered, and growth components as well as the different forecasts provided and how certain forecasts inform other forecasts. This was then followed by a discussion pertaining to budget and investments. We identified the categories of investments and provided budget trend information. We discussed our non-wires alternative analysis, including an overview of the process employed, projects under consideration, and the project evaluation process. We finished with a discussion pertaining to the Company's grid modernization efforts including the AMI meter installation timeline, benefits of potential customer enhancements, reliability and planning benefits of our grid modernization investments, and accessing meter data via My Energy Connection.

Throughout the workshop, participants were offered multiple opportunities to ask questions and provide input.

2. *IDP Preview Workshop Stakeholder Questions and Input*

- Several clarifying questions were asked by participants.
- We were asked how we are accounting for load flexibility, demand response, and energy efficiency in the load forecast to mitigate peak load growth. We indicated that they are included in the corporate energy sales and demand forecast. We are working to break load flexibility, demand response, and energy efficiency out as separate forecast allocations to see what impacts they each have on tapering load growth and demand forecast.
- A stakeholder inquired if we expected to have a non-wires alternative project

out for solicitation this year and if any of the projects have been shown to be cost effective. We indicated that we are still determining which projects meet our criteria and that we would discuss next steps in the IDP filing.

- A participant asked how we have been managing the transformer shortage and if there have been customer impacts. We indicated that global supply chain issues have impacted us. Our transformer repair workshop is being used to refurbish transformers. We noted that we have also approved a new manufacturer of transformers. Lead times for distribution transformers are currently at 170 weeks and power transformers currently have lead times of 3 years; it is a concern for us. We note that we discuss the industry-wide transformer shortage and our actions to mitigate the impacts in *Appendix A2: Standards, Asset Health, and Reliability Management* of this IDP.
- A request was made for us to include forecast information on a year-by-year basis in a tabular format for readability. This has been incorporated into the IDP and is included as Attachments M, N, and O..

IDP Survey Results

After the conclusion of the workshop series, we requested feedback on the series through an online survey. We sent the survey to everyone who participated in one or more of the workshops. The intent of the survey was to obtain feedback on the workshops in order to inform future efforts. The survey included questions pertaining to duration, frequency, location, satisfaction and if the level of information shared was appropriate. Also, we requested feedback on how we could improve stakeholder efforts going forward and if there was support for similar workshops in the future. Of the nearly 160 emails sent requesting a response to the survey, we received six responses, or a response rate of approximately four percent. Those that did respond indicated that:

- They found the duration of the workshops was just right.
- The workshops were informative and helpful.
- They felt they had a better understanding of the process after participation.
- Regarding venue location, one participant suggested that the workshops be held in a location other than downtown Minneapolis, and one indicated that the venue location affected their decision to attend in person.
- Regarding the level of detail that was provided, the majority of respondents found the level of detail "just right." One respondent indicated that they found that the information was often very technical and that while they found they were offered ample opportunity to ask questions and provide feedback, it was difficult to be able to do so while absorbing the information and suggested a more basic conversation. On the other hand, one respondent felt the

information shared was too simplified.

- Three agreed with our IDP process, one did not respond to that question, and two disagreed. Of those that disagreed with our process, one highlighted their view that hosting capacity for load and generation needs to have even treatment. The other participant indicated that they largely agree with our process but indicated that they would prefer to see the Company use one of its higher-level DER/Electrification forecasts as the basis for planning or to use it as a sensitivity or basis for planning in high-priority areas. Currently, our budget scenario is distinct from the DER forecast scenarios because the DER forecast scenarios contain speculative load growth. As we have discussed elsewhere in this IDP, we must prioritize our investments to keep bills low for customers, and we currently focus our investment planning primarily on projects that are required to meet known and expected load growth. However, we recognize that we must still work proactively to meet the rapid pace of load growth represented in the DER forecast scenarios, and we are actively working to determine how to identify "no regrets" projects to prepare for the future. The DER forecast scenarios are appropriate to use to inform long-range planning studies for substations or larger areas.
- Four respondents indicated satisfaction with the stakeholder process and two did not. One that did not agree indicated they felt that it would be helpful to have an even more basic explanation of some of the topics covered so that they are accessible to those working on these matters for the first time. The other expressed appreciation for all the effort put into the workshops but suggested the sharing of the presentation prior to the workshop for review by registrants so that they could be better prepared to ask questions.
- Five respondents indicated that they felt they had sufficient opportunity to offer input during the workshops. The one that indicated they didn't have sufficient opportunity pointed to the poll questions being simplified on complex topics and felt that workshop leaders were guiding the answers.
- Two respondents provided feedback on how we could improve the stakeholder process going forward. One suggested sharing an even more basic explanation of the topics for those new to the work. The other suggested the pre-sharing of slides and holding smaller group discussions instead of broader discussions.
- All supported the Company hosting a series of workshops again in the future.

We appreciate the valuable feedback provided by the six survey respondents and will consider the feedback in future workshops.