414 Nicollet Mall
Minneapolis, MN 55401

PUBLIC DOCUMENT
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October 3, 2025

—Via Electronic Filing—

Sasha Bergman
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: PETITION
REQUEST FOR APPROVAL OF CAPACITY*CONNECT
DOCKET NO. E002/M-25-___

Dear Ms. Bergman:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Petition for approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program.

DCP is an innovative step on the pathway of building the grid of the future that supports the clean energy transition and meets our customers' growing needs and expectations. This Petition outlines our vision and roadmap for Capacity*Connect and seeks Commission approval for Phase 2 of the program.

The Petition includes the following Attachments:

- Attachment A: Tax Credit Background
- Attachment B: Budget Detail
- Attachment C: Cost-Benefit Analysis Model
- Attachment D: Distributed Energy Resources Management System (DERMS) Roadmap and Other Required Information
    - Attachment D1: DERMS Deployment Pathways

Portions of this filing and Attachments B and C are marked "Not-Public" as they contain information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential cost and pricing data, commercial information, and vendor information that derive an independent economic value from not being generally known or readily ascertainable by others who could obtain economic value or a financial advantage from its disclosure or use.

The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500. Attached to this cover letter, we provide the required information as specified in Minn. R. 7829.1300 and Minn. R. 7829.0700, including to whom information requests should be directed.

Attachments B and C are marked "Not-Public" in entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

Attachment B:

1. **Nature of the material:** Capacity*Connect budget detail
2. **Authors:** Customer Energy & Transportation Solutions
3. **Importance:** Contains not-public, proprietary cost data
4. **Date the Information was Prepared:** September/October 2025

Attachment C:

1. **Nature of the material:** The Company's cost-benefit analysis model for Capacity*Connect, provided as a live Excel workbook.
2. **Authors:** Integrated System Planning
3. **Importance:** The Company work product is proprietary to the Company
4. **Date the Information was Prepared:** September/October 2025

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service lists. Copies have also been served on the parties on service lists for Docket Nos. E002/RP-24-67 and E002/CN-23-212. Please contact Karin Haas at karin.haas@xcelenergy.com or contact me at jody.l.londo@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

JODY LONDO
DIRECTOR – REGULATORY & STRATEGIC ANALYSIS

Enclosures
cc: Service Lists

REQUIRED INFORMATION

I. SUMMARY OF FILING

A one-paragraph summary is attached to this filing pursuant to Minn. R. 7829.1300, subp. 1.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission. Pursuant to Minn. R. 7829.1300, subp. 2, the Company has served a copy of this filing on the Department of Commerce and the Office of the Attorney General. A summary of the filing has been served on all parties on the enclosed service list.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, the Company provides the following information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Ian Dobson
Lead Assistant General Counsel
Xcel Energy
414 Nicollet Mall, 401 – 8th Floor
Minneapolis, MN 55401
(612) 370-3578

C. Date of Filing

The Company submits this petition on October 3, 2025 for approval.

REQUIRED INFORMATION

D. Statute Controlling Schedule for Processing the Filing

Commission Rules define this filing as a "miscellaneous filing" under Minn. R. 7829.0100, subp. 11 since no determination of Xcel Energy's overall revenue requirement is necessary. Minn. R. 7829.1400, subp. 1 and 4 permit comments in response to a miscellaneous filing to be filed within 30 days and reply comments to be filed no later than 10 days thereafter.

E. Utility Employee Responsible for Filing

Jody Londo
Director, Regulatory & Strategic Analysis
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, MN 55401
(612) 216-7954

IV. MISCELLANEOUS INFORMATION

Pursuant to Minn. R. 7829.0700, the Company requests that the following persons be placed on the Commission's official service list for this proceeding:

Xcel Energy
Ian Dobson
Lead Assistant General Counsel
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ian.m.dobson@xcelenergy.com

Xcel Energy
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Regulatory Administrator
MN1180-07-MCA
414 Nicollet Mall
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regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to Ms. Marquis at the Regulatory Records email address above.

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey C. Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF CAPACITY*CONNECT, A DISTRIBUTED CAPACITY PROCUREMENT PROGRAM	Docket No. E002/M-25-___ **PETITION**

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, requests the Minnesota Public Utilities Commission to approve a new Distributed Capacity Procurement (DCP) program – Capacity*Connect or C*C – as outlined in this Petition.

The Company submits this Petition in compliance with the Commission's April 21, 2025 Order in Docket Nos. E002/RP-24-67 and E002/CN-23-212, which approved a Settlement Agreement between parties relating to the Company's 2024-2040 Integrated Resource Plan (IRP) and its Petition to acquire 800 megawatts (MW) of firm dispatchable resources (hereafter "IRP Order"). Order Point No. 23 states:

> Xcel must file a Distributed Capacity Procurement (DCP) proposal by October 3, 2025. The filing must include:
> a. An evaluation of how the Distributed Capacity Procurement program could be used to improve equity.
> b. A discussion of how the proposal impacts the Five-Year Action Plan approved in this order, how it impacts the IRP forecasted annual distributed generation solar additions, and whether the DCP could be used to advance compliance with the distributed solar energy standard.
> c. An evaluation of a costs and benefits comparison between a utility-owned and managed DCP model and alternative models allowing participation from customer-owned and third party-owned resources.
> d. An evaluation of the labor standards utilized by Xcel and third-party solar installers.

As the Commission has recognized, "[t]he country's electric grid is undergoing significant and rapid changes driven by several factors, including the push to decarbonize electricity generation, increased load served by the distribution system, and the proliferation of distributed energy resources (DERs)."[1] This broadening use of the distribution system, and consequential need for investment in that system, "provide[s] an opportunity to leverage these resources to optimize grid investments and improve overall power system performance, economic efficiency, and reliability."[2] Xcel Energy has been at the forefront of this evolution, through its development and support of numerous DER programs. Capacity*Connect is the Company's next step in that journey. The vision of this program is one that provides capacity and energy benefits for customers without the need for potentially time-consuming and costly interconnection, upgrades, and investment in the bulk system, while bringing more locally stacked benefits through optimization of the distribution system. These benefits won't all be realized immediately, but we believe this proposal provides critical movement toward an energy future that optimizes the usage of all of our assets.

In this Petition, we outline our vision and roadmap for the Capacity*Connect program – where the program could expand and evolve in phases, increasing in scope and scale over the next five-plus years to deliver customer value and allowing the Company to gain experience and expertise in optimizing distributed grid assets and using the distribution system as an extension of the bulk system.

This Petition seeks Commission approval for DCP Phase 2, Capacity*Connect (C*C), which proposes deployment of approximately 50-200 MW of Company-owned and -operated front-of-the-meter (FTM) battery energy storage systems (BESS) by the end of 2028. We also propose to implement a limited deployment of a Grid Distributed Energy Resources Management System (DERMS) that will support C*C and provide important operational experience to inform the future requirements for an Enterprise DERMS deployment.

The optimal range of potential installed BESS capacity depends on a range of operational capabilities, some that exist today and others that will require more substantial investment and coordination in people, process, and technology. Initial

[1] *In the Matter of Xcel Energy's 2023 Integrated Distribution Plan*, Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements, September 16, 2024, Docket No. E002/M-23-452.
[2] *Distribution System Evolution*, U.S. Department of Energy, Office of Electricity, April 2024 (available at https://www.energy.gov/sites/default/files/2024-05/Distributed%20System%20Evolution%20April%202024_optimized.pdf).

BESS deployments will provide necessary and practical insights into the pace and magnitude at which we can scale this program; simply put, we do not yet know how many megawatts of BESS we can install, and safely and cost-effectively integrate into our operations in this next phase of C*C without continuing to answer several key questions. Customer engagement with site hosts and potential large load partners will provide important insights in this phase as well.

With that in mind, we propose to submit quarterly status reports to the Commission, leading to an Interim Program Assessment after two years from Phase 2 approval or we achieve commercial operation of 20 MW, whichever is earlier. The Program Assessment will be a critical stage gate, in which we will review the costs and benefits, host experience, and operational experience. Based on that assessment, we would propose a path forward – for example, staying the course to 50-200 MW deployment on the planned timeline, adjusting program components, or potentially pausing or halting the program until we believe it can provide meaningful benefits for our customers. As we move through with procurement, design and deployment, we may gain additional information that could also influence our path; quarterly reporting will provide additional opportunity to provide updates before the Interim Program Assessment.

Looking beyond Phase 2, we would evaluate scaling C*C and expanding deployments further.

We respectfully request the Commission approve:

- Implementation of the Phase 2 Capacity*Connect, including:
  - Deployment of approximately 50 MW and up to 200 MW of Company-owned and -operated distribution-interconnected BESS by the end of 2028.
  - A budget range of approximately $152 million (corresponding to the planned 50 MW deployment) to approximately $430 million (estimated for a 200 MW deployment) through 2028.
- Quarterly status reporting until an Interim Program Assessment to be filed after commercial operation of 20 MW or two years from Phase 2 approval, whichever is sooner.
- Implementation of a limited deployment of a grid DERMS to support C*C and inform the Company's requirements for a future Enterprise DERMS.
- The Company's proposal to seek recovery of C*C costs in the Renewable Energy Standard (RES) Rider.

In addition, we respectfully request that the Commission find that the Company has adequately addressed the DERMS information and questions required by Order Point No. 23 of the Commission's September 16, 2024 Order in Docket No. E002/M-23-452.

In the remainder of this Petition, we outline:

- Our Capacity*Connect vision and roadmap.
- Details of Phase 2 implementation, including:
    - How feeders and host sites will be selected.
    - How the sites and batteries will be designed, procured, constructed, and operated.
    - The costs and quantitative and qualitative benefits of Phase 2.
    - Labor standards and how C*C can advance equity and environmental justice.
    - Our proposed plan for cost recovery and reporting.

I. CAPACITY*CONNECT VISION AND BACKGROUND

Capacity*Connect is an innovative way to use BESS to provide grid value and meet our customers' needs by strategically and functionally deploying storage assets on the Company's distribution system. As our most recent IRP demonstrated, the Company needs to add capacity over the next five years and beyond to meet growing customer loads and state policy objectives. C*C is aligned with the five-year plan approved by the Commission in its IRP Order and begins to utilize the distribution system as an extension of the broader bulk, NSP System.

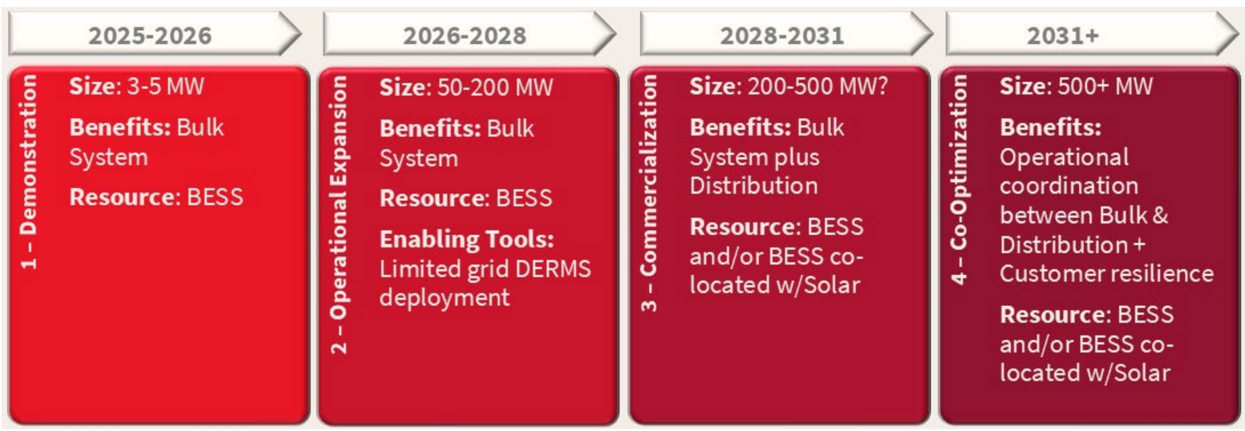
A. Vision

DCP is an innovative step on the pathway of building the grid of the future that supports the clean energy transition and meets our customers' growing needs and expectations. C*C represents a step-change in how Xcel Energy and other utilities are beginning to incorporate distributed energy resources into system planning and operations. C*C assets could be used to offset peak load, mitigate curtailment of renewables and support more renewables on the system, meet bulk system capacity needs and participate in Midcontinent Independent System Operator (MISO) markets, and more. Through the evolution of C*C, the Company is seeking to identify the processes, tools, and capabilities that may allow us to co-optimize benefits between the bulk system and distribution system.

Our Phase 2 proposal builds on the Phase 1 demonstration approved through the Company's Energy Conservation and Optimization (ECO) plan. Over the next five-plus years, we envision a phased program that could expand and optimize as the Company takes a continuous-improvement mindset to incorporate lessons learned, evolve our operational capabilities, and maximize value streams to benefit the grid and our customers – all while managing costs. Phase 2 is intended to carefully inform and shape the future of C*C, as conceptually illustrated in the C*C roadmap and vision that we lay out in this Petition.

Figure 1 below provides a high-level snapshot of our C*C roadmap as we see it today; we emphasize that this roadmap is subject to change.

Figure 1: Conceptual C*C Roadmap



Each phase is designed to build on the previous phase, while leaving room to adjust in response to lessons learned, new data, market changes, validating new processes and methods for scaled deployment, advances in technology and operations, and stakeholder and Commission feedback. Given this vision, we want to also provide a realistic foundation that this is a new approach to meeting system needs, and we will have to remain flexible to assure the capital deployed for this approach is delivering on the benefits as envisioned. If we find this program is not providing meaningful benefits to our customers, we will seek to adjust the program.

B. Background

The Company first raised the concept of DCP in our August 9, 2024 Letter in the IRP docket. Since then, the Company has been working across the many involved business areas at Xcel Energy – alongside our implementation partner, Sparkfund – to gather details and begin to assess the varied impacts and challenges to successful implementation and subsequent scaling of this novel concept. The Phase 2 C*C program will provide important testing and validation of costs, benefits, operational coordination, and scalability. That said, to develop the industry-leading full-scale program that we believe is achievable, we must proceed thoughtfully within and beyond Phase 2.

As we have explored the DCP concept, we have uncovered many questions that merit and require additional due diligence and decisions to ensure that the program is beneficial for customers, including any large load customers who we may partner with in the future. As we look beyond the approximately 50-200 MW deployment we propose in this Petition, a phased approach is necessary to gain operational experience, validate our assumptions, and ensure we have the people, processes, and tools in place to deploy and operate a high volume of assets quickly, safely, and affordably – while maximizing the benefits to all customers. This includes the implementation of a limited grid DERMS deployment – leading to a full Enterprise DERMS deployment – and enhanced analytical and operational capabilities that will enable the Company to integrate diverse distribution-sited technology portfolios more effectively into grid planning and operations. These steps will be critical to ensuring safe and reliable operation coordination between the bulk system and distribution system.

Below we provide a brief overview of each phase on the C*C roadmap, as we envision it today. We discuss considerations and questions that we need to address and tools or capabilities we will need in place for Phase 3 and beyond, and the benefits we would seek to expand with each phase.

It is important to note that Phases 3 and 4 reflect our current vision, but will require a significant amount of additional testing and evaluation – as well as data and experience from Phase 1 and 2, including a Phase 2 Interim Program Assessment – before we will be ready to present a full proposal for future phases. We are committed to keeping the Commission and stakeholders informed as we gather data and lessons learned from Phases 1 and 2, and as we have further discussions with stakeholders, customers, and communities about the program.

C. Phase 1 Overview

Phase 1 of the DCP program was proposed and approved as a modification to the Company's ECO triennial.[3] Phase 1 of the DCP initiative – Demonstration – is a research and development (R&D) effort aimed at evaluating the feasibility and learning more about scalability and economic viability of utility-owned, customer-sited BESS.

Phase 1 will deploy FTM batteries at a handful of commercial customer sites. Participating customers will receive financial incentives in exchange for hosting batteries at locations identified by Xcel Energy. Over a two-year period, we are undertaking the following activities:

- Engaging commercial customers and securing host sites for battery installation.
- Procuring, permitting, and installing 3–5 MW of BESS.
- Coordinating battery operations to optimize charging and discharging.
- Measuring and analyzing load shifting and load management performance over 3-6 months.

Phase 1 is underway. Upon completion of Phase 1, we will prepare a comprehensive report summarizing project outcomes, operational insights, and recommendations for future phases. This report will be included in Xcel Energy's 2027 Annual ECO Status Report, submitted April 1, 2028.

[3] See *Assistant Commissioner's Decision Addenda in Response to Xcel Energy's Proposed Modifications to its 2024-2026 Energy Conservation and Optimization Triennial Plan* (Docket Nos. E,G002/CIP-23-92 & E002/RP-24-67), September 3, 2025.

D. Phase 2 Overview

We briefly summarize Phase 2 here in the context of our broader C*C roadmap vision. Later in this Petition, we present the details of the Company's Phase 2 C*C proposal.

1. *Purpose and Scope*

Phase 2 of C*C expands on the foundational work of Phase 1 by extending the scale, reach, and strategic focus of BESS deployment.

Objectives of Phase 2 include:

- Address evolving grid needs by deploying distributed capacity as part of the distribution system to serve customers system-wide.
- Learn and validate processes, costs, benefits, operations, and market assumptions through targeted deployments.
- Enhance program design based on lessons learned from Phase 1 and iteratively throughout Phase 2.
- Identify and address bottlenecks to scaling C*C through iterative improvements and resources such as people, processes, and tools.
- Build institutional capacity to be able to deploy at scale.
- Add benefit and optimize value streams by developing new tools and business practices.

- Promote equitable access to program opportunities by encouraging participation from a diverse range of developers and site host customers, including those in environmental justice (EJ) areas.
- Provide fair compensation to site host customers, ensuring they share in the program's benefits.
- Assess C*C through an Interim Program Assessment to review costs, benefits, host experience, and operations, and to determine next steps after two years or when 20 MW have achieved commercial operational.

Phase 2 will include:

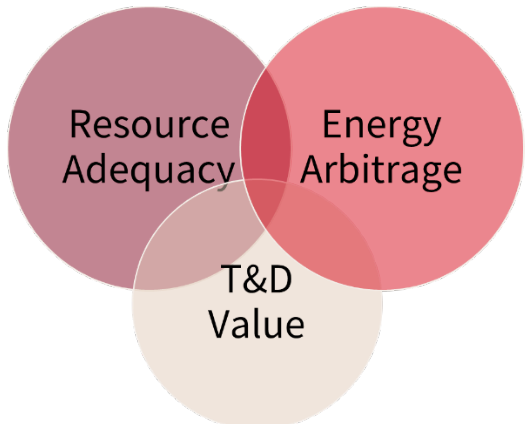
- Deployment of approximately 50 MW of Company-owned and -operated FTM BESS, ranging up to 200 MW, with each site hosting a BESS between 1 and 3 MW.
    - An Interim Program Assessment filed after two years or deployment of the first 20 MW – whichever is sooner.
- Prioritization and implementation of high-value bulk system use cases (e.g. MISO energy and capacity market participation)
- Deployment on a broad set of strategically targeted feeders on which we can speed deployment, minimize costs, and expand the Company's learnings.
- Implementation of a limited Grid DERMS, which is needed to operate the BESS most effectively and inform the Company's future, broader DERMS implementation.
- Exploration and evaluation of additional use cases to provide other system benefits including avoided transmission and distribution value.

2. Phase 2 Benefits

Phase 2 of C*C will primarily seek to maximize bulk system benefits while also testing the realization of benefits related to the transmission and distribution systems. BESS can provide a range of system values when sited as part of the distribution system, yet realizing each value stream depends on how the BESS is operated – in other words, each "use case" derives different (and sometimes mutually exclusive) benefits. Phase 2 will first focus on the grid benefit we can realize operationally after commercial operation: capturing energy and capacity market value via participation in MISO. As part of Phase 2, we will also explore the potential alignment and ability to realize value from other use cases (e.g., distribution net demand reduction).

The expected benefits of C*C Phase 2 include a combination of bulk system benefits and potential power delivery system benefits (i.e., transmission and distribution) as indicated by Figure 2 below.

Figure 2: Illustrative Capacity*Connect Benefits – Phase 2



Resource Adequacy: The Company's modeling suggests that the majority of the value for C*C will be provided through participation as a capacity resource under MISO's resource adequacy construct. Consistent with the Company's initial hypotheses in the IRP, C*C may provide an opportunity to meet resource adequacy needs that have historically been met primarily through large-scale generation resources. While investment in large-scale generation resources will continue to be necessary to meet the pace and scale of customer demands and state policy goals, C*C offers an opportunity to test another way of complementing these investments.

Energy Arbitrage: By discharging the BESS during periods of high locational marginal prices and charging when prices are low, we may be able to generate revenue in the MISO energy market or avoid making market purchases at higher costs.

Transmission and Distribution System Value: By strategically siting batteries on the distribution system, we may be able to realize additional benefit streams. First, to the extent that the Company can identify, site, and operate batteries on parts of the distribution system that have similar load shapes as the bulk system, there may be an opportunity to reduce demand on parts of the distribution system in a manner that could help defer or reduce capacity-related distribution infrastructure investments. Second, C*C may have benefits for the transmission system, which Phase 2 will allow us to evaluate further.

Interaction and Coordination Between Benefit Streams: The value proposition for C*C is dependent upon being able to realize multiple, concurrent benefits streams. However, there is significant operational uncertainty as to whether all of these value streams can be leveraged concurrently. For example, while the Company is generally seeking to deploy batteries in a way that can meet both bulk system needs and distribution system needs, there may be instances where achievement of these benefits are mutually exclusive (e.g., if the Company were to dispatch the batteries for MISO constraints at a time when there is not a constraint on the distribution system). Importantly, Phase 2 seeks to test the possibility of realizing these benefit streams concurrently as well as identify barriers and potential solutions to doing so. The learnings from this phase will be crucial to informing any future C*C phases.

Financial incentives for host customers. Customers who host C*C projects will receive direct payment(s) for program participation. These payments are designed to not only cover the costs of hosting placement of a BESS, but also can be used as another revenue stream for customers. These site host payments can promote equitable access to the benefits of distributed generation, particularly in underserved or EJ communities. We discuss site host compensation further in Section III.B below.

Equity and environmental justice. Our site selection and customer outreach processes aim to ensure site hosting opportunities are available to customers located in EJ areas, Minority and Women-owned Business Enterprises (MWBE), and community organizations. Beyond the straightforward financial value of site host payments discussed above, our goal is that by prioritizing hosting opportunities in part with equity and environmental justice in mind, C*C could have broader benefits for these site hosts and their communities.

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E. Phase 3 Vision: Commercial Scale and Expanded Customer Options

In Phase 3, we anticipate exploring an expanded set of program design options. These may include opportunities to integrate Company-owned distributed solar alongside BESS. Adding solar in this phase could support compliance with Minnesota's Distributed Solar Energy Standard (DSES),[4] which we discuss further below.

In Phase 3, we would seek opportunities to stack additional distribution value streams on top of the bulk system dispatch planned for Phase 2. Siting in this phase could consider additional data points – informed by lessons learned in Phase 2 – to maximize distribution system benefits.

A prerequisite to Phase 3 is the successful deployment and demonstration of Phases 1 and 2, confirming the ability to deploy and operate C*C assets as planned, realizing economies of scale, and growing the program's benefits. Requirements include an Enterprise DERMS, with expanded capabilities to be able to offer resources into the MISO market and operate them as would be required by MISO. There are several potential participation pathways for distribution-connected BESS in MISO. This includes operating the assets as Load Modifying Resources (LMR), registering the assets as Electric Storage Resources (a model that was created in compliance with Federal Energy Regulatory Commission [FERC] Order No. 841), and future opportunities related to DER aggregation that will come with MISO's implementation of FERC Order No. 2222 in 2029. The Company anticipates working closely with MISO to identify the pathway that will allow us to maximize the benefits for our customers and the grid.

[4] Minn. Stat. § 216B.1691, Subd. 2h.

To ensure effective siting and operations as C*C scales, we anticipate the need for incremental new software and/or third-party support to supplement existing planning, analysis, and engineering resources. Beyond MISO coordination, there may be other intersecting policy topics that could impact C*C and may require further analysis or adjustments – including changes in technology; advancements in people and process; and the intersection with ECO, DSES, and grid upgrade policy.

As the Company progresses on Phases 1 and 2, the Company will revise and refine the roadmap and vision before proposing future phases to the Commission.

F. Phase 4 Vision: Co-Optimization

Phase 4 would realize a fully co-optimized C*C program that deploys and operates assets to derive meaningful value for the bulk system *and* the distribution system – as well as offering potential customer resilience value. True co-optimization of these assets will require sophisticated operational tools and capabilities that are not currently in place.

G. C*C as a Pathway to the Grid of the Future

C*C is a novel approach to meeting system and grid needs – an approach that is well aligned with our vision of an integrated grid of the future. As we have explored DCP over the past year, it has become clear that the themes within the evolution of grid planning and operations are well represented in C*C:

- Integration of and coordination between resource planning and distribution planning and operations,
- The intersecting needs of distribution system operations, market operations, and commercial operations,
- When designed appropriately, the ability of distributed energy resources to contribute to meeting grid needs.

These challenges are not new to the industry nor Xcel Energy, yet C*C is coalescing them in a tangible way that will require more immediate action and investment. The actions that will be required to make C*C successful have been underway at Xcel Energy and beyond. C*C represents an opportunity to leverage momentum to benefit the electric system and our customers in ways that extend far beyond the programmatic bounds of C*C itself. We are eager to seize the opportunity to learn and bring value to our customers through the C*C model.

II. PHASE 2 PROPOSAL

C*C Phase 2 is the near-term plan to strategically deploy from 50 MW up to 200 MW of distribution-interconnected battery energy storage assets. Initially, we aim to operate the BESS for bulk system use cases with the highest value (e.g., MISO energy and capacity market participation). As we validate program assumptions and deploy more distributed BESS, we will seek to expand and optimize opportunities to leverage and stack multiple use cases and value streams. Phase 2 will provide an important venue to measure and validate costs and benefits as we learn how to scale C*C and expand its operational capabilities. Phase 2 will provide a foundation for potential wider-reaching C*C in Phases 3 and 4.

A. Phase 2 Introduction

We propose to implement Phase 2 over approximately the next three years, deploying approximately 50-200 MW of BESS by the end of 2028. There are several factors that may influence the timing and pace of deployment including ability to secure site hosts; procurement and construction timelines; and operational readiness. Because C*C is a new, innovative program in the industry and for the Company, we intend to keep the Commission and stakeholders informed throughout the process and by conducting an Interim Program Assessment after 20 MW of BESS installations achieve commercial operation, or after the first two years (2026-2027), whichever is earliest. In this assessment, we will advise the Commission and stakeholders on what we have learned and if the C*C program is recommended for further expansion or not. We expect procurement activities to begin in the first quarter of 2026, with construction of the first Phase 2 projects beginning before the end of 2026.[5] This timing reflects our best current estimation but may be extended depending on initial results and lessons learned.

B. Sparkfund's Role in C*C Implementation

Scaling the novel C*C concept requires dedicated support for implementation and project management. The Company is finalizing agreements with Sparkfund to serve as the Company's implementation partner for C*C. Sparkfund's role is expected to include:

- Partnering with Xcel Energy on C*C program design, ensuring that product design choices maximize scale and scope and position C*C for replication across geographies, sites, and technologies.
- Evaluating, selecting, and securing sites, including marketing to potential hosts and working with hosts throughout the process (e.g., host engagement, proposal development, and contracting).
- Procurement of goods and services, including engineering, procurement, and construction (EPC) subcontractors and BESS equipment, with competitive vendor selection, contracting assistance, and vendor management.
- Managing project delivery, including project scoping, engineering design, construction management, permitting, budgeting, procurement coordination, and inventory management.
- Delivering data and analytics capabilities to support ongoing analysis and reporting, while facilitating data flows that enable both existing and emerging asset monetization streams.
- Operations and maintenance of C*C BESS assets for the life of the program, including any augmentation required to maintain performance standards.

A cross-functional team at Xcel Energy will work with Sparkfund throughout the process. Teams across the Company – such as Customer Energy and Transportation Solutions, Integrated System Planning, Account Management, Community Relations, Energy Supply, Distribution Engineering and Operations, and Commercial Operations – are engaged in program development and working together to ensure adherence to standards for engineering, procurement, safety, and customer and community engagement.

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[5] This timeline subject to change and is dependent on Commission approval.

III. SITE ELIGIBILITY, CUSTOMER EXPERIENCE, AND DEPLOYMENT

The Phase 2 deployment process aims to maximize deployment speed, minimize costs, ensure employee and public safety, support operational excellence, and introduce a smooth experience for site host customers. Importantly, the initial Phase 2 deployment process – along with Phase 1 – will help further develop and validate the processes behind the steps outlined below and surface as-yet-unknown questions and considerations as we seek to standardize and scale C*C. The deployment steps include:

1. Analysis and selection of eligible feeders
2. Review, identification, and prioritization of possible site hosts, and marketing and outreach to potential site hosts
3. Engineering, procurement, permitting, and construction of the BESS and related infrastructure
4. MISO market registration and enrollment
5. Ongoing operations and dispatch

We discuss each of these steps in more detail in the following section. We emphasize that these details are based on the best information at the time of this filing and will necessarily evolve as required to find efficiencies and generally take a continuous-improvement approach to improve the performance of the program.

A. Feeder Selection

In Phase 2, eligible feeders will be identified through a multi-step analysis to ensure safety, maximize deployment speed and volume, manage costs, enable data capture, and ensure beneficial, effective operations of the system that can inform program design refinements. This selection process is subject to change as we learn more about system needs and impacts from these assets, the varying benefits we may be able to realize, and how we can improve efficiency in the analysis and siting processes through enhanced analytical tools and capabilities.

First, we will focus on these minimum criteria to identify feeders, toward maximizing deployment speed and minimizing costs:

- *Have at least 1 MW of available generation hosting capacity*, as indicated by the Company's generation hosting capacity analysis.[6] We expect this will enable

[6] https://mn.my.xcelenergy.com/s/renewable/developers/interconnection/hosting-capacity-map and https://www.xcelenergy.com/hosting_capacity_map.

faster system impact studies and potentially lower upgrade costs compared to DER constrained feeders.

- *Does not exceed feeder native loading standard,* as indicated by the Company's load hosting capacity analysis.[7] Because the BESS will act as load while charging, this ensures that the BESS can interconnect safely and without the need for large system upgrades.

From the resulting list of feeders, we will further refine and prioritize the potential host feeders based on the following criteria to maximize benefits and minimize risk:

- *Do not serve critical customers* (including but not limited to hospitals; water treatment facilities; and first responder facilities and dispatch centers). This limits any potential for disruption during construction and operations.
- *Serve areas where retail load has grown and/or is expected to grow.* This maximizes potential locational benefits, enabling important learnings as we seek to capture and measure the distribution system benefits of these assets.
- *Have feeder peaks generally aligned with system peaks.* This analysis will help identify ideal locations for C*C BESS locations where we may capture distribution system benefits, even as we initially operate the assets to meet bulk system needs. This could provide more data on distribution system benefits, and any lessons learned can be incorporated into the Company's planning for future C*C phases.
- *Include environmental justice and equity perspectives.* In addition to technical, operational, and cost-related considerations, we will also incorporate environmental justice and equity perspectives in feeder selection. While feeders may cover broad and diverse geographies that include a mix of EJ and non-EJ communities, we recognize the importance of ensuring that the benefits of distributed clean energy investments are accessible to historically under-resourced and overburdened communities. To that end, we will evaluate feeders in part based on whether they serve areas with high concentrations of vulnerable or disadvantaged populations, informed by publicly available environmental justice screening tools and demographic indicators. This consideration will not serve as an eligibility requirement but will help guide prioritization to better align project siting with equity and community benefit goals, while continuing to maintain the core technical, safety, and efficiency criteria outlined above.

[7] https://mn.my.xcelenergy.com/s/renewable/developers/interconnection#-32; 2024 tabular results here.

As the use of the distribution system evolves, Minnesota's DER policies as they currently stand – including the Minnesota Distributed Energy Resource Interconnection Process (MN DIP) – do not necessarily contemplate the C*C concept: FTM, utility-owned and -controlled, dispatchable DER, strategically deployed to serve as bulk system assets that are not functionally different from the Company's distribution system. So, while we will perform necessary studies to assess impact of the C*C BESS on the system, C*C assets akin to bulk system resources are not subject to MN DIP. [8]

In order to maintain a safe, reliable system, we will need to conduct system impact studies for each site, similar to studies conducted under MN DIP. Our intention is to *not* deploy C*C assets that would trigger significant upgrades to accommodate addition of these assets, as one of the key benefits of this approach is to accelerate speed to incremental capacity of these systems. Indeed, we would seek to site the C*C BESS with the intent to assess and potentially provide coincident benefits to the distribution system – even as they are dispatched at the bulk system level.

As noted above, feeder selection criteria may need to be adjusted as Phase 2 progresses, based on new information and host customer interest and to ensure we can safely and effectively deploy the BESS for C*C. We are exploring additional tools and analyses that could supplement and speed the feeder and site selection process to ensure C*C assets are efficiently and beneficially sited.

B. Site Host Identification

Once eligible feeders are identified, Sparkfund will lead a multi-step process to identify eligible customer sites and prioritize outreach to eligible sites. Throughout the process, our goal is to identify sites that support the deployment of assets in an equitable manner.

1. *Eligibility and Basic Site Qualification – Primary Screening Criteria*

Xcel Energy will determine eligible customers on selected feeders. Commercial and industrial customers that are current on their Xcel Energy electric service accounts will be eligible.

[8] As part of the Company's distribution system, the assets differ from a BESS that is part of a DER subject to MN DIP, which applies to DER "… interconnecting to, and operating in parallel with, an Area [Electric Power System] distribution system…." (MN DIP 1.1.1).

Sparkfund will then conduct a basic qualification screening through desktop analysis. Sites must meet the following criteria to be considered viable:

- Not located in a FEMA-designated flood zone.
- Adequate potential site footprint of approximately 2,000 square feet of unobstructed, exterior ground space.
- A clear, unobstructed means of access to the site footprint for maintenance equipment and emergency access.

2. Prioritization – Secondary Ranking Criteria

Once the list is narrowed to only qualified sites, Sparkfund will perform a deeper analysis based on below attributes to rank qualified sites. We note that these criteria are subject to change over time based on initial findings and customer, community, and stakeholder feedback.

- *Land and Siting Considerations*. Greenfield, brownfield, or paved open space preferred; landscaped areas with hardscaping or vegetation increase restoration costs.
- *Zoning & Setback Constraints*. Parking lot setbacks, fencing requirements, and/or zoning overlays (e.g., near schools or churches)
- *Interconnection Proximity*. Vacant areas near utility infrastructure (pad-mount transformer, riser pole, or switchgear)
- *Lease or Ownership Complexity*. May impact ease or cost of site control.
- *Equity and environmental justice*. Outreach will prioritize qualified sites that are located in EJ areas; are minority and women-owned business enterprises (MWBE); and/or nonprofits, community centers, or similar organizations, where such information is publicly available.[9]
- *Viewshed risk or opportunity*. Community acceptance reduces risk. Indicators of the potential level community acceptance may include proximity to residential areas, parks, or community gathering areas. Also, whether the customer or community has energy or environmental goals, or has previously indicated an interest in battery storage or innovative projects.

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[9] EJ areas as indicated on the Minnesota Pollution Control Agency's EJ areas map. https://experience.arcgis.com/experience/bff19459422443d0816b632be0c25228/page/Page/?views=EJ-areas. The equity and environmental justice plan is subject to change and refinement based on conversations with stakeholders and the Company's Environmental Justice Advisory Board, as discussed further in Section VII.

3. *Marketing and Outreach*

After feeders are identified and potential sites have been narrowed, Sparkfund will conduct outreach to potential site hosts. Sparkfund will develop outreach materials that will:

- Provide clear, concise, and visually engaging materials to inform customers and potential hosts about the program's benefits, technical details, and alignment with Xcel Energy's commitment to modernizing the energy grid.
  - Marketing materials will be developed for potential site hosts to explain the benefits of participating in the program, the potential site impacts and the opportunity to be a leader in Minnesota's energy future.
- Educate these stakeholders on the safety measures for BESS and proactively address any concerns that might arise.

A website will serve as the main hub of information for all audiences and stakeholders. Additional marketing tactics and materials may include:

- Introduction to Hosting materials
- Email series and call scripts
- FAQs
- Program overview
- Battery safety
- Additional materials for trade partners or other stakeholders

In addition to site-specific outreach materials, we will engage with local Authorities Having Jurisdiction (AHJs) to provide safety training, including fire protocols. The Company will also explore leveraging existing community outreach and engagement events in which the Company regularly leads and/or participates to further provide additional opportunities to educate the public on battery storage and other energy and electricity topics.

4. *Site Host Compensation*

Xcel Energy will offer site hosts **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS].** This compensation approach is consistent with the novel nature of C*C, including the footprint of these installations and the need for ongoing customer engagement and ongoing operations and maintenance (O&M).

C. Engineering, Procurement, Permitting, and Construction

This section outlines expected roles and approaches to engineering, procurement, permitting and construction.

1. *Project Management Overview*

Sparkfund will lead project management of asset deployment, with oversight from and in close coordination with Xcel Energy. We expect each individual project will include a budget, schedule, asset performance requirements, a quality and safety plan, and an ongoing operations and maintenance plan. An assigned Project Management team will lead the execution of commercial agreements. The Project Manager will be responsible for coordination between the broader team, vendors and subcontractors, and the site host. The Project Manager will manage the schedule and scope of work, including leading the permit processes.

2. *Procurement Approach*

Sparkfund will be responsible for Phase 2 C*C procurement activities and will align their work around vendors that have been pre-approved through existing Xcel Energy competitive processes.[10] Sparkfund will align with Xcel Energy's sourcing requirements, especially those that involve any vendors that will be connecting directly to the system to ensure security, compliance, and to manage this group of vendors to optimize pricing for the planned rapid deployment of these assets.

We expect Sparkfund will be responsible for administering a competitive and transparent procurement framework and process that protects customers, secures vendor confidence, and sustains long-run program health. The framework is designed to:

- **Secure cost-prudent outcomes** by **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**
- **Ensure transparency and fairness [PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**

[10] The Company is in the process of finalizing agreements with Sparkfund.

- **Balance portfolio strategy with price [PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**
- **Deliver reporting documentation [PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**

The procurement framework for Phase 2 includes four primary stakeholders, including: (1) the Company; (2) Sparkfund, tasked with designing, executing, and managing the implementation, including request for proposal (RFP) preparations, communications, evaluations, and award recommendations; (3) Vendors; and (4) Site Hosts.

We overview the Phase 2 procurement framework below, covering three distinct RFPs, each beginning with the release of an RFP and concluding with the issuance of awards to selected vendors. We expect each of the corresponding RFPs will follow a set schedule to provide consistency, fairness, and transparency. For Phase 2, Sparkfund will begin by issuing concurrent RFPs for Major Equipment Supply and Design and Engineering after the Commission's final approval of Phase 2. We may modify the RFP packages and associated timelines to address prevailing market conditions and opportunities and challenges within the program.

Major Equipment Supply. This RFP will solicit proposals from BESS OEMs/Integrators. Vendors must meet the Company's technical and safety requirements, which may include varying levels of direct contracting between Xcel Energy and the Vendor, as well as program volume and schedule expectations. Awards for the supply of equipment for the projects may be to multiple vendors based on applicable evaluation criteria.

Design and Engineering. This RFP will solicit proposals from engineering firms with the requisite experience and capacity to support design engineering for multiple project sites. Awards for the Design and Engineering of project sites may be to multiple vendors based on applicable evaluation criteria.

Construction and Installation. Sparkfund plans to issue RFPs in tranches for approximately 3-15 host sites following completion of required engineering milestones for the identified sites, and after the RFPs for corresponding Equipment Supply and Design and Engineering for specific sites. The size and sequencing of respective tranches will be based on the feeder selection and site-host considerations detailed above, as well as considerations regarding geographic location, project similarity, and desired project schedule. The Construction and Installation RFP tranches will include all relevant installation requirements from the Company as well as applicable codes, sourcing and labor standards, and permitting requirements. Awards of Construction and Installation tranches may be made to one or multiple Vendors based on applicable evaluation criteria.

3. Permitting, Design, and Construction

a. Permitting

Deploying BESS requires careful attention to permitting and compliance with all applicable codes and standards. This section summarizes key, anticipated permitting requirements and code compliance considerations for the C*C Phase 2 BESS projects, including relevant national standards,[11] state and local code references, and typical issues such as setbacks, fire safety, site access, and coordination with AHJs. In addition, all designs will adhere to *Xcel Energy Standard for Electric Installation and Use*, covering metering, service connection, pad and clearance requirements, and exception request processes.

Each BESS installation deployed under C*C will require local electrical and building permits. The systems must comply with the applicable NEC, and NFPA codes and UL standards.

Permitting processes vary by jurisdiction and are dynamic based on AHJ resourcing and staffing. Because multiple systems may be deployed concurrently within neighboring jurisdictions, ad hoc submissions could overwhelm AHJ staff. To manage risk and reduce overall project costs and timelines, Sparkfund will streamline the permitting process using the following techniques:

[PROTECTED DATA BEGINS

- [redacted]
- [redacted]

[11] For example, National Fire Protection Association (NFPA), Underwriters Laboratories (UL), National Electrical Code (NEC), Institute of Electrical and Electronics Engineers (IEEE), and National Electrical Safety Code (NESC).

- [redacted]

PROTECTED DATA ENDS]

b. Design Approach and Archetypes

[PROTECTED DATA BEGINS

[redacted]

[redacted]

[redacted]

PROTECTED DATA ENDS]

4. Equipment Standards and Standardization

All site equipment will meet applicable standards, including strong manufacturer performance histories, certified safety ratings, and compatibility with Xcel Energy's technical and operational requirements. Standardizing a repeatable set of components will support consistent installation practices, streamline long-term maintenance, and enable strategic spare parts stocking across the portfolio. While vendor selections and part numbers will be finalized during the detailed engineering and procurement process, the goal is to balance system standardization with sufficient flexibility to address site constraints while maintaining consistency in permitting and construction.

5. Safety and Security

All BESS equipment will be located within a secure, fenced yard with adequate clearance for operation and maintenance. Where BESS equipment is within 100 feet of a public access point (e.g., sidewalk or property line), a concrete masonry unit wall will be included around the relevant portion of the BESS enclosure in accordance with Company standards. Sites will be designed to meet applicable safety standards, including:

- 24/7 remote monitoring with automated alerts and shutdowns,
- Integrated fire detection and suppression systems with emergency services notification,
- Personnel training with appropriate personal protective equipment (PPE) at all times, and
- Emergency response plans.

Site security measures will include controlled access, hazard signage, and testing of safety systems. These protocols are intended to ensure safety and effective response.

6. Construction

Sparkfund will oversee site construction for all projects to ensure work is safe, organized, and compliant with program and industry standards. This enables a scaled and standardized installation process across many project sites and ensures appropriate communications with site hosts, vendors, and the Company, including:

- Coordinating engineering and design with professional engineers.
- Preparing drawings and product information for review and approval.
- Ensuring compliance with all applicable codes, standards, and regulations.

- Managing vendors selected through the competitive RFPs and ensuring compliance with the Company standards.

Site construction will follow a standardized project management framework to ensure consistent construction across the portfolio. On-site oversight includes verifying that technology installations adhere to project design requirements, safety standards, and schedules. Regular and ad-hoc site visits will be conducted for inspections, quality control, and safety activities, with associated reporting. Inspections will confirm compliance with project specifications, safety protocols, regulatory requirements, engineering specifications, and permitting requirements discrepancies will be addressed and communicated to appropriate stakeholders. Project completion will include a comprehensive as-built and formal close out package provided to the Company in accordance with all requirements.

We will commission and energize these assets in accordance with all standard Company safety, commissioning, interconnection, and energization processes. We will also track and report progress against schedules and milestones to inform regular reporting to the Commission, as detailed further in Section IX.

D. MISO Market Registration and Enrollment

As discussed below, the Company's modeling suggests that the majority of benefits for distribution-connected BESS can be achieved through the participation of these assets in MISO's energy and capacity markets. This activity within Phase 2 will require close coordination between internal Xcel Energy teams and MISO.

From its initial due diligence and conversations with MISO, the Company has identified three potential pathways for capturing energy and capacity revenue for distribution-connected batteries in the MISO market. Two of these pathways are available today: Demand Response Resource (DRR) Type 1, and Electric Storage Resource (ESR). A third pathway, the Distributed Energy Resources Aggregation (DERA) model, will not be available until 2029. The Company's analysis currently reflects an assumption that the BESS can participate in MISO either via DRR Type 1 or ESR beginning in 2027. Each of these two pathways comes with pros and cons. For example, the Company understands that the DRR Type 1 pathway allows for aggregation of geographically distributed BESS today and has less onerous metering and telemetry requirements relative to the ESR model, but DRR Type 1 resources are not able to provide regulation services (and the reason why the Company did not model ancillary services in its cost-benefit analysis discussed below). Conversely, the ESR model does not allow for aggregation, which creates challenges for the

Company's operators at the scale potentially envisioned for C*C. The Company will work with MISO in the coming months to identify the optimal path forward that balances operational realities with benefit realization.

E. Ongoing Operations and Dispatch

1. Near-Term Operations and Dispatch

Participation of distribution-connected BESS will require increased orchestration and coordination between the Company's commercial operations and distribution operations teams than exists today. While we are still in the early stages of evaluating the people and process requirements to achieve this, the limited deployment of Grid DERMS will provide the technology foundation for enabling visibility and control to BESS.

Xcel Energy will utilize a limited Grid DERMS deployment to monitor and/or dispatch the BESS for bulk system use cases (e.g., MISO energy and capacity market participation) in close coordination amongst our distribution and commercial operations team. The exact requirements will ultimately be informed by the participation pathways the Company utilizes, as described above, and associated MISO processes and guidelines. The successful implementation of this dispatch strategy will help us develop new and refine existing processes, including planning, operations, and coordination across teams, as well as gain operational experience.

2. Future Operations and DERMS Capabilities

This foundational approach sets the stage for more advanced future use cases such as co-optimization between the bulks system and distribution system, for which we will need additional DERMS capabilities beyond the limited deployment of Grid DERMS as well as investments in people, processes, and organizational structure that do not exist today. The costs for future DERMS software capabilities and investments in people, processes, and organizational structure are not included in the C*C Phase 2 budget.

It is important to recognize that DERMS technology is still new – particularly in regard to the advanced capabilities described above – and technology vendors are continuously enhancing and expanding their capabilities. As a result, not all functionalities will be available or fully functional from the outset, and it is expected the Company will need to work closely with its vendor partners. Moreover, the DERMS platform, while a critical component, is just one piece of a much larger set of components. Forward-looking Enterprise DERMS (which would be implemented after C*C Phase 2 BESS deployment) is a system-of-systems architecture, formed through the integration of multiple information technology (IT) and operational technology (OT) components. For instance, enabling participation in the MISO market may require DERMS to interface with Commercial Operations platforms to facilitate market interactions. It must also connect with other systems responsible for measurement, validation, and reporting to ensure compliance and performance tracking. In addition, to maintain safe and reliable distribution operations, DERMS functionality must be complemented by fail-safe modes that ensure safe operation during system failures or abnormal configurations.

Furthermore, Enterprise DERMS involves more than deploying new technology platforms and system integrations – the Company will need to transform the organizational structure to support it. Beyond the technological considerations outlined above for implementing an Enterprise DERMS, the Company needs to develop new processes, acquire new resources, and align with existing efforts – including governance structures, operational workflows, and cross-functional collaborations. These foundational elements are necessary to fully leverage and scale the platform's capabilities for C*C and beyond.

The Company has adopted an incremental implementation strategy for DERMS. Over time, this experience will support the development of more advanced capabilities – such as those outlined above – and enable broader integration of DERMS technologies and organizational maturity. The gradual rollout also ensures that the adoption of a new, integrated approach, combining technology, people, processes, and organizational efficiencies, is implemented in a way that maintains the safety, reliability, and stability of the electric grid. This approach reflects a meaningful shift in how the company manages its distribution systems, moving toward a more integrated model. By progressing deliberately, the company can mitigate operational risks while positioning itself to fully capitalize on DERs as the programs continue to evolve and mature. The Commission's Order in our 2023 Integrated Distribution Plan (IDP) docket requires the Company to file a detailed DERMS roadmap that addresses specific questions before any DERMS investment will be approved.[12] The Company provides the required information as Attachment D to this filing.

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[12] ORDER ACCEPTING 2023 INTEGRATED DISTRIBUTION PLAN AND MODIFYING REPORTING REQUIREMENTS, Docket No. E002/M-23-452 (September 16, 2024), at Order Point No. 23.

IV. COSTS AND BENEFITS

In this section, we outline the Phase 2 budget and the cost-benefit analysis (CBA) we developed. We discuss the benefits we believe we can reasonably quantify currently, and the CBA inputs and results. We also discuss other benefits we expect to realize but that are not easily quantifiable, and/or require additional tools and capabilities before they can be fully realized. We also address Order Point No. 23.c of the Commission's IRP Order that requires the Company to evaluate costs and benefits between a utility-owned and managed C*C model and alternative ownership models.[13] Finally, we compare C*C to grid-scale resources.

Based on our estimated costs and quantifiable benefits discussed in this section, the Company recognizes that managing costs through prudent procurement, leveraging economies of scale, and ensuring operational efficiencies will be crucial to maximizing C*C cost effectiveness for our customers. As we explain, our CBA assumptions are ambitious – although there are limitations to CBA as a tool to measure cost-effectiveness. Gaining operational experience and careful implementation of the supporting people, processes, and tools will be necessary to validate these assumptions and effectuate the full benefits of this innovative, industry-leading program for our customers.

A. Estimated Costs – Phase 2

The estimated budget range for Phase 2 is $152 million to $430 million for a 50 MW up to a 200 MW deployment through 2028. Attachment B provides additional budget detail. We emphasize this budget is an estimate subject to change; we are in the early stages of procurement, and we do not have firm supply or partner agreements in hand. This budget generally aligns with the costs included in the CBA and reflects ambitious assumptions. The budget does not reflect capture of the Investment Tax Credit (ITC), which we anticipate will offset 30 percent of the capital cost of the BESS after deployment, to the benefit of our customers.

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[13] Specifically, Order Point No. 23c requires, "[a]n evaluation of a costs and benefits comparison between a utility-owned and managed DCP model and alternative models allowing participation from customer-owned and third-party-owned resources."

Table 1: C*C Phase 2 Budget
Based on 200 MW Deployment, 2026-2028
($Nominal)

Category	Total Budget through 2028
BESS Equipment	**[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**
BESS Operations and Maintenance	**PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]** through 2028[14]
Limited Grid DERMS	$2.9 million
Program Management	**[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]** through 2028
Site Host Payments	**[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]** through 2028
Total	**$430 million**

[14] O&M costs continue for the life of the assets.

Table 2: C*C Phase 2 Budget Assumptions

Category	Assumption
BESS Equipment	**[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** per kWh This estimate is informed by internal experience with distributed BESS pilot deployments and a request for information (RFI) conducted by Sparkfund. The costs are inclusive of BESS equipment, installation, permitting, and interconnection. The costs in the budget do not include escalation. We anticipate that economies of scale can be realized over time, reducing the average BESS capital cost.
BESS Operations and Maintenance	**[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, which continue for the 20-year life of the BESS. The budget reflects O&M costs through the anticipated Phase 2 deployment period (2026-2028) only. These numbers assume realization of economies of scale and are informed by an RFI conducted by Sparkfund.
Limited Grid DERMS[15]	$2.9 million The limited Grid DERMS deployment, and the business and customer processes it can help enable, are a critical part of our strategy for planning and operating a modern grid, particularly during this period of rapid change and demand growth in the industry. The Limited Grid DERMS costs we include in this filing are necessary to begin operations of C*C Phase 2.[16] The budgeted amount covers work associated with the Limited Grid DERMS deployment for three initial use cases: flexible interconnection, flexible energization, and C*C. Expenses include but are not limited to work associated with software design, detailed requirements, software license fees, testing and integration. Further investment and expansions of DERMS and associated people, processes, and organization structure are not included in the budget but will be necessary to scale C*C and maximize its benefits. Attachments D and D1 provide the Company's DERMS roadmap and other information required for the Company to provide in order to be eligible for cost recovery, per the Commission's Order in our 2023 IDP docket.

[15] Grid DERMS limited deployment costs are not included in the Company's currently pending electric rate case (Docket No. E002/GR-24-320).

[16] Because the costs for the limited grid DERMS deployment effectuate benefits that extend beyond C*C, the costs are not included in the CBA.

Program Management	**[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]** through 2028. This estimate includes internal labor, modeling and analysis support to identify host sites, third-party measurement & verification, and fees paid to our implementation partner.[17]
Site Host Payments	**[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]** per site per month over the 20-year life of the BESS; the budget reflects site host payments through 2028. This estimate is informed by research conducted by Sparkfund. **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**

B. Overall Estimated Benefits – Approach

We approached C*C benefits for customers and the grid quantitatively, through development of a CBA, and qualitatively through narrative discussion of benefits for which monetization is impracticable. The CBA, discussed in Part C below, focuses on benefits that can be monetized, like reduced energy costs, capacity and resource adequacy, and avoided line losses. The qualitative analysis discussed in Part D below, complements this by describing hard-to-quantify benefits, including time to power, equity and environmental justice, and innovation.

That said, the full range of benefits that we believe can be realized through C*C will take time to validate and bring to fruition. As MISO market constructs evolve – and as the Company deploys an Enterprise DERMS and related processes and tools beyond the limited Grid DERMS deployment included in the C*C budget[18] – BESS aggregations can contribute to the Company's resource adequacy in resource planning and could be similarly dispatched for capacity value – potentially turning the assets into revenue generators while also helping the Company meet its identified capacity needs in ongoing IRPs.

For Phase 2, we will initially focus on the highest value bulk system use cases – benefiting all customers. Site hosts will directly benefit from host payments.

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[17] We are finalizing agreements with our implementation partner; program management costs may change as contracts are finalized.

[18] Because benefits of the DERMS limited deployment extend beyond DCP, the costs are not included in the CBA.

C. Quantitative Benefits – Phase 2

To help illustrate costs and benefits potentially associated with Phase 2 of the C*C program, we developed a CBA. We provide the trade secret CBA model as Attachment C.

While we utilize CBAs as one tool to assess larger projects, it is important to note the limits of a CBA. A cost-benefit model cannot capture benefits that cannot be quantified, such as public policy goals, and may not fully reflect future use cases and benefits. The modeling limitations are especially evident for C*C, a novel and innovative program with the potential to realize future efficiencies and reduce costs, as well as opportunities to operate the BESS for additional, beneficial use cases over time.

Modeling challenges continue because in many cases, the benefits cannot be stacked or realized simultaneously because of the varying use cases and the corresponding covariance of stacked benefits. Maximizing value of one benefit stream may require a dispatch and operational strategy that would in turn reduce the value of another benefit stream. For example, if BESS aggregations are dispatched for capacity/resource adequacy value based on MISO market signals, they would not be available to be dispatched for non-coincident distribution-specific benefits; by siting the BESS on feeders with similar bulk coincident peak, we seek to realize some coincident benefit.

In short, each use case has tradeoffs, increasing one value stream at the expense of another. We discuss some specific benefit tradeoffs further below. We expect operational experience with C*C will provide real-world data to help us validate the extent of these tradeoffs and the coincidence of different value streams.

Table 3 summarizes the CBA assumptions.

Table 3: C*C CBA Assumptions Summary

	CBA Assumptions
Benefits	
Avoided Energy/Energy Revenue Value	Average of locational marginal price (LMP) per MWh from the MISO Minnesota Hub Day-Ahead forecast and marginal energy price (MEP) per MWh from the 2024 Resource Plan
Capacity/Resource Adequacy	MISO Cost of New Entry (CONE) × BESS Effective Load Carrying Capability (ELCC) CONE price escalated at 3.81%
Avoided Distribution Benefit	\$40/kW-yr Applicable to 50% of projects
Avoided Transmission Benefit	\$30/kW-yr (\$250/kW annualized; 12% carrying charge)
Avoided Line Losses	6.47%
Costs	
BESS Capital Cost	**[PROTECTED DATA BEGINS** [redacted]
BESS O&M	[redacted]
Lease Payments	[redacted]
Program Costs	[redacted] **PROTECTED DATA ENDS]**
Taxes and Insurance	Property tax rate = 1.20% Insurance rate = 0.06%
Investment Tax Credit	30% of capital costs, amortized over asset life
Discount Rate	6.34% - after-tax weighted average cost of capital

1. *Summary of CBA Results*

Because we anticipate the cost and benefits streams will become more certain as we incorporate learnings, expand operational capabilities, and build economies of scale, we have conducted the CBA under a single, ambitious scenario. The CBA models multiple benefit streams, optimistic underlying assumptions, and aggressive cost reductions. We discuss the sensitivity of the model to certain assumptions below. We emphasize that achieving the full value and capturing the favorable costs assumed in the CBA depends not only on aggressive contracting and highly efficient use of internal and external resources, but also on fortuitous market and policy dynamics that are outside the Company's control.

The CBA uses costs and quantifiable benefits from a customer view. The CBA is based on an assumed 200 MW total deployment; BESS deployments grow from 50 MW in 2026 to 200 MW in 2028. The model reflects 200 sites hosting 1 MW/4 MWh

BESS, and 274 charge/discharge cycles per BESS per year (a capacity factor of 12.5 percent). To the extent that the Company is able to work with its implementation partner to deploy larger assets at a fewer number of sites, this would reduce costs and improve the CBA result.

Table 4 provides an overview of the CBA results.

Table 4: C*C Phase 2 Benefit-to-Cost
($ millions NPV)

	$ NPV millions
Benefits	
Production Cost Savings	39.28
Capacity / Resource Adequacy	289.00
Avoided Distribution Benefit	41.69
Avoided Transmission Line Loss	7.07
Avoided Transmission Benefit	62.53
Total Benefits	***439.56***
Costs	
Capital Expenses	288.58
O&M Expenses	252.35
Investment Tax Credits	(82.88)
Total Costs	***458.05***
Benefit/Cost Ratio (BCR)	**0.96**

2. *Quantified Benefits*

In the CBA, we include five benefits:

a. Energy value/production cost savings.

This benefit quantifies production cost savings, assuming the BESS will dispatch during times of peak demand to offset the cost of potential purchased power and/or dispatching a peaking unit. To calculate the benefit of production cost savings, we compare the price of energy during the forecasted charging of the batteries versus the price of energy at discharge. The price of energy is an average of the locational marginal price (LMP) per MWh from the MISO Minnesota Hub Day-Ahead forecast and the marginal energy price (MEP) per MWh from the 2024 Resource Plan.

The CBA uses a set, fixed daily charge/discharge for 274 days per year, assuming charging between 2 and 7 a.m. (reflecting a longer charge window to account for similar charge/discharge rates and losses due to round trip efficiency) and discharging from 5 to 9 p.m. The CBA is optimistic in that it allows the BESS to realize energy benefits concurrently with other value streams like MISO capacity and avoided distribution value; in real-world operations, there may be benefit tradeoffs as discussed below that are not reflected in the CBA. These tradeoffs will need to be evaluated during implementation.

b. Capacity/resource adequacy.

This benefit assumes that the Company will be able to register and enroll the assets as a capacity resource in MISO beginning in the 2027/2028 planning year using either the DRR Type 1 or ESR pathway described in Section III.

We calculate the capacity revenue benefit by multiplying the cost of new entry (CONE) by the seasonal effective load carrying capability (ELCC) for a four-hour battery in MISO. The ELCC value decreases over time, reflecting the forecasted declining ELCC for BESS as more capacity is added in MISO. CONE is escalated at 3.81 percent, the average observed year-over-year increase in MISO CONE prices from the 2015/2016 planning year to present. This escalation rate is more optimistic than the modeling in our most recent Integrated Resource Plan modeling, which uses an escalation rate of 2 percent, and reflects a market variable that is outside the Company's control; higher CONE prices would result in larger benefit, but lower CONE prices would result in a lower benefit than modeled.

We clarify that in order to capture the value of the capacity/resource adequacy benefit, we would need additional investment in DERMS – beyond the planned limited deployment – and related people and processes. In addition, some mutual exclusivity may be created with regard to capturing other benefit streams. For example, to the extent that the C*C assets may be dispatched for reliability reasons under MISO's resource adequacy construct outside of the set energy schedule, this will likely result in reduced energy payments. Inversely, it may be necessary to reserve some of the battery capacity to be able to meet MISO's requirements to qualify for capacity payments/resource adequacy, at the expense of maximizing energy revenue. As noted, these tradeoffs between energy and capacity value will need to be analyzed and evaluated in more detail during the implementation phase of DCP. We will continue exploring capacity/resource adequacy options and tradeoffs as we get more information from MISO, work to enable coordination between the Company's control centers – including through Enterprise DERMS deployment, and as the market opportunities mature.

c. Distribution benefits.

As discussed, the C*C assets will be aggregated and dispatched for bulk system benefit, but we also anticipate some coincident distribution system benefit through strategic siting. The CBA assumes a value of $40/kW-yr as an avoided distribution capacity value, fixed for 20 years and applied to 50 percent of distribution feeders for C*C. We apply the avoided distribution capacity value to 50 percent of the C*C locations because not all C*C assets may be on feeders with capacity constraints and coincident peaks. Therefore, aggregated and/or system peak-driven dispatch may not always coincide with individual feeder peaks nor provide a distribution system benefit.

We assumed $40/kW-yr for the CBA because it is between two established values used in other venues: On the low end, demand-side management modeling in Minnesota has used $8.24/kW-yr in the past, but this value has not been updated since 2017 and does not reflect current levels of investment in the distribution system.[19] On the high end, the Company modeled $71/kW-yr as an avoided distribution value calculated for its Colorado service territory per its Aggregator Virtual Power Plant (AVPP) settlement agreement.[20] This value is specific to Colorado and its distribution system needs and the value in and of itself is not directly applicable to Minnesota. In the absence of an industry standard methodology to calculate a Minnesota-specific avoided distribution value, we believe $40/kW-yr is a reasonable starting point within the range of values that exist; however, the value could be higher or lower, and we will need to conduct additional analysis as we obtain additional information. Additionally, the 50 percent feeder applicability may be higher or lower. The time duration of the benefit may also be shorter than 20 years. For example, if an infrastructure project is completed on a C*C feeder five years into deployment, the value of distribution demand reduction may be high initially, but decline over time as more capacity is added through other projects. All of these dimensions of variability and uncertainty reflect the dynamic nature of the distribution system and will need to be evaluated as the Company begins to gain experience with C*C. To illustrate the dimension of uncertainty associated with this assumed value, we included this benefit in the limited sensitivity analysis discussed below.

[19] See Docket No. E,G002/CIP-23-92. $8.24/kW-yr is calculated by subtracting the transmission portion of T&D marginal cost of approximately $11/kW-yr used in that docket.
[20] See Colorado Proceeding No. 25A-0061E.

d. Avoided transmission grid upgrade costs.

By siting the BESS as part of the distribution system, C*C assets avoid transmission upgrade/interconnection costs associated with utility-scale generation resources. The CBA reflects a benefit of $250/kW in avoided capital costs, consistent with the most recent Resource Plan.[21] $250/kW is annualized over the life of the assets using a 12 percent carrying charge, which results in a value of $30/kW-yr. Like the distribution system benefits, this value will be assessed as we gain experience.

e. Avoided transmission line losses.

Distribution system resources incur lower line losses compared to resources located on the transmission system. This difference – 6.47 percent – is included in the CBA, resulting in increased value for capacity denominated benefits for C*C assets.[22]

3. CBA Costs

In this section, we outline and discuss each of the C*C Phase 2 costs included in the CBA. In general, the CBA cost assumptions align with the program budget.[23]

a. BESS capital costs.

The CBA assumes an aggressive BESS capital cost of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** per kWh. This cost assumes that Sparkfund is able to achieve economies of scale and bulk ordering discounts.

b. Host site payments.

Host payments scale at the same rate as the BESS installations in the CBA, totaling 200 sites by the end of 2028. The CBA assumes **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].** Deploying a smaller number of larger batteries – e.g., with some sites hosting 3 MW/12 MWh BESS – would reduce site host payment costs and increase the BCR.

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[21] See IRP Appendix F, Docket No. E002/RP-24-67 (February 1, 2024).

[22] Transmission only estimate of T&D loss factor presented in Docket No. E,G002/CIP-23-92.

[23] We note that because the DERMS limited deployment costs effectuate benefits that extend beyond C*C, the costs are not included in the cost-benefit analysis.

c. BESS O&M costs.

The CBA assumes **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**, which reflects potential economies of scale at 200 sites. Deploying a smaller number of larger batteries – e.g., with some sites hosting 3 MW/12 MWh BESS – would reduce O&M costs and increase the BCR.

d. Program costs.

The CBA assumes program costs of **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**, during deployment, then declining to **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**.

e. Offset to Costs – ITC.

We assume ITC capture of 30 percent reduction in capital costs, amortized over the life of the asset. This is consistent with the tax benefit treatment for Company-owned assets that qualify for the ITC. For some C*C assets, we may be able to site them in an energy community and achieve an additional bonus ITC for our customers. As discussed in Attachment A, challenges regarding compliance with foreign entity of concern (FEOC) and broader federal policy uncertainty may impact the level of ITC we are able to capture.

4. Limited Sensitivity Analysis

To illustrate the range of potential outcomes based on the sensitivity of the model to different assumptions, we conducted a limited sensitivity analysis on distribution benefits and BESS capital costs. The results of this analysis help illustrate a possible range of outcomes and shows that the cost-effectiveness of C*C will depend on maximizing benefits over time and managing internal and external costs.

Distribution benefits. Adjusting the distribution value to $8.24/kW-yr or $71/kW-yr, with all other inputs held constant, results in the BCR ranges shown in Table 5. As noted above, this value will need to be revisited in the future as we learn more. The lower range of the benefit was based upon the Company's previous demand-side management study and is the total T&D value net of transmission. This approach assumes a uniform application (i.e., non-targeted) of T&D benefits across the system. Conversely, the $71/kW-yr value is reflective of the value the Company calculated for its AVPP program in Colorado. This approach evaluated forecasted capacity investments relative to loading on specific feeders. The values are based upon Colorado-specific capacity needs and mitigation costs, it cannot be assumed that the resulting values are directly applicable in Minnesota. Given both of these considerations, the Company believes that the value is likely somewhere between these two values.

Table 5: BCR Sensitivity to Distribution Benefit Assumptions

All other inputs held constant

Distribution Benefit Value	BCR
$8.24/kW-yr	0.89
$40/kW-yr (baseline value)	*0.96*
$71/kW-yr	1.03

BESS capital costs. As noted above, careful sourcing and cost management will be crucial to realizing the ambitious capital costs assumed in the CBA and potentially achieving further cost reductions through economies of scale. The BCR is sensitive to the BESS capital costs. Table 6 shows the BCR result at a higher capital cost.

Table 6: BCR Sensitivity to BESS Capital Cost Assumptions

All other inputs held constant

BESS Capital Cost	BCR
[PROTECTED DATA BEGINS [redacted]	*.96*
[redacted] **PROTECTED DATA ENDS]**	.68

D. Qualitative Benefits – Phase 2

This section discusses those benefits we believe we will realize with C*C, but that are not practicably quantifiable with sufficient precision or confidence to be included in a CBA model. As C*C progresses and we gain experience, we may be able to quantify some of these benefits in the future.

1. Time to Power

In certain use cases, C*C could accelerate connection of new generation or load – whether generation such as DSES assets or loads such as public EV charging or customer load growth. Connecting load and generation more quickly by deploying C*C assets could impact sales and revenue for Xcel Energy and for customers who rely on electric service to power their businesses and generation. We consider "time to power" as a qualitative benefit for two reasons. First, we cannot confidently estimate or isolate the effect of C*C on accelerating connection of new generation or load. Second, we are not aware of a standardized approach for calculating or monetizing the value of this benefit. Nevertheless, accelerating connection of new generation and load is an important qualitative benefit of C*C.

2. Equity and Environmental Justice

Through the feeder and site selection and prioritization process, we aim to ensure that site hosts located in EJ areas, MWBE, and community organizations can take advantage of host site payments for C*C. Beyond the straightforward monetary value of site host payments, we hope that prioritizing payments in this way will have broader benefits for the site hosts and their communities. We consider this a qualitative benefit but one that is no less important than the quantitative benefits included in our CBA.

3. Program Innovation

Developing and implementing an innovative program can have wider-ranging benefits. Continued Phase 2 program development is itself an important qualitative benefit of C*C. The process of innovating brings to light new challenges and opportunities to better operate our system and deliver value to our customers. Already, we are discovering the potential for intangible benefits such as improved internal coordination, new and expanded use of existing technology, and identifying and addressing process improvement opportunities. As we have stated, C*C is an innovative new program that could provide intangible benefits that are broader than the direct benefits within the program's bounds.

E. Alternative Analysis – Other Ownership Structures

Order Point No. 23.c of the Commission's IRP Order requires:

> [a]n evaluation of a costs and benefits comparison between a utility-owned and managed DCP model and alternative models allowing participation from customer-owned and third-party-owned resources.

As shown in our cost-benefit analysis, BESS strategically deployed on the distribution system can provide system value across a range of use cases when integrated with Company planning, engineering, and operational functions. When these assets are sited, installed, and dispatched in a coordinated manner, they have the potential to meet customer needs and benefit the grid. Realizing the full value of C*C depends not only on the underlying assets themselves, but also on the ability to strategically site and effectively integrate them into the Company's grid planning and operations. Absent strategic deployment in target locations, coordinated control and dispatch, and total visibility, non-utility-owned resources could deliver, at best, a portion of the anticipated system and customer benefits.

But perhaps the most significant benefit of the Company owning and operating the BESS is that third-party or customer ownership introduces additional costs and risks. Anything less than full operational control and visibility of these assets – which will operate functionally as part of our system – could present safety risks for our employees and the public and could create cybersecurity risks for our system. Without full operational control over the assets, we would not be able to maximize system benefits, which rely on market and operational signals that are core utility functions. Enabling full operational control and visibility of third party-owned C*C assets may require additional, unknown levels of investment.

That said, C*C process provides multiple opportunities for third parties to participate in the procurements of major equipment supply, design and engineering services, and construction and installation. In addition to these procurement opportunities, third parties will benefit from the broader system improvements delivered along with C*C. These opportunities and system enhancements mean that while the Company maintains ownership and operational control of C*C assets to protect reliability, safety, and equity objectives, third parties can benefit from C*C – both as participants in the procurement process and as beneficiaries of the long-term system improvements C*C enables. Together, these efforts will increase market access for local firms, strengthen Minnesota's clean energy workforce, and support local and regional economic development.

We also emphasize that C*C is deploying small-scale BESS as part of the distribution system, aggregated and operated to meet overall NSP System needs and serve all customers. This could be considered a virtual power plant. By contrast, smaller, customer-owned, behind-the-meter DER such as rooftop solar or small energy storage systems are primarily used by individual customers to meet their own energy or resilience needs, and the Company has other programs that encourage development of DER including storage owned by customers. Customers may be incentivized to allow their utility partial control over their behind-the-meter DER; C*C instead takes the approach of achieving broader system benefits more efficiently by deploying system-wide resources, fully operated by the Company.

For these reasons, focusing C*C Phase 2 on Company-owned and -operated resources is appropriate. Owning and operating the resources ensures we retain full control to ensure deployment and operations that are safe, beneficial, and can advance equity objectives.

F. Comparative Analysis – C*C Compared to Grid Scale Resources

In this section, we briefly compare the C*C, small-scale BESS to grid-scale BESS and a traditional peaking facility.

Small-scale BESS compared to grid-scale BESS differ significantly in their cost, operational use, and other key characteristics. While both generally use the same commercially available lithium-ion technology, the scale of their application drives a number of distinctions.

For example, grid-scale BESS are measured in tens to hundreds of megawatts and megawatt-hours, while small-scale systems are rated in kilowatts (kW) and kilowatt-hours (kWh), or in the case of C*C, 1-3 MW (1,000-3,000 kW). Grid-scale systems benefit from economies of scale, resulting in a lower installed cost per MW. From our latest resource acquisition efforts, the average capital cost for a utility-scale BESS was approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. In contrast, we estimate the capital cost of C*C BESS is approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS**.

The cost difference is also impacted by other system component differences, such as battery enclosures, fire suppression systems, and transformers, which are required for each small-scale BESS project. Grid-scale BESS enclosures typically range in size from 3 to 6 MWh per enclosure. Distribution level BESS enclosures tend to feature smaller energy capacities, typically less than 2 MWh, as small as 100 kWh depending on enclosure or cabinet sizing. Both distribution and grid scale BESS enclosures can be grouped together to form a block of enclosures which are paired with either string or central power conversion systems, depending on the Original Equipment Manufacturer (OEM) and design. From the power conversion system, the energy flows to either a low or medium voltage transformer, where voltage is stepped up. For distribution-connected systems, this is typically the only transformer needed. Transmission connected BESS projects, will require an additional voltage increase to the interconnection voltage level, which is conducted through the project's Main Power Transformer (MPT).

The process to develop the small-scale BESS, such as C*C, also differs from grid-scale resources. Resources that interconnect to the transmission system typically must complete the MISO queue process, which includes paying for any network upgrade costs, to obtain an interconnection agreement. The MISO queue process can add costs and uncertainty to the development process. Small-scale BESS avoids the MISO queue process, but may require investment in the distribution system. The permitting process for small-scale BESS can also differ from the permitting process for grid-scale BESS and may be able to completed in a shorter timeframe.

Operationally, small-scale BESS, such as those contemplated for C*C can be used to offset energy needs or as capacity resources – however, depending on the specific use case or market participation model, this approach may add significant operational complexity due to the necessary interaction of the distribution and bulk grids, differing grid management technologies, and the need to aggregate large numbers of small-scale BESS to achieve the same load reduction.[24] Grid-scale BESS are able to provide a range of grid services critical for managing the wider electrical grid, for example, in addition to peak shaving, frequency regulation, and voltage support. Beyond cost and operation, other distinctions include physical size and location. Small-scale BESS are installed at homes or commercial buildings and historically have been designed to power a single property – although with C*C, the Company proposes to harness an aggregation of small systems to operate much like a grid-scale BESS. Grid-scale systems, which can be massive in size, are often built at or near utility substations or renewable energy generation sites to serve a broader area. This may make site control more efficient on a per-MW basis compared to small, distributed systems.

The differences between a small-scale BESS and a natural gas peaking plant (Combustion Turbine or CT) include the underlying technology, operational characteristics and capabilities, environmental impact, construction, and costs. While both can provide power to the grid during periods of high demand, a small-scale BESS can provide smaller amounts of capacity for shorter durations (typically four hours), while a natural gas peaking plant can meet system needs for multiple days.[25] A

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[24] Generally, using stored energy during periods of high electricity prices.

[25] For additional discussion of firm dispatchable attributes, see our last Resource Plan (Docket No. E002/RP-24-67) and Firm Dispatchable Proceeding (Docket No. E002/CN-23-212).

CT relies on natural gas combustion, so it is exposed to fuel price volatility and also emits greenhouse gases; for C*C, the small-scale BESS will charge from the grid with varying costs and levels of emissions, but a BESS does not directly emit carbon or other greenhouse gases when discharging. The estimated per MW capital cost for the proposed C*C assets is **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**, compared to an estimated **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]** for the Company's Lyon County CT.[26] Finally, a CT typically requires a larger land area and access to a natural gas pipeline and a connection to the bulk electric grid. A small-scale BESS can be deployed in a smaller area.

V. C*C IMPACT ON IRP ACTION PLAN, FORECASTS, AND DISTRIBUTED SOLAR ENERGY STANDARD COMPLIANCE

Order Point No. 23.b of the Commission's IRP Order requires:

> A discussion of how the proposal impacts the Five-Year Action Plan approved in this order, how it impacts the IRP forecasted annual distributed generation solar additions, and whether the DCP could be used to advance compliance with the distributed solar energy standard.

We address each topic below. Ultimately, C*C Phase 2 is in the public interest because it is consistent with the Commission-approved Five-Year Action Plan. As C*C evolves, future phases could contribute to compliance with Minnesota's DSES.

A. C*C is consistent with the Five-Year Action Plan

The approved Five-Year Action Plan requires the Company to pursue 600 MW of standalone storage to be installed by a target date of end-of-year 2030. C*C can support the Action Plan – starting with deployment of 50-200 MW by the end of 2028. While C*C does not offset the resources approved as part of the Five-Year Action Plan, the additions are consistent with the approved Resource Plan, which demonstrates a capacity need. To the extent C*C assets can be registered with MISO in the future, any accredited capacity would be added to our reference case for future Resource Plans, possibly offsetting future resource needs in the outer years of the current Five-Year Action Plan. The next Resource Plan is due to be filed no later than April 21, 2027.

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[26] *See* Xcel Energy *Combined Application for A Certificate Of Need, Site Permit, Transmission Line Route Permit, & Partial Exemption and Pipeline Routing Permit for the Lyon County Generating Station Project*, Not Public Appendix K, Docket No. E002/CN-25-145 (May 9, 2025).

B. Future phases of C*C could impact the distributed solar forecast

Phase 2 of the C*C will not include solar, so we do not anticipate the C*C will impact our distributed solar forecasts. As discussed, Phase 2 of the C*C is designed be to support bulk system needs in the near term, so any impact to distributed generation (DG) hosting capacity would be incidental. With the phased approach and fully deployed technical capabilities, Phase 4 could allow the Company to co-optimize siting and operations of C*C assets.

In Phases 3 and 4, we envision C*C could directly include solar deployment. In those phases, C*C would impact the distributed solar forecast. Future C*C program iterations could help drive supplemental distributed solar adoption, but may also offset some of the DG solar additions we would expect to see otherwise. The extent of C*C's impact on the DG solar forecast would depend on factors such as the specific program design, any other incentives (e.g., tax credits) and programs available in the market, and the latest market trends.

C. C*C could contribute to DSES compliance in the future

The DSES, established in Minn. Stat. § 216B.1691, subd. 2h, requires the Company to obtain 3 percent of its retail electric sales from distributed solar energy systems by the end of 2030. We anticipate we will need at least 500 MW of new distributed solar to meet the DSES requirements.[27]

To qualify under the DSES, solar energy systems must meet the following criteria:

- Have a capacity of 10 megawatts (MW) or less,
- Be connected to the Company's distribution system,
- Be located within the Company's Minnesota service territory,
- Be constructed or procured after August 1, 2023, and
- Be selected through a competitive bidding process approved by the Commission.

For systems with a capacity of 100 kilowatts (kW) or more, the Company must also verify that:

- Construction workers were paid the prevailing wage rate, and

[27] The Company launched its first DSES request for proposals in January 2025. We plan to bring forward the resulting projects for Commission approval later this year; we anticipate needing additional resources to meet the DSES requirement. *See* Docket No. E002, E015, E017/CI-23-403.

- The employer participated in a registered apprenticeship program under state or federal law.

Battery storage systems, which we are deploying in Phase 2 of C*C, do not currently count toward DSES compliance, nor does the DSES value storage as a resource that can contribute to DSES. Therefore, Phase 2 of C*C would not support compliance with DSES as it currently stands.

That said, while the C*C program is not primarily designed to fulfill DSES obligations, the program phases outlined in this Petition could support DSES compliance directly and indirectly.

Phases 1 and 2 of the C*C program will not deploy solar, and the BESS will be dispatched initially for bulk system capacity and energy use cases. To the extent the storage systems also relieve distribution system congestion or increase grid capacity, that may support future deployment of solar, including DSES projects.

In our C*C roadmap, we envision that solar could be deployed as part of the C*C program starting in Phase 3, and the Company would intend to maximize efficiency and customer value by ensuring any new solar deployed through C*C also counts toward DSES compliance. Future C*C solar projects could easily comply with these DSES requirements, as outlined above, with the exception of a Commission-approved competitive bidding process.[28] Although we plan to conduct competitive processes for certain portions of Phases 1 and 2, as discussed in Section III, the process we outline – which will be conducted by Sparkfund to procure the BESS – is not explicitly approved by the Commission such that future distributed solar procured under this process would comply with the DSES requirement.

Therefore, as we continue to develop future phases of C*C that may include DSES-compliant resources, we would consider either (a) using the Commission-approved Track 1 or Modified Track 2 process, or (b) proposing an alternative acquisition process and seeking Commission approval. This would ensure C*C solar could contribute to the DSES. As C*C evolves over the coming months and years, we will work with stakeholders to ensure we design a competitive, fair, and streamlined bid process to present to the Commission, should an alternative process be needed for C*C.

[28] Minn. Stat. § 216B.1691 Subd. 2h(e).

Lastly, we note that we believe consideration of additional resource options, such as distributed storage, to comply with the DSES could offer the flexibility needed to best utilize distributed resources on our system. As we proceed with the DSES, the Company intends to bring forward any additional options we believe are in the best interest of our customers.

VI. LABOR STANDARDS

Order Point No. 23.d of the Commission's IRP Order requires this filing to address, "an evaluation of the labor standards utilized by Xcel and third-party solar installers."

Below, we provide an overview of the labor standards we employ at Xcel Energy for owned and purchased system resources, regardless of resource type. Because we do not work with third-party installers that do not comply with our own high labor standards, other parties may wish to provide additional information on labor standards utilized by other installers on non-Xcel Energy projects.

Xcel Energy is proud to employ local, union labor for owned and purchased system resources. The Company has long-standing labor standards for our vendor partners. For example, Xcel Energy's most recent model power purchase agreement (PPA) includes the following language, requiring parties to ensure all Construction Craft Employees are covered by a collective bargaining agreement or site-specific project agreement:

> An officer of Seller, authorized to bind Seller and who is familiar with the Facility, shall certify in writing that all Construction Craft Employees were covered by a collective bargaining agreement with a union affiliated with the local council of North America's Building Trades Unions ("Building Trades CBA"). If Seller cannot provide such certification as to a specified portion of the work, then an officer of Seller, authorized to bind Seller and who is familiar with the Facility shall certify in writing that Seller met and conferred, in good faith, with the local council of North America's Building Trades Unions and attempted to find and hire those trade(s) of Construction Craft Employee(s) covered by a Building Trades CBA for that portion of the work, and, if such Construction Craft Employee(s) covered by a Building Trades CBA were not available, that Seller (or Seller's construction contractor) entered into a site-specific building trades collective bargaining agreement covering that portion of the work.

The Company intends to take the same approach throughout the lifecycle of C*C. As discussed above, the C*C procurement strategy will ensure our high labor standards are upheld throughout the process.

As discussed in Attachment A, tax credits for BESS do not expire until 2036, so we intend to take full advantage of available Investment Tax Credits and pass those savings to our customers. To qualify for the ITC, developers must pay prevailing wage and comply with all other ITC/Inflation Reduction Act (IRA) requirements, such as weekly pay, apprenticeship requirements, payroll certifications, etc., and provide documentation to Xcel Energy.

From a policy standpoint, Minnesota generally supports robust labor protections and standards. For example, the Community Solar Garden statute requires contractors or subcontractors to pay no less than prevailing wage for construction of such projects at least 1 MW in size. The law also subjects contractors and subcontractors to other employer-related laws in the State of Minnesota.[29]

Absent a contract or other enforceable policy that explicitly requires the use of collective bargaining agreements, project-specific labor agreements, and/or other labor standards, third-party solar installers' labor standards may vary.

VII. HOW C*C CAN ADVANCE EQUITY

IRP Order Point No. 23.a requires this filing to include "[an] evaluation of how the Distributed Capacity Procurement program could be used to improve equity."

As an initial matter, we emphasize that we do want and intend to design and implement C*C in support of equity and EJ objectives wherever possible. We are considering the following ways to support equity and EJ through C*C:

- *Procurement* – Sparkfund's competitive procurement processes will include higher scoring for women- and minority-owned business enterprises (WMBE) bidders; bidders that contract with WMBE; and bidders with apprenticeship programs, scholarship programs, or other equity-supporting initiatives.
- *Feeder selection and site host prioritization* – Once eligible sites are determined through the steps outlined in Section III above, we will prioritize outreach to sites that are:
    - Located in EJ areas.
    - Non-profits/community-based organizations.
    - WMBE, where information is publicly available.
- *Community engagement and custom site host benefits* – C*C site hosts in EJ areas could be offered additional, customized community programming or other benefits

[29] Minn. Stat. § 216B.1645, subd. 6(c).

concurrently with C*C, such as holding energy-themed education opportunities and community outreach at the site.

In addition, we plan to engage the Company's Environmental Justice Advisory Board (EJAB) to gather input on these tactics. At a future meeting, we plan to present an overview of C*C and our ideas on how best to reflect equity and EJ tenets in Phase 2 implementation and potential future program design. Based on feedback from EJAB, we may adjust these tactics.

We will provide an update to the Commission in our first quarterly report (as proposed in Section IX below).

VIII. COST RECOVERY

The Company respectfully requests Commission approval to recover costs associated with the C*C program – beginning with Phase 2-specific costs that are separate and incremental to Phase 1 – through the RES Rider, pursuant to Minn. Stat. § 216B.1645. Cost recovery through the RES rider is appropriate.

Minn. Stat. § 216B.1645, subd. 1(2), authorizes the Commission to approve utility investments made to satisfy the renewable energy objectives in Minn. Stat. § 216B.1691, including expenditures to "provide storage facilities for renewable energy generation facilities that contribute to the reliability, efficiency, or cost-effectiveness of renewable facilities." Further, subd. 2a(3) permits recovery of "other expenses incurred that are directly related to a renewable energy project, including expenses for energy storage," provided the utility demonstrates certain facts about the expenses, including that they "advance research and understanding of how storage devices may improve renewable energy projects."

Recovery of the Company's C*C costs is consistent with the RES Rider. C*C is designed to support a carbon-free system, including supporting integration, reliability, and optimization of renewable energy resources on the Company's system. The C*C BESS projects will be deployed and operated as system assets that can meet energy and capacity needs that may otherwise need to be met by non-renewable resources. Further, we will deploy batteries as part of C*C with the aim to grow operational capabilities over time and directly support future integration of distributed solar; in this way, C*C will "advance research and understanding of how storage devices may improve renewable energy projects." C*C aligns with the statutory intent for cost recovery under the RES Rider and contributes to the Company's – and the State's – broader strategy of enabling higher renewable penetration and grid decarbonization.[30]

As noted above, the RES Rider is a tariff mechanism approved by the Commission that allows utilities to recover prudently incurred costs related to investments made to comply with the state's Renewable Energy Standard. These recoverable costs may include capital expenditures, operations and maintenance, and administrative expenses associated with facilities or programs that have received prior Commission approval.

The statute specifically allows for:

- Automatic annual adjustments to customer rates to reflect eligible costs,
- Recovery of costs for facilities constructed, owned, or operated by the utility to meet RES obligations, and
- Inclusion of distributed energy resources (DERs) and energy storage systems that meet the definition of eligible energy technologies.

All C*C-related costs proposed for RES Rider recovery will be:

- Submitted with supporting documentation, including cost breakdowns and specific activities;
- Reviewed and approved by the Commission, ensuring that only reasonable and prudent costs are passed on to customers; and
- Tracked and reported in each Petition, with updates to the rider rate based on actual expenditures and forecasted needs.

This approach ensures that cost recovery for C*C investments is consistent with statutory requirements, transparent to stakeholders, and aligned with Minnesota's clean energy objectives.

The C*C Phase 2 budget is fully incremental to the Phase 1 costs approved for cost recovery through ECO.

[30] The Commission also has authority under Minn. Stat. § 216B.16 subd. 7e to approve a rate schedule (i.e., rider recovery) for energy storage system pilot projects.

IX. PROPOSED REPORTING

Some details of the Phase 2 implementation we propose in this Petition require further development and are subject to change as we make continuous adjustments based on lessons learned along the way. Moreover, the novel nature of C*C overall merits ongoing assessment to ensure the program is achieving the expected benefits in a cost-effective way. We intend to keep the Commission and stakeholders informed as details are solidified and refined, and as we validate our assumptions and learn from our experience. To that end, we propose initial quarterly reporting leading to an Interim Program Assessment filing within two years that would provide stakeholders and the Commission with a formal opportunity to weigh-in on progress and how we should proceed with Phase 2. Table 7 outlines our proposed program reporting and assessment.

Table 7: Program Reporting and Assessment

Report	Frequency/Timing	Report Purpose and Contents
Program Implementation Update	Quarterly after Commission approval, until Interim Program Assessment is filed.	More frequent update to share updates on implementation details as C*C progresses toward construction. Narrative updates on Phase 2 implementation details and progress, any adjustments made, procurement progress, lessons learned, and new or emerging challenges or questions. As information is available, the Implementation Update may also include: • Number of MW and sites • Number of MW and sites in EJ areas • Spend compared to plan • Site host payments • $/MW installed • Procurement update
Interim Program Assessment	Two years after Commission approval *or* after 20 MW of Phase 2 BESS is online and operational, whichever is earlier	An evaluation of the progress and results of C*C to date. The Assessment is designed to serve as a stage-gate to determine next steps, providing the Commission and parties with an opportunity to review and weigh in on the C*C progress. Contents to include: • Costs and benefits assessment • Operational experience review • Host experience and equity review • Discussion of other relevant lessons learned • Recommendation on next steps (e.g., continue as planned, update costs or benefit assumptions, revise scale or timeline, etc.)

In addition to these Phase 2-specific reports, we will also report on Phase 1 information in the ECO docket. Cost recovery petitions will include full cost information and updates on activities and program progress.

This reporting plan will provide ample opportunity for the Company to track lessons learned and report on progress validating assumptions and performance of this innovative program. The Interim Program Assessment in particular will provide a specific opportunity for the Company, stakeholders, and ultimately the Commission to determine whether C*C is meeting or exceeding the goals and customer benefits intended and whether and how to proceed with Phase 2.

X. CONCLUSION

We are excited to take the next steps on the Distributed Capacity Procurement program – an innovative and industry-leading approach to deploying and managing distributed BESS at scale. Many unknowns remain, and we expect more questions to surface as we continue down this novel path. In designing Phase 2 and our Capacity*Connect roadmap, we have sought to manage risk and maximize potential benefit, while maintaining flexibility to adjust as we proceed. Building flexibility into the process is a necessary recognition of the innovative nature of the program, including the unknowns and lessons yet to be learned. To get to this point and develop our conceptual C*C vision and work toward a Phase 2 program, we have made assumptions – assumptions that will be tested through Phase 2 and beyond. We have discussed these assumptions throughout this Petition and recognize that not all will prove accurate or complete. As we continue on this new path, we are committed to keeping the Commission and stakeholders informed and engaged through regular reporting and discussions.

We respectfully request the Commission approve:

- Implementation of the Phase 2 Capacity*Connect, including:
  - Deployment of approximately 50 MW and up to 200 MW of Company-owned and -operated distribution-interconnected BESS by the end of 2028.
  - A budget range of approximately $152 million (corresponding to the planned 50 MW deployment) to approximately $430 million (estimated for a 200 MW deployment) through 2028.
- Quarterly status reporting until an Interim Program Assessment to be filed after commercial operation of 20 MW or two years from Phase 2 approval, whichever is sooner.
- Implementation of a limited deployment of a grid DERMS to support C*C and inform the Company's requirements for a future Enterprise DERMS.
- The Company's proposal to seek recovery of C*C costs in the Renewable Energy Standard (RES) Rider.

In addition, we respectfully request that the Commission find that the Company has adequately addressed the DERMS information and questions required by Order Point

No. 23 of the Commission's September 16, 2024 Order in Docket No. E002/M-23-452.

Dated: October 3, 2025

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey C. Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF CAPACITY*CONNECT, A DISTRIBUTED CAPACITY PROCUREMENT PROGRAM	Docket No. E002/M-25-___ **PETITION**

SUMMARY OF FILING

Please take notice that on October 3, 2025, Northern States Power Company doing business as Xcel Energy filed with the Minnesota Public Utilities Commission a Petition requesting approval for implementation of Phase 2 of Capacity*Connect, a distributed capacity procurement program that includes deployment of approximately 50-200 megawatts of Company-owned and -operated front-of-the-meter battery energy storage systems, installed at customer locations and connected to the Company's distribution system. The program also includes implementation of a limited deployment of a Grid Distributed Energy Resources Management System (DERMS) that will support Capacity*Connect and provide important operational experience to inform the future requirements for an Enterprise DERMS deployment.

TAX CREDITS AND CAPACITY*CONNECT

This Attachment provides additional background and updates on tax credit implications for Capacity*Connect (C*C) assets. As always, we will seek to maximize tax credit value for the benefit of our customers.

BACKGROUND

The One Big Beautiful Bill Act (OBBBA), enacted on July 4, 2025, restructured Inflation Reduction Act (IRA) federal tax incentives for renewable energy. As always, the Company intends to maximize the value of tax credits for our customers. The Company and Sparkfund will obtain necessary certifications and documentation in bid forms, scopes of work, and master service agreements to ensure compliance with IRS certification and recordkeeping requirements. While the OBBBA phases out wind and solar tax credits more quickly, the Investment Tax Credit (ITC) for BESS phases out gradually starting in 2034, ending completely by 2036. Future policy uncertainty notwithstanding, we expect to take advantage of the ITC for C*C assets to benefit our customers.

ELIGIBILITY & CREDIT RATE

Stand-alone or co-located BESS placed in service after December 31, 2024 qualify for the Clean Electricity Investment Tax Credit, 26 USC § 48E, as "energy storage technology." The ITC rates are:

- Base rate: 6%
- Full rate: 30% if prevailing wage and apprenticeship (PWA) requirements are met
- Energy community[1] bonus: +10% with PWA
- Domestic content bonus: +10% with PWA

Our budget estimate assumes we will be able to achieve at least the "full rate" of 30 percent ITC. For some C*C assets, we may be able to site them in an energy community and achieve an additional bonus ITC for our customers. The domestic content bonus may require further analysis during the procurement process to determine whether the value of the bonus tax credit would be higher than the potential incremental cost of a compliant storage system. Furthermore, there

[1] As defined in 26 U.S.C. § 45(b)(11)(B).

continues to be broad policy uncertainty at the federal level, and we are still awaiting IRS guidance on certain aspects of the tax provisions in OBBBA. Notably, OBBBA extended foreign entity of concern (FEOC) restrictions to 48E and battery storage technology. According to the new FEOC restrictions, credits may be denied if the taxpayer is a Specified Foreign Entity (SFE) or Foreign-Influenced Entity (FIE), or the project receives "material assistance" from a Prohibited Foreign Entity (PFE – including an SFE or FIE) based on cost-ratio thresholds for covered components or materials. The Department of Treasury has not yet issued FEOC safe-harbor cost tables and related rules regarding material assistance for storage eligibility. Those rules are expected to be released by December 31, 2026. Until that time, we will continue to adapt and update certifications as final regulations are issued.

LABOR COMPLIANCE

To access the 30 percent ITC, developers must pay prevailing wages and satisfy apprenticeship labor ratios during construction and during certain alterations and/or repairs within the recapture period;[2] certified payroll, apprenticeship participation, correction payments and penalty procedures apply. As such, all Sparkfund bid documents and service agreements will require (1) certified payrolls and apprenticeship reporting; (2) PWA obligations for contractors and subcontractors; and (3) retention of records for the applicable statutory and recapture window. Sparkfund will include these requirements in its bidding processes and contracts, and provide the required information to Xcel Energy in compliance with the law so that Xcel Energy can claim the tax credit value.

[2] The "recapture period" refers to the period – typically five years – after the credit has been claimed during which time all or some of the credit may need to be repaid in the event of noncompliance with the associated requirements.

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Attachment B is marked "Not-Public" as it contains information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential cost and pricing data, commercial information, and vendor information that derive an independent economic value from not being generally known or readily ascertainable by others who could obtain economic value or a financial advantage from its disclosure or use. The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500. Attached to this cover letter, we provide the required information as specified in Minn. R. 7829.1300 and Minn. R. 7829.0700, including to whom information requests should be directed.

Attachment B is marked "Not-Public" in entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

Attachment B:

1. **Nature of the material:** Capacity*Connect budget detail
2. **Authors:** Customer Energy & Transportation Solutions
3. **Importance:** Contains not-public, proprietary cost data
4. **Date the Information was Prepared:** September/October 2025

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

Attachment C is marked "Not-Public" as it contains information the Company considers to be trade secret data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential cost and pricing data, commercial information, and vendor information that derive an independent economic value from not being generally known or readily ascertainable by others who could obtain economic value or a financial advantage from its disclosure or use. The Company takes efforts to protect this information from public disclosure. Thus, Xcel Energy excises this information as protected data pursuant to Minn. Rule 7829.0500. Attached to this cover letter, we provide the required information as specified in Minn. R. 7829.1300 and Minn. R. 7829.0700, including to whom information requests should be directed.

Attachment C is marked "Not-Public" in entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

Attachment C:

1. **Nature of the material:** The Company's cost-benefit analysis model for Capacity*Connect, provided as a live Excel workbook.
2. **Authors:** Integrated System Planning
3. **Importance:** The Company work product is proprietary to the Company
4. **Date the Information was Prepared:** September/October 2025

Distributed Energy Resource Management System

To support the Company's request for approval of Capacity*Connect (C*C), a distributed capacity procurement (DCP) program that includes a limited deployment of a grid Distributed Energy Resource Management System (DERMS), we provide our initial DERMS roadmap and other DERMS-related information specified in Order Point Nos. 22 and 23 of the Commission's Order in the Company's 2023 Integrated Distribution Plan (IDP).[1]

The Order requires the Company to "adequately address…[specific] questions before any DERMS investments will be approved." While we are seeking Commission approval of a limited deployment of a Grid DERMS necessary to implement C*C in conjunction with our C*C proposal in this docket, the DERMS roadmap, use cases, and benefits we discuss in this Attachment are broader than C*C, and reflect the Company's current overall plans and vision for an Enterprise DERMS.

In the balance of this document, we provide detailed information about:

- Our DERMS roadmap, including the parallel deployment of limited Grid DERMS deployment and Aggregator DERMS – leading to an integrated Enterprise DERMS
- Alternatives to DERMS
- Use cases and beneficiaries
- Details about participation in DER management
- Communications, and related costs, between our DERMS and Customer DERs
- Capacity allocation and upgrades
- Information for prospective interconnectors
- DERMS costs
- DERMS people and process considerations
- Equity and justice principles
- DERMS-related stakeholder engagement

As we will discuss, ultimately, the Company views DERMS not just as a software solution. DERMS implementation also requires development of new business processes and skillsets. The combination of the DERMS technology, people, and process can facilitate improved integration of distributed energy resources (DER) with

[1] See Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements, Docket No. E002/M-23-452 (September 16, 2023).

the grid, unlocking new value streams and supporting the transition to a more resilient and responsive energy system.

I. ROADMAP TO DERMS DEPLOYMENT

A. Background

To begin, it is important to establish clear definitions around DERMS. The Company does not view DERMS as a single system, but rather as an ecosystem of software platforms, business processes, and policy frameworks. Our definition of Grid DERMS and Aggregator DERMS broadly aligns with the guidelines from the Electric Power Research Institute (EPRI).[2] Our definition of Enterprise DERMS is also included below:

Grid DERMS: Primarily manages front-of-the-meter resources and serves as the DER monitoring, control, and coordination application as an extension to the existing Advanced Distribution Management System (ADMS). It maintains the as-operated network model used in grid operations and supporting applications, and ensures that DER operations stay within distribution grid limits.

Aggregator DERMS: Primarily behind-the-meter resources, such as solar arrays and demand response assets. It also could facilitate control of these resources in coordination with the market and Distributed Energy Resource Aggregators (DERA). It is important to note that unlike Grid DERMS, Aggregator DERMS does not have situational awareness of the grid conditions.

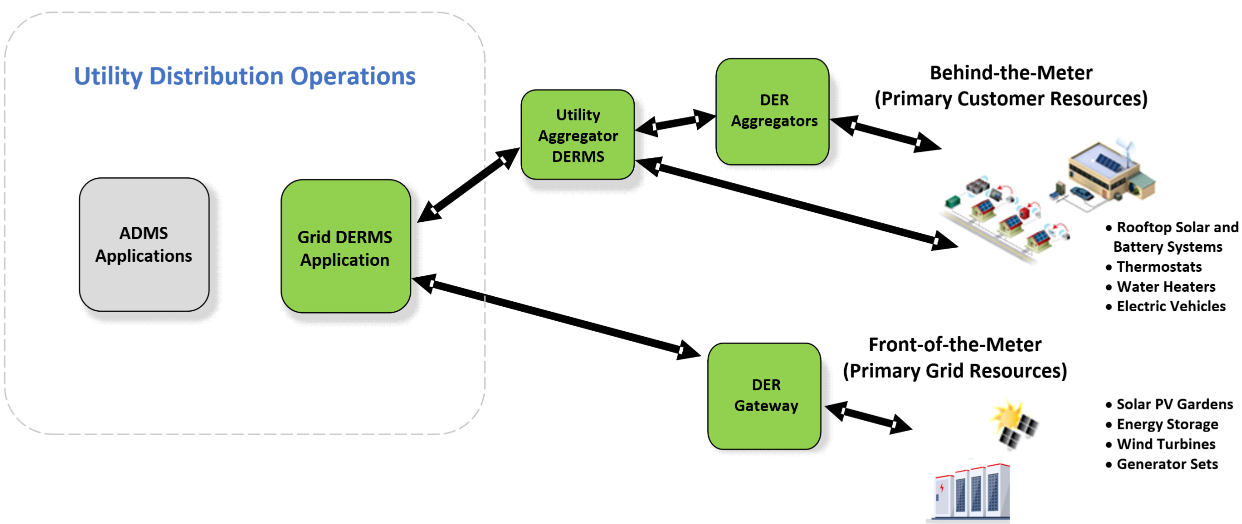
Enterprise DERMS: Represents a unified platform that helps integrate Grid DERMS and Aggregator DERMS, as well as other supporting IT and OT systems and across vendors, supported by secure and reliable communication networks. It enables real-time situational awareness and coordinated control of DER across the grid and utility operations. These DER can include utility-owned and customer-owned assets, as well as resources managed by utility-affiliated and third-party aggregators. By bridging operational systems and some existing silos, Enterprise DERMS supports efficient grid operation and asset utilization, enhances grid resiliency and reliability, and provides a foundational framework for DER participation in energy markets through market integration and operational coordination. An enterprise solution is not an "off the shelf" solution because of the complex integration requirements and utility-specific needs and priorities, and

[2] EPRI, *Aggregator DERMS-Use Cases and Requirements: Reference Language for Implementation and Integration of a DER Aggregation Type/Grid-Service Providing DERMS* (2024).

we view the journey towards enterprise DERMS as a process that will need to integrate technology, people, and processes.

The figure below illustrates the high-level architecture of Enterprise DERMS. It is important to note that Enterprise DERMS is not a one-stop implementation, but rather a phased deployment as new use cases are defined and as enabling technologies and market processes mature. This phased and iterative rollout ensures safe, reliable integration of new capabilities while effectively managing project risks.

Figure 1: High-Level Enterprise DERMS Architecture – Illustrative Example

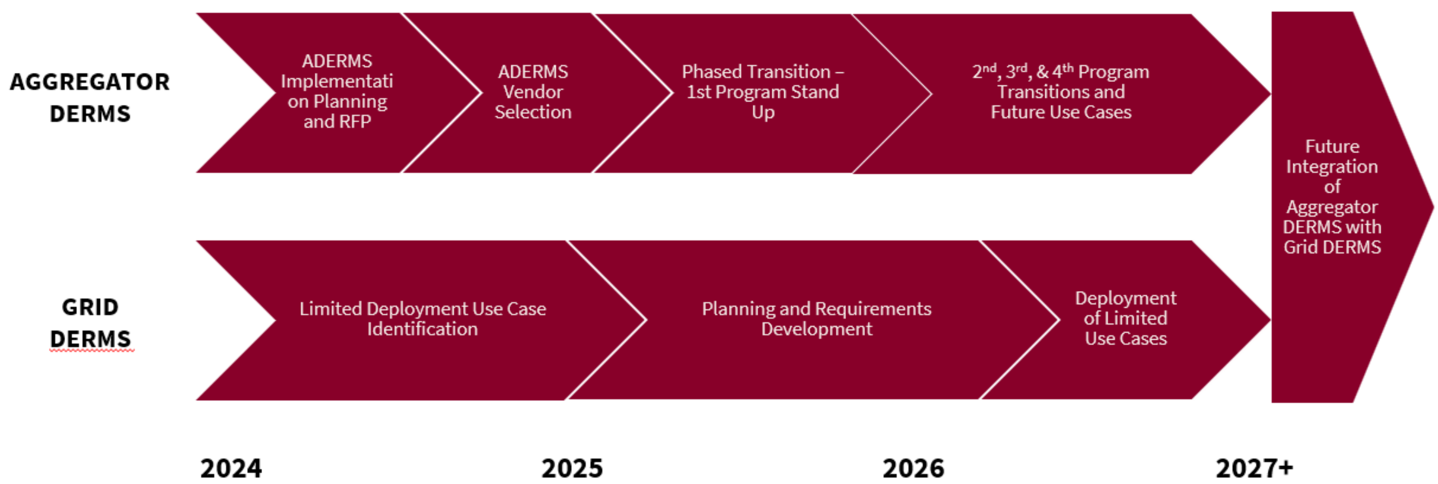


B. DERMS Roadmap and Implementation Timeline

In developing our DERMS roadmap, the Company has considered and evaluated multiple deployment strategies relative to the current level of maturity of the DERMS market and our organizational capabilities.

Planning and implementing our Aggregator DERMS and Grid DERMS platforms are progressing through defined phases through 2027 and beyond. These efforts lay the groundwork for the future Enterprise DERMS. This is a multi-year journey designed to enhance grid flexibility, optimize DER, and align with evolving regulatory and market needs. Figure 2 below shows the strategic progression from foundational planning to full integration of Aggregator DERMS and Grid DERMS to Enterprise DERMS. We explain our phased approach below.

Figure 2: DERMS Technology Implementation Timeline



1. *Phase 1: Foundation & Planning (2024)*

In 2024, the Company laid the groundwork for Grid DERMS deployment by identifying a limited number of use cases to serve as early pilots. These use cases were selected based on operational feasibility and strategic value. Concurrently, teams developed detailed requirements, engaging internal stakeholders and external technology partners to ensure alignment across business units.

The Company also initiated the development of a formal Request for Proposal (RFP) for the Aggregator DERMS platform. This included defining a comprehensive catalog of use cases, technical requirements, and architectural considerations. The RFP was released to potential vendors, and the process ultimately led to the selection of a strategic partner to support the management and operations of our demand management and load flexibility portfolio.

This foundational work emphasized data security, interoperability, and scalability – setting the stage for a future Enterprise DERMS.

2. *Phase 2: Initial Implementation (2025)*

In 2025, efforts shifted towards transitioning existing customer programs to the centralized Aggregator DERMS software platform, with the first program successfully operationalized in our Xcel Energy Colorado operating company.

The Grid DERMS team collaborated with the Company's ADMS provider to prepare for a limited deployment, refining technical requirements and integration strategies to support targeted use cases. We also reviewed and augmented business processes and personnel structures to support the new technology.

Security remained a top priority, with ongoing research into data integration architectures that could enable behind-the-meter (BTM) resources to contribute to both transmission and distribution services.

3. *Phase 3: Phased Deployment & Integration (2026)*

In 2026, the Company will continue with the phased transition of operationalizing additional customer programs in Colorado on the Aggregator DERMS platform. Plans also include initiating the transition of programs in Minnesota to the Aggregator DERMS platform.

The Grid DERMS platform will enable the limited deployment use cases and test initial platform operations and enhancements. Operational experience gained from initial deployments will help validate assumptions and inform refinements to system architecture and business processes.

Operational planning and system integration criteria will become clearer, with increasing emphasis on integrating Aggregator DERMS and Grid DERMS functionality with broader grid modernization initiatives.

4. *Phase 4: Expansion & Optimization (2027+)*

Building on the integration efforts and operational insights gained in 2026, the Company will focus on expanding Aggregator DERMS and Grid DERMS capabilities and optimizing their impact. Future use cases will be developed to capture a broader set of grid benefits, including enhanced flexibility, reliability, and market participation.

Integration requirements between Aggregator and Grid DERMS platforms will be further refined, informed by lessons learned during initial deployments. These refinements will support regulatory mechanisms that enable flexible agreements and innovative market structures. In this phase, we will evaluate both technological readiness and organizational capacity.

Ultimately, DERMS is not just a software solution—it is a transformative business initiative that will continue to evolve, requiring ongoing changes to people, processes, and operational technology. These efforts will enable deeper integration of DER with the grid, unlocking new value streams and supporting the transition to a more resilient and responsive energy system.

The integration and business transformation activities undertaken in Phase 4 represent a critical inflection point in the Company's DERMS roadmap. These efforts lay the operational and organizational foundation necessary to advance toward the Company's long-term vision of an Enterprise DERMS, delivering coordinated and scalable DER management.

5. Long Term Vision: Enterprise DERMS

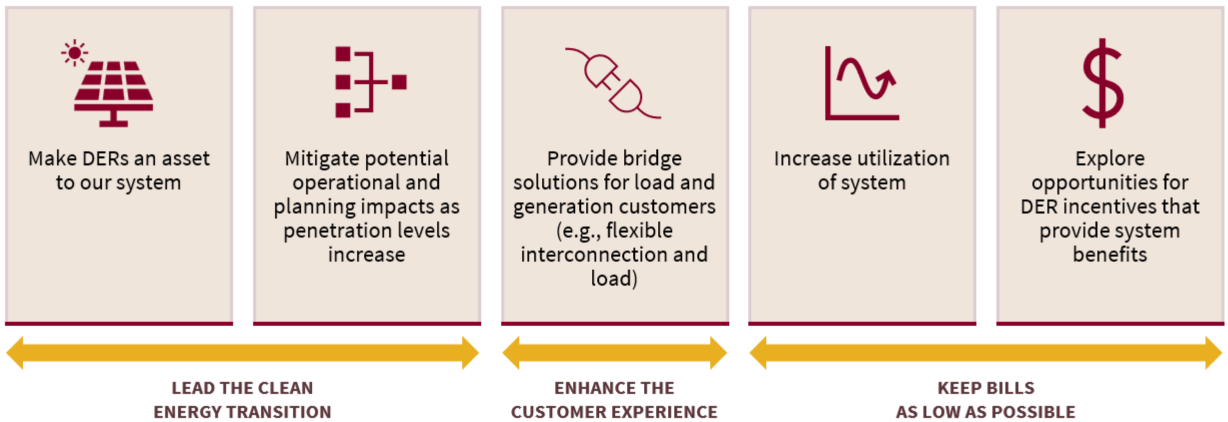
The Company's Enterprise DERMS strategy reflects a broader shift toward a more integrated, resilient, flexible, and customer-centric energy system. By actively managing DER as a unified portfolio, Enterprise DERMS will improve real-time visibility, dynamic control, and coordinated dispatch across the grid. Enterprise DERMS enables this by facilitating situational awareness and seamless coordination across utility operations, utility- and customer-owned assets and aggregators, and market participation.

The Company views Enterprise DERMS and the business and customer processes that it can help enable, as a critical part of our strategy for planning and operating the grid – particularly during this period of rapid change and demand growth in the industry. Specifically, Enterprise DERMS can support several outcomes that benefit our customers and the grid including:

- Enabling higher penetration levels of DER on the grid
- Supporting public policy objectives while maintaining safe, reliable operations of the grid
- Improving customer experience by offering more options to connect load and distributed generation
- Potentially reducing the cost and time to interconnect
- Increasing overall flexibility of the system
- Managing load in a way that minimizes costs and retail rate impacts

Figure 3 below shows how the Company's approach directly supports the Company's commitment to delivering excellent service by streamlining interconnection processes, expanding customer access to clean energy programs, and more dynamically utilizing the capacity of the grid. At the same time, Enterprise DERMS is a foundational tool in leading the clean energy transition, enabling deeper integration of renewables, supporting electrification, and optimizing distributed resources to meet evolving system demands.

Figure 3: Alignment of DERMS and DER Management to Outcomes



Advancing towards an Enterprise DERMS is essential to achieving the Company's strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills as low as possible.

C. DERMS Deployment Pathways

In developing our DERMS roadmap, we considered and evaluated multiple deployment strategies relative to the current level of maturity of the DERMS market and our organization capabilities. In this section, we summarize the alternatives and discuss our chosen phased parallel path deployment. We provide a detailed comparison of the three different pathways as Attachment D1.

The three deployment strategies are:

1. Phased parallel path (Company's chosen approach)
2. Consolidated single vendor approach
3. Vendor dependent

Below, we discuss each in turn.

1. Phased Parallel Path (Selected Approach)

As the name implies, this deployment approach is incremental and builds upon prior phased implementations to mature the DERMS capabilities. In our case, this approach starts with a phased deployment of Aggregator DERMS followed by the limited deployment of priority use cases for Grid DERMS – including for C*C.

Benefits of this approach include our ability to manage risk by "right sizing" the requirements and implementation to existing commitments and regulatory requirements. It is also a focused and agile method that starts with a minimum viable product that builds capabilities over time. A potential drawback is future integration risk – eventually we will need to integrate Aggregator DERMS with Grid DERMS.

2. Consolidated Single Vendor Approach (Approach Not Selected)

With this approach, we would draft a comprehensive set of functional and non-functional requirements for both Aggregator DERMS and Grid DERMS for a RFP, toward selecting a single vendor to meet all the Company's DERMS needs. A benefit of this approach is that we would have enhanced vendor accountability, because a single vendor would be responsible for integration and maintenance. However, drawbacks include longer timelines for implementation and substantially higher costs. This approach would also restrict Xcel Energy from meeting near-term regulatory deadlines for certain capabilities in some of its states.

3. Vendor Dependent (Approach Not Selected)

With this approach, the Company would continue to depend upon a patchwork of vendors all under separate software licensing agreements and management by multiple internal resources. While this would allow for the fastest implementation, it would be challenging to a have a consolidated, "single pane of glass" view of DER impacts on the system – leading to operational inefficiencies due to siloed and manual processes. We also believe there would be contractual and labor inefficiencies.

II. ALTERNATIVES TO DERMS

We believe Enterprise DERMS is an integrated approach for the Company to reliably and safely integrate DER with the grid, and also unlock new value streams and support the transition to a more resilient and responsive energy system.

In this section, we discuss alternatives to deploying a DERMS in compliance with Order Point No. 23(a) of the Commission's 2023 IDP Order. The Company responds specifically to these order points related to use cases which it views as initially being part of Grid DERMS, but these capabilities would ultimately be subsumed into the Company's longer-term vision for Enterprise DERMS. To do so meaningfully, it is important to first understand the historical context in which DER has been integrated with the grid.

Historically, most DER have been interconnected without active monitoring or management through centralized software platforms like DERMS. At low DER penetration levels, the distribution system had sufficient inherent hosting capacity to accommodate DER without triggering technical violations and the need for distribution upgrades.

Higher DER penetration levels and larger DER systems without any active management introduce more situations in which voltage violations, thermal overloads, and other reliability concerns can arise. Traditionally, system upgrades were specified to manage such risks. However, Flexible Interconnection strategies have emerged as a way to manage DER more dynamically, curtailing output during times when constraints occur to avoid the constraints and the need for system upgrades. These emerging solutions create the opportunity for more dynamic and coordinated DER management solutions.

In this section, we explore two primary alternatives to DERMS: (1) maintaining the status quo, and (2) implementing local control at the DER site. We discuss the pros and cons of these approaches before outlining our recommendation for the more sophisticated and coordinated DERMS functionality.

A. Maintain Status Quo

Maintaining the current approach (e.g. static interconnection with no active DER management) – without deploying a DERMS – is one strategy that could be used. From a cost and operational standpoint, this option may appear attractive in the short term. It is also the simplest for customers as DER customers and developers are more familiar with static DER interconnection processes and requirements.

However, the limitations of this approach become increasingly apparent as DER penetration increases. Without active monitoring and management capabilities, the grid lacks the visibility and control needed to respond dynamically to changing conditions. This restricts the Company's ability to integrate higher levels of DER in constrained areas cost-effectively. Additionally, the absence of centralized coordination reduces flexibility in optimizing DERs as both supply and demand-side resources, which could hinder efforts to meet future reliability, affordability, and decarbonization goals.

We summarize the pros and cons of a status quo approach:

- Pros:
  - Minimal cost and resource requirements
  - No major changes to existing systems or processes

- Cons:
  - Limited visibility and control over DER
  - Limited ability to integrate higher levels of DER in constrained areas
  - Reduced ability to optimize DER for grid support

B. Local DER Control

Another alternative to centralized DERMS is to implement local control mechanisms at the DER site. These typically include manual management tools such as pre-programmed seasonal curtailment schedules, or smart inverter functions such as Volt-Var and Volt-Watt. In some cases, manual operator action may be required to disconnect DER during abnormal system configurations (e.g., outages or alternate feeds) to prevent violations of distribution system limits.

Local control is a mature and proven approach, but application of local control for DER management is still a relatively nascent field. Local control approaches still typically require development of new business processes to support the technology implementation. However, this approach presents significant performance limitations due to the lack of real-time grid awareness and load and generation forecasting. Due to this lack of real-time awareness, local control settings may need to be set using worst-case conservative assumptions, resulting in DER being curtailed more than necessary in some situations. Therefore, the limitations of this approach would prevent the Company from assessing system impacts in real-time, coordinating operation with other DER, and optimizing performance.

To summarize, curtailment with local control is often based upon worst-case grid conditions, which can lead to inefficient utilization of DER. Moreover, relying on extensive manual intervention to manage DER introduces operational risk and inconsistency.

We summarize the pros and cons of a local DER control approach:

- Pros:
  - No integration with DERMS needed to manage DER dynamically
  - Fewer centralized business processes required
  - Enables basic DER curtailment to avoid grid constraints

- Cons:
  - Limited grid visibility and situational awareness
  - Static schedules may lead to inefficient performance and additional curtailment of DER
  - Manual intervention needed during abnormal grid events
  - Requires same additional Flexible Interconnection study as DERMS implementation

C. Our Recommendation to Implement DERMS

Ultimately, while both alternatives offer certain tradeoffs, they fall short of providing the comprehensive, scalable, and flexible capabilities that DERMS enables.

By managing DER as a unified, optimized portfolio, DERMS provides the tools needed to maximize the value of DER as both supply and demand resources. It enables near real-time visibility, dynamic control, and coordinated dispatch, which are essential for maintaining reliability, supporting decarbonization goals, and unlocking the full potential of distributed energy. It can also be scaled to a large portfolio of DER more easily, as it requires neither manual intervention at each DER site, nor increasingly complex interconnection studies.

For these reasons, the Company views DERMS as a critical investment in the future of grid management.

III. USE CASES AND INTENDED BENEFICIARIES

Order Point 23(b) of the Commission's 2023 IDP Order directs the Company to describe the specific use cases for which DERMS will be utilized, along with the intended beneficiaries. The Company notes that DERMS platforms are typically deployed through targeted use cases designed to achieve specific operational and customer outcomes. These use cases are aligned with both Grid DERMS and Aggregator DERMS functionalities.

D. Grid DERMS Use Cases

As part of a limited deployment of Grid DERMS in Minnesota, the Company is currently exploring three primary use cases:

4. *Flexible Interconnection (FI)*

FI enables Grid DERMS to modify DER operating behavior—such as curtailing generation output—during critical periods when the distribution system is constrained. This ensures that operational limits are respected while allowing DER to remain interconnected. FI has the potential to reduce interconnection costs and timelines for customers, particularly solar PV developers, by avoiding costly upgrades and associated longer construction timeliness typically required under traditional interconnection agreements. Beneficiaries include DER developers, customers seeking faster interconnection, and grid operators managing system constraints.

5. *Flexible Energization (FE)*

Similar to FI, Flexible Energization uses Grid DERMS controls to manage load during capacity-constrained periods. This approach can allow new load customers to energize and interconnect while necessary upgrades are underway. Grid DERMS can curtail capacity either as a firm limit or during peak periods, while allowing full load access during off-peak times. FE helps accelerate interconnection timelines for customers in constrained areas and provides the Company with enhanced visibility and control to operate the grid within its capabilities. Beneficiaries include new load customers, customers adding load, distribution planners, and grid operators.

6. *Distributed Capacity Procurement (DCP)* – Capacity*Connect

Capacity*Connect is a new way to use Battery Energy Storage Systems (BESS) to meet our customers' needs by deploying storage assets on the Company's distribution system to provide grid value. Beneficiaries include distribution system planners and grid operators.

B. Aggregator DERMS Use Cases

In parallel, the Company is exploring a phased transition of approximately 680 MW of its existing load flexibility and interruptible load programs into an Aggregator DERMS platform. This transition will be guided by regulatory priorities and funding availability, with the goal of increasing program integration and modernizing operations.

Key use cases and benefits of Aggregator DERMS include:

Scalable DER Management. Aggregator DERMS will enable the integration and management of a broader range of DERs—including behind-the-meter assets—within the Company's demand management programs. Beneficiaries include residential and commercial customers, program administrators, and aggregators.

Enhanced Grid Visibility and Control. Aggregator DERMS will provide utilities with improved visibility and control for peak load management and other grid services. It will support various models, including utility-led, aggregator-driven, hybrid, and dynamic pricing approaches, to optimize DER value across generation, transmission, and distribution systems. Beneficiaries include grid operators, regulators, and customers participating in flexible load programs.

C. Enterprise DERMS – Grid DERMS and Aggregator DERMS Integration

As DER penetration and resource diversity on the grid continues to grow, the integration of Grid DERMS and Aggregator DERMS is emerging as a critical solution for efficiently managing DER impacts and unlocking their full value. The Company envisions Enterprise DERMS as a unified platform that integrates multiple IT and OT systems from various vendors, supported by secure and reliable communication networks. This integrated platform enhances and enables real-time situational awareness and control of DER across the grid and utility operations, while maintaining grid safety and reliability and supporting the needs of the grid, customers, and markets.

These DER include both utility-owned and customer-owned assets, as well as utility-affiliated and third-party aggregators. By bridging different operational areas, Enterprise DERMS supports more efficient grid operation and asset utilization, enhances grid resiliency and reliability, and provides a foundational framework for DER participation in energy markets through market integration and operational coordination.

Further development of requirements is needed to fully define and prioritize the capabilities of Enterprise DERMS. The following use cases illustrate the types of advanced functionality being considered:

- Providing real-time and predictive visibility for grid operators into the aggregate behavior of BTM DER, helping grid operators evaluate DER performance, assess DER program effectiveness, and identify root causes of potential power quality issues.
- Enabling distribution level services through coordinated control of aggregated energy storage, EV charging, and demand response to manage distribution system constraints (e.g., managing distribution system peak load, or enhancing usage of renewable energy).
- Support for FERC Order 2222 through enhanced market integration and operational coordination. Specific requirements would be developed as the Company gains better insight into the processes necessary to enable participation by both market participants and utilities.

It is important to note that Enterprise DERMS is not a one-step implementation. Rather, it is developed in phases as new use cases are defined and as enabling technologies and market processes mature. This phased and iterative rollout ensures the safe and reliable integration of new capabilities while effectively managing project risks and understanding costs

IV. DER MANAGEMENT PARTICIPATION

Order Point 23(c) of the Commission's 2023 IDP Order asks the Company to clarify whether participation in DER management will be voluntary or required, and whether participation requirements will vary based on factors such as resource size, resource type, program or market participation, or interconnection characteristics (e.g., load interconnections or limited import/export control systems).

Participation Model. Participation in DER management will be voluntary, facilitated through enrollment in Company programs or through bilateral contracts or agreements between the Company and the DER customer or developer. This approach allows customers to opt into DERMS-supported use cases based on their specific needs, business models, and technical capabilities.

Use Case-Driven Requirements. For customers who choose to participate, the requirements will vary depending on the specific use case. Factors that may influence participation criteria include:

- **Resource size** (e.g., small-scale residential vs. large commercial installations)
- **Resource type** (e.g., solar PV, energy storage, controllable loads)

- **Program participation** (e.g., demand response, interruptible load, capacity procurement)
- **Market participation** (e.g., participation in wholesale markets or aggregator programs)
- **Interconnection characteristics** (e.g., load-only sites such as EV charging hubs, or sites using limited import/export control systems)

This flexible framework ensures that DERMS participation is tailored to the operational context and customer capabilities, while maintaining alignment with regulatory priorities and system needs.

Applicability to Load Interconnections and Import/Export Control Systems. The Company is actively exploring DERMS use cases that apply to both load interconnections (such as EV charging hubs) and distributed generation. Import/Export systems, such as Power Control Systems certified by UL 3141, are a local function, implemented at the customer site. Our initial Grid DERMS use cases do not directly support interconnections that utilize limited import/export control systems. Instead, the Grid DERMS use cases enable more precise control of power flows and enhance grid reliability in constrained areas.

These use cases are described in detail in Section III above, including Flexible Interconnection, Flexible Energization, and C*C. Each of these use cases demonstrates how Grid DERMS can be applied to a range of interconnection types and customer scenarios.

This voluntary, use-case-driven approach supports the Company's commitment to delivering excellent service by offering customers flexible participation pathways and accelerating interconnection timelines. It also reinforces the Company's role in leading the clean energy transition by enabling broader integration of DER, supporting electrification, and optimizing distributed resources to meet evolving grid demands.

V. COMMUNICATIONS

Order Point 23(d) of the Commission's 2023 IDP Order asks the Company to address two key questions:

1. How will communications be established between Xcel Energy's DERMS and customer DER?

2. Who will bear the ongoing cost of any necessary communications infrastructure?

D. Communications Approach

The Company is currently developing detailed, use case–specific communication requirements. In general, the communication pathway between DERMS and customer DER will depend on several factors, including:

- The specific use case (e.g., real-time control vs. schedule-based control)
- The type of DER being monitored or controlled
- The cost and complexity of integration

To support secure communications, the Company utilizes a DER gateway device that interfaces with the customer's DER through an IEEE Standard 1547 Local DER Communication Interface. This gateway performs protocol translation between Grid DERMS and DER, while incorporating fail-safe mechanisms to maintain operational integrity in the event of communication failures or non-compliance with control commands.

To support a range of DER technologies and integration models, the Company is evaluating multiple additional communication protocols and pathways, including:

- IEEE 2030.5
- OpenADR
- DNP3
- MODBUS
- Private LTE for FTM DER

These protocols will enable secure, two-way communication between Grid DERMS and DER, supporting functions such as dispatch, telemetry, and performance monitoring.

The communication architecture will also vary based on the control strategy. For example, real-time control use cases may require low-latency, high-reliability communication channels, while schedule-based control may rely on less frequent data exchanges. Communication requirements will also extend beyond the DER itself to include Grid DERMS, grid monitoring systems, and other operational platforms.

For Aggregator DERMS, communication pathways will differ based on the type of demand management program and the DER technology involved:

- **Direct Load Control Programs**
  In these programs, commercial customers' DER are equipped with local control devices—such as Remote Terminal Units (RTUs) or DER Local Communication Interfaces—that enable two-way communication with Aggregator DERMS. These devices support real-time dispatch and control of DER.
- **Indirect Load Control Programs**
  For programs involving third-party aggregators or original equipment manufacturers (OEMs), integration is established between the aggregator's platform and the Company's Aggregator DERMS platform. This setup allows dispatch signals and telemetry data to flow through the aggregator's infrastructure and into the Company's Aggregator DERMS for monitoring and control.

E. Cost Responsibility

Cost responsibility for communications infrastructure will vary by use case and participation model. However, the Company anticipates that most use cases will involve a shared cost structure between the customer and the Company:

- **Customer Costs**
  Customers may be responsible for communication-related costs as part of their interconnection process or program participation requirements. This could include installing compatible control devices or enabling communication capabilities at the DER site.
- **Company Costs:**
  The Company will bear costs associated with integrating DERMS into its operational systems, maintaining its communication networks, and supporting DERMS platform functionality.

This cost-sharing approach ensures that communications infrastructure is deployed efficiently and equitably, while enabling the flexibility needed to support a wide range of DER technologies and customer use cases.

VI. CAPACITY ALLOCATION

Order Point 23(e) asks two questions:

1- How capacity will be allocated across new and existing managed and unmanaged interconnectors.

2- How capacity upgrades will be justified, and from whom will upgrade costs be recovered.

The Company responds to this in the context of flexible interconnections for distributed generation and/or flexible energization for load.

In general, a new flexible interconnection will not impact existing load or generation customers. Customers with firm (static or unmanaged interconnections) retain their existing rights and are not affected by the addition of new flexible (managed) connections.

For new flexible interconnection or energization requests, capacity will be managed through the Company's Grid DERMS FI control scheme. Under this approach, new customers will be interconnected with the understanding that their generation or load will be actively managed to avoid or defer system upgrades that otherwise would be triggered under a traditional, static interconnection approach. These customers are typically subject to curtailment or energization limits based on near-real-time system conditions.[3] This strategy allows the Company to:

- Optimize existing capacity and assets without compromising reliability for firm customers.
- Avoid or reduce costly interconnection-related upgrades[4]

If a capacity upgrade becomes necessary – for example, to convert a flexible interconnection to firm service – the upgrade would be justified through standard interconnection study processes. Cost recovery would follow existing tariff provisions, typically assigning upgrade costs to the customer requesting the enhanced service.

VII. INFORMATION FOR PROSPECTIVE INTERCONNECTORS

Order Point No. 23(f) of the Commission's 2023 IDP Order requests the Company to address the following:

1- How will prospective applicants understand the impact of DER management on the economics of their project?
2- What information will be provided to prospective interconnectors related to expected curtailment and existing and expected grid conditions?

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[3] Curtailment or energization limits are dispatched based on day-ahead forecasted grid conditions.
[4] While flexible interconnection may help better utilize existing capacity, it does not increase existing asset capacity. Upgrades to serve new capacity to meet long-term system needs will still be required.

The Company responds to this in the context of flexible interconnections for distributed generation and/or flexible energization for load.

Evaluating the economic impact of flexible interconnection or energization requires a detailed, time-series analysis of the proposed generation or load relative to potential grid constraints. This type of study estimates the frequency and magnitude of curtailment or energization limits that may be imposed under active network management (ANM).

To support prospective applicants, the Company would work directly with developers or customers during the interconnection process to provide:

- Schedules that reflect expected operating envelopes or limits based on forecasted grid conditions.
- Identification of relevant system constraints (e.g., feeder capacity, voltage limits).

In our experience, developers typically use the curtailment estimates to inform their financial pro formas, adjusting revenue expectations and project economics accordingly. While the Company does not provide financial modeling, we aim to deliver transparent and actionable technical data to support informed decision-making.

VIII. DERMS COSTS

Order Point No. 23(g) of the Commission's 2023 IDP Order requests the Company to respond to the following:

1- What are the expected deployment and integration costs for DERMS?
2- What are the expected ongoing licensing, operating, and infrastructure costs to execute and maintain DERMS functionality? From whom will these costs be recovered?

The Company has planned deployments for both Aggregator DERMS and a limited Grid DERMS, so it responds to these questions with known cost information for these specific DERMS functionalities. As discussed earlier, these initial focused and phased deployments will inform us of the requirements and plans for Enterprise DERMS in the future. Those costs are not known currently but are expected to have the same categories of costs – deployment, licensing, and ongoing operating costs.

A. Aggregator DERMS

Xcel Energy has structured the costs of an Aggregator DERMS to reflect the success and anticipated growth of its demand management portfolio. The cost structure for this "software-as-a-service" (SaaS) solution includes several components:

Deployment Costs. The Company anticipates working with the vendor to establish deployment costs associated with integrating the platform for Minnesota programs. These costs may include initial configuration, integration with existing systems, and establishing basic operational readiness.

Licensing Costs. The annual software license fee is based on a tiered pricing model, similar to a declining block rate. The cost per megawatt (MW) under management decreases as the total number of MWs controlled by the platform increases. As more programs and resources are transitioned onto Aggregator DERMS, the Company moves through pricing tiers, reducing the per-MW cost and improving cost efficiency. This tiered approach makes technology investment more controllable, allowing for predictable scaling and consistent cost recovery over time. By aligning licensing costs with actual usage and program growth, the Company minimizes the risk of a stranded asset – ensuring that the platform remains cost efficient and adaptable as DER participation expands.

Ongoing Operating and Infrastructure Costs. These include regular software maintenance, updates, cloud hosting, cybersecurity, and support services. Costs scale with the size and complexity of the portfolio managed by Aggregator DERMS.

The Company anticipates recovering these costs through existing regulatory mechanisms, such as ECO program budgets, which are evaluated and approved by the Department of Commerce. Specific recovery pathways may vary depending on the nature of the program, the docket in which the program is approved, and the customer class(es) involved.

B. Grid DERMS

The total estimated cost for the limited Grid DERMS deployment in Minnesota is approximately $2.9 million. This budget supports the initial implementation of three key use cases—flexible interconnection, flexible energization, and C*C—and includes:

- Software design and architecture
- Development of detailed process, functional and technical requirements
- Software licensing fees

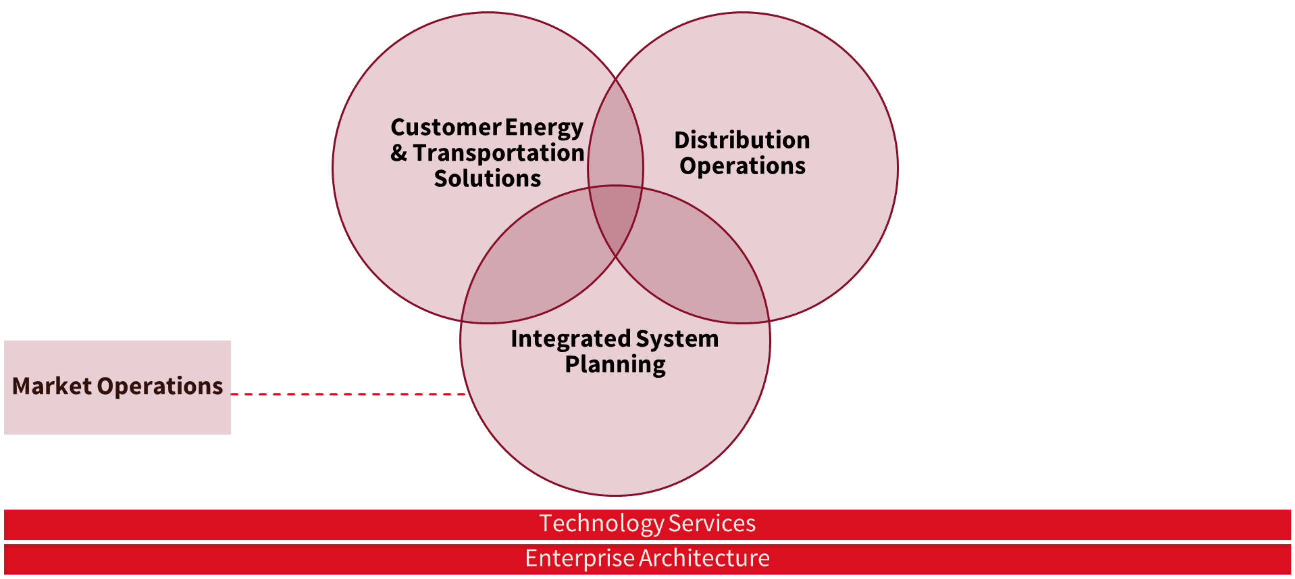
- System testing and validation
- Integration with existing grid systems and platforms

These costs represent the minimum investment required to begin operationalizing C*C Phase 2 and to establish a scalable foundation for future DERMS capabilities. As noted, additional investments will be necessary to expand DERMS functionality, support organizational readiness, and fully realize the benefits of distributed energy resource management across the grid.

IX. DERMS PEOPLE AND PROCESS CONSIDERATIONS

It is important to note that procuring DERMS software is one small component of enabling many of the use cases associated with DERMS. It is also critical to address the business process, organizational skillsets, change management, control and communication strategy and standards to DER, and tariff/regulatory requirements associated with supporting DERMS capabilities. DERMS deployments must also consider evolution and more granular analysis required in the DER interconnection and study process as well as operational reliability and safety implications from actively managing constraints on the distribution system.

Figure 4: DERMS Organizational Interface



Successfully implementing DERMS requires more than just deploying new technology—it demands a coordinated transformation across a complex ecosystem of people, processes, technologies, and policies. DERMS must serve the needs of a wide array of internal and external stakeholders, including grid operations, IT, regulatory teams, customer programs, and third-party DER providers. This breadth of impact necessitates a deliberate and inclusive approach to change management.

X. EQUITY AND ENERGY JUSTICE PRINCIPLES

Order Point 23(h) asks how equity and energy justice principles can be incorporated into the use cases, process design, and cost allocation of our DERMS.

We held a discussion with stakeholders on this Order Point at our DERMS Workshop 2 on July 8, 2025. To frame this question, we first clarified that DERMS is not a resource, but rather a tool that facilitates the broader deployment and management of DER. We also emphasized that many equity and energy justice related decisions—such as DER siting, who benefits from them, how financial incentives are shared, and whether developers hire diverse workers or offer training—are made by DER developers, not by Xcel Energy. These decisions are generally outside our control, except in limited cases where Xcel Energy builds, owns, or operates DER directly. Considering this, decisions about use cases, process design and cost allocation for DERMS may have relatively little impact on whether DER developers choose to deploy DER with equity in mind.

We then asked stakeholders to identify actions within the Company's control where DERMS deployment could support equity and energy justice. Three tangible suggestions emerged:

- *Supporting DER adoption in low-income areas:* DERMS enables FI, which could allow customers in these areas to connect DERs without triggering costly upgrades. However, capacity constraints are more common in less dense, generally higher-income suburban/exurban areas where large-scale DER—like community solar gardens—have generally been sited, often causing small DER projects to face hosting capacity constraints and high upgrade costs in order to interconnect. In contrast, recent studies filed in the Company's Safety, Reliability and Service Quality (SRSQ) docket have suggested that urban areas with lower incomes and more people of color actually have greater hosting capacity available.[5] Because of this, there may be less need for FI to enable DER to connect in those areas. Thus, while DERMS can lower the cost to

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[5] Gabriel Chan & Bhavin Pradhan, *Racial and Economic Disparities in Electric Reliability and Service Quality in Xcel Energy's Minnesota Service Area*, at 3 (2024), retrieved from the University Digital Conservancy, https://hdl.handle.net/11299/261434. ("We also identify correlations that suggest neighborhoods with a higher proportion of people of color, lower income, and lower population density tend to have increased DER hosting capacity availability.").

interconnect in constrained areas through FI, this benefit may not directly impact urban areas with higher concentrations of low-income and BIPOC residents.

- *Job and training opportunities for operations, management, and/or project management:* DERMS may create long-term job opportunities in operations, management, and project delivery within the Company. We are already building diverse talent pipelines, and our internal DERMS-related job opportunities would align with these efforts.
- *Using alternative cost allocation methods, like non-firm capacity and export tariffs, to lower the cost of upgrades for interconnecting customers:* This suggestion is more relevant to utility ratemaking than DERMS and would require significant changes to existing regulatory and business processes.

The Company will continue to keep equity and energy justice in mind as we develop DERMS use cases and process design, but we expect that most DER-related decisions with the greatest impact on equity and energy justice will be made by DER developers.

XI. STAKEHOLDER ENGAGEMENT

In this section, we discuss the two DERMS-specific workshops we hosted with stakeholders in summer 2025, in response to Order Point Nos 22 and 23 of the Commission's 2023 IDP Order, as follows:

Order Point No. 22 required the Company to:

> Conduct robust stakeholder outreach, including specifically with DER owners/operators, and describe in a filing with the Commission its stakeholder engagement process, the materials it used to inform stakeholders about DERMS (addressing, e.g., costs, benefits, alternatives, purpose, problems it is solving), the feedback it received, and how it has addressed it.

Order Point No. 23 required the Company to file a detailed roadmap for DERMS deployment that addresses specific questions provided by the Commission.

A. DERMS Workshop 1

Logistics: virtual, held June 16, 2025
Attendance: 101 participants
Meeting Materials: Link to eDockets 20257-221344-01[6]

1. *Summary of Workshop 1*

The objective of this Workshop was to provide an overview of Xcel Energy's current DERMS roadmap, provide context for the evolution of the grid and how DERMS can play a valuable part of the solution, create a common understanding and definitions of DERMS, provide transparency into the Company's near-terms DERMS plans, level-set on the current state of DERMS and to answer questions, and gather feedback and input from our stakeholders. The overview of the roadmap included a discussion of alternatives to DERMS, use cases, technical requirements, process changes, costs, and equity considerations.

In the Workshop, we provided a brief history of the electric system in the United States, its evolution over time, and the current transformation of the electric grid. DERMS was defined as a tool that facilitates and enables the management and integration of DER to advance both system and customer benefits. Achieving these benefits requires new business processes and organizational change management. We noted that DERMS is a foundational technology that supports the further integration of DER on the system. We also emphasized that DERMS is not simply a technology – it also requires the development of key business processes, the recruitment of new talent, organizational change management, and a systematic approach to integrating both information technology and operational technology systems.

We shared that our current DERMS strategy involves a parallel path deployment of both Aggregator and Grid DERMS. This approach allows us to align requirements and implementation with existing commitments and regulatory orders, begin with a limited deployment to better understand operational and process requirements that will inform our next steps, support the maturation of the Grid DERMS market, and build on existing capabilities to expand deployment. Other strategies we considered were: (1) a consolidated, single-vendor approach, and (2) a vendor-dependent approach. We discussed the pros and cons of each.

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[6] *See* Xcel Energy DERMS Workshop 1 Meeting Materials, Docket Nos. E002/M-23-452 and E002/M-25-142 (July 23, 2025) 20257-221344-01

We discussed that our current focus and future vision for DERMS is to help lead the clean energy transition, enhance customer experience and keep bills as low as possible for our customers. We stated that we are proposing to limit DERMS deployment to three high priority use cases supporting evolving customer demands and regulatory and legislative directives with the intent to phase in the deployment of Aggregator DERMS from 2024 through 2027 in conjunction with limited deployment of Grid DERMS.

We outlined our objectives for our Grid DERMS deployment are:

- Support increased penetration of DERS through real-time and forecasted dispatching,
- Create new value streams, and
- Augment DER and load interconnection processes.

The primary use cases identified for GRID DERMS were noted as:

- Flexible interconnection of large-scale DER (>1 MW Solar PV),
- Flexible Energization of loads (e.g., EV Charging), and
- Distribution-connected capacity solutions (e.g., batteries).

We noted the objectives of our Aggregator DERMS deployment are:

- The management and integration of the Company's load flexibility programs, and
- Customer DER offerings by modernizing and creating operational efficiencies, expanding bulk system benefits, and improving customer communications.

The primary use cases identified for Aggregator DERMS were noted as:

- Moving away from single vendor dependencies via standard enrollment and integration,
- Phased transition of existing load flexibility and interruptible load offerings, and
- Enhancement of customer and grid benefits.

We followed this with a discussion of our near-term plans for both Aggregator and Grid DERMS indicating that in the future we would integrate lessons learned from our limited deployments, evaluate the role DERMS plays in aggregated DER markets, taking into consideration regulatory mechanisms to enable flexible arrangements, allow for further integration into planning and operations, and assess the maturation of DERMS capabilities. We also shared the Company's long-term DERMS architecture vision.

Next, we presented regulatory considerations and DERMS dependencies pointing to relevant Commission Orders in our 2023 IDP docket (Docket No. E002/M-23-452). We identified DERMS dependencies for both the regulatory process (stakeholder engagement, filing of the DERMS Roadmap and cost recovery) and the interconnection process (Distributed Generation Working Group (DGWG) flexible interconnections, Minnesota's DER Interconnection Process (MN DIP) and DER Interconnection Agreement (MN DIA) processes, and static and dynamic flexible interconnections).

At closing, we shared a preview of the questions that we intended to pose to stakeholders at Workshop 2.

2. Stakeholder Questions and Input

Participants asked about whether there are any industry DERMS metrics that have been established similar to reliability metrics such as System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI) etc. We stated that system-wide metrics typically do not exist for DERMS as DERMS is deployed more strategically on parts of the system. We indicated that a typical success metric for DERMS is the percent flexible load or generation peak load. The Company will consider these questions about metrics as it gains operational experience through its limited deployment. The objective of this Workshop was to level set and outline our plans, so it was intended to be informative toward facilitated discussion in Workshop 2. As such, we did not receive significant input from stakeholders. We appreciate the questions and discussion regarding potential metrics to inform DERMS implementation.

B. DERMS Workshop 2

Logistics: virtual, held July 8, 2025
Attendance: 28 participants
Meeting Materials: Link to eDockets 20258-221838-01[7]

[7] Xcel Energy DERMS Workshop 1 Meeting Materials, Docket Nos. E002/M-23-452 and E002/M-25-142 (August 6, 2025) 20258-221838-01

3. Overview

The purpose of this meeting was to gather stakeholder input from our stakeholders on the information provided in DERMS Workshop 1 and a range of DERMS-related topics, which were included as Attachment A to the invitation filed to the docket, and that stemmed from Order Point Nos.22 and 23 of the Commission's 2023 IDP Order. We presented the questions from Order Point 23 to stakeholders, plus a few additional questions. To start the conversation, we provided our thoughts and asked for stakeholder feedback. We outline these discussion questions, our response, and stakeholder feedback below.

4. Facilitated Questions and Answers

Q1. What do you believe are the alternatives to DERMS?

A. We indicated that we think the alternatives to DERMS are to:

- Maintain the status quo/do nothing, or
- Install local controls at DER sites for manual DER management

Stakeholder feedback. One stakeholder recommended that we could utilize special power control systems to limit generation or load, which would allow for higher capacity connections. We considered this but believe a coordinated, centralized approach is best for the Company, as described above.

Q2. What do you believe are the specific use cases for DERMS and who are the intended beneficiaries?

A. We indicated that for *Grid DERMS* there is a specific use case for flexible interconnection and energization with the beneficiaries being project applicants and DER sites hosts and additional renewable generation on the system which benefits all customers

We indicated that for *Aggregator DERMS* that specific use cases are for the standard enrollment and integration of DER and to migrate all existing load flexibility and interruptible load offerings to this platform. The intended beneficiaries are to enhance both customer and grid efficiencies.

Q3. Interactive polling question: "for Grid DERMS what other use cases would you consider?"

- It was suggested that we consider active voltage management using DERMs as well as a dynamic volt var implementation (IVVO). This was evaluated and summarized in our 2023 IDP.
- It was suggested that we consider large load flexible connections e.g., active management of data center load. We will take this into consideration as part of our overall efforts to examine FI/FE.
- A stakeholder commented that to the extent there are incentives for building and installing DER, required participation for a DERMS platform makes sense.
- A stakeholder also noted that a business case for DERMS should be required and that the business case will drive participation if programs are created that are attractive for owners with hybrid systems and take the next leap with other flexible technologies such as heat pumps and water heaters. We indicated agreement with this – that as we implement DERMS use cases, measuring customer and business value will be important and will help inform future use cases.

Q4. Interactive polling question: "For aggregator DERMS, what other use cases would you consider?"

We received no responses to this question.

Q5. What is your view of DER Management – should it be voluntary or required, and why? Will requirements vary based on resource size, resource type, program participation, market participation, or other factors?

A. We indicated that we view participation in DERMS as voluntary through enrollment in Company programs or via bi-lateral contracts between the Company and DER Owner. We also indicated that we envision that future requirements will vary based on customers program-specific use cases and objectives and will vary based on resource size, resource type and other factors.

Stakeholder feedback. In response to the question, we confirmed our DERMS integrations include both Gateway and SCADA systems.

Q6. How will communications be established between Xcel Energy's DERMS and customer DER? Who will bear the ongoing cost for any necessary communication infrastructure?

A. We shared that the Company is developing detailed, use-case specific requirements and those requirements will be informed by the specific DER control strategy. We noted that we think that most use cases will include both customer specific and Company costs.

Stakeholder feedback. None

Q7. How will capacity be allocated across new and existing, managed and unmanaged interconnectors? How will capacity upgrades be justified and from whom will upgrade costs be recovered [i.e., flexible interconnection] and what information do you need from Xcel Energy to determine the impact of DER management on the economics of your project(s)?

A. We clarified that DERMS implementation would not affect previous interconnections and that the objective of flexible programs is to minimize upgrade needs. Our view is that upgrade costs will be the responsibility of the individual site developers with cost sharing programs available under certain conditions.

Stakeholder feedback.

- A stakeholder noted that that customers will need to sign up for a flexible interconnection; outreach for this should be considered, which we agree will be important.
- For purposes of avoiding an upgrade versus a proactive upgrade, FI can be used as an alternative.
- If you think of FI as a system wide strategy to improve grid utilization, FI becomes a tool you can systemize and offer broadly whether it addresses a specific grid need at the time. If you have the DERMS to exercise that, there are benefits to doing that anyway, whether it is on the grid or capacity upgrade or not.

Q8. What information would you like from Xcel Energy related to expected curtailment and existing and expected grid conditions and how will a prospective applicant understand the impact of DER management on the economics of their project? What information will be provided to prospective interconnectors related to expected curtailment and existing and expected grid conditions?

A. We noted that information will be provided based on specific program needs and that we are in the early stages of developing our study methods for various use cases.

Stakeholder feedback. Developers wanted to know if we will be doing pro-rata or last in first out curtailment. We shared that one FI will be deployed per circuit initially, as we will need to test FI deployment.

Q9. How should equity be taken into consideration in the deployment of DERMS? Interactive polling question: "What equity and energy justice principles should Xcel Energy consider or incorporate within the use cases, process design, and/or cost allocation of the DERMS?

Stakeholder feedback.

- Xcel Energy should make sure that the grid can support DER adoption in low-income areas.
- DERMS is a tool for DER and is not a resource itself. If it can help avoid outages in areas that are historically marginalized that could be a useful outcome or metric.
- One stakeholder took issue with the statement from another stakeholder that DERMS is not a resource in itself. Their view was that DERMS enables provision of non-firm capacity at the distribution level that can be integrated into planning processes.
- Xcel Energy could develop job opportunities or training that are not specifically DER installation oriented such as operations, management or project management.

Q10. What industry methods/metrics are you aware of to evaluate the effectiveness of DERMS implementation?

A. We suggested focusing on metrics intended to measure effectiveness of target use cases.

Stakeholder feedback. The number of DER participating in bulk power system markets could be used as a metric. We will include this in with other metric ideas shared at Workshop 1.

A table summarizing the potential deployment options that were explored by the Company is presented below. Based on the outlined factors, the Company has chosen Pathway 1, which reflects the pursuit of DERMS on a parallel path trajectory consisting of Aggregator DERMS and Grid DERMS.

Table 1: DERMS Deployment Pathways

Pathway 1 – Phased Parallel Path Deployment	**Alt. Pathway 2 – Consolidated Single Vendor Approach**	**Alt. – Pathway 3 – Vendor Dependent**
• Phased Deployment of Aggregator DERMS, followed by the limited deployment of priority use cases for Grid DERMS (e.g., flexible interconnection, managed fleet charging, flexible load request). Depending upon the outcome of the limited deployment of Grid DERMS priority use cases, these use cases would potentially be integrated with other OT systems.	• Under the consolidated, single vendor approach, we would draft a comprehensive set of functional and non-functional requirements for both Aggregator DERMS and Grid DERMS into a single RFP.	• Under pathway 3, the Company would continue to depend upon a patchwork of vendors all under separate software licensing agreement and management by multiple internal resources. This is how we manage the Renewable Battery Connect program today (i.e., relying on proprietary third-party software).
Pros: • Allows us to manage risks by "right sizing" the requirements and implementation to existing commitments and regulatory orders. • Focused agile/phased approach with this pathway. Start with a minimum viable product and build it by keep on adding additional capabilities/integration with other tools. • Optimizes around strengths and capabilities in each DERMS vendor. • Allows Grid DERMS market to mature and the Company to develop experience and operational process and procedures.	• Enhanced vendor accountability – a single vendor would be responsible for integration between Aggregator DERMS and Grid DERMS. • Potential integration and maintenance efficiencies.	• Implementation speed.
Cons: • Future integration risk – eventually we will need to integrate Aggregator DERMS with Grid DERMS.	• Longer timeline for implementation and failure to meet near-term regulatory deadlines for Renewable Battery Connect, Virtual Power Plant, etc. • Unclear business value for Grid DERMS use cases. Many of the Grid DERMS use cases have customer value (e.g., avoiding interconnection costs) but not always for a broader customer base. • Substantially higher costs for both software licensing and implementation.	• Challenging to a have a consolidated, "single pane of glass" view of DER impacts on the system – leads to operational inefficiencies due to siloed and manual processes. • Contractual and labor inefficiencies (vendors consistently charging more for less).

CERTIFICATE OF SERVICE

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

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

xx electronic filing

DOCKET NOS. E002/RP-24-67
E002/CN-23-212
Xcel Energy Miscellaneous Electric Service List

Dated this 3rd day of October 2025

/s/
____
Victor Barreiro
Regulatory Administrator

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Steve	Albrecht	steve.albrecht@shakopeedakota.org	Shakopee Mdewakanton Sioux Community		Shakopee Mdewakanton Sioux Community 2330 Sioux Trail NW Prior Lake MN, 55372 United States	Electronic Service		No	24-67
2	Jared	Alholinna	jalholinna@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369 United States	Electronic Service		No	24-67
3	Keith	Anderson	keith.anderson@shakopeedakota.org	Shakopee Mdewakanton Sioux Community		Shakopee Mdewakanton Sioux Community 2330 Sioux Trail NW Prior Lake MN, 55372 United States	Electronic Service		No	24-67
4	Shannon	Anderson	sanderson@solarunitedneighbors.org	Solar United Neighbors			Electronic Service		No	24-67
5	Beren	Argetsinger	bargetsinger@keyesfox.com			PO BOX 166 Burdett NY, 14818 United States	Electronic Service		No	24-67
6	Ray	Auginaush, Sr.	ray.auginaush@whiteearth-nsn.gov	White Earth Nation		White Earth Tribal Headquarters 35500 Eagle View Road Ogema MN, 56569 United States	Electronic Service		No	24-67
7	Mark	Bakk	mbakk@lcp.coop	Lake Country Power		26039 Bear Ridge Drive Cohasset MN, 55721 United States	Electronic Service		No	24-67
8	Daniel	Becchetti	dbecchetti@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369 United States	Electronic Service		No	24-67
9	Todd	Beck	tbeck@grenergy.com			null null, null United States	Electronic Service		No	24-67
10	Amadeo	Bellino	amadeo.bellino@whiteearth-nsn.gov	White Earth Nation		White Earth Tribal Headquarters 35500 Eagle View Road Ogema MN, 56569 United States	Electronic Service		No	24-67
11	Melanie	Benjamin	melanie.benjamin@millelacsband.com			43408 Oodena Drive Onamia MN, 56359 United States	Electronic Service		No	24-67
12	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission		Electronic Service		No	24-67
13	Laura	Bishop	laura.bishop@state.mn.us		Minnesota Pollution Control Agency	520 Lafayette Rd Saint Paul MN, 55155 United States	Electronic Service		No	24-67
14	Ingrid	Bjorklund	ingrid@bjorklundlaw.com	Bjorklund Law, PLLC		855 Village Center Drive #256	Electronic Service		No	24-67

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						North Oaks MN, 55127 United States				
15	Hunter	Boldt	hunterboldt@redlakenation.org	Red Lake Nation		15484 Migizi Drive Red Lake MN, 56671 United States	Electronic Service		No	24-67
16	Peter	Boney	pboney@boisforte-nsn.gov	Bois Forte Band of Chippewa		Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake MN, 55772 United States	Electronic Service		No	24-67
17	Sheldon	Boyd	sheldon.boyd@millelacsband.com	Mille Lacs Band of Ojibwe		43408 Oodena Drive Onamia MN, 56359 United States	Electronic Service		No	24-67
18	Jon	Brekke	jbrekke@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	24-67
19	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	24-67
20	B. Andrew	Brown	brown.andrew@dorsey.com	Dorsey & Whitney LLP		Suite 1500 50 South Sixth Street Minneapolis MN, 55402-1498 United States	Electronic Service		No	24-67
21	Marvin Ray	Bruneau	marvin.bruneau@millelacsband.com	Mille Lacs Band of Ojibwe		43408 Oodena Drive Onamia MN, 56359 United States	Electronic Service		No	24-67
22	Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron		60 S 6th St Ste 1500 Minneapolis MN, 55402-4400 United States	Electronic Service		No	24-67
23	Scott	Buchanan	scottbuchanan@fdlrez.com	Fond du Lac Band of Lake Superior Chippewa		1720 Big Lake Road Cloquet MN, 55720 United States	Electronic Service		No	24-67
24	Shelley	Buck	shelley.buck@piic.org	Prairie Island Indian Community		Prairie Island Indian Community 5636 Sturgeon Lake Road Welch MN, 55089 United States	Electronic Service		No	24-67
25	Robert	Budreau	robert.budreau@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	24-67
26	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN,	Electronic Service		Yes	24-67

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						55101 United States				
27	Cathy	Chavers	cchavers@boisforte-nsn.gov	Bois Forte Band of Chippewa		Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake MN, 55772 United States	Electronic Service		No	24-67
28	Marc	Child	mchild@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	24-67
29	Michael	Childs, Jr.	michael.childsjr@piic.org	Prairie Island Indian Community		Prairie Island Indian Community 5636 Sturgeon Lake Road Welch MN, 55089 United States	Electronic Service		No	24-67
30	John	Coffman	john@johncoffman.net	AARP		871 Tuxedo Blvd. St, Louis MO, 63119-2044 United States	Electronic Service		No	24-67
31	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	24-67
32	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	24-67
33	Rebecca	Crooks Stratton	rebecca.crooks-stratton@shakopeedakota.org	Shakopee Mdewakanton Sioux Community		Shakopee Mdewakanton Sioux Community 2330 Sioux Trail NW Prior Lake MN, 55372 United States	Electronic Service		No	24-67
34	Brooke	Cunningham	health.review@state.mn.us	Minnesota Department of Health		PO Box 64975 St. Paul MN, 55164-0975 United States	Electronic Service		No	24-67
35	Miyah	Danielson	miyahdanielson@fdlrez.com	Fond du Lac Band of Lake Superior Chippewa		1720 Big Lake Road Cloquet MN, 55720 United States	Electronic Service		No	24-67
36	Jason	Decker	jason.decker@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	24-67
37	Bobby	Deschampe	robertdeschampe@grandportage.com	Grand Portage Band of Lake Superior Chippewa		PO Box 428 Grand Portage MN, 55605 United States	Electronic Service		No	24-67
38	Kami	Diver	kamidiver@fdlrez.com	Fond du Lac Band of Lake Superior Chippewa		1720 Big Lake Road Cloquet MN, 55720 United States	Electronic Service		No	24-67

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
39	Becky	Dobbs	bdobbs@grenergy.com			null null, null United States	Electronic Service		No	24-67
40	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	24-67
41	Shane	Drift	sdrift@boisforte-nsn.gov	Bois Forte Band of Chippewa		Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake MN, 55772 United States	Electronic Service		No	24-67
42	Christopher	Droske	christopher.droske@minneapolismn.gov	Northern States Power Company dba Xcel Energy-Elec		661 5th Ave N Minneapolis MN, 55405 United States	Electronic Service		No	24-67
43	Adam	Duininck	aduininck@ncsrcc.org	North Central States Regional Council of Carpenters		700 Olive Street St. Paul MN, 55130 United States	Electronic Service		No	24-67
44	Wally	Dupuis	wallydupuis@fdlband.org	Fond du Lac Band of Lake Superior Chippewa		1720 Big Lake Road Cloquet MN, 55720 United States	Electronic Service		No	24-67
45	Kevin	Dupuis, Sr.	kevindupuis@fdlrez.com			Reservation Business Committee 1720 Big Lake Rd Cloquet MN, 55720 United States	Electronic Service		No	24-67
46	Jamie	Edwards	jamie.edwards@millelacsband.com	Mille Lacs Band of Ojibwe		43408 Oodena Drive Onamia MN, 56358 United States	Electronic Service		No	24-67
47	Michael	Fairbanks	michael.fairbanks@whiteearth-nsn.gov	White Earth Reservation Business Committee		PO Box 418 White Earth MN, 56591 United States	Electronic Service		No	24-67
48	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-Reliance Minneapolis MN, 55406 United States	Electronic Service		No	24-67
49	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	24-67
50	Terri	Finn	terri.goggleye@llojibwe.net			null null, null United States	Electronic Service		No	24-67
51	Christine	Fox	cfox@itasca-mantrap.com	Itasca-Mantrap Coop. Electric Assn.		PO Box 192 Park Rapids MN, 56470 United States	Electronic Service		No	24-67
52	Lucas	Franco	lfranco@liunagroc.com	LIUNA		81 Little Canada Rd E Little Canada MN, 55117 United States	Electronic Service		No	24-67

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
53	Gary	Frazer	gfrazer@mnchippewatribe.org	Minnesota Chippewa Tribe		PO Box 217 Cass Lake MN, 56633 United States	Electronic Service		No	24-67
54	Stacey	Fujii	sfujii@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	24-67
55	Edward	Garvey	garveyed@aol.com	Residence		32 Lawton St Saint Paul MN, 55102 United States	Electronic Service		No	24-67
56	Shannon	Geshick	shannon.geshick@state.mn.us	Minnesota Indian Affairs Council (MIAC)		null null, null United States	Electronic Service		No	24-67
57	Allen	Gleckner	gleckner@fresh-energy.org	Fresh Energy		408 St. Peter Street Ste 350 Saint Paul MN, 55102 United States	Electronic Service		No	24-67
58	Jeffrey	Haase	jhaase@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	24-67
59	Hal	Halpern	halhalpern@clpower.com	Cooperative Light & Power		1554 Hwy 2 P0 Box 69 Two Harbors MN, 55616 United States	Electronic Service		No	24-67
60	Jeremy	Hamilton	jhamilton@uppersiouxcommunity-nsn.gov	Upper Sioux Community		Upper Sioux Community PO Box 147 Granite Falls MN, 56241 United States	Electronic Service		No	24-67
61	David A.	Hansen	hansen@federatedrea.coop	Federated Rural Electric Association		77100 U.S. Highway 71 PO Box 69 Jackson MN, 56143 United States	Electronic Service		No	24-67
62	Amy	Hastings	amyh@uppersiouxcommunity-nsn.gov	Upper Sioux Community		5722 Travers Lane PO Box 147 Granite Falls MN, 56241 United States	Electronic Service		No	24-67
63	Erik	Hatlestad	erik@cureriver.org			117 1st St Montevideo MN, 56265 United States	Electronic Service		No	24-67
64	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	24-67
65	Kristin	Henry	kristin.henry@sierraclub.org	Sierra Club		2101 Webster St Ste 1300 Oakland CA, 94612 United States	Electronic Service		No	24-67
66	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	24-67

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
67	Ronald	Horman	rhorman@redwoodelectric.com	Redwood Electric Cooperative		60 Pine Street Clements MN, 56224 United States	Electronic Service		No	24-67
68	Robbie	Howe	robbie.howe@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	24-67
69	John	Ihle	ljihle@rrt.net	PlainStates Energy LLC		27451 S Hwy 34 Barnesville MN, 56514 United States	Electronic Service		No	24-67
70	Annie	Jackson	cheryl.jackson@whiteearth-nsn.gov	White Earth Nation		White Earth Tribal Headquarters 35500 Eagle View Road Ogemo MN, 56569 United States	Electronic Service		No	24-67
71	Faron	Jackson, Sr.	faron.jackson@llojibwe.net			190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	24-67
72	Justin	Jahnz	justin.jahnz@ecemn.com	East Central Energy		412 Main Ave N Braham MN, 55006 United States	Electronic Service		No	24-67
73	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	24-67
74	Kevin	Jensvold	kevinj@uppersiouxcommunity-nsn.gov	Upper Sioux Community		PO Box 147 Granite Falls MN, 56241-0147 United States	Electronic Service		No	24-67
75	Annette	Johnson	annette.johnson@redlakenation.org	Red Lake Nation		15484 Migizi Drive Red Lake MN, 56671 United States	Electronic Service		No	24-67
76	Jody	Johnson	jody.johnson@piic.org	Prairie Island Indian Community		5636 Sturgeon Lake Rd Welch MN, 55089 United States	Electronic Service		No	24-67
77	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	24-67
78	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-67
79	Mark	Kaminski	mark.kaminski@gsa.gov	General Services Administration		1800 F Street NW Washington DC, 20405 United States	Electronic Service		No	24-67
80	Veda	Kanitz	vmkanitz@gmail.com			null null, null United States	Electronic Service		No	24-67

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
81	Jenny	Kartes	jkartes@arrowhead.coop	Arrowhead Electric Cooperative, Inc.(P)		PO Box 39 5401 W Hwy 61 Lutsen MN, 55612 United States	Electronic Service		No	24-67
82	David	Kempf	dkempf@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	24-67
83	William	Kenworthy	will@votesolar.org			1 South Dearborn St Ste 2000 Chicago IL, 60603 United States	Electronic Service		No	24-67
84	Bobby	King	bking@solarunitedneighbors.org	Solar United Neighbors		3140 43rd Ave S Minneapolis MN, 55406 United States	Electronic Service		No	24-67
85	Therese	LaCanne	tlacanne@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	24-67
86	Matthew	Lacey	mlacey@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	24-67
87	Arthur	LaRose	arthur.larose@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	24-67
88	Robert L	Larsen	robert.larsen@lowersioux.com	Lower Sioux Indian Community		PO Box 308 39527 Reservation Highway 1 Morton MN, 56270 United States	Electronic Service		No	24-67
89	Mark	Larson	mlarson@meeker.coop	Meeker Coop Light & Power Assn		1725 Highway 12 E Ste 100 Litchfield MN, 55355 United States	Electronic Service		No	24-67
90	Michelle	Larson	michelle@redwingchamber.com	Red Wing Area Chamber of Commerce		439 Main Street Red Wing, MN Bay Point Park MN, 55066 United States	Electronic Service		No	24-67
91	Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.		8300 Norman Center Drive Suite 1000 Bloomington MN, 55437 United States	Electronic Service		No	24-67
92	Dan	Lesher	dlesher@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	24-67
93	Michelle	Lommel	mlommel@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	24-67

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
94	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	24-67
95	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		No	24-67
96	Shena	Matrious	shena.matrious@millelacsband.com	Mille Lacs Band of Ojibwe		43408 Oodena Drive Onamia MN, 56349 United States	Electronic Service		No	24-67
97	April	McCormick	aprilm@grandportage.com	Grand Portage Band of Lake Superior Chippewa		PO Box 428 Grand Portage MN, 55605 United States	Electronic Service		No	24-67
98	Ronald	Meier	rmeier@mcleodcoop.com	Mcleod Cooperative Power		3515 11th St East Glencoe MN, 55336 United States	Electronic Service		No	24-67
99	Peder	Mewis	pmewis@cleangridalliance.org	Clean Grid Alliance		570 Asbury St. St. Paul MN, 55104 United States	Electronic Service		No	24-67
100	Valentina	Mgeni	valentina.mgeni@piic.org	Prairie Island Indian Community		Prairie Island Indian Community 5636 Sturgeon Lake Road Welch MN, 55089 United States	Electronic Service		No	24-67
101	Cole W.	Miller	cole.miller@shakopeedakota.org	Shakopee Mdewakanton Sioux Community		Shakopee Mdewakanton Sioux Community 2330 Sioux Trail NW Prior Lake MN, 55372 United States	Electronic Service		No	24-67
102	Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis		350 S. 5th Street Room M 301 Minneapolis MN, 55415 United States	Electronic Service		No	24-67
103	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	24-67
104	Sarah	Mooradian	sarah@curemn.org	CURE		117 South 1st Street Montevideo MN, 56265 United States	Electronic Service		No	24-67
105	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	24-67
106	Travis	Morrision	travis.morrison@boisforte-nsn.gov	Bois Forte Band of Chippewa		Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake	Electronic Service		No	24-67

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55772 United States				
107	David	Morrison, Sr.	david.morrison@boisforte-nsn.gov	Bois Forte Band of Chippewa		Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake MN, 55772 United States	Electronic Service		No	24-67
108	Evan	Mulholland	emulholland@mncenter.org	Minnesota Center for Environmental Advocacy		1919 University Ave W Ste 515 Saint Paul MN, 55101 United States	Electronic Service		No	24-67
109	Sonny	Myers	smyers@1854treatyauthority.org	1854 Treaty Authority		4428 Haines Rd Duluth MN, 55811-1524 United States	Electronic Service		No	24-67
110	Pouya	Najmaie	najm0001@gmail.com	Cooperative Energy Futures		3416 16th Ave S Minneapolis MN, 55407 United States	Electronic Service		No	24-67
111	Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment		212 3rd Ave N Ste 560 Minneapolis MN, 55401 United States	Electronic Service		No	24-67
112	Deb	Nelson	dnelson@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	24-67
113	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	24-67
114	Duane	Ninneman	duane@cureriver.org	Clean Up the River Environment		117 South 1st St Montevideo MN, 56265 United States	Electronic Service		No	24-67
115	Logan	O'Grady	logrady@mnseia.org	Minnesota Solar Energy Industries Association		2288 University Ave W St. Paul MN, 55114 United States	Electronic Service		No	24-67
116	Joseph	OBrien	joey.obrien@lowersioux.com			39527 Highway 1 Morton MN, 56270 United States	Electronic Service		No	24-67
117	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	24-67
118	Gregory	Padden	gpadden@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	24-67
119	Jessica	Palmer Denig	jessica.palmer-denig@state.mn.us		Office of Administrative Hearings	600 Robert St N PO Box 64620 St. Paul MN,	Electronic Service		Yes	24-67

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						55164 United States				
120	Marsha	Parlow	mparlow@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	24-67
121	Priti	Patel	ppatel@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369-4718 United States	Electronic Service		No	24-67
122	Earl	Pendleton	earl.pendleton@lowersioux.com	Lower Sioux Indian Community		39527 Highway 1 Morton MN, 56270 United States	Electronic Service		No	24-67
123	Gordon	Pietsch	gpietsch@grenergy.com	Great River Energy		12300 Elm Creek Blvd. Maple Grove MN, 55369-4718 United States	Electronic Service		No	24-67
124	Joe	Plumer	joe.plumer@redlakenation.org	Red Lake Nation		15484 Migizi Drive Red Lake MN, 56671 United States	Electronic Service		No	24-67
125	Kevin	Pranis	kpranis@liunagroc.com	Laborers' District Council of MN and ND		81 E Little Canada Road St. Paul MN, 55117 United States	Electronic Service		No	24-67
126	Robert	Prescott	bob.prescott@lowersioux.com	Lower Sioux Indian Community		39527 Highway 1 Morton MN, 56270 United States	Electronic Service		No	24-67
127	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	24-67
128	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	24-67
129	Stephan	Roos	stephan.roos@state.mn.us		Minnesota Department of Agriculture	625 Robert St N Saint Paul MN, 55155-2538 United States	Electronic Service		No	24-67
130	Alan	Roy	alan.roy@whiteearth-nsn.gov	White Earth Nation		White Earth Tribal Headquarters 35500 Eagle View Road Ogema MN, 56569 United States	Electronic Service		No	24-67
131	Bill	Rudnicki	bill.rudnicki@shakopeedakota.org	Shakopee Mdewakanton Sioux Community		Shakopee Mdewakanton Sioux Community 2330 Sioux Trail NW Prior Lake MN, 55372 United States	Electronic Service		No	24-67

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132	Nathaniel	Runke	nrunke@local49.org			611 28th St. NW Rochester MN, 55901 United States	Electronic Service		No	24-67
133	Zachary	Ruzycki	zruzycki@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369 United States	Electronic Service		No	24-67
134	Miranda	Sam	miranda.sam@lowersioux.com	Lower Sioux Indian Community		39527 Reservation Highway 1 PO Box 308 Morton MN, 56270 United States	Electronic Service		No	24-67
135	Adam	Savariego	adams@uppersiouxcommunity-nsn.gov	Upper Sioux Community		5722 Travers Lane PO Box 147 Granite Falls MN, 56241 United States	Electronic Service		No	24-67
136	Ronald J.	Schwartau	rschwartau@noblesce.com	Nobles Electric Cooperative		22636 U.S. Hwy. 59 Worthington MN, 56187 United States	Electronic Service		No	24-67
137	Jessie	Seim	jessie.seim@piic.org	Prairie Island Indian Community		5636 Sturgeon Lake Rd Welch MN, 55089 United States	Electronic Service		No	24-67
138	Darrell	Seki, Sr.	dseki@redlakenation.org			15484 Migizi Drive Red Lake MN, 56671 United States	Electronic Service		No	24-67
139	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN, 55423 United States	Electronic Service		Yes	24-67
140	Joel	Smith	jsmith@mnchippewatribe.org	Minnesota Chippewa Tribe		PO Box 217 Cass Lake MN, 56633 United States	Electronic Service		No	24-67
141	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	24-67
142	Nizhoni	Smith	nizhoni.smith@lowersioux.com	Lower Sioux Indian Community		PO Box 308 39527 Reservation Highway 1 Morton MN, 56270 United States	Electronic Service		No	24-67
143	Roger	Smith, Sr.	rogermsmithsr@fdlrez.com			1720 Big Lake Road Cloquet MN, 55720 United States	Electronic Service		No	24-67
144	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	24-67
145	Marie	Spry	mariespry@grandportage.com			PO Box 428 Grand	Electronic Service		No	24-67

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
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147	LeRoy	Staples Fairbanks III	leroy.fairbanks@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	24-67
148	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	24-67
149	Mark	Strohfus	mstrohfus@grenergy.com	Great River Energy		12300 Elm Creek Boulevard Maple Grove MN, 55369-4718 United States	Electronic Service		No	24-67
150	Samuel	Strong	sam.strong@redlakenation.org	Red Lake Nation		15484 Migizi Drive Red Lake MN, 56671 United States	Electronic Service		No	24-67
151	Timothy	Sullivan	tsullivan@whe.org	Wright Hennepin Coop. Electric Assn.		6800 Electric Drive PO Box 330 Rockford MN, 55373 United States	Electronic Service		No	24-67
152	David	Sunderman	daves@benco.org	BENCO (DUPLICATE)		PO Box 8 Mankato MN, 56002-0008 United States	Electronic Service		No	24-67
153	Camille	Tanhoff	kamip@uppersiouxcommunity-nsn.gov	Upper Sioux Community		5722 Travers Lane PO BOX 147 Granite Falls MN, 56241 United States	Electronic Service		No	24-67
154	Tim	Thompson	tthompson@lrec.coop	Lake Region Electric Cooperative		PO Box 643 1401 South Broadway Pelican Rapids MN, 56572 United States	Electronic Service		No	24-67
155	Geoffrey	Tolley	geoff.tolley@gmail.com			855 Stanley Road Two Harbors MN, 55616-1176 United States	Electronic Service		No	24-67
156	Caralyn	Trutna	carrie@uppersiouxcommunity-nsn.gov	Upper Sioux Community		Upper Sioux Community P.O. Box 147 Granite Falls MN, 55372 United States	Electronic Service		No	24-67
157	Jackie	Van Norman	jvannorman@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	24-67
158	Sam	Villella	sdvillella@gmail.com			10534 Alamo Street NE Blaine MN, 55449 United States	Electronic Service		No	24-67

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
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160	Amelia	Vohs	avohs@mncenter.org	Minnesota Center for Environmental Advocacy		1919 University Avenue West Suite 515 St. Paul MN, 55104 United States	Electronic Service		No	24-67
161	Trent	Waite	twaite@grenergy.com			null null, null United States	Electronic Service		No	24-67
162	Heather	Westra	heather.westra@piic.org	Prairie Island Indian Community		5636 Sturgeon Lake Rd Welch MN, 55089 United States	Electronic Service		No	24-67
163	Steve	White	steve.white@llojibwe.net	Leech Lake Band of Ojibwe		190 Sailstar Drive NW Cass Lake MN, 56633 United States	Electronic Service		No	24-67
164	Cody	Whitebear	cody.whitebear@piic.org	Prairie Island Indian Community		5636 Sturgeon Lake Road Welch MN, 55089 United States	Electronic Service		No	24-67
165	John	Williams	jwilliams@grenergy.com	Great River Energy		12300 Elm Creek Blvd Maple Grove MN, 55369 United States	Electronic Service		No	24-67
166	Virgil	Wind	virgil.wind@millelacsband.com	Mille Lacs Band of Ojibwe		43408 Oodena Drive Onamia MN, 56359 United States	Electronic Service		No	24-67
167	Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine		225 South Sixth Street, Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	24-67
168	Laurie	York	laurie.york@whiteearth-nsn.gov	White Earth Reservation Business Committee		PO Box 418 White Earth MN, 56591 United States	Electronic Service		No	24-67
169	Curtis	Zaun	czaun@mnseia.org	MnSEIA		PO Box 8141 Saint Paul MN, 55108 United States	Electronic Service		No	24-67
170	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	24-67
171	Patrick	Zomer	pat.zomer@lawmoss.com	Moss & Barnett PA		150 S 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	24-67

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
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2	Gary	Ambach	gambach@slipstreaminc.org	Slipstream, Inc.		8973 SW Village Loop Chanhassen MN, 55317 United States	Electronic Service		No	23-212Official
3	Dennis	Anderson	whatelse@q.com			5295 Anderlie Lane White Bear Lake MN, 55110 United States	Electronic Service		No	23-212Official
4	Katherine	Arnold	katherine.arnold@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	23-212Official
5	Susan	Arntz	sarntz@mankatomn.gov	City Of Mankato		P.O. Box 3368 Mankato MN, 56002-3368 United States	Electronic Service		No	23-212Official
6	Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy		414 Nicollet Mall Fl 5 Minneapolis MN, 55401 United States	Electronic Service		No	23-212Official
7	Ryan	Barlow	ryan.barlow@lawmoss.com	Moss & Barnett, a Professional Association		150 South Fifth St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
8	Jessica L	Bayles	jessica.bayles@stoel.com	Stoel Rives LLP		1150 18th St NW Ste 325 Washington DC, 20036 United States	Electronic Service		No	23-212Official
9	David	Bell	david.bell@state.mn.us		Department of Health	POB 64975 St. Paul MN, 55164 United States	Electronic Service		No	23-212Official
10	David	Bender	dbender@earthjustice.org	Earthjustice		1001 G Street NW Suite 1000 Washington DC, 20001 United States	Electronic Service		No	23-212Official
11	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission		Electronic Service		No	23-212Official
12	Ingrid	Bjorklund	ibjorklund@avisenlegal.com	Avisen Legal		901 S. Marquette Ave. #1675 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
13	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	23-212Official
14	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		Yes	23-212Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
15	James	Canaday	james.canaday@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota St. St. Paul MN, 55101 United States	Electronic Service		No	23-212Official
16	Thomas	Carlson	thomas.carlson@edf-re.com	EDF Renewable Energy		10 2nd St NE Ste. 400 Minneapolis MN, 55413 United States	Electronic Service		No	23-212Official
17	Joey	Cherney	joey.cherney@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota Street STE 1800 Saint Paul MN, 55101 United States	Electronic Service		No	23-212Official
18	John	Coffman	john@johncoffman.net	AARP		871 Tuxedo Blvd. St, Louis MO, 63119-2044 United States	Electronic Service		No	23-212Official
19	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	23-212Official
20	Jean	Comstock	jean.comstock.dbcc@gmail.com	St. Paul 350		729 6th St E St. Paul MN, 55106 United States	Electronic Service		No	23-212Official
21	Water Programs	Coordinator	waterprograms.bwsr@state.mn.us		Minnesota Board of Water and Soil Resources	520 Lafayette Road N St. Paul MN, 55155 United States	Electronic Service		No	23-212Official
22	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	23-212Official
23	James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	23-212Official
24	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	23-212Official
25	Randall	Doneen	randall.doneen@state.mn.us		Department of Natural Resources	500 Lafayette Rd, PO Box 25 Saint Paul MN, 55155 United States	Electronic Service		No	23-212Official
26	Richard	Dornfeld	richard.dornfeld@ag.state.mn.us		Office of the Attorney General - Department of Commerce	Minnesota Attorney General's Office 445 Minnesota Street, Suite 1800 Saint Paul MN, 55101 United States	Electronic Service		No	23-212Official
27	J.	Drake Hamilton	hamilton@fresh-energy.org	Fresh Energy		408 St Peter St Ste 350 Saint Paul MN, 55101 United States	Electronic Service		No	23-212Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
28	Christopher	Droske	christopher.droske@minneapolismn.gov	Northern States Power Company dba Xcel Energy-Elec		661 5th Ave N Minneapolis MN, 55405 United States	Electronic Service		No	23-212Official
29	Adam	Duininck	aduininck@ncsrcc.org	North Central States Regional Council of Carpenters		700 Olive Street St. Paul MN, 55130 United States	Electronic Service		No	23-212Official
30	Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota St Ste W1360 Saint Paul MN, 55101 United States	Electronic Service		No	23-212Official
31	Kate	Fairman	kate.fairman@state.mn.us		Department of Natural Resources	Box 32 500 Lafayette Rd St. Paul MN, 55155-4032 United States	Electronic Service		No	23-212Official
32	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-Reliance Minneapolis MN, 55406 United States	Electronic Service		No	23-212Official
33	Annie	Felix Gerth	annie.felix-gerth@state.mn.us			Board of Water & Soil Resources 520 Lafayette Rd Saint Paul MN, 55155 United States	Electronic Service		No	23-212Official
34	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	23-212Official
35	Mike	Fiterman	mikefiterman@libertydiversified.com	Liberty Diversified International		5600 N Highway 169 Minneapolis MN, 55428-3096 United States	Electronic Service		No	23-212Official
36	Lucas	Franco	lfranco@liunagroc.com	LIUNA		81 Little Canada Rd E Little Canada MN, 55117 United States	Electronic Service		No	23-212Official
37	Todd J.	Guerrero	todd.guerrero@kutakrock.com	Kutak Rock LLP		Suite 1750 220 South Sixth Street Minneapolis MN, 55402-1425 United States	Electronic Service		No	23-212Official
38	Kim	Havey	kim.havey@minneapolismn.gov	City of Minneapolis		350 South 5th Street, Suite 315M Minneapolis MN, 55415 United States	Electronic Service		No	23-212Official
39	Philip	Hayet	phayet@jkenn.com	J. Kennedy and Associates, Inc.		570 Colonial Park Drive Suite 305 Roswell GA, 30075-3770 United States	Electronic Service		No	23-212Official
40	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington	Electronic Service		No	23-212Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55024 United States				
41	Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors		413 Wacouta Street #230 St.Paul MN, 55101 United States	Electronic Service		No	23-212Official
42	Kristin	Henry	kristin.henry@sierraclub.org	Sierra Club		2101 Webster St Ste 1300 Oakland CA, 94612 United States	Electronic Service		No	23-212Official
43	Katherine	Hinderlie	katherine.hinderlie@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St Suite 1400 St. Paul MN, 55101-2134 United States	Electronic Service		No	23-212Official
44	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	23-212Official
45	Kari	Howe	kari.howe@state.mn.us		DEED	332 Minnesota St, #E200 1ST National Bank Bldg St. Paul MN, 55101 United States	Electronic Service		No	23-212Official
46	Dean	Hunter	dean.hunter@state.mn.us		Minnesota Department of Labor & Industry	443 Lafayette Rd N St. Paul MN, 55155-4341 United States	Electronic Service		No	23-212Official
47	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	23-212Official
48	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
49	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
50	William	Kenworthy	will@votesolar.org			1 South Dearborn St Ste 2000 Chicago IL, 60603 United States	Electronic Service		No	23-212Official
51	Samuel B.	Ketchum	sketchum@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
52	Raymond	Kirsch	raymond.kirsch@state.mn.us		Department of Commerce	85 7th Place E Ste 500 St. Paul MN, 55101 United States	Electronic Service		No	23-212Official
53	Frank	Kohlasch	frank.kohlasch@state.mn.us		Minnesota Pollution Control Agency	520 Lafayette Rd N. St. Paul MN, 55155 United States	Electronic Service		No	23-212Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
54	Brian	Kolbinger	brian@beckertownship.org	Becker Township Board		PO Box 248 12165 Hancock St Becker MN, 55308 United States	Electronic Service		No	23-212Official
55	Chad	Konickson	chad.konickson@usace.army.mil	U.S.Army Corps of Engineers		332 Minnesota St. Suite E1500 Saint Paul MN, 55101 United States	Electronic Service		No	23-212Official
56	Stacy	Kotch Egstad	stacy.kotch@state.mn.us		MINNESOTA DEPARTMENT OF TRANSPORTATION	395 John Ireland Blvd. St. Paul MN, 55155 United States	Electronic Service		No	23-212Official
57	Kay	Kuhlmann	teri.swanson@ci.red-wing.mn.us	City Of Red Wing		315 West Fourth Street Red Wing MN, 55066 United States	Electronic Service		No	23-212Official
58	Brenda	Kyle	bkyle@stpaulchamber.com	St. Paul Area Chamber of Commerce		401 N Robert Street Suite 150 St Paul MN, 55101 United States	Electronic Service		No	23-212Official
59	Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
60	Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.		8300 Norman Center Drive Suite 1000 Bloomington MN, 55437 United States	Electronic Service		No	23-212Official
61	Amber	Lee	amber.lee@stoel.com	Stoel Rives LLP		33 S. 6th Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
62	Rachel	Leonard	rachel.leonard@ci.monticello.mn.us	City of Monticello		505 Walnut St Ste 1 Monticello MN, 55362 United States	Electronic Service		No	23-212Official
63	Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota		332 Minnesota Street, Suite W1360 St. Paul MN, 55101 United States	Electronic Service		No	23-212Official
64	Alice	Madden	alice@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	23-212Official
65	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	23-212Official
66	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		No	23-212Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
67	Dawn S	Marsh	dawn_marsh@fws.gov	U.S. Fish & Wildlife Service		Minnesota-Wisconsin Field Offices 4101 American Blvd E Bloomington MN, 55425 United States	Electronic Service		No	23-212Official
68	Emily	Marshall	emarshall@lourismarshall.com	Miller O'Brien Jensen, PA		120 S. 6th Street Suite 2400 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
69	Katherine	Marshall	katie.marshall@lawmoss.com	Moss & Barnett		150 S 5th St Ste 1200 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
70	Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc		414 Nicollet Mall 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	23-212Official
71	Gregg	Mast	gmast@cleanenergyeconomymn.org	Clean Energy Economy Minnesota		4808 10th Avenue S Minneapolis MN, 55417 United States	Electronic Service		No	23-212Official
72	Daryl	Maxwell	dmaxwell@hydro.mb.ca	Manitoba Hydro		360 Portage Ave FL 16 PO Box 815, Station Main Winnipeg MB, R3C 2P4 Canada	Electronic Service		No	23-212Official
73	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	23-212Official
74	Taylor	McNair	taylor@gridlab.org			668 Capp Street San Francisco CA, 94110 United States	Electronic Service		No	23-212Official
75	Melanie	Mesko Lee	melanie.lee@burnsvillemn.gov	City of Burnsville		100 Civic Center Parkway Burnsville MN, 55337-3867 United States	Electronic Service		No	23-212Official
76	Peder	Mewis	pmewis@cleangridalliance.org	Clean Grid Alliance		570 Asbury St. St. Paul MN, 55104 United States	Electronic Service		No	23-212Official
77	Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis		350 S. 5th Street Room M 301 Minneapolis MN, 55415 United States	Electronic Service		No	23-212Official
78	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	23-212Official
79	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
80	Evan	Mulholland	emulholland@mncenter.org	Minnesota Center for		1919 University Ave W Ste 515	Electronic Service		No	23-212Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
				Environmental Advocacy		Saint Paul MN, 55101 United States				
81	Alan	Muller	alan@greendel.org	Energy & Environmental Consulting		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	23-212Official
82	Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment		212 3rd Ave N Ste 560 Minneapolis MN, 55401 United States	Electronic Service		No	23-212Official
83	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
84	M. William	O'Brien	bobrien@mojlaw.com	Miller O'Brien Jensen, P.A.		120 S 6th St Ste 2400 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
85	Ric	O'Connell	ric@gridlab.org	GridLab		2120 University Ave Berkeley CA, 94704 United States	Electronic Service		No	23-212Official
86	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	23-212Official
87	Jessica	Palmer Denig	jessica.palmer-denig@state.mn.us		Office of Administrative Hearings	600 Robert St N PO Box 64620 St. Paul MN, 55164 United States	Electronic Service		No	23-212Official
88	J.	Porter	greg.porter@nngco.com	Northern Natural Gas Company		1111 South 103rd St Omaha NE, 68124 United States	Electronic Service		No	23-212Official
89	Brian H.	Potts	brian.potts@huschblackwell.com	Husch Blackwell		33 E Main St Ste 300 Madison WI, 53703 United States	Electronic Service		No	23-212Official
90	Kevin	Pranis	kpranis@liunagroc.com	Laborers' District Council of MN and ND		81 E Little Canada Road St. Paul MN, 55117 United States	Electronic Service		No	23-212Official
91	Kurt	Rempe	krempe@nationalgridrenewables.com	National Grid Renewables Development, LLC		8400 Normandale Lake Blvd Suite 1200 Bloomington MN, 55437 United States	Electronic Service		No	23-212Official
92	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	23-212Official
93	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	23-212Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
94	Stephan	Roos	stephan.roos@state.mn.us		Minnesota Department of Agriculture	625 Robert St N Saint Paul MN, 55155-2538 United States	Electronic Service		No	23-212Official
95	Nathaniel	Runke	nrunke@local49.org			611 28th St. NW Rochester MN, 55901 United States	Electronic Service		No	23-212Official
96	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
97	Richard J.	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, PA		332 Minnesota St Ste W2750 St. Paul MN, 55101 United States	Electronic Service		No	23-212Official
98	Jeff	Schneider	jeff.schneider@ci.red-wing.mn.us	City of Red Wing		315 West 4th Street Red Wing MN, 55066 United States	Electronic Service		No	23-212Official
99	Peter	Scholtz	peter.scholtz@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	Suite 1400 445 Minnesota Street St. Paul MN, 55101-2131 United States	Electronic Service		No	23-212Official
100	Douglas	Seaton	doug.seaton@umwlc.org	Upper Midwest Law Center		8421 Wayzata Blvd Ste 300 Golden Valley MN, 55426 United States	Electronic Service		No	23-212Official
101	Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates		7400 Lyndale Ave S Ste 190 Richfield MN, 55423 United States	Electronic Service		Yes	23-212Official
102	Andrew R.	Shedlock	andrew.shedlock@kutakrock.com	Kutak Rock LLP		60 South Sixth St Ste 3400 Minneapolis MN, 55402-4018 United States	Electronic Service		No	23-212Official
103	Beth	Smith	bsmith@greatermankato.com	Greater Mankato Growth		1961 Premier Dr Ste 100 Mankato MN, 56001 United States	Electronic Service		No	23-212Official
104	Joshua	Smith	joshua.smith@sierraclub.org			85 Second St FL 2 San Francisco CA, 94105 United States	Electronic Service		No	23-212Official
105	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	23-212Official
106	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	23-212Official
107	Anna	Sommer	asommer@energyfuturesgroup.com	Energy Futures Group		PO Box 692 Canton NY, 13617 United States	Electronic Service		No	23-212Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
108	Mark	Spurr	mspurr@fvbenergy.com	International District Energy Association		222 South Ninth St., Suite 825 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
109	Sean	Stalpes	sean.stalpes@state.mn.us		Public Utilities Commission	121 E. 7th Place, Suite 350 Saint Paul MN, 55101-2147 United States	Electronic Service		No	23-212Official
110	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
111	Jayme	Trusty	execdir@swrdc.org	SWRDC		2401 Broadway Ave #1 Slayton MN, 56172 United States	Electronic Service		No	23-212Official
112	Jen	Tyler	tyler.jennifer@epa.gov	US Environmental Protection Agency		Environmental Planning & Evaluation Unit 77 W Jackson Blvd. Mailstop B-19J Chicago IL, 60604-3590 United States	Electronic Service		No	23-212Official
113	Carla	Vita	carla.vita@state.mn.us	MN DEED		Great Northern Building 12th Floor 180 East Fifth Street St. Paul MN, 55101 United States	Electronic Service		No	23-212Official
114	Julie	Voeck	julie.voeck@nee.com	NextEra Energy Resources, LLC		700 Universe Blvd Juno Beach FL, 33408 United States	Electronic Service		No	23-212Official
115	Amelia	Vohs	avohs@mncenter.org	Minnesota Center for Environmental Advocacy		1919 University Avenue West Suite 515 St. Paul MN, 55104 United States	Electronic Service		No	23-212Official
116	Cynthia	Warzecha	cynthia.warzecha@state.mn.us	Minnesota Department of Natural Resources		500 Lafayette Road Box 25 St. Paul MN, 55155-4040 United States	Electronic Service		No	23-212Official
117	Julianna	Wei	julianna.wei@rondo.com	Rondo Energy, Inc.		1960 North Loop Alameda CA, 94502 United States	Electronic Service		No	23-212Official
118	Alan	Whipple	sa.property@state.mn.us		Minnesota Department Of Revenue	Property Tax Division 600 N. Robert Street St. Paul MN, 55146-3340 United States	Electronic Service		No	23-212Official
119	Laurie	Williams	laurie.williams@sierraclub.org	Sierra Club		Environmental Law Program 1536 Wynkoop St Ste 200 Denver CO,	Electronic Service		No	23-212Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						80202 United States				
120	Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine		225 South Sixth Street, Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
121	Rob	Witwer	rob.witwer@onwardenergy.com	Onward Energy Holdings, LLC		767 Third Ave 17th Floor New York NY, 10017 United States	Electronic Service		No	23-212Official
122	Jonathan	Wolfgram	jonathan.wolfgram@state.mn.us		Office of Pipeline Safety	445 Minnesota St Ste 147 Woodbury MN, 55125 United States	Electronic Service		No	23-212Official
123	Tim	Wulling	t.wulling@earthlink.net			1495 Raymond Ave. Saint Paul MN, 55108 United States	Electronic Service		No	23-212Official
124	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	23-212Official
125	Emily	Ziring	eziring@stlouispark.org	City of St. Louis Park		5005 Minnetonka Blvd St. Louis Park MN, 55416 United States	Electronic Service		No	23-212Official
126	Patrick	Zomer	pat.zomer@lawmoss.com	Moss & Barnett PA		150 S 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	23-212Official
127	David	Zoppo	david.zoppo@huschblackwell.com	American Transmission Company LLC		33 East Main Street Suite 300 Madison WI, 53703 United States	Electronic Service		No	23-212Official

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission		Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
2	Matthew	Brodin	mbrodin@allete.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
3	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
4	John	Coffman	john@johncoffman.net	AARP		871 Tuxedo Blvd. St, Louis MO, 63119-2044 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
5	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
6	George	Crocker	gwillc@nawo.org	North American Water Office		5093 Keats Avenue Lake Elmo MN, 55042 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
7	Christopher	Droske	christopher.droske@minneapolismn.gov	Northern States Power Company dba Xcel Energy-Elec		661 5th Ave N Minneapolis MN, 55405 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
8	John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance		2720 E. 22nd St Institute for Local Self-Reliance Minneapolis MN, 55406 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
9	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-	Electronic Service		No	Northern States Power Company dba Xcel

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						2198 United States				Energy-ElecXcel Miscl Electric
10	Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association		4300 220th St W Farmington MN, 55024 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
11	Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.		445 Etna Street Ste. 61 St. Paul MN, 55106 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
12	Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law		2950 Yellowtail Ave. Marathon FL, 33050 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
13	Richard	Johnson	rick.johnson@lawmoss.com	Moss & Barnett		150 S. 5th Street Suite 1200 Minneapolis MN, 55402 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
14	Sarah	Johnson Phillips	sjphillips@stoel.com	Stoel Rives LLP		33 South Sixth Street Suite 4200 Minneapolis MN, 55402 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
15	Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.		8300 Norman Center Drive Suite 1000 Bloomington MN, 55437 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
16	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
17	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric

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18	Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis		350 S. 5th Street Room M 301 Minneapolis MN, 55415 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
19	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
20	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
21	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
22	Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
23	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
24	Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy		26 E Exchange St, Ste 206 St. Paul MN, 55101-1667 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
25	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
26	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	Northern States Power Company dba Xcel

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										Energy-ElecXcel Miscl Electric
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28	Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine		225 South Sixth Street, Suite 3500 Minneapolis MN, 55402 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
29	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric
30	Patrick	Zomer	pat.zomer@lawmoss.com	Moss & Barnett PA		150 S 5th St #1200 Minneapolis MN, 55402 United States	Electronic Service		No	Northern States Power Company dba Xcel Energy-ElecXcel Miscl Electric