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October 31, 2025

—Via Electronic Filing—

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

RE: 2025 INTEGRATED DISTRIBUTION PLAN
DOCKET NO. E002/M-25-142

Dear Ms. Bergman:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed 2025 Integrated Distribution Plan (IDP). This IDP outlines our distribution strategy and goals; planning process; historical actual and budgeted expenditures; and present and forecasted levels of distributed energy resources. In this IDP, we also discuss our distribution five-year plan and long-term vision.

This IDP complies with all of the filing requirements provided in the above-referenced Order. For additional compliance information, see the Compliance Matrix provided as Attachment B to this filing.

Portions of this IDP contain protected data including Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b). See Attachment A to this filing for the trade secret justifications for each piece.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service lists. Please contact Taige Tople at taige.d.tople@xcelenergy.com or me at brian.t.monson@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

BRIAN MONSON
MANAGER, DISTRIBUTION REGULATORY STRATEGY

Enclosures
cc: Service Lists



INTEGRATED DISTRIBUTION PLAN

2026-2035

NORTHERN STATES POWER COMPANY
MPUC DOCKET NO. E002/M-25-142
OCT. 31, 2025



GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ADIT	Accumulated Deferred Income Taxes
ADMS	Advanced Distribution Management System
AFUDC	Allowance for Funds Used During Construction
AGIS	Advanced Grid Intelligence and Security
AMI	Advanced Metering Infrastructure
ANM	Active Network Management
AOM	Advanced Outage Management
APM	Advanced Project Manager
ANSI	American National Standards Institute
ARR	Avoided Revenue Requirement
ASHP	Air Source Heat Pumps
AUC ROC	Area Under the Curve
BE	Beneficial Electrification
BES	Bulk Energy System
BESS	Battery Energy Storage Systems
BTM	Behind the Meter
BYOD	Bring Your Own Device
C*C	Capacity*Connect
CAIDI	Customer Average Interruption Duration Index
CBA	Cost-Benefit Analysis
CBG	Census Block Groups
CELI	Customers Experiencing Lengthy Interruptions
CEMI	Customers Experiencing Multiple Interruptions
CEUD	Customer Energy Usage Data
CI	Confidential Information
CIA	Confidentiality, Integrity, and Availability
CIAC	Contributions In Aid of Construction
CIM	Common Information Model
CMO	Customer Minutes Out
CPP	Critical Peak Partner
CRI	Confidential Restricted Information
CRS	Customer Resource System
CSF	Cyber Security Framework
CSG	Community Solar Garden
CTI	Coordination Time Interval
CWP	Construction Work in Progress
DCC	Distribution Control Center
DCP	Distributed Capacity Procurement
DEF	Duke Energy Florida
DEMI	Devices Experiencing Multiple Interruptions
DER	Distributed Energy Resource
DERA	Distributed Energy Resource Aggregators
DERMS	Distributed Energy Resources Management System

Acronym/Defined Term	Meaning
DF	Dependability Factor
DFPV	Dependability Factor for Photovoltaics
DG	Distributed Generation
DGWG	Distributed Generation Working Group (DGWG)
DI	Disproportionately Impacted
DI	Distributed Intelligence
DML	Daytime Minimum Load
DOE	U.S. Department of Energy
DQ	Disproportionately Impacted
DR	Demand Response
DRIVE	EPRI's Distribution Resource Integration and Value Estimation tool (for Hosting Capacity Analysis)
DSES	Distributed Solar Energy Standard
D-SCADA	Distribution Supervisory Control and Data Acquisitions
DSM	Demand Side Management
DSPx	DOE's Next Generation Distribution System Platform
DVE	Domestic Violent Extremists
ECO	Energy Conservation & Optimization
EE	Energy Efficiency
EDC	Electric Distribution Companies
EDDIE	Electric Distribution Data Inspection and Estimation
EDP	Electric Distribution Planning
EEI	Edison Electric Institute
EFS	Efficient Fuel Switching
EIA	U.S. Energy Information Administration
ELCC	Effective Load Carrying Capacity
ELPC	Environmental Law and Policy Center
EMF	Electromagnetic Field
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
EPSS	Enhanced Powerline Safety Settings
ESS	Enterprise Security System
EV	Electric Vehicle
EVSE	EV Supply Equipment
EVSI	EV Supply Infrastructure
FAN	Field Area Network
FE	Flexible Energization
FERC	Federal Energy Regulatory Commission
FI	Flexible Interconnection
FIRE	Feeder Infared Evaluation
FLISR	Fault Location, Isolation, and Service Restoration
FLM	Feeder Load Monitoring
FPIP	Feeder Performance Improvement Program
FPL	Florida Power & Light
FTM	Front of the Meter

Acronym/Defined Term	Meaning
GFOV	Ground Fault Over-Voltage
GIS	Geographical Information System or Geospatial Information System
GRIP	Grid Resilience & Innovation Partnerships
GVT	Grid Visibility Tool
GWAC	GridWise Architecture Council
HAN	Home Area Network
HC	Hosting Capacity
HCA	Hosting Capacity Analysis
ICE	Internal Combustion Engine
ICE	Interruption Cost Estimate
IDP	Integrated Distribution Plan
IDS	Intrusion Detection System
IEEE	Institute of Electrical and Electronics Engineers
II	Internal Information
IIJA	Infrastructure Investment and Jobs Act
IPS	Intrusion Prevention System
IQ	Income-Qualified
IRA	Inflation Reduction Act
IREC	Interstate Renewable Energy Council
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISP	Integrated System Planning
IT	Information Technology
LCI	Large Commercial and Industrial
LROV	Load Rejection Over-Voltage
LTE	Long-Term Evolution
M&V	Measurement & Verification
MAIC	Minneapolis American Indian Center
MAIFI	Momentary Average Interruption Frequency Index
MDU	Multi-Dwelling Unit
MEC	My Energy Connection
MED	Major Event Day
MISO	Midcontinent Independent System Operator
MN DIA	Minnesota Distributed Energy Resources Interconnection Agreement
MN DIP	Minnesota Distributed Energy Resources Interconnection Process
MPUC, PUC, or Commission	Minnesota Public Utilities Commission
MVA	Megavolt Amperes
MW	Megawatt
MWh	Megawatt-hour
N-0	System intact operating condition
N-1	Single contingency operating condition
NACS	North American Charging Standard

Acronym/Defined Term	Meaning
NDZ	Non-Detection Zone
NERC	North American Electric Reliability Corporation
NESC	National Electrical Safety Code
NIST	National Institute of Standards and Technology
NREL	National Renewable Energy Laboratory
NSPM or Company	Northern States Power Company-Minnesota (Minnesota, North Dakota, and South Dakota operating company)
NWA	Non-Wires Alternatives
O&M	Operations and Maintenance
OMS	Outage Management System
OT	Operational Technology
PEPCo	Potomac Electric Power Company
PiE	Partners in Energy
PL&C	Pole Loading & Clearance
PLUG	Power Line Undergrounding
PNL	Planned Net Loading
POC	People of Color
POI	Point of Interconnection
PPA	Power Purchase Agreement
PSCo	Public Service Company of Colorado (Colorado operating company)
PSPS	Public Safety Power Shutoffs
PV	Photovoltaic
QA	Quality Assessment
QSP	Quality of Service Plan
RERRA	Relevant Electric Retail Regulatory Authority
RBC	Renewable Battery Connect
REP	Renewable Energy Partners
RFI	Request for Information
RFP	Request for Proposal(s)
RMP	Resilient Minneapolis Project
RR	Revenue Requirements
RTO	Regional Transmission Operator
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SDK	Software Development Kit
SFE	Substation Field Engineering
SMRP	System Modernization and Reliability Project
SPS	Southwestern Public Service (Texas and New Mexico operating company)
SSUP	Storm Secure Underground Program
SVRA	Security Vendor Risk Assessment
TCR	Transmission Cost Recovery (Rider)
TEP	Transportation Electrification Plan

Acronym/Defined Term	Meaning
TLG	Transformer Loading Guide
TLY	Typical Load Year
TOU	Time of Use
TOV	Transient Over-Voltage
TPS	Technical Planning Standard
TSHC	Time-Series Hosting Capacity
UDP	Universal Data Platform
UI	Unsecured Information
V2G	Vehicle-to-Grid
VLL	Line-to-Line Voltage
VLN	Line-to-Neutral Voltage
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital
WAN	Wide Area Network
WiSUN	Wireless Smart Utility Network
WSO	Wildfire Safety Operating
WPS	Wisconsin Public Service Corporation
Xcel Energy	Xcel Energy Inc.

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INTEGRATED DISTRIBUTION PLAN

INTRODUCTION

The electric distribution system is the front line of the grid—where our customers connect with the power we deliver every day. Xcel Energy is proud of the resilient and safe infrastructure we have built and maintained over decades, and the role our employees play in powering our customers’ lives with affordable, increasingly clean electricity.

Today’s rapid load growth demands strategic, forward-looking planning. This is a strategic roadmap for how we plan, operate, and invest in our Minnesota electric distribution system to meet both current and future customer needs. Our Integrated Distribution Plan (IDP) describes how we integrate technical, economic, and policy considerations to ensure a reliable, resilient, and sustainable grid that supports Minnesota’s energy goals.

The following themes for our 2025 IDP describe how Xcel Energy plans to meet the challenges of the evolving distribution grid landscape and deliver a resilient, customer-focused energy future.

- (1) **Deliver Excellent Service:** We are strengthening customer reliability and grid resilience by leveraging advanced tools and data from our grid modernization investments—including smart meters, Advanced Distribution Management System, fault location, isolation and service restoration (FLISR), and load forecasting software. These technologies enable us to better predict customer needs and reliability risks. Our planning also considers wildfire risks, community engagement, equipment maintenance and growing capacity needs, helping us build a robust and adaptable electric distribution network.
- (2) **Lead the Clean Energy Transition:** The distribution grid plays a critical role in enabling economy-wide decarbonization. Our vision includes integrating distributed energy resources (DERs) into our long-term resource planning. As electrification and DER adoption accelerate, our strategy ensures the distribution system operates in concert with the broader grid. We are developing frameworks and programs to support necessary investments and shape customer energy use, helping to secure a sustainable energy future for Minnesota.
- (3) **Guide with Expertise:** We actively plan the electric grid by combining deep technical expertise with inclusive stakeholder engagement, positioning

ourselves as trusted guides in the energy transition. Our IDP reflects legislative requirements, commission priorities, and customer needs—shaped through workshops, outreach, and ongoing dialogue. These efforts not only inform stakeholders about grid planning and modernization but also invite meaningful input that helps design a more resilient and equitable energy future. Our employees are embedded in the communities we serve, which strengthens our understanding of local needs and enhances the relevance of our planning efforts. We proactively anticipate future system needs and engineer solutions to meet them. Details of our stakeholder engagement are documented in a dedicated chapter of the IDP.

- (4) **Keep Bills as Low as Possible:** As demand grows and grid needs evolve, we are committed to making smart, value-driven investments that avoid placing undue financial strain on customers. Our budgets are carefully evaluated through the lens of customer impact—balancing the need for infrastructure upgrades, grid modernization and resilience, with the goal of keeping bills as low as possible. We measure success not just by operational outcomes, but by how well we maintain cost-effective, reliable, and equitable energy access for all our customers.

I. OVERVIEW: XCEL ENERGY AND ITS DISTRIBUTION SYSTEM

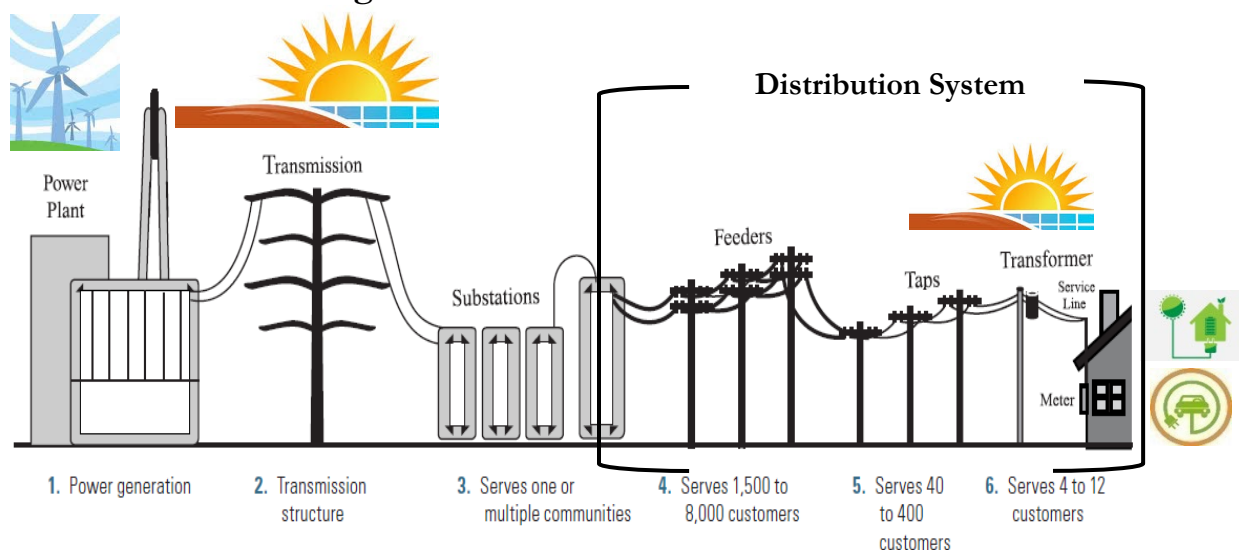
Xcel Energy, based in Minneapolis, is a leading U.S. electric and natural gas utility. In the Upper Midwest, our integrated Northern States Power (NSP) System—made up of NSP-Minnesota and NSP-Wisconsin—provides generation and transmission services to customers in five states (shown in Figure 1), with each operating company also providing distribution service to the customers in their respective states. NSP-Minnesota has 1.6 million electric customers and 600,000 natural gas customers.

Figure 1: NSP-Minnesota Service Area



While 86 percent of NSP-Minnesota customers are residential, commercial and industrial customers account for 59 percent of electricity sales. The distribution system is the final link in the grid, delivering electricity from substations to customers through a network of over 1,200 feeders, 250 substations, 13,000 miles of overhead lines, and 10,500 miles of underground cable. An illustration of our electric grid is shown below in Figure 2.

Figure 2: Illustrative Electrical Grid



Our distribution team maintains and operates this system, focusing on outage restoration, infrastructure upgrades, and reliability improvements—work that laid the foundation for Minnesota’s IDP process, which began in response to the need to evolve the grid and increase transparency of utility planning.

II. IDP BACKGROUND

Minnesota’s IDP process began in 2015 with the Commission’s grid modernization docket (E999/CI-15-556), leading to utility-specific IDP requirements in 2018. Xcel Energy was directed to file its first IDP by November 1, 2018, and now submits a full plan biennially, with financial and non-wires alternatives (NWAs) updates in off-years. The IDP provides regulators and stakeholders with a transparent, standardized view into distribution system planning. Its goals include enhancing grid reliability and resilience, supporting customer choice, enabling distributed technologies, optimizing system costs, and informing regulatory decisions.¹

Since its inception in 2018, the IDP has undergone significant transformation in scope and strategic focus. The early iterations of the IDP were centered on grid modernization, with a strong emphasis on deploying foundational technologies such as Advanced Metering Infrastructure (AMI) and Advanced Distribution Management System (ADMS). These investments laid the groundwork for enhanced operational efficiency and visibility into grid conditions across the distribution system. By 2021, the IDP reflected our growing investment in smart technologies and asset health. We

¹ See the Commission’s Dec. 8, 2022 Order (Docket No. E002/M-21-694).

began using tools and data that help monitor equipment conditions, predict issues before they happen, and make faster decisions to keep everything running smoothly and reliably.

By 2023 and continuing into the present, the IDP had broadened to encompass the full distribution grid landscape. Our focus has expanded beyond technology deployment to include long-term planning around reliability, resiliency, interconnection, and capacity. This evolution acknowledges the growing complexity of the grid, driven by increasing DER, electrification, and customer expectations. Today's IDP reflects our commitment not only to modernize our distribution infrastructure but also to ensure that our grid is resilient, flexible, and capable of supporting future energy needs through strategic investments and policy alignment.

III. DISTRIBUTION GRID LANDSCAPE

Minnesota's distribution grid is rapidly evolving to meet the demands of a more dynamic, inclusive, and resilient energy future. Our distribution grid must accommodate new loads and DERs through forward-looking infrastructure investments that reduce system stress, enhance resilience, and adapt to diverse customer needs.

Our near-term distribution investments are designed to strengthen the “last mile” of our electric system by improving reliability, safety, and flexibility on the part of the system that is closest to our customers. These investments support both the Company's and Minnesota's clean energy goals and focus on:

- *Replacing aging infrastructure* through asset health and reliability programs, including pole, cable, and substation renewals.
- *Expanding capacity* to accommodate growing demand, including new types of load such as electrified heating, transportation, and DER.
- *Modernizing the grid* with technologies through our Advanced Grid Intelligence and Security initiative.
- *Implementing wildfire mitigation strategies* to enhance safety and system resilience in high-risk areas.
- *Reliability and resiliency measures* such as targeted undergrounding of overhead lines in areas with frequent outages.

Together, these efforts strengthen grid performance, reduce outage and ignition risks, and ensure the system is prepared for future demands and evolving customer expectations.

Our long-term distribution strategy prioritizes safety, reliability, and operational flexibility to manage uncertainty. We will maximize the value of both existing and new infrastructure through innovative technologies and asset health programs. Where feasible and cost-effective, we will pursue solutions such as NWAs and DER. Load forecasting will continue to evolve to reflect customer adoption of DER and electrification, while supporting broader policy goals. Investment strategies must balance capacity needs with affordability, enhance transparency, and align with local, state, and federal policies.

Our distribution system's strategy, vision, and design principles must remain relevant today and for the next 50 years.

IV. 2025 IDP HIGHLIGHTS

This section outlines key components of the 2025 IDP, including an updated load and DER forecast, new targeted undergrounding and wildfire mitigation strategies, distribution financials, stakeholder engagement efforts, and our mobile battery certification request. We discuss each in turn below.

A. Load and DER Forecast

To support our mission to lead the clean energy transition and deliver excellent service, we continue to refine our long-term planning tools. Figure 3 illustrates the increasing demand for customer native load that must be met by the distribution system, excluding contributions from DER generation. Figure 4 shows the forecasted increase in installed DER solar capacity over time.

Figure 3
State of Minnesota Total Non-Coincident Distribution Peak Demand 10-Year
Forecast – Aggregated Feeder Peak Load

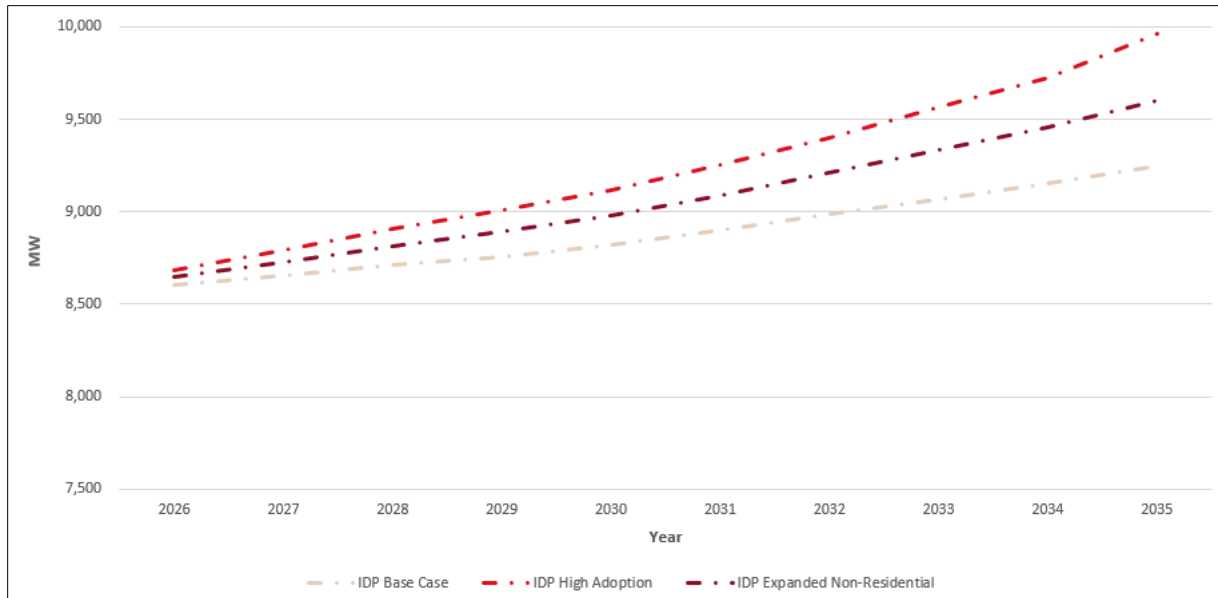
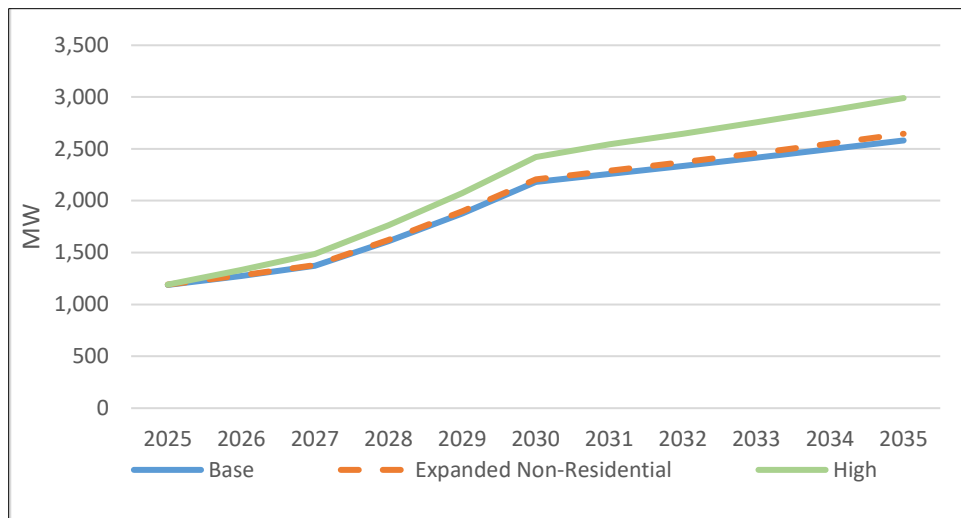


Figure 4
State of Minnesota Distributed Solar Photovoltaic Forecast
(MWac)



This year’s analysis underscores the importance of using three distinct scenarios to forecast future grid needs. Each scenario reflects different assumptions about industry, policy, and customer trends—helping to manage uncertainty and support more resilient planning. In contrast, the 2023 IDP created alternative scenarios by applying percentage adjustments to the base case. The 2025 scenarios, however, are built on distinct assumptions. As a result, they provide a clearer and more meaningful

range of potential outcomes to better inform and prepare for evolving customer demands and widespread electrification. The three scenarios include:

- *Base Case* – reflects known and expected growth in load and distributed generation.
- *High Adoption* – assumes significantly higher load growth and DER adoption across nearly all customer classes.
- *Expanded Non-Residential* – assumes high load growth and DER adoption in commercial and industrial classes, while other classes follow Base Case trends.

Across all three scenarios, the forecast shows distribution system growth from approximately 8.5 GW today to between 9 and 10 GW by 2035. This projected increase of 0.5 to 1.5 GW over the next ten years is substantial. To put this into perspective, a 1 GW increase would require *at least* 10 new substations, 20 new substation transformers, and 150 new feeders to support the additional load. This level of infrastructure investment highlights the urgency and importance of proactive planning and flexible budgeting.

Of note, the 2025 forecast shows slightly slower load growth than the 2023 forecast—particularly in the Base Case and Expanded Non-Residential scenarios. This is largely due to an updated EV forecast. While EV adoption is still expected to grow, the 2025 forecast uses an improved method for assigning EV load to feeders that better reflects how managed charging affects the distribution grid.

We also note that distribution and Integrated Resource Plan (IRP) forecasts differ in scope and methodology. The distribution forecast reflects *aggregate non-coincident peak loads* at the feeder level—capturing the highest demand on each feeder, regardless of timing. In contrast, the IRP forecast focuses on the *coincident system peak*, representing the highest total demand across the system at a single moment. The IRP also includes transmission service customers, such as large data centers and other major loads, which are not part of the distribution forecast.

In distribution planning, we conduct annual forecast analyses and adjust our plans based on industry, policy, and customer trends. Our budget and project strategies are designed to be flexible, allowing us to pivot as those trends evolve. This adaptability is essential to meet future needs.

Our load forecast is a key driver of projected capital expenditures and O&M costs; the next section outlines the financial highlights that reflect the impact of these projections.

B. Distribution Financial Highlights (Capital and O&M)

Electric and gas utilities are long-term, capital-intensive businesses. Each year, we develop a five-year financial forecast to anticipate the needs of each Xcel Energy utility, including NSPM. This includes Capital and O&M budgets that reflect our commitment to delivering excellent service, guiding with expertise, and keeping customer bills as low as possible.

Historically, most distribution spending has focused on near-term reliability—building and maintaining feeders, substations, and service lines; restoring service after storms; and relocating infrastructure to meet local requirements. These investments have been essential to maintaining safe, reliable service.

To lead the clean energy transition, we are evolving our planning and budgeting approach. In addition to maintaining existing infrastructure, we are investing in new technologies, expanded capacity, and workforce development to support electrification, enhance resilience, and modernize customer interactions with the grid.

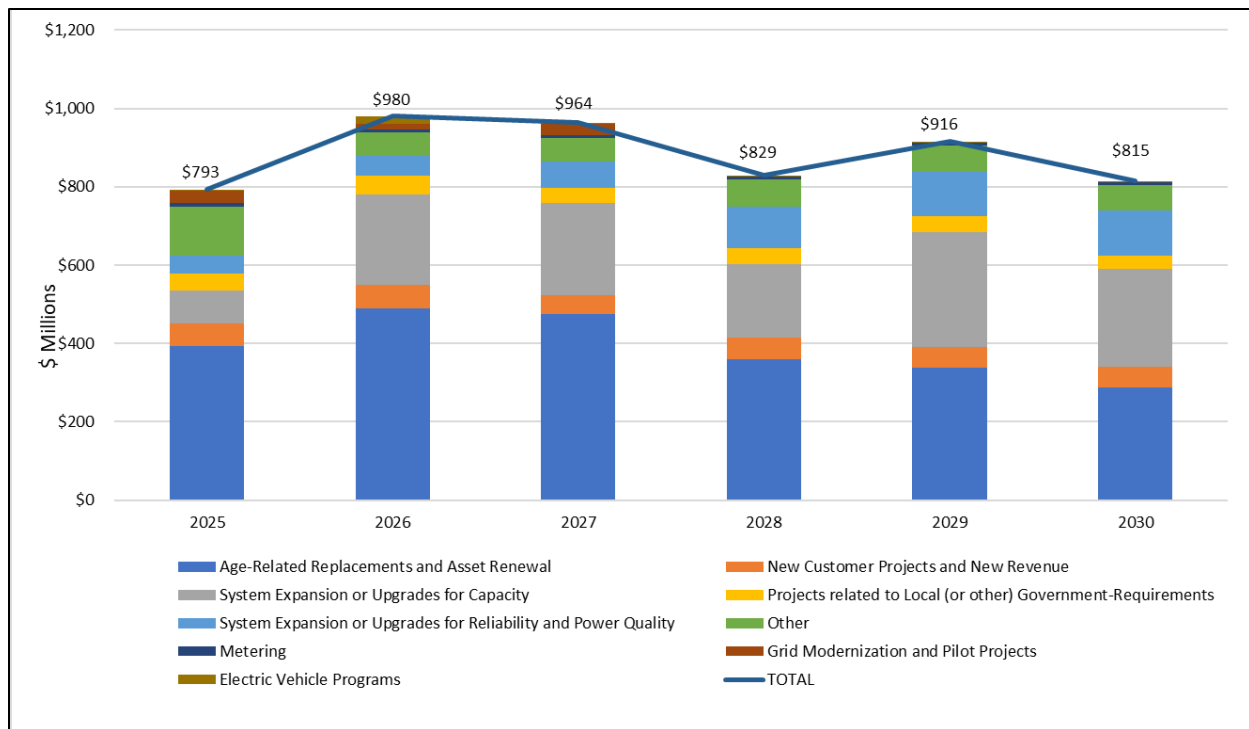
The health of our distribution system is critical to meeting today’s needs and preparing for tomorrow. While the first year of each five-year budget is finalized, years two through five remain flexible and are updated annually to reflect new information, policy shifts, and emerging system and customer needs. This ensures we can adapt to changing conditions while continuing to deliver excellent service and manage costs responsibly.

The Company’s Capital and O&M Budget Forecasts are summarized below.

1. Capital Budget Forecast

While detailed Capital Budget Forecasts are provided in Chapter 6, Figure 5 below displays forecasted budgets for the next five years (2025–2030) across IDP investment categories.

**Figure 5: Distribution Capital Expenditures Budget –
State of Minnesota – Electric 2025-2030 (Millions)**



The upcoming five-year plan focuses on infrastructure renewal and capacity expansion:

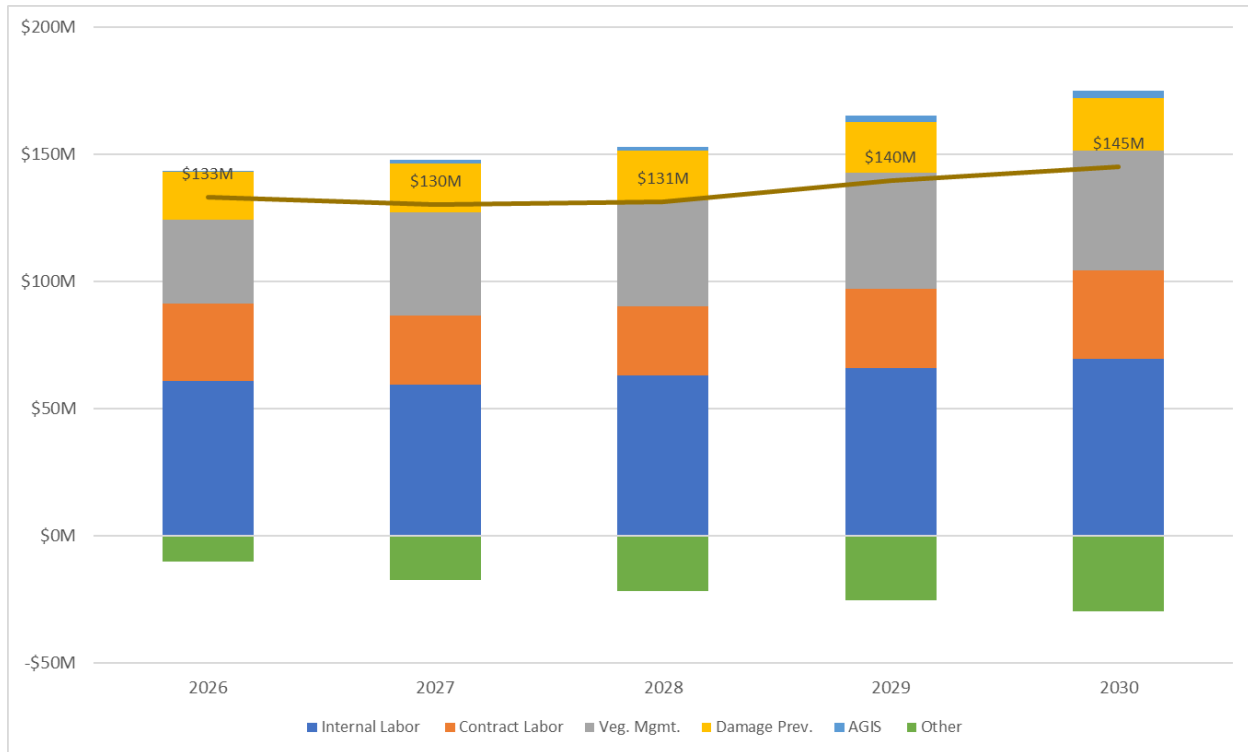
- \$ 1.9 billion is allocated to Age-Related Replacements and Asset Renewal, aimed at replacing aging infrastructure to maintain system reliability. Of this amount, \$845 million is dedicated to Wildfire Mitigation. This investment is essential to reduce the risk of catastrophic wildfires that threaten public safety, property, and service continuity. The program includes advanced situational awareness technologies for early detection, comprehensive vegetation management to reduce fuel sources, and targeted upgrades to harden assets against extreme conditions. These measures not only protect communities but also enhance grid resilience in the face of increasing climate-related challenges.
- \$1.2 billion is budgeted for System Expansion and Upgrades for Capacity, supporting anticipated load growth across the grid.
- \$500 million is directed to System Expansion or Upgrades for Reliability and Power Quality, focusing on projects that maintain or improve the reliability and quality of electric service. These projects aim to reduce outages, improve voltage stability, and enhance resilience against equipment failures and environmental risks

These investments represent a significant commitment to maintaining and modernizing the grid. They are designed to ensure safe, reliable service while supporting our broader goals of delivering excellent service, guiding with expertise, and keeping customer bills as low as possible—all while preparing the grid for a cleaner, more resilient energy future.

2. *O&M Budget and Forecast*

The Distribution O&M budget covers labor and material costs for maintaining, inspecting, installing, and constructing distribution infrastructure such as poles, wires, transformers, and underground electric facilities. It also includes vegetation management—ensuring proper line clearances, maintaining pole rights-of-way, and addressing vegetation-related outages—and damage prevention activities like locating underground facilities and complying with “Call 811” requirements to prevent accidental damage. Additionally, the budget includes fleet-related expenses (vehicles, trucks, trailers) and miscellaneous tools and materials needed to support the operation and maintenance of the electric distribution system. Figure 6 below provides an overview of our 5-year O&M budget for the distribution business unit.

Figure 6
Distribution O&M Expenditures Budget –
NSPM Electric 2025 – 2030 (Millions)



O&M expenditures associated with grid modernization and EV programs are presented separately as holistic initiatives; Other includes bad debt, First Set Credits, use costs, office supplies, janitorial, dues, donations, permits, etc.

Key O&M expenditures in the 2026-2030 distribution budget include:

- *Vegetation Management:* Annual increases of approximately 3 percent are expected to account for inflation and rising wages. In 2028, however, we are projecting an additional 7 percent increase due to anticipated higher labor costs after the expiration of our current contract at the end of 2027.
- *Internal Labor:* Most year-over-year increases reflect wage growth aligned with inflation. Additional increases are included to address staffing shortages in certain distribution work groups, as we work to close those gaps.
- *Other:* This category appears increasingly negative due to the First Set Credits process. Under this process, we purchase meters and transformers in bulk to secure supply and favorable pricing. These assets, along with their installation, are capitalized at the time of acquisition. As the equipment is installed, there are offsetting credits—resulting in a negative balance. The growing negative value reflects the high volume of meters and transformers needed to support both system growth and replacement of aging infrastructure as we rebuild and harden our distribution system.

We now turn to two areas of strategic investment—our targeted undergrounding and wildfire mitigation efforts.

C. Key Initiative Highlights

1. Targeted Undergrounding

As part of our commitment to delivering excellent service, Xcel Energy is launching a long-term reliability initiative focused on Targeted Undergrounding—a strategic effort to relocate high-risk overhead distribution lines underground. This program is designed to improve storm resilience, reduce outages, enhance public safety, and lower operational costs with aging infrastructure and elevated exposure to weather and vegetation-related risks.

Rather than full-scale undergrounding, which is often cost-prohibitive, we will use data-driven criteria—such as outage history, reliability metrics, and equity considerations—to prioritize segments where undergrounding delivers the greatest customer benefit. Our primary focus is on areas that have older distribution infrastructure with a high percentage of overhead lines—making them more vulnerable to outages caused by storms and vegetation.

Implementation will follow a phased investment strategy from 2025 to 2030, beginning with some limited initial projects and scaling to full deployment. Early efforts will focus on areas with high outage volumes and lower construction complexity, allowing us to refine engineering practices and engage stakeholders. Planned capital investments total \$233.7 million, as shown in Table 1.

Table 1: Planned Capital Investments (millions)

Year	Capital Investment
2025	\$1.5
2026	\$8.0
2027	\$25.0
2028	\$62.0
2029	\$67.5
2030	\$69.7
Total	\$233.7

Site selection will be guided by technical assessments and a third-party equity evaluation to ensure underserved communities benefit. Initial projects identified to-date span 59 cities and townships, primarily targeting single-phase backlot lines that are difficult to access and prone to long-duration outages. While our projects are still being finalized based on financial and practical considerations, we currently estimate that they will result in approximately 150 miles of undergrounded lines.² Further details on methodology, site selection, and

² This is a rough approximation and subject to change as planning progresses.

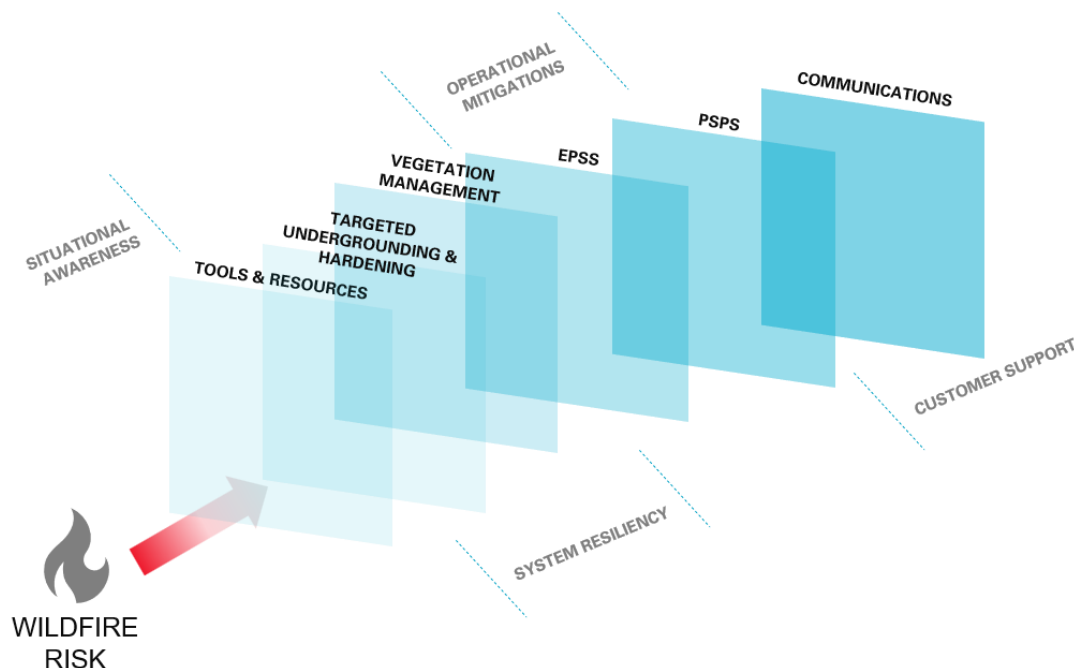
implementation strategy are provided in Chapter 2.

Benchmarking against peer utilities confirms the reliability and effectiveness of targeted undergrounding, with demonstrated improvements in outage metrics and customer satisfaction. This initiative represents a forward-looking investment in grid resilience, operational efficiency, and the high-quality service our customers expect.

2. *Wildfire Mitigation*

Xcel Energy's wildfire mitigation strategy reflects our commitment to delivering excellent service by proactively addressing emerging risks to grid resilience and public safety. While Minnesota's wildfire risk is lower than in western states, changing climate conditions such as increased drought, vegetation stress, and extreme weather require a comprehensive and forward-looking approach. Our strategy uses a layered defense model that integrates situational awareness, infrastructure upgrades, operational protocols, and vegetation management to reduce ignition risk and improve system resilience.

Figure 7: Wildfire Risk Layered Mitigation Strategy



We begin with advanced wildfire risk mapping, classifying areas into three tiers based on GIS analysis, expert judgment, and local insights (shown in Figure 8). This mapping identifies over 107,000 poles in Tier 2 and 4,700 in Tier 3, guiding targeted mitigation efforts ensuring resources are deployed where they have the greatest impact. All our mitigation efforts are focused exclusively on Tiers 2 and 3.

Planned capital expenditures for wildfire mitigation from 2025 to 2030 are outlined in Table 2 and described below.

Figure 8: Wildfire Risk Map

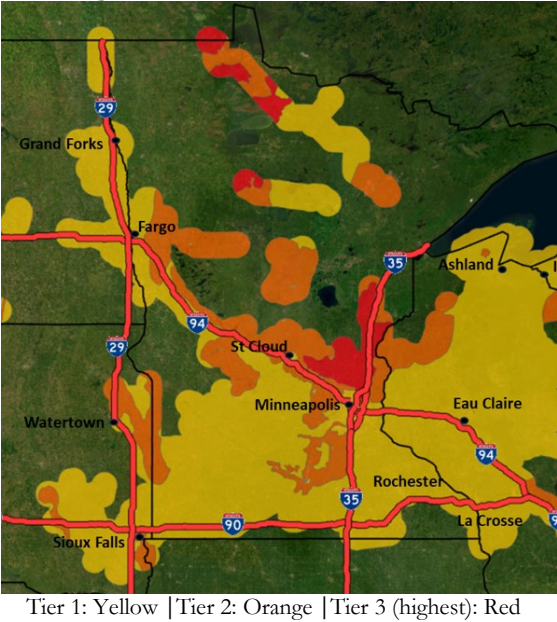


Table 2: 2025-2030 Wildfire Expenditures (Millions)³

Year	2025	2026	2027	2028	2029	2030
Capital	\$92.1	\$233.0	\$214.5	\$137.9	\$124.5	\$124.5
O&M	\$2.6	\$4.7	\$6.2	\$2.6	\$2.7	\$2.7

To enhance situational awareness, we are deploying 45 weather stations and 38 AI-enabled cameras in 2025, with additional installations planned for 2026. These technologies, along with advanced fire modeling and fault detection systems, enable early identification of ignition risks and faster response times. Infrastructure upgrades include drone-assisted inspections, LiDAR-based pole loading analysis, and replacement of vulnerable components with fire-resistant materials. We are also transitioning to Cal Fire-rated fuses and arresters to minimize spark risk during fault conditions.

Vegetation management remains a cornerstone of our strategy, with conductor clearance programs, defensible space creation, and hazard tree identification focused on high-risk areas. Operational protocols such as Enhanced Powerline Safety Settings (EPSS) and Public Safety Power Shutoffs (PSPS) are activated during elevated fire risk periods to prevent ignition and protect communities.

³ Table 2 presents the most current wildfire expenditures, which are also included in the rate case. These figures differ slightly from the wildfire allocations in our five-year capital budget because they were captured at different points in time. The capital budget reflects our July 2025 budget load, which has not yet been trued up.

Distribution system upgrades including small wire replacements, covered conductor installations, and deployment of nontraditional fault detectors not only reduce fire risk, but also improve reliability and system durability.

Our investments are aligned with our broader reliability goals and demonstrate our commitment to delivering safe, resilient, and high-quality service to all customers.

D. Stakeholder Engagement

As part of our preparation for the IDP filing, we prioritized meaningful and sustained stakeholder engagement. Over the past several months, we hosted a series of targeted workshops to gather input and share updates, including three sessions focused on Planned Net Loading, two on Cost Benefit Analysis, and two dedicated to distributed energy resource management systems (DERMS). We also held an IDP preview workshop to provide stakeholders with a comprehensive overview of our approach and progress. In total, we hosted eight IDP workshops, and to deepen engagement and broaden perspectives, we invited stakeholders to present at several workshops for the first time.

Beyond these workshops, we actively participated in several collaborative workgroup processes lead by Commission Staff in 2025. Of note was the development of a Framework for proactive distribution grid upgrades, which is expected to facilitate streamlined regulatory review and clearer pathways for cost recovery of certain investments. We expect these investments will closely align with our grid modernization goals and ultimately enable us to build a smarter, more resilient grid ahead of emerging challenges. The Company is submitting a proposal under the approved Proactive Distribution Grid Upgrade Framework concurrent with this IDP. We also continue to engage in the ongoing grid and customer security issues related to public display or access to electric distribution grid data, and the discussions regarding tariffs for distribution system cost sharing for interconnection in constrained areas. Through the Cost-Sharing Framework also being developed through a collaborative workgroup process lead by Commission Staff, we aim to reduce financial barriers, promote fairness, and support broader participation in Minnesota's clean energy transition.

E. Mobile Battery Certification Request

To support grid modernization and meet evolving customer needs, the Company requests certification of a mobile battery system. This flexible, deployable asset will temporarily address distribution system capacity constraints for new or expanding

customer loads, particularly when traditional infrastructure upgrades cannot be completed in time to meet emergent customer needs. The mobile battery will be stored in inventory and deployed to customer sites to reduce peak feeder loading by discharging during peak hours and recharging off-peak, until such time as sufficient permanent infrastructure is in place.

This proposal aligns with the Company's broader grid modernization strategy, including making interactions with our customers easier, delivering excellent service, anticipating future system needs, and considering policy guidance relative to customer offerings and the technological capabilities of the grid.

The mobile battery offers a reusable, scalable, and cost-effective near-term alternative to traditional upgrades. While no specific deployment site has been identified, the Company anticipates future needs based on load forecasts, including the accelerating pace of electrification. In some areas, demand may exceed the Company's ability to complete permanent upgrades in time, and the mobile battery is intended to bridge that gap. Although we have not historically experienced this specific circumstance, the rate of expected load growth combined with ongoing supply chain challenges for utility infrastructure presents a new issue—one that calls for flexible, innovative solutions like the mobile battery to maintain reliability and responsiveness. To ensure readiness, we must act now, given the long lead times associated with procuring this equipment.

We expect the total initial cost of the battery to be approximately \$6-\$7 million, with ongoing operating and maintenance costs of approximately \$35,000 per year. The Company respectfully requests the Commission certify this mobile battery system as serving the public interest under Minn. Stat. § 216B.2425, subd. 3(b). The mobile battery system we propose is necessary to modernize the distribution system, as defined in Minn. Stat. § 216B.2425, subd. 2(e), which states energy storage as one of the innovative technologies to “enhance reliability” and “enable demand response.” This battery will enhance reliability through temporary capacity relief and support of new or growing customer load; it will also support demand response by reducing the feeder peak – delaying the need for traditional infrastructure and avoiding other customer, onsite methods customers' may choose to use to meet their energy usage needs.

Finally, we respectfully request that the Commission streamline the certification process going forward in a way that better balances the need for innovation and flexibility with transparency and accountability. Specifically, we propose the following informational requirements to support the Commission's evaluation of whether the proposed project serves the public interest:

1. A description of why the project is necessary for grid modernization;
2. A description of the project's objectives and potential benefits to customers;
3. A cost range for the project; and
4. The expected timing for project implementation.

CONCLUSION

Effective distribution planning starts with having the right infrastructure in place at the right time to deliver safe, reliable service and support evolving customer needs. Since the first IDP in 2018, we have made foundational investments in technologies like AMI, ADMS, and advanced system planning tools to improve grid visibility, planning, and operational efficiency. Over time, our strategy has evolved to include smart technologies, asset health, and long-term system planning—ensuring today's grid remains dependable while building the grid of the future.

We take a long-term, expert-driven approach to system planning that balances reliability, affordability, and sustainability. Our goal is to deliver excellent service, keep bills as low as possible, lead the clean energy transition, and guide with expertise. The 2025 IDP reflects our commitment to modernize our distribution infrastructure while planning for a resilient, flexible grid that can meet future energy needs. We respectfully request that the Commission accept this IDP.

CHAPTER 1: SYSTEM PLANNING

The Distribution system is a critical component of the electric grid, facilitating delivering electricity to homes and businesses across the NSP–Minnesota service area. Distribution plays a vital role in providing excellent service by ensuring power is safe, reliable, and affordable. This includes connecting new customers, expanding system capacity to meet growing demand, restoring service after storms, and maintaining infrastructure such as poles, wires, underground cables, meters, and transformers.

Distribution is also leading efforts to modernize the grid—enhancing security, efficiency, and reliability; integrating more Distributed Energy Resources (DERs); supporting electrification¹; and enabling new customer products and services. These efforts are central to our commitment to the clean energy transition.

As a core business unit, Distribution directly impacts customers’ daily lives. Its investments are guided by the Company’s priorities: delivering excellent service, guiding our customers with expertise, leading the clean energy transition, and keeping bills as low as possible.

This Chapter outlines our approach to system planning, including load and DER forecasts, forecast scenarios, and our risk analysis process—featuring an evaluation of Planned Net Loading (PNL). For this year’s IDP, we have consolidated all forecasting information here to provide a more comprehensive view. We also present results from our DER forecast scenarios using LoadSEER.

I. OVERALL APPROACH TO SYSTEM PLANNING

Distribution system planning involves evaluating the electric grid’s ability to serve current and future electricity needs by analyzing historical and forecasted load levels and evaluating the capability of key components like substations and feeders. As our planning evolves, we continue to broaden our planning horizon to more affordably meet future needs.

In the past, the Company has generally observed gradual, localized load growth. Mitigation projects could be implemented relatively quickly, with longer lead times

¹ IDP Requirement No. 3 states: the following definitions are adopted for the purposes of these requirements. b) Electrification: the conversion of an energy-consuming device, system, or sector from non-electric sources of energy to electricity. This includes but is not limited to transportation electrification, cooking appliances, space heating and cooling, water heating, and industrial processes.

often limited to large construction projects. These were predictable and relatively homogenous load growth patterns that allowed the Company to plan for required upgrades.

By contrast, customers today are driving rapid, system-wide load growth that is diverse, and often in locations with minimal existing infrastructure. The need for short lead times to interconnection, even for very large connection requests like community solar or EV charging hubs, creates a much more complex planning optimization problem due to rapid, concurrent system-wide changes.

These new dynamics have required the Company to re-evaluate approaches to forecasting, planning, and operating the grid. This section outlines our current planning processes and highlights how we're advancing our capabilities and processes.

Our planning is informed by three high-level principles as indicated by Figure 1-1. First, the amount of change on the system requires foundational investments in infrastructure that unlocks new capacity. These investments are driven by our design standards, which balance the need to address existing risks while making investments today to meet long-term needs. Second, we must efficiently maintain and maximize the use of existing and planned infrastructure through asset health and reliability programs. Finally, we recognize that the available solution set for grid needs must include expanded consideration of non-traditional solutions such as non-wires alternatives (NWA's), virtual power plants (VPPs), and other options. When and where feasible and prudent, the Company aims to deploy these non-traditional solutions while recognizing that the distribution system is the backbone that requires investment to enable these solutions.

Figure 1-1 Distribution Planning Principles

Planning for the distribution system of the future requires an integrated approach to achieving multiple objectives.

Invest in Infrastructure



Based on our system design principles, aiming for lower system loading levels than can meet a diverse and evolving set of customer needs.

Maximize Infrastructure Life



Maximize the use of existing and new infrastructure through asset health and reliability programs.

Pursue Cost-Effective Alternatives



For example, DER, Load Flexibility, NWAs when and where feasible (with the right market signals), while also deploying grid technologies to help improve how we plan and operate the grid.

In evaluating the electric grid's ability to serve current and future electricity needs, one milestone of this evaluation is to identify where we anticipate risks in the short term or have observed risks in the past. Specifically, we seek to identify capacity constraints that could lead to overloads under normal ("system intact" or N-0) and single contingency (N-1) conditions. Normal operation assumes all equipment is functioning, while single contingency refers to the loss of a single element, such as a feeder or substation transformer.

Corrective actions may include building new feeders or substations, adding tie connections, rebalancing feeder phases, switching, installing regulators or capacitors, or upsizing transformers. As technologies mature, we continue to evaluate NWAs, discussed further in *Chapter 8: Non-Wires Alternatives*.

For each project, we develop scopes and associated cost estimates based on operational needs, technical feasibility, and future system demand. Projects are prioritized and funded through an annual budgeting process using a risk-ranking methodology. This process also allocates resources to other priorities such as asset health, grid modernization, and emergent issues—including storm response and mandated relocations of infrastructure for public projects.

In this section, we describe the Company's distribution system planning approach, including planning processes and tools used to develop the annual plans in compliance with IDP Requirement Nos. 3.D.2.m and 3.D.2.n:

- m. The results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology.*
- n. Information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for feeders and substation transformers that have a risk score or planned investment in the budget cycle in future IDPs.*

We conduct a comprehensive analysis of our distribution system each year, with additional assessments throughout the year as new information becomes available—such as changes in customer load or system conditions. Our annual planning process begins each fall, starting with a forecast of peak customer load and ending with the design and construction of prioritized, funded capacity projects, as outlined in Figure 1-2.

Figure 1 - 2
Annual Distribution Planning Process



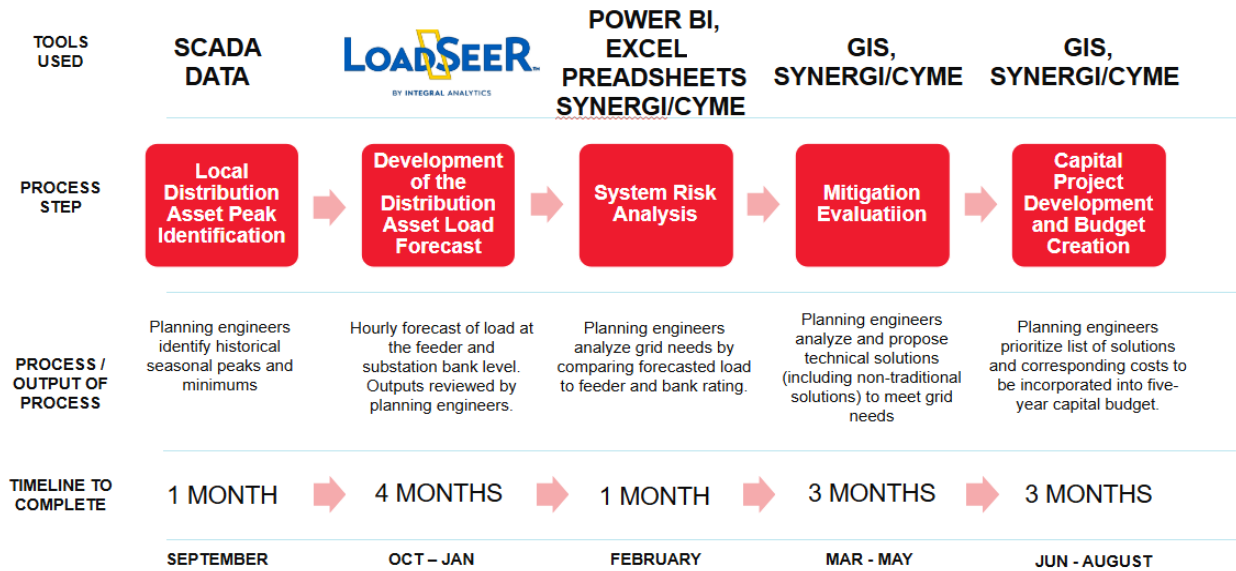
As part of this process, we thoroughly review existing and historical conditions, including:

- Feeder and substation reliability performance

- Any condition assessments of equipment,
- Current peak load versus previous annual peak loads,
- Quantity and types of DER,
- Total system load forecasts, and
- Previous planning studies.

Planning begins in Q4 using LoadSEER to forecast system loads. Risk analysis is then performed using those load projections. For this IDP, the planning process began in Q4 2024, using 2023 and 2024 actuals and system updates to forecast peak loads, with risk analysis based on the forecasted 2026 peak. Figure 1-3 below shows our annual distribution planning process.

**Figure 1-3
Annual Distribution Planning Process**



A. Current Planning Tools

Planning Engineers rely on a set of tools to perform the annual full system snapshot, ongoing distribution system assessments – including assessment of specific DER interconnections – and long-range area assessments. In this section, we discuss our current planning tools in compliance with the following requirement.

IDP Requirement No. 3.A.1 requires the following:

Modeling software currently used and planned software deployments.

Table 1-1 below summarizes the tools and how we use them in our planning process. We then discuss in more detail how we use each of the tools.

Table 1 – 1
Planning Tool Summary

Tool	Process	Description
Eaton CYME	Power flow	Contains a geospatially accurate model of the electric distribution Feeder system with known conductor and facility attributes such as ampacity, construction, impedance, and length to simulate the distribution system.
Integral Analytics LoadSEER	Medium to long-range load forecasting of major distribution system components, including feeders and transformers	Analyzes historical supervisory control and data acquisition (SCADA) and weather data to determine typical annual loading, and simulates impact of load and DER growth to develop a load forecast for feeders and substation transformers out 10-30 years. This is also the system of record for historical peak feeder and substation transformer load information.
Microsoft Excel Spreadsheets	Contingency planning	Analyze feeder and transformer contingency capacity by evaluating the available capacity on neighboring feeder ties and substation transformers for the forecasted years.
CYMCAP	Determines normal and emergency ampacity for Feeder circuit cables	Determines the amount of amps that can flow through cables for various system configurations, soil types, and cable properties before they are thermally overloaded.
Geographical Information System (GIS)	Provides the connectivity model source data to Synergi, as well as Feeder topology.	Contains location-specific information about system assets and components, allowing us to view, understand, question, interpret and visualize data in many ways that reveal relationships, patterns, and trends in the form of maps.
Distribution SCADA	Peak load forecasting	Monitors and collects system performance information for feeders and substation transformers.
WorkBook	Project prioritization	An internal tool used to help rank projects based on levels of risk and estimated costs.
PI Datalink	Load forecast	Tool used in conjunction with Excel to help us determine our minimum loads, as well as our gross peak and minimum loads for feeders and transformers that have generation on them.

Additionally, we outline our hosting capacity tool that is not currently part of the annual system planning process in Table 1-2. Table 1-3 provides a tool summary in relation to the distribution planning process.

Table 1-2
Hosting Capacity Tool

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

Table 1-3:
Tool Summary by Distribution Planning Process

Tool	Planning Process Component						Hosting Capacity
	Forecast	Risk Analysis	Mitigation Plans	Budget Create	Initiate Construction - EDP Memo	Long-Range Plans	
CYME			X			X	X
LoadSEER	X	X				X	
MS Excel		X		X		X	
CYMCAP		X					
GIS			X			X	X
SCADA	X						
WorkBook		X	X	X	X		
PI Datalink	X						
DRIVE							X

CYME. CYME is a distribution planning tool used for modeling and analysis of electrical distribution networks. It is used to perform load flow, fault, and protection coordination studies. CYME supports the hosting capacity analysis process by creating models for the DRIVE tool. It also plays an important role in the DER

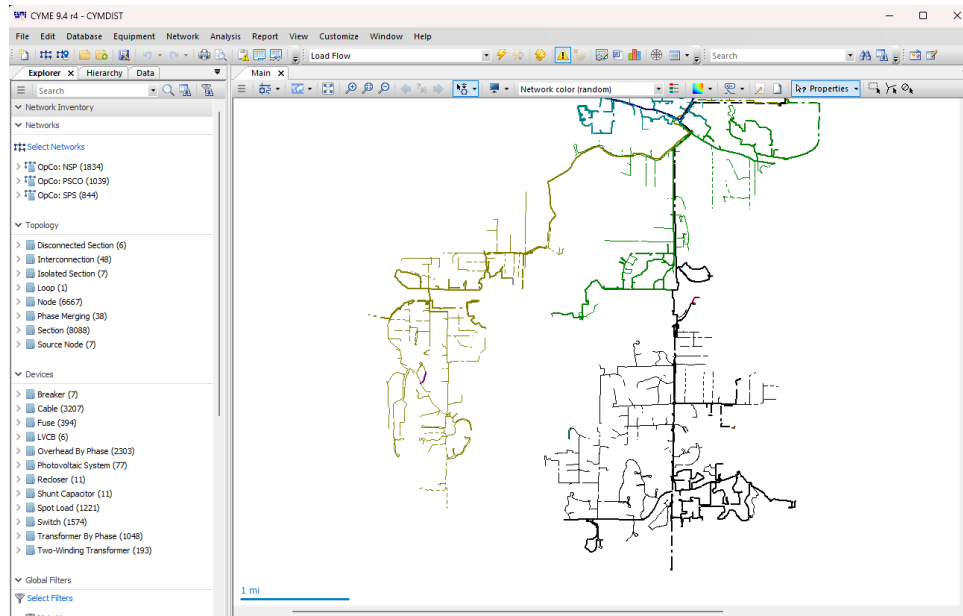
interconnection screening and study processes and in verifying available capacity for new business. CYME can be used to model a variety of different scenarios that can occur on the distribution system, understand their impacts, and design solutions such as reconfigurations, deployments of advanced technologies, or construction of new power lines.

CYME Gateway, Eaton's data transformation and ingest tool, imports data from enterprise systems such as GIS and SCADA to automate creation and updates of models. This process allows for grid equipment such as lines, transformers, switches, fuses, and capacitor banks to be extracted from GIS and modeled in CYME. This process requires ongoing support from the Company and Eaton as new data sources are needed and as existing data sources evolve over time.

The Advanced Project Manager (APM) module allows for changes and corrections to be tracked and stored separately from the base network and equipment model. This is used to make the model clean-up process more efficient, because it allows for modifications to persist between data refreshes while corrections are being made in sources systems. It is also used for designing and managing detailed representations of planned distribution system upgrade projects.

CYME also has capabilities for scripting and customization, which allow for increased efficiency of complex engineering analysis. It offers more flexibility and control when analyzing non-standard scenarios, importing data for ad-hoc simulations, or running computationally intensive studies.

Figure 1 - 4
CYME Application Example



Integral Analytics LoadSEER (Figure 1-5). We use LoadSEER for medium- to long-range load forecasting of distribution feeders and substation transformers. The LoadSEER system is the historical peak system of record for those distribution elements. LoadSEER also analyzes historical SCADA, customer billing, and weather data to determine the typical annual hourly loading on each feeder and substation transformer. The tool combines this typical loading with a simulation of load and DER growth to develop an annual load forecast up to 30 years into the future.

Once our forecasted loads are updated every year, we use LoadSEER to create a peak substation load report for Transmission Planning and Transmission Real Time Planning. We also use these forecasts in our risk analysis evaluation, long range plans, and to populate models in CYME for various purposes. LoadSEER is also a repository for feeder and substation transformer capacity limits that we use to identify areas of the system where there are capacity constraints. These limits are also passed on to Distribution Operations to ensure the correct notifications occur in the Control Center for any potential overloads.

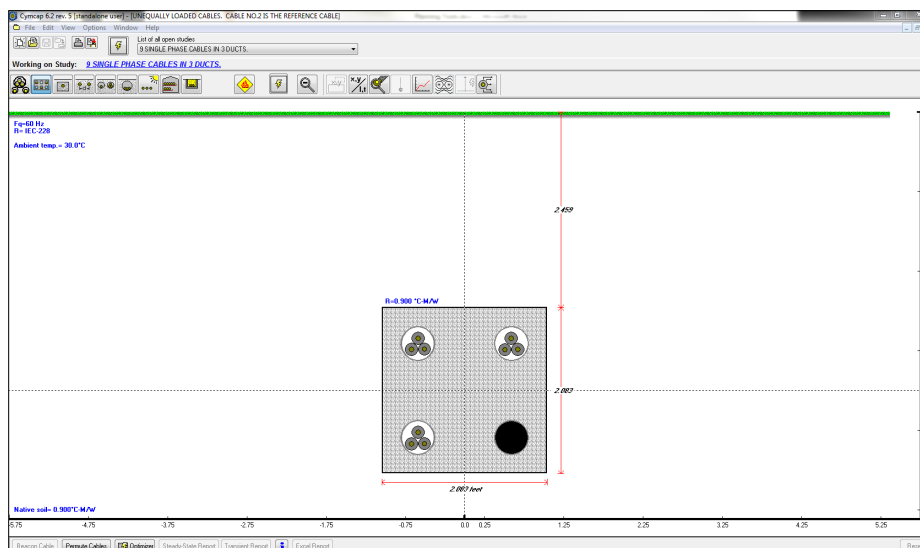
Figure 1 – 5
LoadSEER Application Example



Microsoft Excel Spreadsheets. We use Microsoft Excel spreadsheets to perform feeder and substation transformer contingency planning. A key part of distribution planning is identifying risks, not only for normal operating situations, but also for situations where the system is in a contingency state (i.e., when the system is not whole). This helps in creating a system with flexibility. To do this, we use a series of spreadsheets that include the tie points to other feeders and the capacity that is available at peak times through those tie points. While this is a fairly simple tool, these spreadsheets provide valuable information about our system, which we use to perform engineering analyses. These Excel spreadsheet-based tools are anticipated to be phased out with the development of more advanced tools such as Power BI and Databricks as discussed later.

Eaton CYMCAP (Figure 1-6). Planning Engineers use CYMCAP for determining maximum normal and emergency feeder circuit cable capacities. This helps to determine the amps that can flow through a given cable before it is thermally overloaded (ampacity). CYMCAP considers appropriate factors in determining these values, such as duct line configuration, soil conditions, and cable properties. Unlike overhead conductors that are exposed to the air and wind, underground cables have a tougher time dissipating heat. To ensure the cables are not overloaded, we model the true ampacity of them with the help of this program.

Figure 1 – 6
CYMCAP Application Example



General Electric Smallworld Geospatial Information System (GIS). Our GIS contains location-specific information about system assets and provides connectivity model source data and feeder topology to CYME, as well as other data to many other applications within the Company. The GIS allows us to view, understand, question, interpret, and visualize data in many ways that reveal relationships, patterns, and trends in the form of maps.

GIS is also very helpful in capturing changes to the distribution system that may not always be visible to all. For example, we rely on GIS to show changes that would occur as the result of a new Community Solar Garden (CSG) installation. Any upgrades to the feeder that occurred as a result of that addition plus the details of the new CSG itself, would be added into GIS. This would then be used to update our CYME models for accurate modeling going forward.

Distribution Supervisory Control and Data Acquisition. Our SCADA system provides information to control center operators regarding the state of the system, provides appropriate alarms (including outage notifications), and provides for remote control of substation and certain field equipment. For operational purposes, every few seconds, it provides system status information, such as operating parameters for our generation and substation facilities. It monitors and collects system performance information for feeders and substations used to ensure the system is safely and efficiently operating within its capabilities. This performance information is also used

by planning engineers to perform load and operating analyses to establish system improvement programs that ensure we adequately meet load additions and continue to provide our customers with strong reliability.

For feeders where we have SCADA capabilities, we can monitor the real time average or three phase amps on the feeder for operational purposes. For planning purposes, the SCADA system typically collects enough information throughout the course of a year to determine daytime minimum load and peak demands for all feeders that have this functionality. However, it takes some manual effort beyond collecting the data to adequately decipher those values.² The data is maintained in a data warehouse and combined with the historical LoadSEER hourly load data. When three phase Ampere data is available, we use the highest recorded phase measurement to determine facility loading. We discuss feeder load monitoring and SCADA further in *Chapter 4: Distribution System Statistics*.

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

PI Datalink. This Microsoft Excel add-in provides SCADA information from our equipment in the field. We utilize the data from this tool in our analyses for load forecasting, minimum daytime loads, and CSGs. By having this tool in Microsoft Excel, we are able to streamline complex and repetitive calculations. As a result, we gain better visibility of the distribution system which in turn enables us to make more informed decisions about how to mitigate risks. It's important to recognize that the analysis that we perform using this tool is limited by the availability of high-quality reliable data, which is decreasing as we continue to add DER to our system. Additionally, we are limited in scale of data by the computation power of Microsoft Excel. Some of the tools described below are anticipated to address these challenges.

² This manual effort involves factoring out our minimum loads during non-daytime hours, adjusting for daytime minimum loads that occur under abnormal configurations, and eliminating other erroneous data possibly due to faults, other disturbances on the feeder, or DER.

Salesforce: Used to track customer interactions, service requests, and DER interconnection inquiries. Salesforce is the “source of truth” for DER interconnection information and provides vital data about DERs in the field and in queue for interconnection. Salesforce data is integrated into planning workflows to determine existing and queued DER for calculating the Technical Planning Standard (TPS), perform HCA, and support customer-centric planning.

B. Continuing Development of Planning and Analysis Capabilities

The Company has made strides since the filing of its last IDP regarding better integrating our planning processes across functional groups as well as leveraging technology to better understand, anticipate, and plan for the needs of our system. Many of these new expectations are being directly driven by the way in which our customers choose to interact with the grid.

1. Leveraging Bottom-up Forecasting to inform Integrated System Planning

The Company developed the Base Forecast for this IDP and corresponding capital budget for capacity investments using a granular, locationally specific forecasting methodology that includes targeted forecasts of adoption (and the corresponding load modifying impacts) of various distributed energy resources, beneficial electrification, etc. Moving forward, it will continue to be necessary to plan at this level of granularity. These processes will be the foundation of broader energy system load forecasting that feeds into the Company’s generation and transmission planning processes. We expect this trend to continue as we further learn new methods of cross-system optimization and better ways to leverage technology to operate our system. We intend to update our planning framework as technology and analysis practices mature.

2. Leveraging technology and data and analytics to inform planning and forecasting

Many of the changes on our system are occurring at the edge of our grid. This is an area into which utilities historically have had limited visibility. However, as the Company continues to deploy new technology and advanced metering infrastructure (“AMI”) across our service territory, we are beginning to leverage AMI data to further enhance our load forecasting, planning, and DER interconnection capabilities and processes.

Foundational to this effort is centralization of data through what the Company refers to as a “Xcel Data Fabric”, which was formerly known as the Universal Data Platform, an enterprise analytics and AI platform designed to unify data across domains for advanced insights, governance, and scalability. The Company is already leveraging AMI meters and data to support several use cases that provide planning and operational benefits as described in more detail in the Grid Modernization and Grid Innovation section. In addition, the Company is continuing to explore ways to leverage AMI meters; a few examples under consideration include:

- AMI meters enable more timely visibility to support outage detection and grid loading as well voltage monitoring and power quality.
- AMI data enables better understanding of customer load patterns for planning and optimization.
- Proactively identify stressed distribution assets.

The Company is also pursuing the development of several tools to further aid in data processing (some of which are mentioned below). These tools, methods, and practices in addition to enhancing our planning and operation processes, will give us the ability to better understand our system and allow us to dynamically plan for and operate our system in the future. Rather than utilizing a snapshot of system conditions, the ability to conduct more detailed modeling in conjunction with technologies like DERMS could allow us to offer more flexible connection options to customers including use cases like flexible interconnection and flexible load connections.

3. Exploring Machine Learning Applications for Data Processing

The Company is in the early stages of leveraging operational data in conjunction with Machine Learning. We are also exploring the development of new software tools that offer the potential to facilitate integrated planning across historical seams between transmission, distribution, and the gas system. One intent of these tools is to incorporate the granular adoption of technologies (DERs, BE, EVs, etc.) early within the load forecasting process, allowing a more consistent view of changing load patterns. Incorporating these technology adoptions early on, without losing granularity, allows for their impact to be equally represented across financial and planning applications.

Internal development of “propensity to adopt” models for load modifying technologies also presents the opportunity to directly evaluate their alignment with adoption within the Company’s service territory. Initial models for the Company’s

Colorado service territory for propensity of solar, electric vehicles, and all-electric space heating yielded an AUC ROC³ ranging from 0.84 for space heating to 0.9 for EV and solar. The results seen for these adoption models indicate a strong likelihood that models are reliably characterizing adopters, providing confidence that they can be used to identify likely new adopters. The ongoing extension of these models to the Minnesota service territory should build on this same framework and is expected to yield similar results.

4. *Ongoing Tool Development*

The Company is also informing the Commission and stakeholders about several new tools and capabilities that have begun development as of the last IDP and that will be essential for advancing integrated planning and grid operations. While the Company is not seeking Commission approval of these tools, they are nevertheless important milestones in continuing to evolve our capabilities in line with our vision.

Electric Distribution Data Inspection and Estimation (EDDIE): A machine-learning-based tool designed to supplement SCADA cleaning efforts. Specifically, when available data shows artifacts indicating that the data may not be reliable (indication of bad reading, loss of signal, etc.) EDDIE flags these data for investigation by an engineer. Then, EDDIE allows the engineer to select historical data that is then used to train a machine learning model. This ML model combined with weather modeling (when appropriate) is used to approximate the flagged data. It's important to note that all of this is guided by experienced engineers who are familiar with the data source and intimately understand what is reasonable for a given feeder. Additionally, the Company is working towards addressing those upstream data issues to increase the reliability of our raw data. EDDIE will be an important tool as the number of devices which need to be metered and accounted for in models grows.

Databricks and Power BI: Databricks is a cloud-based analytics platform used to process large datasets, including AMI, SCADA, and DER metering data. Databricks supports

³ AUC ROC refers to the “area under the curve” for the receiver-operating characteristic curve, a common representation of the performance of classification models. In classification models, whether a data point is put into one class or another depends on where between 0 and 1 modelers set the threshold between the two classes. The rate of true positives and false positives will vary based upon that threshold and, as such, the accuracy of the model depends on relationship between those two metrics. The area under the curve captures that relationship across all possible thresholds. A model that assigns classes purely randomly would achieve an AUC ROC of 0.5, while a value of 1 indicates perfect classification. Further visualizations of this concept can be found here:

<https://developers.google.com/machine-learning/crash-course/classification/roc-and-auc>

scalable data engineering workflows and enables advanced analytics for planning engineers. This will be used in combination with Power BI as the platform for modernizing most of the Excel spreadsheet tools currently being used.

Grid Visibility Tool (“GVT”). GVT is a tool the Company built that uses AMI interval and event data with GIS asset information to help visualize grid information such as power quality information, transformer and feeder loading. GVT is a transformational tool that provides the Company visibility to energy usage, power flow, power quality, and meter events at customer meters and distribution transformers that previously was not possible. This will enable more proactive planning and operations on this portion of the distribution system that include identification of overloaded transformers and power quality issues that will support more proactive and improved service quality for customers.

Gridsight is a software and analytics firm that was founded in Australia. Gridsight has been helping distribution network operators in Australia leverage data and analytics capabilities to better assess the potential for network flexibility and associated mitigations like flexible interconnections. Both of these concepts are foundational to supporting higher-levels of DER penetration on the distribution system as already demonstrated by the strategies implemented by utilities in Australia to support higher small DER solar penetration in Australia.

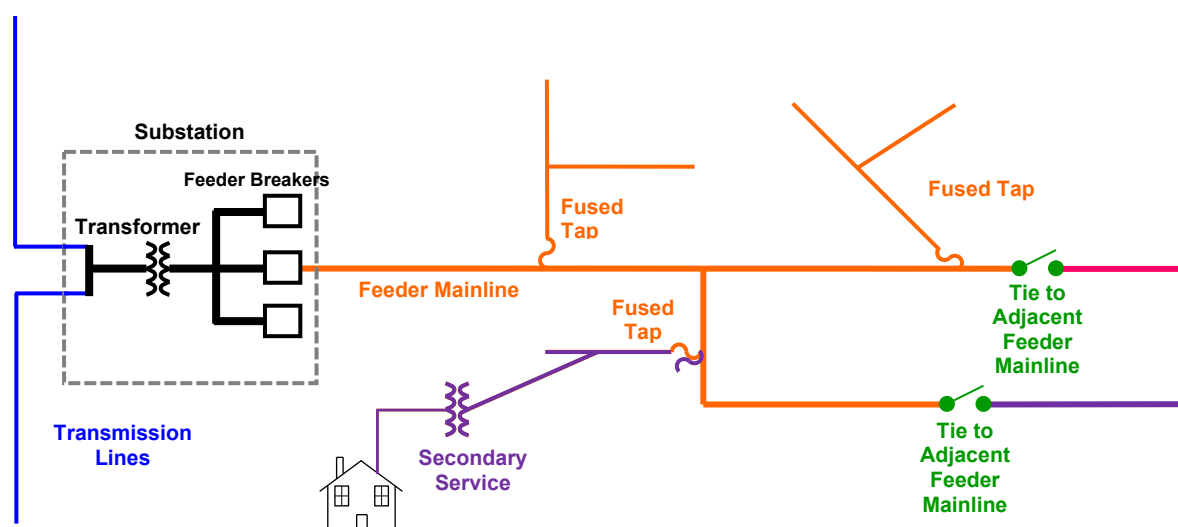
AMI Informed Load shapes. The Company is working to leverage data from Advanced Metering Infrastructure (AMI) to refine hourly electric load models for emerging customer technologies. By comparing 15-minute interval consumption data from before and after a technology is adopted at a specific premise, the company can enhance previously developed energy usage models. Technologies that benefit from AMI-informed load shapes include electric vehicle charging, electrified space and water heating, and behind-the-meter storage. Currently, this work is limited by the small sample size of customers with both AMI meters and sufficient pre- and post-installation data. However, as more customers with AMI meters adopt these technologies, data availability is improving.

C. Feeder and Substation Design

Distribution feeders for standard service to customers are designed as radial circuits, as illustrated in Figure 1-7. Therefore, the failure of any single critical element of the feeder causes a customer outage. This is an allowed outcome for a distribution system, within established standards for reliability, which typically measure the average

duration (System Average Interruption Duration Index or SAIDI) and frequency (System Average Interruption Frequency Index or SAIFI) of interruptions. The distribution system is planned to generally facilitate single-contingency switching to restore outages within approximately one hour or if the feeders are FLISR enabled, they are restored immediately. Foundational components in distribution system design and planning are substations and feeders.

Figure 1-7
Distribution System Basic Design Schematic of
Typical Radial Circuit Design



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

Cost considerations include the transmission and distribution capital investment in the lines, losses (which are generally proportional to line length), land cost, and space to accommodate growth. Customer service and reliability implications include line length

and route, integration with the existing system, access, and security. Over time, transformers and feeders are incrementally added within the established footprint until the substation is built to its ultimate design capacity. Higher levels of DER affect substation capacity, system protection, and voltage regulation.

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

Feeders typically serve approximately 1,500 – 8,000 customers, though this varies based on voltage, location, customer load density, and the utilization of the feeder. The industry benchmark for feeder capacity is approximately 600 amps, which provides an efficient balance of the costs of conductors, capacity, losses, and performance. This translates to a maximum load-serving capability of about 15 megavolt amperes (MVA) on 13.8 kV feeders, and 37 MVA on 34.5 kV feeders.

D. Planning Criteria and Design Guidelines

We plan, measure, and forecast distribution system load with the goal of ensuring we can serve all electric load under normal and first contingency conditions on each and every distribution asset that we forecast for. Our goal is always to keep electricity flowing to as many customers on the feeder as possible and to deliver affordable, safe, and reliable solutions when we anticipate any challenges in serving customers. Designing our system for adequate first contingency capacity allows for restoration of all customer load by reconfiguring the system by means of electrical switching, in the event of the outage of any single element. For example, we generally strive to utilize feeders to our planned loading limits, which provides back stand capacity that can be used to interconnect new customers more quickly, as well as provide increased operational capability and carry the load of adjacent feeders during first contingency N-1 conditions.⁴

⁴ The five-year budget presented in *Chapter 6: Distribution Financial Information* reflects the funding necessary to bring Minnesota feeder loading within this guideline.

The planned loading limits are 75 percent of normal capacity for 15kV class feeders (e.g., 12.47kV, 13.2kV, 13.8kV) and 50 percent for 25kV and 35kV class feeders. The lower planned loading limits for higher voltage classes reflect the unique two-feeder configuration of most 25/35kV substations. These feeders are often used to cover longer distances, making them well-suited for outstate regions, but this extended reach also limits the number of available field ties for contingency support.

The planned loading limits serve as a guiding principle that enables consistent evaluation across the system and provides a scalable abstraction for complex analyses—such as in long-term studies or in dense metro areas with network feeders. In practice, we regularly load feeders beyond the planned loading limit with analysis from engineering determining where risks may be present and mitigations are necessary. Additionally, when designing a mitigation, we seek to achieve the planned loading limits to ensure the solution meets the design needs for the life of the solution. These thresholds are flagged in our planning tools and processes to ensure that higher loading levels are carefully assessed and mitigated when doing so is determined to be prudent.

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

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

- Voltage at the customer meter is maintained within five percent of the customer's nominal service voltage, which for residential customers is typically 120 volts.
- Voltage imbalance goals on the feeder circuits are less than or equal to three percent. Feeder circuits deliver three-phase power from a distribution substation transformer to customers. Three-phase electrical motors and other equipment are designed to operate best when the voltage on all three phases is the same or balanced.
- The currents on each of the three phases of a feeder circuit are assessed and the

load rebalanced as a first solution to reduce the risk of overload or address a voltage issue. When phase currents are balanced, more power can be delivered through the feeders, and this is generally a more affordable mitigation than the construction/reinforcement of infrastructure.

- Under system intact, N-0 operating conditions, typical feeder circuits should be loaded to less than the planned loading limit unless higher loading is determined to be prudent by engineer analysis. We developed these limits to help ensure that service to customers can be maintained in an N-1 condition or contingency and provide space for typical continuous load growth. If feeder circuits were loaded to their maximum capacity and there was an outage, the remaining system components would not be able to make up for the loss, because adding load to the remaining feeder circuits would cause them to overload. Additionally, if a new customer sought interconnection to a feeder loaded to 100 percent, the lead time for interconnection could be substantial and could impact their business/livelihood.

All distribution system equipment has capacity, or loading, limits that must factor into our planning processes. Exceeding these limits stresses the system, causes premature equipment failure, and results in customer outages. Our planning processes primarily focus on the substation and feeder levels but also consider limitations and utilization of other system components such as cable, conductors, circuit breakers, transformers, and more. The granularity of our analysis will continue to increase (i.e. include more components in our capacity analysis) with the development of future technologies and workflows.

Spatial and thermal limits restrict the number of feeder circuits that may be installed between a distribution substation transformer and customer load. Consequently, this limits substation size. Normal overhead construction is one feeder circuit on a pole line; high density overhead construction is two feeder circuits on a single pole line (double deck construction). In circumstances where overhead feeder circuit routes have reached maximum capacity, where enhanced reliability is required, or where underground installation is mandated or preferred by local permitting authorities or municipal governments, the Company evaluates the installation of underground conduit within established utility easements as the most practical and cost-effective alternative to meet distribution system needs.

Thermal limits require certain minimum spacing between multiple feeder circuit main line cables to avoid mutual heating and allow for sufficient cooling. Thermal limits for primary distribution lines are defined in our Electric Distribution Standards. When we

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

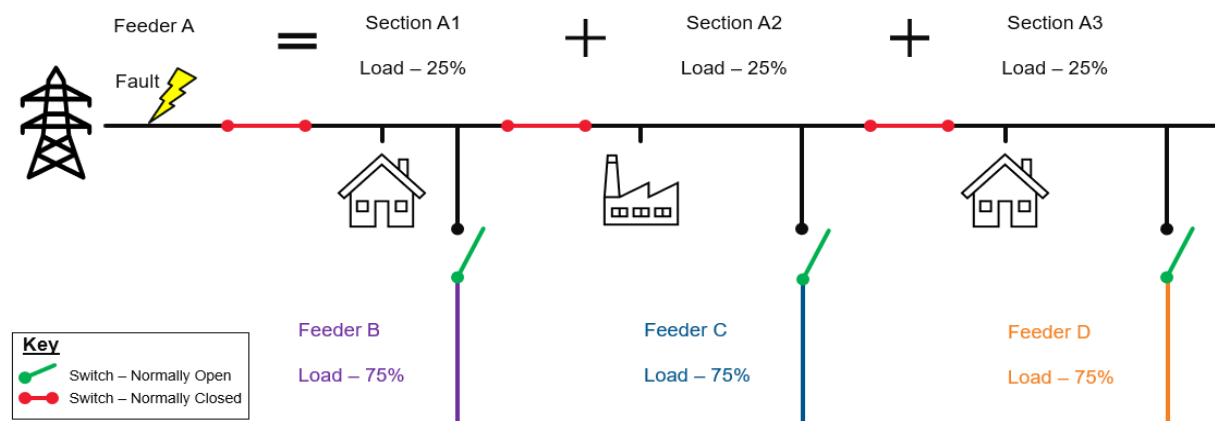
When feeder cables are concentrated, they are typically installed underground in groups of pipes encased in concrete, known as *duct banks*. Cables in duct banks experience mutual heating, which imposes more severe thermal limits compared to individually buried underground feeder circuits. To account for this, Planning Engineers use software tools to determine the maximum N-0 and N-1 capacities for feeder circuits installed in duct banks.

When existing duct lines are full and no additional space is available in utility easements or street rights-of-way, routing options from a substation to the distribution load become exhausted. In such cases, new facilities must be constructed from a different location to serve the load.

To maintain a robust distribution system capable of operating under first contingency (N-1) conditions, planning criteria aim to keep feeder utilization rates at or below the planned loading limit. To assess system robustness over time, Planning Engineers analyze both historical and forecasted utilization rates. For broader area studies, they generally apply the planned loading limits, as it is often impractical to perform detailed section and tie-transfer breakdowns for each individual feeder—an approach reserved for the annual planning process.

These breakdowns are highly specific to the geography and topology of individual feeders, making it easier to compare solution options using a consistent planned loading limit. Figure 1-8 illustrates this concept using a 75 percent planned load limit for a mainline feeder, with three sections each loaded to 25 percent of total capacity. Green and red symbols represent switches that can isolate or connect feeder sections in the event of a fault. In such cases, the substation breaker isolates the faulted feeder, and section switches are operated to maintain service to unaffected customers while repairs are made. This process is similar to FLISR operations, though FLISR requires more granular engineering analysis during implementation.

Figure 1-8
Typical Mainline Distribution Feeder with Three Sections Capable of System
Intact N-0 and First Contingency N-1 Operations
Mainline Feeder No. 1



In this circumstance, Feeders A to D all have the same rated capacity – and are all loaded to 75 percent – so each of the feeder sections can be safely isolated and transferred to adjacent Feeders B, C, and D through the corresponding tie switches. This reconfiguration results in Feeders B, C, and D each being loaded to 100 percent (i.e., their original 75 percent, plus the transferred 25 percent from the adjacent Feeder A sections). This reconfiguration capability maintains electric service to customers while we repair the fault to the feeder and return the system to normal operation.

Area studies are typically initiated on a case-by-case basis, when Distribution Planning identifies a high number of individual risks or loading constraints within a localized area. These localized area studies vary in size, scope, and scale based on the issues identified, and can encompass a single substation, an entire city, or an entire geographic region. When a planned load limit is applied in an area study, it provides an efficient means of approximating how much additional capacity is needed in that area. When the total feeder circuit utilization within the study area exceeds the planned load limit (as calculated using the equation shown in Figure 1-9 below), it is generally no longer sufficient to perform more simple solutions – such as feeder reconfigurations or installing new feeder tie connections between existing feeders.

Figure 1-9
Total Feeder Circuit Utilization in Study Area

$$\text{Total Feeder Circuit Utilization} = \frac{\sum \text{Feeder Circuit Load in Area}}{\sum \text{Feeder Circuit Capacity in Area}}$$

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

While keeping loading under the planned loading limit is ideal, it may not be feasible or prudent depending on system configurations. Feeder utilization in Minnesota is on average 63 percent; approximately 35 percent of the feeders are above planned loading limit. When we analyze feeders and transformers, we use the specific loading and configuration to determine the N-0 and N-1 overloads. Because of the wide variety of system configurations, the evaluation may show certain transformers or feeders may be loaded to higher utilization without causing an N-1 overload. The opposite could also be true due to the sparse topology of certain outstate areas. Regardless of whether an N-1 risk is present if a 15kV class feeder is loaded beyond the planned load limit, any new load seeking >3MVA will need to have another feeder installed and likely would face an extended lead time for interconnection.

Distribution systems that start out with adequate N-1 and N-0 capacity can quickly progress beyond isolated overloads when a large part of the distribution system is redeveloped, or focused redevelopment is targeted in an area or along a corridor. After examining feeder circuit peak demands, we look at the loading levels for the transformers housed at the substations.

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

Engineers to determine normal and single-cycle transformer loading limits that Planning Engineers use for transformer loading analysis.

A transformer's normal loading limit, known as its *loadability*, represents the maximum load it can safely handle over any duration. In contrast, the single-cycle loading limit refers to the maximum load a transformer can safely carry during an emergency for one load cycle (typically 24 hours). This limit is used in substation transformer N-1 contingency analysis.

If internal temperatures exceed design thresholds, the transformer may suffer irreparable damage, commonly referred to as *loss-of-life*. This term describes the accelerated aging and degradation of transformer components, leading to premature failure. A transformer's design life depends on the durability of all its internal parts. Most substation transformers consist of high-voltage and low-voltage coils, electrically insulated and submerged in oil. As load increases, so does heat generation; excessive heat can damage insulation and internal connections. Engineers monitor hottest-spot temperatures and top-oil temperature limits to ensure safe operation.

In multi-transformer substations, each transformer's peak load is non-coincident, meaning peak usage occurs at different times across transformers. This is due to each transformer serving multiple feeder circuits with varying load profiles. As a result, a transformer's peak load is typically less than the sum of the peak loads of its associated feeder circuits.

Using the planning criteria described above, Planning Engineers evaluate transformer and feeder loading to identify risks under both normal and contingency conditions. In response to the Minnesota Public Utilities Commission's July 26, 2022 IDP Order (Docket No. E002/M-21-694), the Company has begun prioritizing the use of net load in its forecasting processes.⁵ Unlike *native load*, net load accounts for the impact of distributed energy resources (DERs) in reducing demand at the substation level. Following Order Points No. 17 and 18 of the Commission's September 24, 2024 Order, the Company has continued stakeholder engagement and adopted the Planned Net Load methodology in its 2023 planning cycle. This approach allows planners to account for reduced risk at certain substations and feeders due to existing DERs. Further details on this methodology are provided in Section III.B.

⁵ Order Point No. 6 outlines the topics covered in the required stakeholder series. Order Point No. 6.f states that the stakeholder series should include the topic of "Prioritizing the use of "net load" in its load forecasts and system planning, including developing a methodology for incorporating the load reducing impact of distributed generation into its load forecasts and system planning process."

II. INTEGRATED SYSTEM PLANNING

IDP Requirement No. 3.A.5 requires the following:

Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans, including:

- a. Setting the forecasts for distributed energy resources and electrification consistently in its resource plan and its IDP.*
- b. Conducting advanced forecasting to better project the levels of distributed energy resource and electrification deployment at a feeder level, using Xcel's advanced planning tool.*
- c. Proactively planning investments in hosting capacity and other necessary system capacity to allow distributed generation, electrification, and electric vehicle additions consistent with the forecast for distributed energy resources and electrification.*
- d. Improving non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources.*
- e. Planning for aggregated distributed energy resources to provide system value including energy/capacity during peak hours*

In this section, we discuss the overall planning landscape and evolution of our integrated system planning approach. Then, we address each subpart of IDP Requirement No. 3.A.5.

Achieving the goal of a sustainable, clean energy future depends upon having sufficient infrastructure to support delivery of renewable and distributed generation resources and customer reliability. Modernized transmission and distribution systems are critical to our ability to serve our customers in a reliable and safe manner, deliver growing levels of choice, increase renewable energy, meet the challenges of emerging technologies, and take a holistic view of resource planning.

As we actively prepare our distribution system for the needs of the future, we consider the need for thoughtful investments to meet our core obligation: safely and reliably delivering energy to our customers. We are also focused on adopting smarter technologies to further enable DER on our system. Additionally, we face new challenges and opportunities for the transmission grid as traditional baseload units retire, large scale renewables significantly increase, and DERs are increasingly adopted. In some cases, such as increasing consideration of distribution-level DER

impacts on the transmission grid, changes in the market and planning constructs are underway.

Overall, we envision continuing to build on our planning capabilities for an integrated grid that supports the Company's clean energy transition, leveraging the strength of an interconnected system to make the best use of available resources while continuing to serve our customers with resilient and reliable power. We also envision a highly integrated operating technology environment.

This need for long-term planning that considers the impacts of generation, transmission, and distribution on each other spurred the creation of the Integrated System Planning (ISP) business unit within the Company. The purpose of ISP is to develop generation, transmission, distribution, and natural gas infrastructure investment plans that deliver on the Company's sustainability goals while keeping bills low and delivering excellent service. ISP also bridges the gaps between modeling tools with human processes in addition to tackling challenges of the overall planning landscape, such as inflection points with technologies – such as EVs and beneficial electrification – and pricing. The Company's, and indeed the industry's, exploration of integrated planning frameworks is nascent and will continue to evolve and improve as we make progress toward a clean energy future and our vision to lead the clean energy transition.

Below, we address each subpart of IDP Requirement No. 3.A.5.

A. 3.A.5.a - DER Forecast Consistency

IDP Requirement No. 3.A.5.a requires discussion of planning modifications or changes to improve coordination and integration between the IDP and the Integrated Resource Plan (IRP), including:

Setting the forecasts for distributed energy resources and electrification consistently in its resource plan and its IDP.

While forecasting plays a role in both the IRP and IDP, the processes are fundamentally different and serve disparate functions. The IRP process is a long term (15-year) resource planning process that has been in place for decades and is governed by established Minnesota Statutes and Rules (which result in Orders that constitute prima facie evidence in other proceedings). Similarly, transmission planning is largely governed by the Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) requirements and overseen by the

Midcontinent Independent System Operator (MISO). The IDP process is nascent by comparison – intended to be informational in nature – and is based on a set of reporting requirements that the Commission has established on a utility-by-utility basis. While IDP requirements may change over time, evolving it to have an IRP-like process would require significant time, work, and stakeholder input – and that is only if the Commission desires to evaluate or pursue such a change.

Another key difference between the IRP and the IDP is the time horizon and planning cycle duration and cadence. The IRP indicates size, type, and timing of resource needs over a 15-year time horizon, while the IDP shows a five-year budget of discrete projects and investments. The five-year budget shown in the IDP is built every year on the forecast from the previous autumn, i.e., the five-year budget presented in this IDP is based on forecast data from Fall 2024, and we will soon begin our next planning cycle using an updated forecast. This is significantly different in the IRP, where the modeling happens about six months in advance of the filing date, every few years. Despite the fundamental differences between the purposes of the IRP and the IDP, there are opportunities to align some of the forecast vintages used in the creation of both filings. We are using the same forecasts in similar ways in both the IRP and IDP to align the plans, but if a new version of a forecast comes out after the completion of the distribution planning cycle reflected in the IDP but before the IRP, it is appropriate that the IRP should use the more recent forecast vintage – and vice versa. This issue cannot be addressed by filing the IRP and the IDP on the same day because, as previously mentioned, the forecast for the IDP happens at the beginning of the planning process – over one year in advance – whereas the IRP modeling happens closer to the filing date. Finally, the sensitivity and scenario analyses presented in the IRP and the IDP serve to capture the minimal year-to-year variation in base forecasts.

As we will discuss throughout Section II, there are many components to our DER forecast, including forecasts for Rooftop Solar, Front of the Meter Solar, Distributed Energy Storage, Energy Efficiency, Demand Response (DR), Electric Vehicles, and Beneficial Electrification. Table 1-4 notes which modeling vintages are reflected in the corporate-level DER forecasts shown in Section II.B. Due to the timing difference, the LoadSEER modeling that was done by Distribution Planning to develop the DER forecast scenarios in Section III.C reflects a more recent corporate-level forecast than what was used in the 2024 IRP.

Table 1-4
Forecast Vintage Comparison

Forecast	Vintage Used in 2024 IRP DER Scenario Modeling	Vintage Used in LoadSEER DER Scenario Modeling
Rooftop Solar	July 2023	July 2025
Front of the Meter Solar	July 2023	July 2025 ⁶
Distributed Energy Storage	None assumed	July 2025
Energy Efficiency	July 2023	July 2025
Demand Response	Developed in 2023	Embedded in 2025 Energy Sales & Demand forecast
Electric Vehicles	July 2023	July 2025
Beneficial Electrification	July 2023	July 2025

The Company’s distribution system planning process is grounded in a granular, component-level forecasting methodology. Rather than relying on a single system-wide coincident peak, our distribution forecasts explicitly account for every non-coincident peak across all components of the distribution system—including substations, feeders, and other critical infrastructure. This approach ensures that each element of the system is evaluated yearly based on its unique demand profile, enabling more accurate identification of capacity constraints and investment needs. By forecasting at this level of detail, we ensure that our planning is responsive to localized conditions and supports a resilient, efficient, and customer-focused distribution network.

B. 3.A.5.b - Feeder-Level DER Forecasting in LoadSEER

IDP Requirement No. 3.A.5.b requires discussion of planning modifications or changes to improve IRP-IDP coordination and integration, including:

Conducting advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level, using Xcel's advanced planning tool [LoadSEER].

As noted above, there are fundamental differences between the functions of the IRP and the IDP processes, but we are continuing to take steps to integrate our planning processes. Resource planning identifies the size, type, and timing of the system’s needed resource mix – it has not traditionally considered location, although certain modeling proxies may be able simulate locational constraints in an IRP process.

⁶ This scenario includes a forecast for solar that will meet Distributed Solar Energy Standard (DSES), Minn. Stat. § 216B.1691, subd. 2h, as added by 2023 Session Laws Chapter 60, Article 12, Section 16, and is discussed in section II.C.7.

Distribution planning by contrast is highly location-based. As we explain in detail in Section III below, LoadSEER enables advanced forecasting at the feeder level. DER that is approved as part of our IRP feeds into the base forecast and is then spatially allocated within LoadSEER, which is an important tool for our planning process, which prioritizes and budgets for specific system upgrades and investments that can accommodate DER that is planned as part of the IRP.

C. 3.A.5.c - Proactive Capacity Investments to Allow DG and EV Additions Consistent with the DER Forecast

IDP Requirement No. 3.A.5.c requires discussion of planning modifications or changes to improve IRP-IDP coordination and integration, including:

Proactively planning investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources.

The Company participated in a Commission-led workgroup process to develop a Proactive Distribution Grid Upgrade Framework in Docket No. E002/CI-24-318. Over the course of nine months, a wide range of stakeholders engaged in the workgroup process and later submitted comments on the proposed framework.

On July 24, 2025, the Commission approved an initial version of the Framework, which will guide the evaluation of our proposals for proactive distribution grid upgrades. These upgrades are intended to address projected load growth and DER needs beyond the standard five-year planning horizon. The Framework enables the Company to propose infrastructure investments that, once approved, will be funded through a combination of pro-rata payments from customers who use the new capacity (for a period of 10 years) and standard cost recovery from all customers.

We are submitting our first Proactive Upgrade Proposal under this Framework—along with the proposed tariff—in conjunction with this IDP. The proposal is for a new feeder in South Minneapolis, driven by a forecast that the Midtown substation will exceed its planned loading limit by 2034.

The Company will continue to support the development of the Proactive Distribution Grid Upgrade framework as the workgroup reconvenes for Phase 2 over the coming years. This framework will be a critical tool for enabling proactive planning and investment to support the DER and electrification adoption reflected in the Company's forecast.

D. 3.A.5.d - Improving Non-Wires Alternatives Analysis

IDP Requirement No. 3.A.5.d requires discussion of planning modifications or changes to improve IRP-IDP coordination and integration, including:

Improving non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources.

We have continued to improve and expand our NWA analysis. As discussed in *Chapter 8*, the stacked values used in our NWA analysis are consistent with the IRP assumptions, where applicable. For the 2024 NWA analysis we updated the Surplus Capacity Credit value based on the 2024 IRP, and this value was used again for the 2025 NWA analysis. Similar to last year, we continue to use the National Renewable Energy Laboratory's (NREL's) 2023 Annual Technology Baseline costs as a source for cost assumptions to remain consistent with the assumptions in our most recent IRP.

In January 2025, we issued a Request for Information (RFI) seeking feedback on the feasibility of NWA solicitations and NWA compensation and received one response. We are also planning to issue a Request for Proposals (RFP) for two of the projects studied in our NWA analysis to begin engagement with potential vendors. We provide more detail about our RFI and upcoming RFP in *Chapter 8*.

E. 3.A.5.e - Planning for Aggregated DER

IDP Requirement No. 3.A.5.e requires discussion of planning modifications or changes to improve IRP-IDP coordination and integration, including:

Planning for aggregated distributed energy resources to provide system value including energy/ capacity during peak hours.

We note that in the context of the IDP, the Commission defines DER as “supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter. This definition...may include, but is not limited to: distributed generation, energy storage, electrified end uses that can be used as a resource, demand side management, and energy efficiency.”⁷

⁷ IDP Requirement No. 3.

For distribution system planning, as we explain further in this Chapter, we plan for peak loads at a more granular, location-specific level than bulk system planning. Additionally, the assumed “use cases” for various DERs in distribution system planning may differ from the use case(s) assumed in bulk system planning for the IRP. In these ways, “system value” may mean something different in the context of distribution system planning versus resource planning.

From a distribution system perspective, through our NWA analysis, we annually evaluate and plan for combinations of DERs to provide value during peak times at the feeder and substation level. Further, our NWA analysis considers the effects of DR and distributed solar already present on a given feeder or substation.

From a resource planning perspective, we have many DR and energy efficiency programs that can be considered “aggregated” in the sense that they are designed to benefit the bulk system. Although these aggregated resources may also benefit the distribution system at the times of feeder and substation peak times, the primary optimization criteria and assumptions used in the IRP seek to benefit the bulk system at times of peak system demand on the bulk system, as well as use cases that are optimal for bulk system planning.

III. LOAD FORECAST



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

A. Planning to Meet Peak Load

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

Then, we generate a forecast, aggregate the results, and compare this analysis with system projections. See *Chapter 6: Distribution Financial Information and Action Plans* for the load forecast resulting from this analysis in compliance with IDP Requirement 3.D.2, which requires, in part, that we provide our load growth assumptions and how we plan to meet it in our five-year action plan. We additionally provide our long-term system load projections in compliance with IDP Requirement No. 3.D.3 in *Chapter 6*.

We then provide our distribution forecast to our transmission planning staff, who incorporate the load forecast into their planning efforts. In addition to this load forecast hand-off, we also communicate with transmission regularly throughout the year. Specifically, any time we become aware of larger loads or significant DER at any time of the year, we share that information with transmission. Distribution and transmission personnel meet regularly as a cross-functional group to further ensure we are each aware of plans and projects which may impact either system. The interaction between distribution planning and transmission planning has increased recently with the inception of the Company's new Integrated System Planning organization, discussed above.

Our load forecast focuses on demand (kVA) not energy (kWh) to ensure we can serve loads during system peaks.⁸ For planning purposes, we define "peak load" as the largest power demand at a given point during the course of one year. Measured peak loads fluctuate from year-to-year due to the impacts of duration and intensity of hot weather and customer air conditioning usage, economic conditions, and other factors. In examining each distribution feeder and substation transformer for peak loading, we use specific knowledge of distribution equipment, local government plans, and customer loads to forecast future electrical loads. Planning Engineers consider many types of information for the best possible future load forecasts including historical load growth, customer planned load additions, corporate energy sales and demand forecasts, DER forecasts, circuit and other distribution equipment additions, circuit reconfigurations, and local government-sponsored development or redevelopment.

Finally, the Commission's September 16, 2024 IDP Order in Docket No. E002/M-23-452 requires the Company to implement the planned net loading (PNL) methodology, and related 15 percent Dependability Factor for Photovoltaics (DFPV), in the load forecast and risk analysis processes for N-0 overload risks.⁹ Compared with "native loading," the PNL accounts for how the presence of DER on the distribution system offsets the absolute peak demand at any given time. This new initial methodology allows for the consideration of certain distribution substations and feeders to have a reduced N-0 overload risk due to the load-masking impact of existing DER on the distribution system. This is further expanded upon in Section IV.B below.

⁸ When three phase Ampere data is available, we use the highest recorded phase measurement in our load forecast.

⁹ Order Point No. 18 states "Xcel shall implement the 15 percent DFPV in the next planning cycle for N-0 risk analysis in the next IDP."

B. DER Forecast Methodologies

In this section, we present our forecasts for each DER type and summarize our forecast methodologies, which respond to the following IDP requirements:

IDP Requirement No. 3.C.1:

In order to understand the potential impacts of faster-than-anticipated DER and electrification adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER and electrification deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER and electrification adoption and aggregated or bundled DER/ electrification service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER and electrification growth take place first, and how the [utility] would anticipate the combined impacts of simultaneous DER and electrification growth.

Xcel must provide detail on how, in aggregate, the energy and climate goals of the Minnesota communities it serves, along with customer preference trends, are reflected. In particular, distribution generation planning should include consideration of local community generation goals and beneficial electrification.

For electric vehicle forecasts scenarios, Xcel shall provide base-case, medium, and high adoption, capacity, and energy forecasts by sector (light duty, medium duty, and heavy duty).

IDP Requirement No. 3.C.2:

Include information on methodologies used to develop the low, medium, and high scenarios, including the DER and electrification adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER and electrification load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.

Order Point 2 of the Commission's 2023 IDP Order:

Xcel shall report all DERs and DER forecasts in MWac in future IDPs.

The forecasts in this section represent our corporate-level DER adoption forecasts and associated scenarios, which do not always align with the +10 percent and +25 percent scenarios outlined in IDP Requirement No. 3.C.2. As we will discuss in Section III.C below regarding the LoadSEER DER forecast scenarios, we take the

corporate-level DER forecasts discussed in this section and, unless otherwise described, allocate them to specific locations on the distribution system using LoadSEER's spatial forecasting capabilities. This process produces a distribution-level forecast that illustrates how corporate-level DER adoption is expected to materialize across specific locations within the distribution system.

We have also worked to align scenario inputs between the IDP and the IRP. As discussed in Section II above, there are significant differences between the purpose, functionality, and timing of the IDP and the IRP, which affects the vintages of forecasts that are most relevant at the time of modeling. We will provide more information about our efforts to align modeling scenario inputs between our IDP and IRP in our forthcoming IRP, which is due April 21, 2027. Tabular data in live Excel format for the forecasts below is provided as *Attachment L*.

1. *DER Treatment in the Corporate Load Forecast*

IDP Requirement No. 3.A.6 requires the following:

Discussion of how DER and electrification is considered in load forecasting and any expected changes in load forecasting methodology.

We discuss how DER is factored into both the corporate-level load forecast and the distribution system planning forecasts below.

The Company's corporate sales forecast relies on econometric models and other statistical techniques that relate our historical electric sales to demographic, economic, and weather variables. We also adjust for known and measurable changes by large customers, and incorporate the effects of our customers' energy efficiency, distributed generation solar PV adoption, electric vehicle adoption, and water and space heating electrification. The resulting sales forecasts for each major customer class in each state across the Company footprint are summed to derive a total system sales forecast.

The sales forecast is converted into energy requirements at the generator by adding energy losses. The system peak demand forecast is developed using a regression model that relates historical monthly base (uninterrupted) peak demand to energy requirements and weather. The energy requirements forecast and normal peak-producing weather are used in the model to create the base peak demand forecast.

Forecast Adjustments. After determining the base forecast, we develop net forecasts that include adjustments for future demand-side management programs, distributed solar

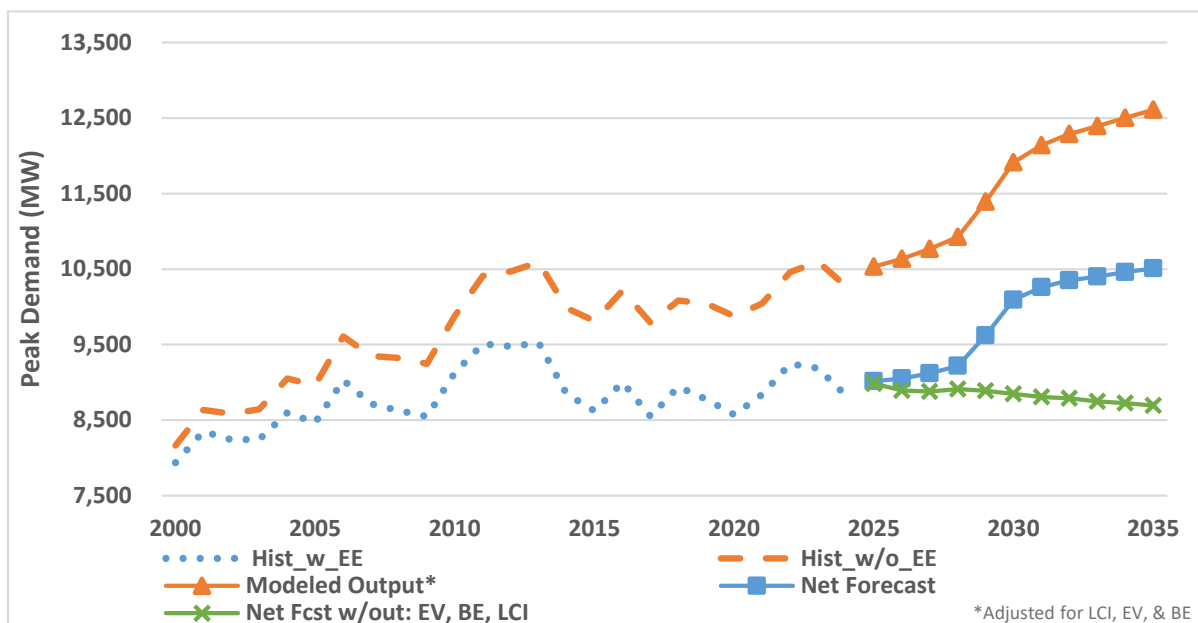
behind-the-meter generation, and electric vehicles. We also account for the effects on the system peak demand forecast of our load management programs by subtracting expected load management amounts to derive a net peak demand forecast.

Demand-Side Management Programs. One important adjustment to the forecasts is the impact from our conservation improvement programs. Modeling raw, unadjusted sales would implicitly result in an outlook with some unquantifiable volume of energy savings, and adjustments to this kind of outlook for DSM would result in double counting of DSM effects. The Company avoids this issued by adjusting raw sales for historical Company-sponsored Demand Side Management (DSM) prior to modeling and forecasting. This produces an outlook that effectively includes no energy savings. The projected savings effects of all past and future measures are then netted from the outlook.

This “add back” method allows the Company to avoid over or under accounting and accurately addresses the distinct effects of DSM in both Minnesota and South Dakota. States without NSP sponsored DSM programs (ND, WI, and MI) are not adjusted for DSM prior to modeling. The Company accounts for the distinct impacts of Lighting and Other DSM for both Residential and Commercial & Industrial sectors when modeling peak demand.

The Company-sponsored Minnesota DSM adjustments are based on the Company’s June, 2023 Xcel Energy’s 2024-2026 Energy Conservation and Optimization Triennial Plan. Figure 1-10 graphically illustrates the DSM adjustment described above.

Figure 1-10
DSM Adjustment in Corporate Load Forecast



Distributed Solar PV. Distributed solar is modeled similar to DSM. Minnesota and Wisconsin raw class-level sales are adjusted to remove the historical impacts distributed solar prior to modeling. The resulting forecast represents sales without distributed solar, and the Company then “adds back” the projected impacts of future rooftop solar generation. The sales and peak demand forecasts are not adjusted for CSGs or distribution-connected utility-scale solar because these do not affect customers’ loads.

Electric Vehicles. The approach for Electric Vehicles (EV) is similar to DSM and Distributed Solar where the historical effects of EV consumption are removed from raw historical sales prior to modeling so the resulting forecast represents future sales without EV. The projected impacts of future EV charging are then added back to produce an outlook that fully accounts for effects of EV. The Company accounts for the distinct hourly impacts of different charging when modeling peak demand, including: managed and unmanaged Residential light duty charging, commercial public and workplace charging, and Medium and Heavy Duty Vehicle charging.

The EV forecast is developed internally based on assumptions related to both adoption (energy) and charging behavior (demand) as described below. Inputs to the adoption models include electricity prices, vehicle battery prices, gasoline prices, car ownership, car usage, and efficiency. Both the managed and unmanaged charging

behavior is estimated using data obtained from a third-party consultant (Guidehouse) for light, medium, and heavy-duty vehicles.

Large Customer Adjustments. We also adjust the forecast to account for planned or recent changes in production levels for large customers. This includes: 1) modifying historical consumption for the recent addition of customer-owned Combined Heat and Power generator prior to modeling. This is similar to our approach to DSM, where effects are removed from the historical, modeled, and then added back in the forecast timeframe to avoid double counting these impacts, and 2) adjusting the consumption in the forecast timeframe for addition of new large customer loads such as data centers. We note, however, that many of these large customer loads are not served through distribution.

Data Sources:

- *Megawatt-hour (MWh) Sales and megawatt (MW) Peak Demand.* The Company uses internal and external data to create its MWh sales and MW peak demand forecast.
- *Historical MWh Sales and MW Peak Demand.* Historical MWh sales are taken from the Company's internal company records, fed by its billing system. Historical coincident net peak demand data is obtained through Company records. The load management estimate is added to the net peak demand to derive the base peak demand used in the modeling process.
- *Weather Data.* Weather data (dry bulb temperature and dew points) were collected from National Oceanic and Atmospheric Administration weather stations for the Minneapolis/St. Paul, Fargo, Sioux Falls, and Eau Claire areas. The heating degree-days and temperature-humidity index degree-days are calculated internally based on this weather data. The Company uses a 20-year rolling average of weather conditions to define normal weather.
- *Economic and Demographic Data.* Economic and demographic data is obtained from the Bureau of Labor Statistics, U.S. Department of Commerce, and the Bureau of Economic Analysis. Typically they are accessed from IHS Markit data banks, and reflect the most recent values of those series at the time of modeling.

In terms of changes to our load forecasting methodology as it relates to DER, and all peak forecasting, the Company updated its peak forecast methodology in 2023 to better account for the potential peak shifting due to future adoption of Distributed Solar Generation (DG Solar), managed and unmanaged EV charging, Beneficial

Electrification (BE), and new Large Commercial and Industrial (LCI) customer loads. These technologies and new customer loads will, on net, shift load from typical summer peak hours (afternoon/early evening) into late evening.

The Company also continues to account for the lasting effects of historical Demand Side Management (DSM) programs (Energy Efficiency), any/all planned or expected future DSM, and load from new large Commercial and Industrial customers such as data centers. The Company's new "8760" peak forecasting approach uses hourly profiles of each major component of NSP's load forecast to determine the magnitude and timing of monthly peaks. Each component (Base load by state, EV, BE, DG Solar, LCI, and DSM) grows at a different rate over the forecast timeframe, and each has a unique hourly shape that impacts overall NSP load. The "8760" modeling approach takes these effects into account, aggregates all components' load on an hourly basis, and then identifies all monthly peaks and peak-coincident effects. The 8760 peak forecast approach is substantially more complicated to produce but is a vast improvement over the prior monthly peak methodology. As noted by the MN Department of Commerce in the Company's recent Integrated Resource Plan filing, the Department "analyzed inputs and outputs [of the 8760 forecast method] and believes this procedure is reasonable, and an improvement from the previous IRP towards a more realistic and accurate forecast."¹⁰

The Company's prior monthly peak modeling approach could not account for peak shifting, and this almost certainly contributed to inaccuracies in the forecast timeframe. This old method required the Company to assume the peak hour before it can develop the future peak-coincident impacts of DG solar or Electric Vehicles (for example). As a result, the adjustments applied for peak-coincident DG solar or DSM (for example) likely had larger load reduction impacts than were reasonable. In an example scenario with no peak shifting: a projected, unadjusted July peak of 9,000 MW would then be adjusted for 100 MW of DG solar, producing a peak of 8,900 MW. Under the same example scenario, but with peak shifting: the peak would simply shift later in the day when the unadjusted load is only 8,970 MW but DG solar's impact is 50 MW, producing a peak forecast of 8,920 MW. The steps for executing the "8760" approach are as follows:

1. Select annual hourly load profiles for each major component (Base load by state, EV, BE, DG Solar, LCI, DSM),

¹⁰ Department Comments, Docket No. E002/RP-24-67 pg. 8¹¹ Minn. Stat. § 216B.1641 as amended by 2023 Session Laws Chapter 60, Article 12, Section 14.

2. Extrapolate the hourly load profiles to extend through the forecast timeframe, accounting for the unique calendar of each forecast year,
3. Develop the energy and base “status quo” peak series that will be used to scale the hourly profiles,
4. Develop the “Exogenous Adjustment” energy series that will be used to scale hourly profiles for EV, BE, DG Solar, Large CI, and DSM,
5. Scale profiles using Metrix LT software,
6. Aggregate series and identify monthly peaks.

2. *DER Forecast – Distributed Solar PV*

We offer several programs to customers interested in solar as a renewable opportunity. Specifically, we provide incentives under our Solar*Rewards program, and the opportunity to earn bill credits for CSGs in our Solar*Rewards Community program. Until its discontinuance in October of 2018, customers also had the opportunity to participate in the Made in Minnesota program. In addition, for larger systems, we offer a net-metering option. We have factored all these distributed solar PV options into our base, and high distributed solar forecasts.

The Solar*Rewards installations for 2025-2027 were estimated based on historical trends of funding levels and project conversion rates.

For net metering and CSGs, we assume that customers that participate in solar programs would consider, in most cases, that these programs are substitutes for each other. Therefore, the incremental growth in one category is interchangeable with another category.

We used the average of a Bass Diffusion and an economic model to derive the forecast of net metered solar. Bass Diffusion models are used to describe various technology adoptions that penetrate an existing market through an “S” shaped diffusion characteristic. Economic models use a simple payback to estimate potential adoption.

The Bass Diffusion model is calibrated using state specific, historical solar installed capacity through December 2024. Additionally, we have incorporated into both the Bass diffusion and economic model, a factor for the percentage of customers unable to install solar on their roof for various reasons (e.g., renters, shaded roof, inability to access the roof, etc.). The main variables impacting adoption in the economic payback model are installation and maintenance cost, inverter replacement, investment tax

credit, utility rates, and capacity factors. Models and estimates are updated as new data becomes available and estimates can vary significantly.

The Bass Diffusion model was also used in determining the base scenario for the CSG forecast. The Bass Diffusion model coefficients are calibrated using state-specific historical data, with adjustments made to account for anticipated available capacity constraints on the distribution system. The high case matches the annual cap for CSGs established in the legislation (100 MW/year, then 80 MW/year, then 60 MW/year).¹¹

Distributed solar scenarios were developed using outlooks for community solar. The Expanded Non-Residential scenario assumes a base outlook for Residential customer distributed solar but scales the base Commercial and Industrial outlook up per the difference between the base and high community solar outlook. The High scenario scales Residential, Commercial, and Industrial distributed solar per the difference between the base and high community solar outlook.

The Expanded Non-Residential scenario assumes the base outlook for community solar, and the High scenario assumes the high outlook for community solar.

The scenario summary below shows all rooftop distributed and community solar assumed in the Distribution Plan modeling. The Base outlook assumes approximately 2,582 MW for total installed distributed solar by 2035. The Expanded Non-Residential scenario assumes installed solar at nearly 2,645 MW by 2035, and the High scenario assumes installed distributed solar at approximately 2,991 MW by 2035.

We provide a tabular and graphical view of the aggregate distributed solar generation¹² forecast in the following Table and Figure.

Table 1 - 5
NSPM State of Minnesota Distributed Solar PV Forecast (Installed Capacity)

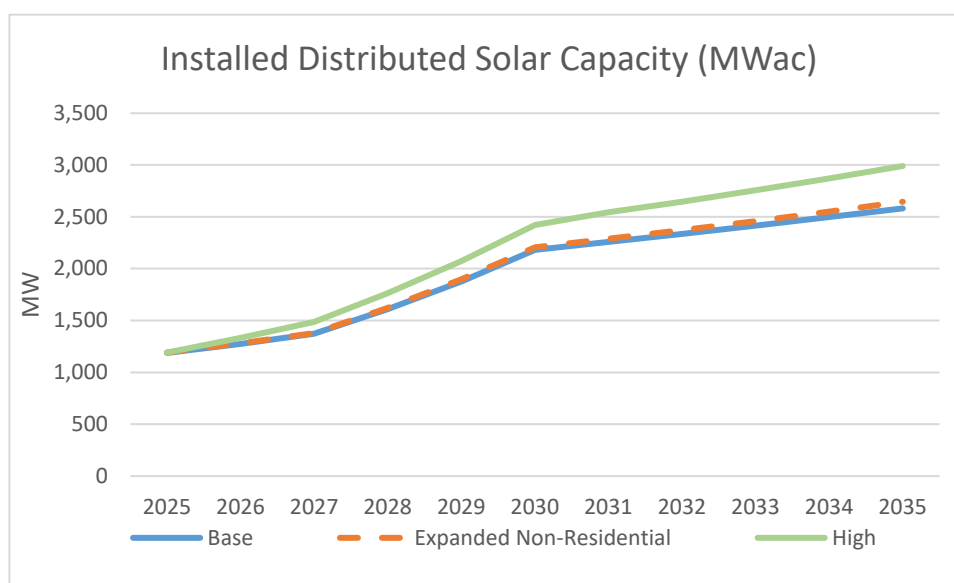
	Total Base (MWac)	Total Expanded Non-Residential (MWac)	Total High (MWac)
2025	1,189	1,190	1,191
2026	1,275	1,280	1,332

¹¹ Minn. Stat. § 216B.1641 as amended by 2023 Session Laws Chapter 60, Article 12, Section 14.

¹² Includes rooftop and community solar garden

2027	1,371	1,379	1,485
2028	1,609	1,622	1,763
2029	1,878	1,897	2,074
2030	2,180	2,206	2,422
2031	2,257	2,289	2,543
2032	2,335	2,372	2,647
2033	2,414	2,459	2,756
2034	2,496	2,550	2,870
2035	2,582	2,645	2,991

Figure 1-11
NSPM State of Minnesota Distributed Solar PV Forecast



3. DER Forecast – Distributed Wind Generation

We believe future DER growth will primarily be through solar PV and distributed storage, and that distributed wind will continue to be a very small proportion of DER on our distribution system, largely due to the rapid development of solar and storage markets – and their relative ease of adoption compared to wind. Additionally, there is little information available in the industry regarding the adoption of distributed wind. For these reasons, we do not provide a forecast in conjunction with this IDP.

4. *DER Forecast – Distributed Energy Storage*

Through the end of 2024, we have 537 energy storage systems on our Minnesota electric distribution system. The total behind-the-meter battery storage installed on our Minnesota distribution system was approximately 2.329 MW at the end of 2024. We provide an annual breakdown in Table 1-6.

Table 1-6
Storage Systems – NSPM State of Minnesota

Time Period	Cumulative Systems	Cumulative kW (Max Continuous)
2017	8	35
2018	37	175
2019	62	290
2020	123	595
2021	189	879
2022	364	1598
2023	514	2244
2024	537	2329
2025 YTD	624	2971

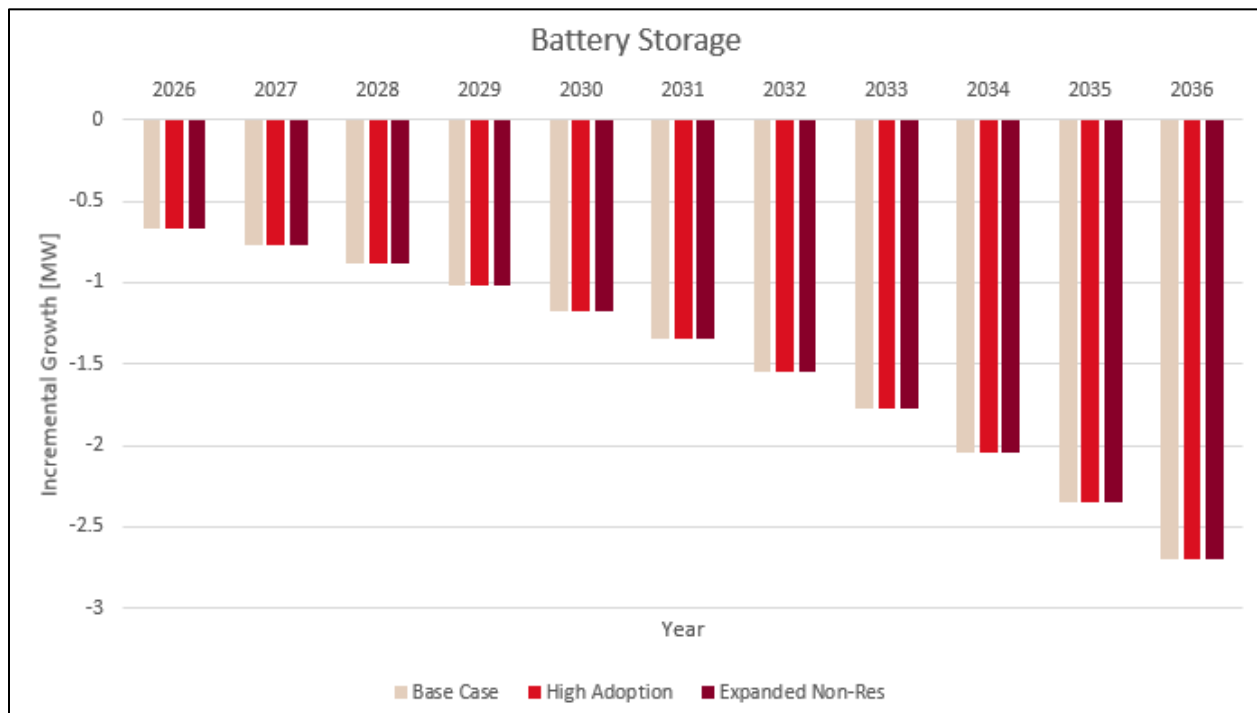
In order to forecast the distributed storage for our system, we used the Bass Diffusion model. The model coefficients are calibrated using state specific, historical storage systems installed through December 2024. Table 1-7 and Figure 1-12 show the distributed storage forecast in MW.

Table 1-7
Distributed Storage Forecast* – NSPM State of Minnesota

Year	Incremental Battery kW
2026	668
2027	769
2028	885
2029	1,018
2030	1,171
2031	1,346
2032	1,547
2033	1,778
2034	2,034
2035	2,347
2036	2,696

*Forecasts do not include DCP

Figure 1-12
NSP Distributed Storage Forecast* – Minnesota (Incremental MW)



*Forecasts do not include Capacity*Connect, our proposed Distributed Capacity Procurement

Due to the emerging state of distributed energy storage within Minnesota, we note that the various scenarios developed are sensitive to externalities such as policy

changes (e.g., incentive changes), technology changes (e.g., improvements in existing battery technologies and new disruptive battery technologies), and possible geopolitical risks and supply chain disruptions that could negatively impact the availability of raw materials.

5. *DER Forecast – Energy Efficiency*¹³

Order Point 4 of the Commission’s September 24, 2024 Order requires:

In future IDPs, Xcel shall provide standalone forecasts for demand response, load flexibility, and energy efficiency.

Demand Side Management, or what we call Energy Conservation and Optimization (ECO) in Minnesota, delivers energy and cost savings for customers. In addition, energy efficiency reduces the capacity needs on the distribution system. The Company has one of the longest-running and most successful DSM programs in the country. Our DSM programs have saved over 13,500 GWh of energy and over 4,800 MW of demand since 1990. Our actions to consistently adapt and judiciously grow our customer offerings have proven worthwhile as we continue to meet and exceed the state’s statutory energy savings targets.

The Company-sponsored Minnesota DSM assumptions included in this distribution plan are based on the Company’s June, 2023 Xcel Energy’s 2024-2026 Energy Conservation and Optimization Triennial Plan. The Expanded Non-Residential and High scenarios were derived from the Company’s 2024 Upper Midwest Resource Plan¹⁴ High DSM assumptions (i.e. Energy Savings Bundle 3 in addition to base assumptions of Bundle 1 and 2), as shown in Table 1-8 below. The Expanded Non-Residential scenario assumes the addition of IRP Bundle 3 savings for Commercial and Industrial customers. The High scenario assumes the addition of IRP Bundle 3 savings for all customers: Residential, Commercial, and Industrial.

¹³ IDP Requirement No. 3 states: The following definitions are adopted for the purposes of these requirements. c) Energy Efficiency: measures or programs that target consumer behavior, equipment, processes, or devices and are designed to reduce the consumption of electricity on either an absolute or per unit of production basis.

¹⁴ Docket No. E002/RP-24-67

Table 1-8
Energy Efficiency Bundles from 2024 Integrated Resource Plan

Year	Energy (GWh)			Demand (MW)			Cost (\$000)		
	Bundle 1: Statutory Minimum	Bundle 2: Programatic	Bundle 3: High	Bundle 1: Statutory Minimum	Bundle 2: Programatic	Bundle 3: High	Bundle 1: Statutory Minimum	Bundle 2: Programatic	Bundle 3: High
2024	477	138	159	91	26	30	\$ 86,040	\$ 47,971	\$ 79,937
2025	887	256	310	169	49	59	\$ 86,202	\$ 54,143	\$ 81,246
2026	1,298	400	460	247	76	88	\$ 82,934	\$ 62,811	\$ 79,928
2027	1,691	531	654	322	101	124	\$ 82,108	\$ 57,926	\$ 108,775
2028	2,075	659	864	395	125	164	\$ 82,108	\$ 57,926	\$ 123,859
2029	2,455	785	1,023	467	149	195	\$ 82,108	\$ 57,926	\$ 97,752
2030	2,832	835	1,268	539	159	241	\$ 92,536	\$ 31,685	\$ 152,953
2031	3,204	893	1,498	610	170	285	\$ 92,536	\$ 31,685	\$ 152,953
2032	3,565	948	1,725	678	180	328	\$ 92,536	\$ 31,685	\$ 152,953
2033	3,908	1,010	1,947	744	192	371	\$ 89,458	\$ 34,764	\$ 152,953
2034	4,234	1,066	2,161	806	203	411	\$ 89,458	\$ 34,764	\$ 152,953
2035	4,554	1,121	2,327	867	213	443	\$ 89,458	\$ 34,764	\$ 125,340
2036	4,419	1,089	2,259	841	207	430		\$ -	
2037	4,347	1,069	2,222	827	203	423		\$ -	
2038	4,270	1,049	2,181	813	200	415		\$ -	
2039	4,113	1,007	2,116	783	192	403		\$ -	
2040	3,963	969	2,050	754	184	390		\$ -	
2041	3,807	925	1,980	725	176	377		\$ -	
2042	3,591	863	1,882	683	164	358		\$ -	
2043	3,379	802	1,779	643	153	339		\$ -	
2044	3,012	692	1,635	573	132	311		\$ -	
2045	2,655	599	1,470	505	114	280		\$ -	
2046	2,316	501	1,312	441	95	250		\$ -	
2047	1,986	409	1,144	378	78	218		\$ -	
2048	1,658	324	957	315	62	182		\$ -	
2049	1,330	241	787	253	46	150		\$ -	
2050	1,009	184	599	192	35	114		\$ -	
2051	774	143	455	147	27	87		\$ -	
2052	541	103	314	103	20	60		\$ -	
2053	321	61	183	61	12	35		\$ -	
2054	160	30	84	30	6	16		\$ -	
2055	-	-	-	-	-	-		\$ -	

6. DER Forecast – Demand Response

Order Point 4 of the Commission’s September 24, 2024 Order requires:

In future IDPs, Xcel shall provide standalone forecasts for demand response, load flexibility, and energy efficiency.

The Company provides residential customers several opportunities to manage their energy during system peak periods. Residential Demand Response programs enable residential customers to reduce energy consumption (and corresponding demand) either actively or passively during times of system need. For example, Saver’s Switch, connects to a customer’s residential AC unit and allows the Company to automatically

cycle a customer's equipment during peak events. AC Rewards automatically adjusts participating customer thermostat setpoints to reduce load while still allowing customers to opt out of specific events. The Company also offers Energy Action Days, a behavioral DR program that encourages reduced usage during peak periods.

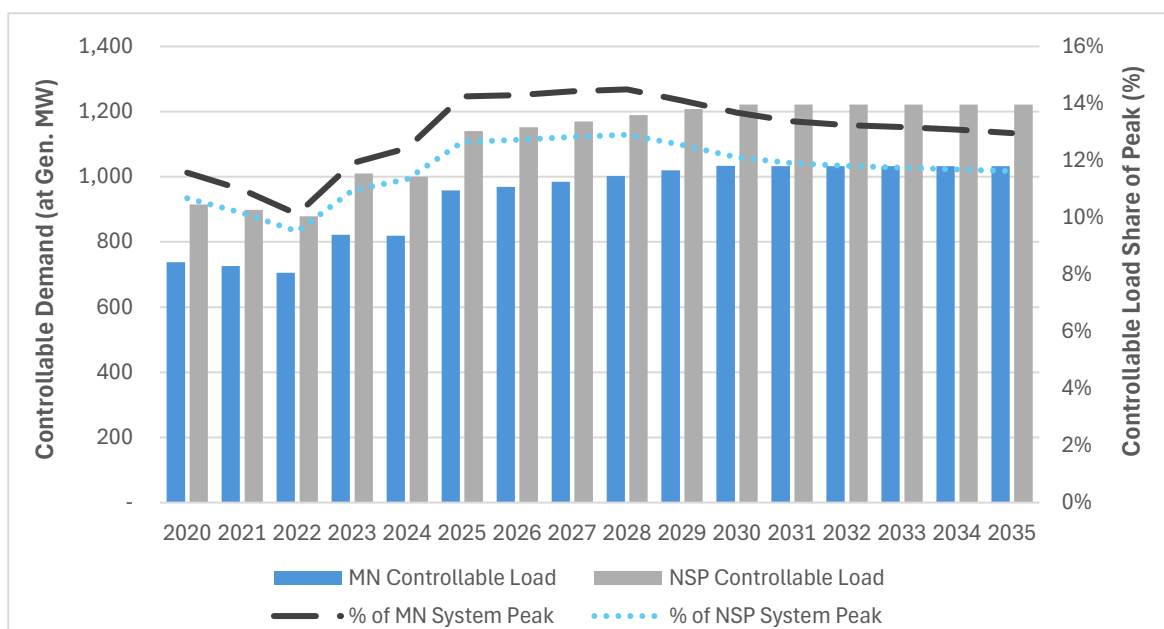
Through the Transportation Electrification Plan, the Company currently offers the Optimize Your Charge electric vehicle charging product. We also plan to propose an active managed charging program, scheduled to be launched in 2026. Additionally, a residential battery offering is scheduled for launch in Q1 2026 through the ECO filing.

For commercial customers, we offer several DR programs including Electric Rate Savings, Peak Partner Rewards, Peak Day Partners, Saver's Switch, Critical Peak Pricing, and AC Rewards programs. These programs offer bill credits or interruptible rates to incentivize load reduction during utility-initiated curtailment events. The Company recently closed the Peak Flex Credit pilot to new enrollments and is currently evaluating the best path forward for existing participants.

Most DR programs are utilized to reduce load during bulk system peak events. While these events may correlate with peaks on individual feeders, banks, or substations, the Company does not generally dispatch DR resources based on specific distribution system needs. However, the Company is exploring the potential to group residential program participants for targeted dispatch in areas where distribution benefits have been identified. Additionally, the Company reviews the impact on specific substations and feeders as part of the NWA analysis, which is discussed in more detail in *Chapter 8*.

The Company continues to grow our demand response resources. Our resources show an expedited increase through 2028. Further, we anticipate further growth with the additional opportunities presented by Advanced Metering Infrastructure (AMI) in the future and a potential future Distributed Energy Resource Management System (DERMS). Figure 1-13 below provides an outlook on the forecast for NSP and MN system level Demand Response through 2035.

Figure 1-13
Minnesota DR Forecast – Demand Savings



As noted above regarding DSM, the Company utilized the corporate energy forecast for demand response, which decrease load. When this forecast is allocated to the distribution system, it is included in the impacts of the corporate energy sales and demand forecast, so while demand response impacts are included in the forecast, they are not discretely modeled.

As we begin to refine our forecasting opportunities with updated forecasting tools, modeling software, and future AMI technology – we will gain a more granular view of the load impact of demand response. Today, without knowing the specific load shapes and comparing them to the precise capacity constrained areas, it is difficult to precisely predict the impact to distribution. As these processes are refined, we hope to be able to match the needed load to active demand response programs and/or develop programs that can further meet these needs.

We further continue our exploration of new technologies and opportunities to shift load rather than shed only during system peaks; these options are discussed in our 2024-2026 Triennial Plan.

7. DER Forecast – Load Flexibility

Order Point No. 4 of the Commission’s September 24, 2024 Order requires:

In future IDPs, Xcel shall provide standalone forecasts for demand response, load flexibility, and energy efficiency.

For the 2025 IDP, we provide a standalone forecast for load flexibility in the form of EV Managed Charging. Recognizing that a substantial portion of customer EV charging is naturally flexible, the Company forecasted participating vehicles and modeled how those participants can shift charging away from peak hours into late evening and early morning hours, thereby delivering load flexibility to the system. The participation rate for managed residential/home EV charging escalates from nine percent in 2025 (accounting for approximately 20,000 MWh of annual energy sales) to 40 percent by 2035 (920,000 MWh in annual energy sales). The increase in EV managed charging participation results in approximately 100 MW of reduction in coincident peak contributions from EV charging in 2035. However, the concentration of EV charging within a single managed charging window risks creating new peak conditions if allowed to grow unconstrained.

Figure 1-14
Share of LDV Managed and Unmanaged Home EV Charging in Minnesota

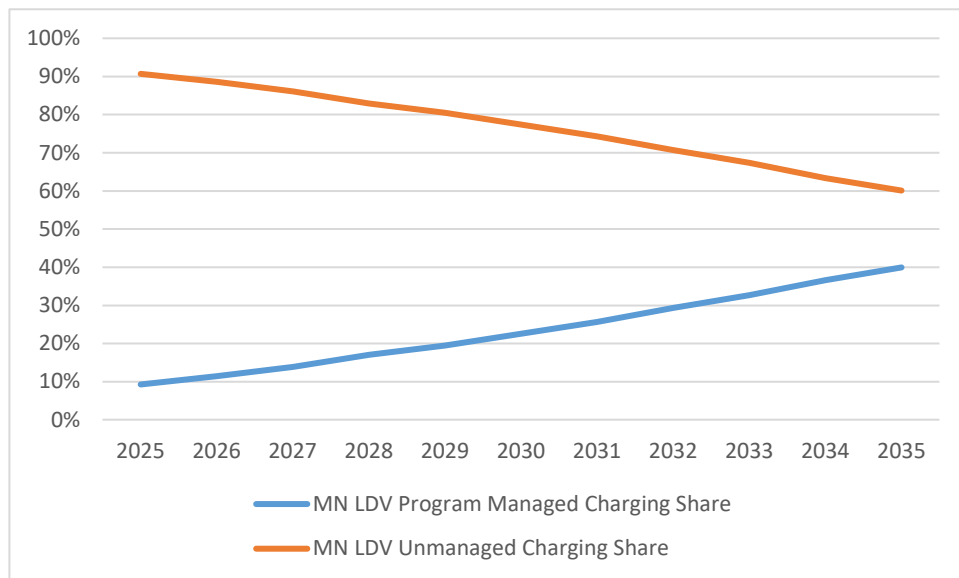
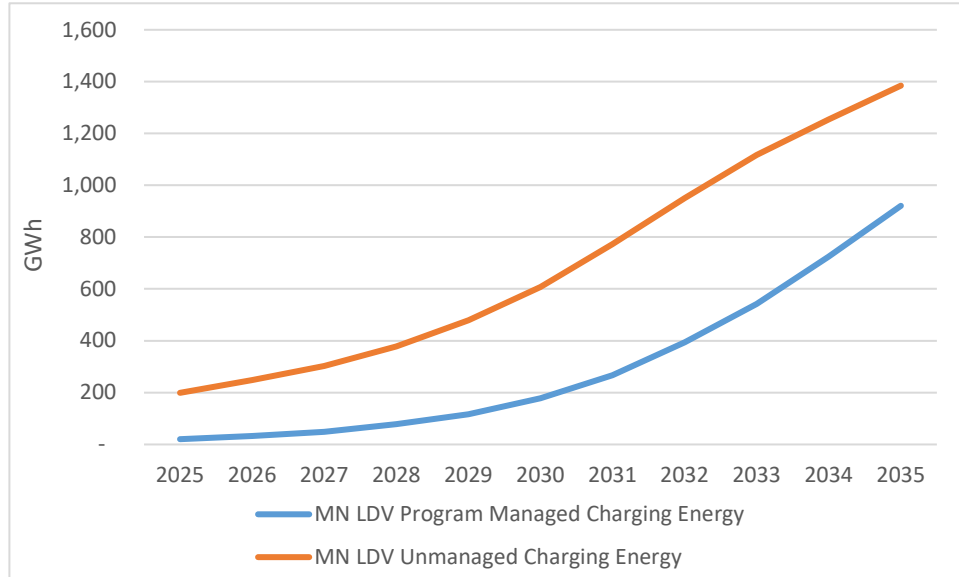


Figure 1-15
LDV Managed and Unmanaged Home EV Charging Energy Consumption in Minnesota



8. DER Forecast – Electric Vehicles

IDP Requirement No. 3.C.1 states in part:

For electric vehicle forecasts scenarios, Xcel shall provide base-case, medium, and high adoption, capacity, and energy forecasts by sector (light duty, medium duty, and heavy duty).

With an increase of available models, EV adoption has increased to approximately 84,000 light-duty EVs in Xcel Energy’s NSPM service territory as of June 2025. The EV forecasts discussed below were updated in July 2025.

We currently estimate light-duty EV adoption using two modeling techniques: (1) Bass Technology Diffusion, and (2) Economic models. Bass Diffusion models are used to describe various technology adoptions that penetrate an existing market through an “S” shaped diffusion characteristic. Economic models use total cost of ownership to estimate potential adoption and represent the second approach in modeling EV adoption.

We have estimated a total cost ownership model scenario for EV ownership compared to traditional internal combustion engine (ICE) automobiles. An average of the both the Bass Diffusion and total cost ownership models are used as an estimate of EVs. Our cumulative base adoption estimate for 2035 is approximately 11 percent

of all registered cars and light trucks in the NSP Minnesota service territory in that year.

Our current approach is based on state-specific and Xcel Energy service area specific data. The Bass Diffusion model is calibrated using state specific historical EV sales with data through December 2024. Additionally, we have incorporated into both the Bass Diffusion and economic models a factor for the percentage of vehicles in urban and rural areas. Presently, higher adoption is occurring in urban areas with the rural areas anticipated to ramp-up slowly. As we describe above, the Company has also incorporated a forecast of participation in EV managed charging.

The Expanded Non-Residential and the High scenarios were developed by scaling distinct charging types (e.g. residential/home LDV, public and workplace LDV, etc.). Under the High scenario, all EV charging types were scaled to align with the High EV scenario in the Company's Upper Midwest Resource Plan¹⁵. Under the Expanded Non-Residential scenario, Heavy/Medium duty vehicle charging as well as general commercial and workplace charging components were scaled to align with the High EV scenario in the Company's Upper Midwest Resource Plan; residential/home and public charging components were unscaled and are the same as assumed in the Base Scenario.

We note that EV fuel efficiency could be impacted by advances in technology. Analysis indicates that battery costs are a significant factor for higher EV prices. Main variables impacting adoption are available tax incentives, price differential between EV and ICE cars, and gasoline prices. Models and estimates are updated annually with new relevant available data and estimates can vary significantly. Since we are in the early stages of EV adoption, we expect our future estimates will be increasingly robust with additional data available every year.

Our estimates are also sensitive to several externalities like policy changes (e.g., incentive changes, cybersecurity requirements, carbon requirements); technology changes (e.g., improvements in existing battery technologies and new disruptive battery or electric motor management technologies, autonomous vehicles, alternate technologies like fuel cell vehicles); geopolitical factors such as trade and tariff issues; availability of raw materials such as lithium, cobalt, and nickel; and infrastructure availability.

¹⁵ Docket No. E002/RP-24-67

Additionally, many of the inputs change frequently and could produce significant swings in the model outputs. As can be seen in the below Tables and Figures, the range of high and low estimates is large, reflective of the sensitivities, volatility and uncertainty associated with the estimates. It should be noted that the Electric vehicle kW values shown in Table 1-10 are the sum on all non-coincident peak loads for the different types of EVs. The totals shown do not reflect the diversity of the hourly load profile for each vehicle type, therefore the maximum load for any hour of the aggregation of LDV, MD and HDV in any scenario would be less than the total shown. Similarly, the values were calculated independently of the hourly load profiles for individual feeders. As such the summation of the increases to the maximum load on all feeders due to EV adoption would be significantly less than total MW values shown here.

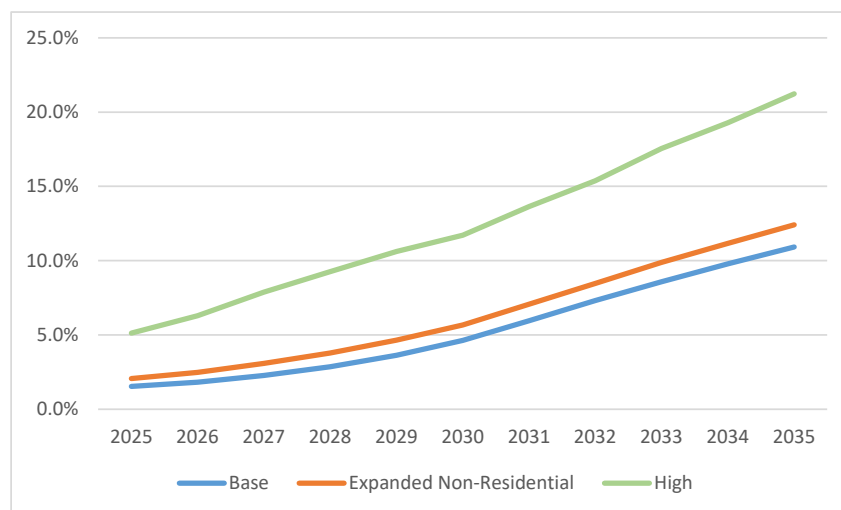
Table 1-9
Forecasted EV Adoption Numbers – NSPM Service Territory
(July 2025 Forecast Vintage)

Type and Scenario	2025	2030	2035
LDV (Base)	79,942	276,139	751,100
MDV (Base)	439	2,847	7,213
HDV (Base)	156	1,876	5,066
Total (Base)	80,537	280,863	763,379
LDV (ExpNonRes)	106,776	337,126	853,894
MDV (ExpNonRes)	1,455	7,185	14,022
HDV (ExpNonRes)	518	4,734	9,847
Total (ExpNonRes)	108,749	349,044	877,762
LDV (High)	265,002	696,736	1,460,023
MDV (High)	1,455	7,185	14,022
HDV (High)	518	4,734	9,847
Total (High)	266,975	708,654	1,483,892

Table 1-10
Forecasted EV Load¹⁶ – NSPM Service Territory
(July 2025 Forecast Vintage)

	2025		2030		2035	
EV Type and Scenario	MW	MWh	MW	MWh	MW	MWh
LDV (Base)	39	286,141	139	1,026,166	381	3,013,299
MDV (Base)	4	9,277	15	75,646	34	190,246
HDV (Base)	8	18,393	50	248,529	119	664,296
Total (Base)	50	313,812	203	1,350,341	534	3,867,841
LDV (ExpNonRes)	52	382,188	174	1,252,799	447	3,425,692
MDV (ExpNonRes)	174	30,752	37	190,865	217	369,809
HDV (ExpNonRes)	447	60,973	125	627,071	765	1,291,289
Total (ExpNonRes)	672	473,914	336	2,070,735	1,429	5,086,790
LDV (High)	128	948,536	351	2,589,153	2,456	5,857,391
MDV (High)	12	30,752	37	190,865	217	369,809
HDV (High)	26	60,973	125	627,071	765	1,291,289
Total (High)	166	1,040,261	513	3,407,089	3,438	7,518,489

Figure 1-16
Cumulative EV Adoption Rate (LDV) – NSP Minnesota Service Area



¹⁶ Undiversified demand by electric vehicles.

Figure 1-17
Cumulative Numbers of EVs – NSP Minnesota Service Area

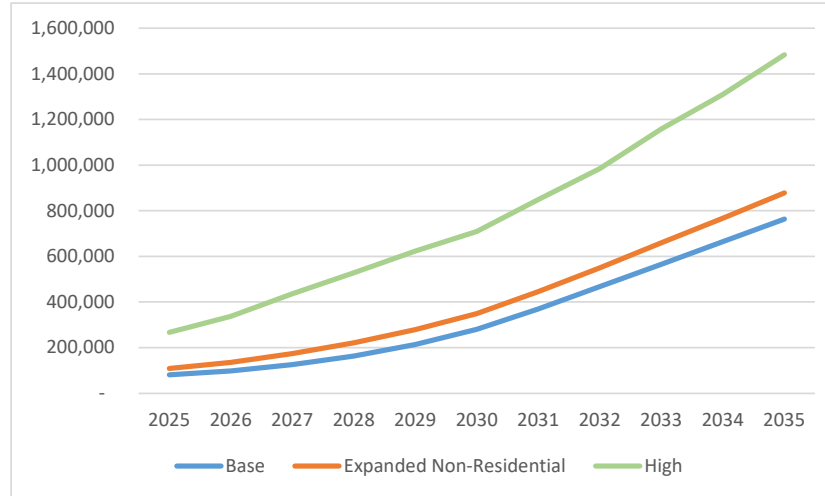
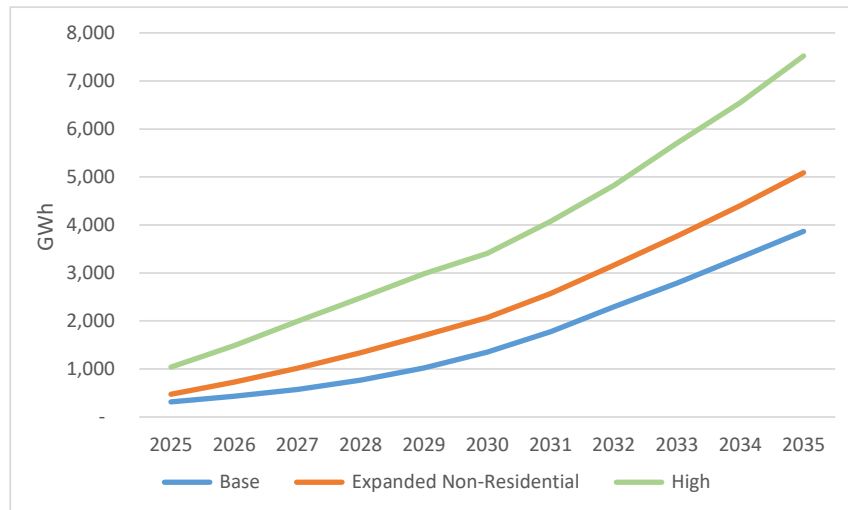


Figure 1-18
EV Consumption – NSP Minnesota Service Area (GWh)



We utilize estimates from a third-party consultant for medium and heavy-duty electric vehicle adoption and consumption estimates in the Company's service territory. We have made benchmarking part of our annual update process to ensure that our forecast is in-line with estimates from other reputable sources.

Impacts of the Inflation Reduction Act (IRA) on Forecasting. The Company did not include

any direct impacts from the IRA tax credits in the EV and solar forecasts beyond 2025, however total cost ownership model inputs for both technologies utilized third party economic data based on current policy, which included the IRA. The indirect impacts on EV and solar adoption is estimated to be minimal.

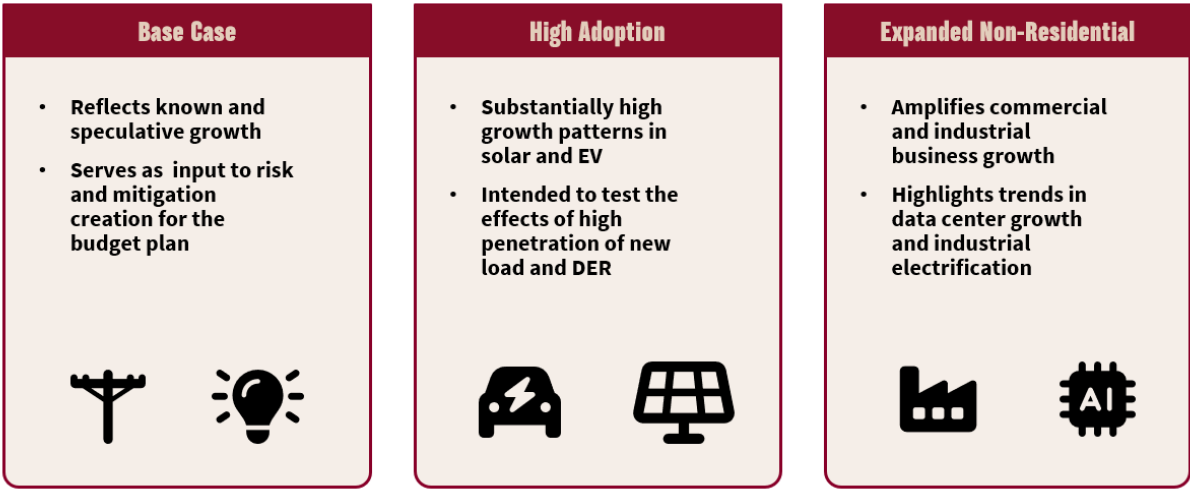
C. Distribution Planning – LoadSEER DER Forecast Scenarios

IDP Requirement No. 3.C.1 requires, in part:

In order to understand the potential impacts of faster-than-anticipated DER and electrification adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER and electrification deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER and electrification adoption and aggregated or bundled DER/ electrification service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER and electrification growth take place first, and how the [utility] would anticipate the combined impacts of simultaneous DER and electrification growth.

The above sections discussed the development of DER forecast scenarios at the corporate- or state-wide level. However, adoption of DER on the distribution system is location-specific, and adoption impacts are unique to each individual feeder. To better understand the potential location-specific impacts of the DER forecast scenarios on the distribution system, the forecasts were then allocated to the distribution system using LoadSEER. The scenarios that were created and then analyzed in LoadSEER comprise various combinations of the corporate-level DER adoption forecasts.

To align with the intent of IDP Requirement No. 3.C.1, The IDP Base Case scenario reflects known and speculative growth (the expected adoption forecast for each DER technology forecasted). The budget was developed using the 2024 version of the base case scenario, and then the IDP Base Case scenario was updated with the corporate forecast values in summer 2025. The IDP High Adoption scenario includes substantially higher growth patterns across almost all forecast layers. The third scenario is IDP Expanded Non-Residential, which amplifies commercial and industrial business growth rather than all forecast types.

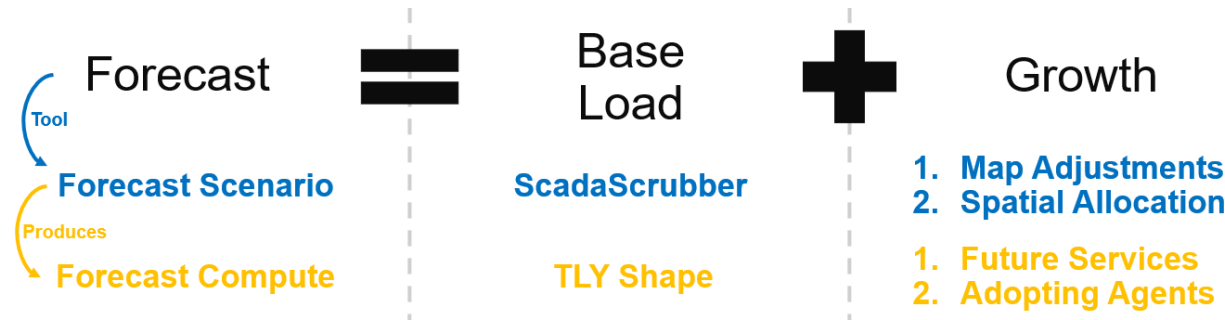


In the following sections, we describe the methodology and corporate forecast allocations that were used for each growth component to create the LoadSEER forecast scenarios. *Attachment L* provides the tabular forecast data for the charts below in live Excel format.

1. *LoadSEER Forecasting Methodology*

LoadSEER is a spatial load forecasting tool that is used by electric distribution system planners to predict how much power must be delivered, where on the grid the power is needed, and when it must be supplied. It integrates geospatial data, system and customer level data, historical and forecasted weather patterns, as well as distribution load flow application data to produce a forecast.

The methodology behind how a forecast is assembled can be illustrated by a generalized formula:

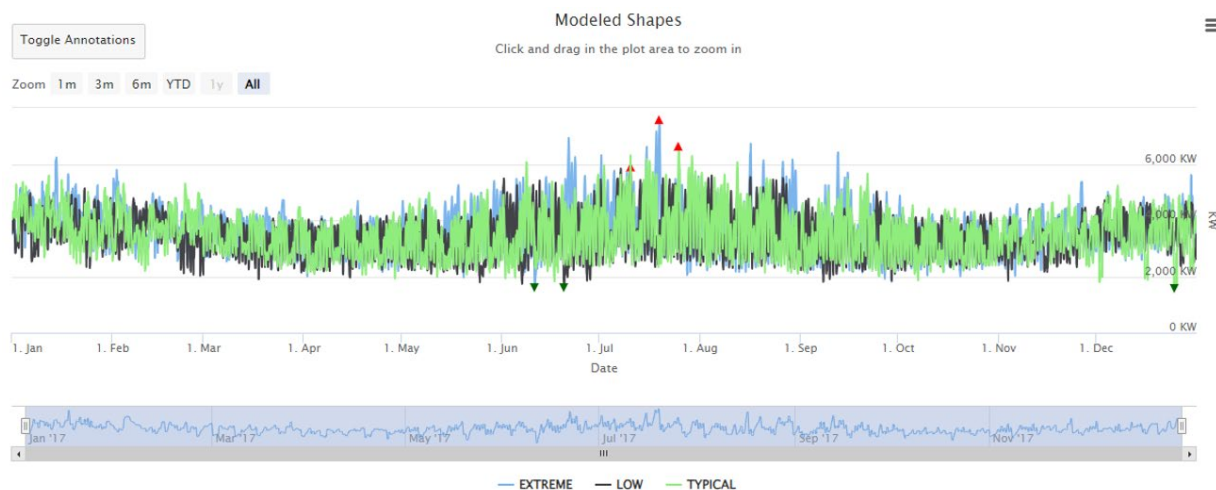


The forecast consists of two main components, which involve constructing a base load and then adding a growth propensity.

The base load is compiled using a LoadSEER tool called ScadaScrubber. The primary function of this tool is to develop Typical Load Year (TLY) shapes, which represent the load on the circuit today under different weather scenarios. The TLYs are 8,760 shapes, meaning that they represent the hourly loading on the feeder throughout a full year.

Users of ScadaScrubber have the capability to clean historical SCADA data, which eliminates operational switching impacts as well as any other data abnormalities. ScadaScrubber also load- and weather-normalizes the SCADA data before re-simulating it against a low, typical, and extreme weather scenario to produce the TLY shape. It does this by assembling 30 years of hourly historical weather datasets that are available at the weather station closest to the feeder or substation transformer being analyzed. Once a TLY has been produced, as shown below in Figure 1-19, it then can be imported into LoadSEER for inclusion in a load forecast.

Figure 1-19
TLY Shape Example in LoadSEER



Once a TLY has been created to represent the base load, load growth in the forecast is then accounted for via map adjustments and spatial allocation.

Map adjustments are primarily used to represent known load growth in the load forecast. When a customer applies to interconnect load to our distribution system or requests a capacity check, a map adjustment can be used to account for that added load at the corresponding geographic location in the LoadSEER model. When a map

adjustment is added, a load shape that represents the expected hourly demand of that customer is also identified in LoadSEER. This is helpful for distribution planning because the customer's peak demand is not always coincident with the feeder or substation transformer peak demand, so using load shapes for map adjustments enables a more accurate capacity check process than was possible prior to the LoadSEER implementation.

Map adjustments can also be used to flag areas where the Company anticipates there to be higher levels of adoption of a particular technology. For example, if a strip mall has reached out to the Company to inquire about adding EV chargers at their parking lot but is not ready to install for several more years, a map adjustment for the potential of that load addition can still be added. Rather than “locking” the map adjustment, which effectively guarantees that the load will be included in the forecast, it would instead have a representative probability of adoption that is fed as an input into the Spatial Allocation. These conceptual future potential map adjustments can assist in increasing the accuracy of the forecast by focusing the probabilistic, long-term load growth to geographic areas with a higher propensity of adoption of a particular technology.

Whereas map adjustments are manually added to the LoadSEER model by the Company, Spatial Allocation is generally done in collaboration with Integral Analytics, the developer of LoadSEER. Spatial Allocation is a significantly more intelligent and automated approach to simulating load growth across the distribution system than map adjustments. However, having both map adjustments and Spatial Allocation work in conjunction with each other significantly increases forecast accuracy, so both are necessary.

The concept of Spatial Allocation can be summarized into a generalized formula:

$$\text{Spatial Allocation} = \text{Future Potential Adoption Points} + \text{Shapes} + \text{Forecasts}$$

The key function of Spatial Allocation is to simulate load growth across the system via a probabilistic model for agent adoption that determines likely innovators and imitators. It takes a forecast that is typically at a high-level node in the asset hierarchy, like state or operating company, and then disaggregates that forecast intelligently to existing and future customers at specific locations on the distribution system. The

Company provides LoadSEER with a system-wide forecast and hourly shape for a particular technology as inputs for the Spatial Allocation. The Company then collaborates with Integral Analytics to identify future potential adoption points relevant to the forecast supplied. During this process, the goal is to guide Integral Analytics to indicate which data services to target, supply any relevant external data sets, and supply internal information regarding high adoption areas.

Shapes in LoadSEER provide an hourly estimation of customer loads for a particular technology or customer type. These shapes are developed using both internal data sets and industry collaborations with institutions, such as NREL and EPRI. As AMI data availability proliferates, the Company anticipates that these shapes will improve in accuracy. These shapes are used in LoadSEER for map adjustments, Spatial Allocation, and the forecast as a whole.

Growth can come from a variety of different factors, including new customers being interconnected with the distribution system, changes in customer usage patterns, and the adoption of different DER technologies such as solar PV, electric vehicles, and more. To address this, each type of growth is allocated in a unique run of the Spatial Allocation that is designed to target and model the adoption of that specific type of growth or technology. To compute a load forecast, Distribution Planners can select any individual or combination of Spatial Allocation runs to add to the base load TLY shapes. This allows the Company to either isolate a particular growth factor to understand how it is individually affecting distribution system loading or merge multiple growth factors together to see the aggregate net impact that a variety of technologies will have in the long term.

Once all TLY base load shapes, Spatial Allocations, and map adjustments have been developed, they are all merged into a grouping called a scenario. Scenarios in LoadSEER allow a user to run sensitivity studies on different forecast components. For example, if desired, a user can see the impacts of increasing the impact of a particular spatial allocation and decreasing a different one.

Once the scenarios are configured as desired, a load forecast can then be computed. To compute a load forecast, LoadSEER adds the load growth from all the selected Spatial Allocations and map adjustments to the TLY base load shapes for each affected feeder and substation transformer. This then creates an 8,760-hour representation of the feeder and bank loading for each year of the 30-year forecast. Figure 1-20 shows an example of this forecast data, summarized to an annual peak load value.

Figure 1-20
Example of Node-Level Forecast Data Shown in LoadSEER

Node Name	NodeID	2024 Peak Load	2025 Peak Load	2026 Peak Load	2027 Peak Load	2028 Peak Load	2029 Peak Load	2030 Peak Load
Substation 1	SUB1	118552	121987	125513	129268	133782	138336	144282
SUB1_13.8 kV	SUB1_13.8 kV	118552	121987	125513	129268	133782	138336	144282
Substation 1 115/13.8 kV TR2	SUB1_TR2	24701	25349	25785	26447	27314	27816	29022
Substation 1 115/13.8 kV TR3	SUB1_TR3	58373	60542	62653	64531	66850	69243	72038
Substation 1 115/13.8 kV TR4	SUB1_TR4	49646	50518	51770	53267	54938	56881	58920
Substation 1 115/13.8 kV FDR071	FDR071	0	0	0	0	0	0	0
Substation 1 115/13.8 kV FDR072	FDR072	8942	9034	9287	9768	9993	10159	10451
Substation 1 115/13.8 kV FDR073	FDR073	6657	6657	6660	6660	6661	6661	6781
Substation 1 115/13.8 kV FDR074	FDR074	0	0	0	0	0	0	0
Substation 1 115/13.8 kV FDR075	FDR075	5068	5070	5071	5072	5141	5142	5142
Substation 1 115/13.8 kV FDR076	FDR076	9484	10038	10217	10398	10962	11297	12100
Substation 1 115/13.8 kV FDR081	FDR081	3024	3027	3106	3187	3500	3504	3740
Substation 1 115/13.8 kV FDR082	FDR082	7881	7900	8080	8437	8871	9137	9406
Substation 1 115/13.8 kV FDR083	FDR083	8710	9268	9511	9696	10101	10892	11367
Substation 1 115/13.8 kV FDR084	FDR084	7151	7704	8528	8950	9594	10002	11045
Substation 1 115/13.8 kV FDR085	FDR085	9970	10328	10497	10747	11010	11321	11802
Substation 1 115/13.8 kV FDR086	FDR086	11523	11663	11861	12026	12125	12350	12447
Substation 1 115/13.8 kV FDR087	FDR087	4953	5169	5191	5343	5364	5448	5467
Substation 1 115/13.8 kV FDR088	FDR088	12791	12954	13196	13359	13456	13704	13805

2. *Expected DER Output and Generation Profiles*

IDP Requirement No. 3.D.2.e requires the Company to provide:

...costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, load profiles of electrification, etc.).

For more robust scenario analyses on a feeder, DER generation profiles are helpful and available. With PV systems, we can refer both to our internal generation profiles developed from conducting load research on our customer PV systems or utilize a public tool like NREL’s PVWatts tool. We have also made some assumptions on EV charging usage, based on information through our residential EV service pilot program, but also compare against industry research to validate our assumptions. We additionally have several end-use load shapes available through our DSM program. These energy efficiency load shapes are generally used to determine the avoided marginal energy benefits of various DR and energy efficiency achievements.¹⁷ In the future, we anticipate that additional capabilities from AMI meters will be the primary source of data used for load research load profiles.

¹⁷ The Company’s 2024-2026 ECO Triennial shows the energy efficiency and incremental demand response targets including load shape information.

3. Corporate-Level Forecasts in LoadSEER Spatial Allocation

IDP Requirement No. 3.C.1 requires, in part:

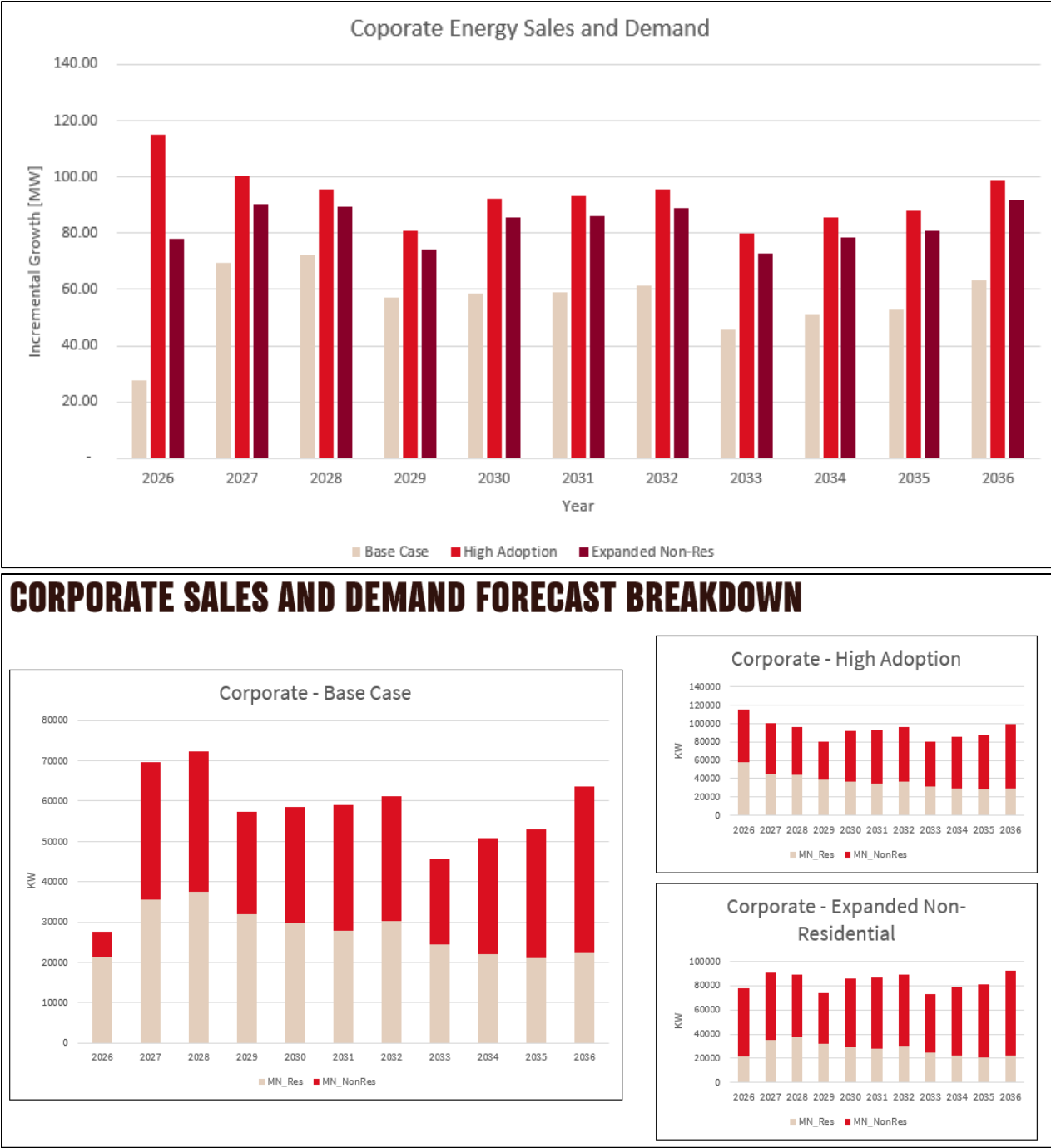
In order to understand the potential impacts of faster-than-anticipated DER and electrification adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER and electrification deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER and electrification adoption and aggregated or bundled DER/ electrification service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER and electrification growth take place first, and how the [utility] would anticipate the combined impacts of simultaneous DER and electrification growth.

The following section addresses how corporate-level forecasts are modeled in the LoadSEER Spatial Allocation; the corporate forecast methodologies are discussed in Section III.B above. Each allocated forecast has unique characteristics to consider when implementing in a load forecast in LoadSEER. The forecasts that are currently allocated in LoadSEER are the corporate energy sales and demand, electric vehicle, beneficial electrification, solar PV, battery storage, and energy efficiency.

4. Corporate Energy Sales and Demand

This year, one of the improvements made to this forecasting layer is that we now have separate forecasts for residential vs non-residential sales and demand growth. In 2023 it was lumped into one forecast. Another improvement this year is that there is a different energy sales and demand forecast for all three IDP scenarios. The third improvement is that energy efficiency is now a standalone forecast allocation in LoadSEER rather than being embedded into the Corporate Energy Sales and Demand forecast totals. The IDP Base Case forecast is based on the Company's corporate-level July 2025 forecast, and the Expanded Non-Residential scenario increases the anticipated load growth for non-residential types (including data centers connected on the distribution system). The High Adoption scenario builds off the Expanded Non-Residential forecast by also including increased load growth for residential customers. To allocate this forecast to the distribution system in LoadSEER, the difference in annual system peak load is calculated year-over-year and that change in peak demand is allocated to the feeders. The corporate demand forecast currently includes the impact of demand response, so those load-reducing impacts are balanced against anticipated new customer interconnections. Figure 1-21 shows the incremental growth allocated to the distribution system for each year of the 10-year forecast in LoadSEER.

Figure 1-21
Incremental Growth from Corporate Demand Forecast in LoadSEER



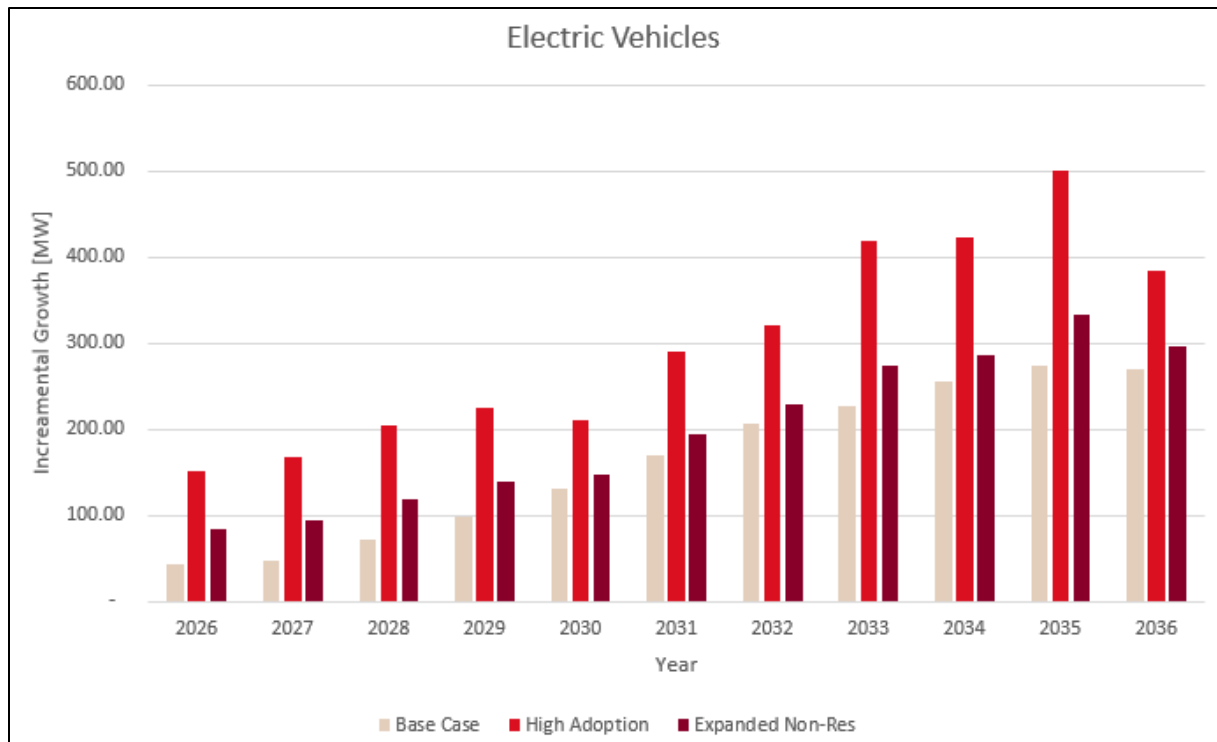
5. *Electric Vehicles*

Previously in the 2023 IDP, the EV forecast was allocated to the distribution system in LoadSEER based on the quantity of EVs. In this 2025 IDP, one of the improvements made is that the EV forecast is now allocated in kW to better reflect the actual loading impact on the distribution system, including through managed charging.

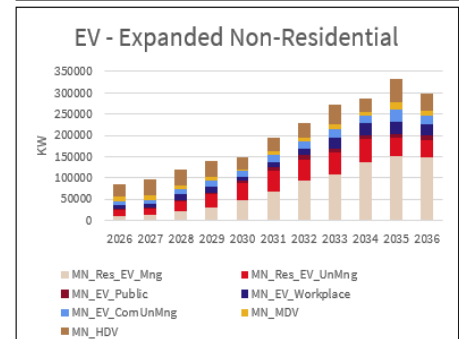
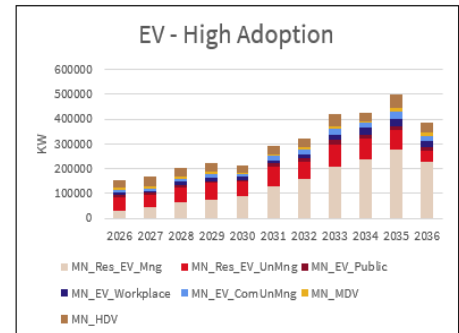
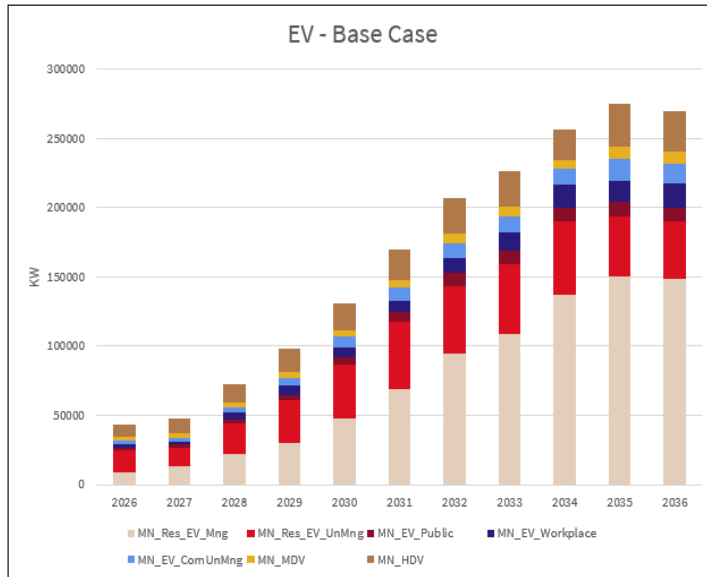
For EVs, the IDP Base Case forecast is based on the Company's corporate-level July 2025 forecast. The Expanded Non-Residential scenario increases the anticipated load growth for EV's at non-residential locations, such as fleet charging. The High Adoption scenario builds off the Expanded Non-Residential forecast by also including high adoption of EV's for residential customers. Separate allocations were created for LDV residential, LDV Public, LDV Workplace, LDV Commercial, MDV and HDV. For LDV residential, this year one of the improvements made was to split the forecast up into both managed and unmanaged charging.

The EV forecast allocations that were used in LoadSEER are shown in Figures 1-22.

Figure 1-22
Incremental Growth from EV Forecast in LoadSEER



ELECTRIC VEHICLE FORECAST BREAKDOWN



6. Beneficial Electrification

Order Point No. 3.a of the Commission's September 16, 2024 Order in Docket No. E002/M-23-453:

In its next IDP, Xcel shall report on its progress to improve forecasting, including:

a) Refining its residential beneficial electrification forecasts to include low, medium, and high adoption scenarios.

Order Point No. 3.b of the Commission's September 16, 2024 Order in Docket No. E002/M-23-453:

In its next IDP, Xcel shall report on its progress to improve forecasting, including:

b) Presenting an initial C&I beneficial electrification forecast, or if the Company is unable to complete one by that time, the Company shall explain why not and include a detailed explanation of how it is thinking about this forecast, information challenges it raises, and approaches Xcel is considering.

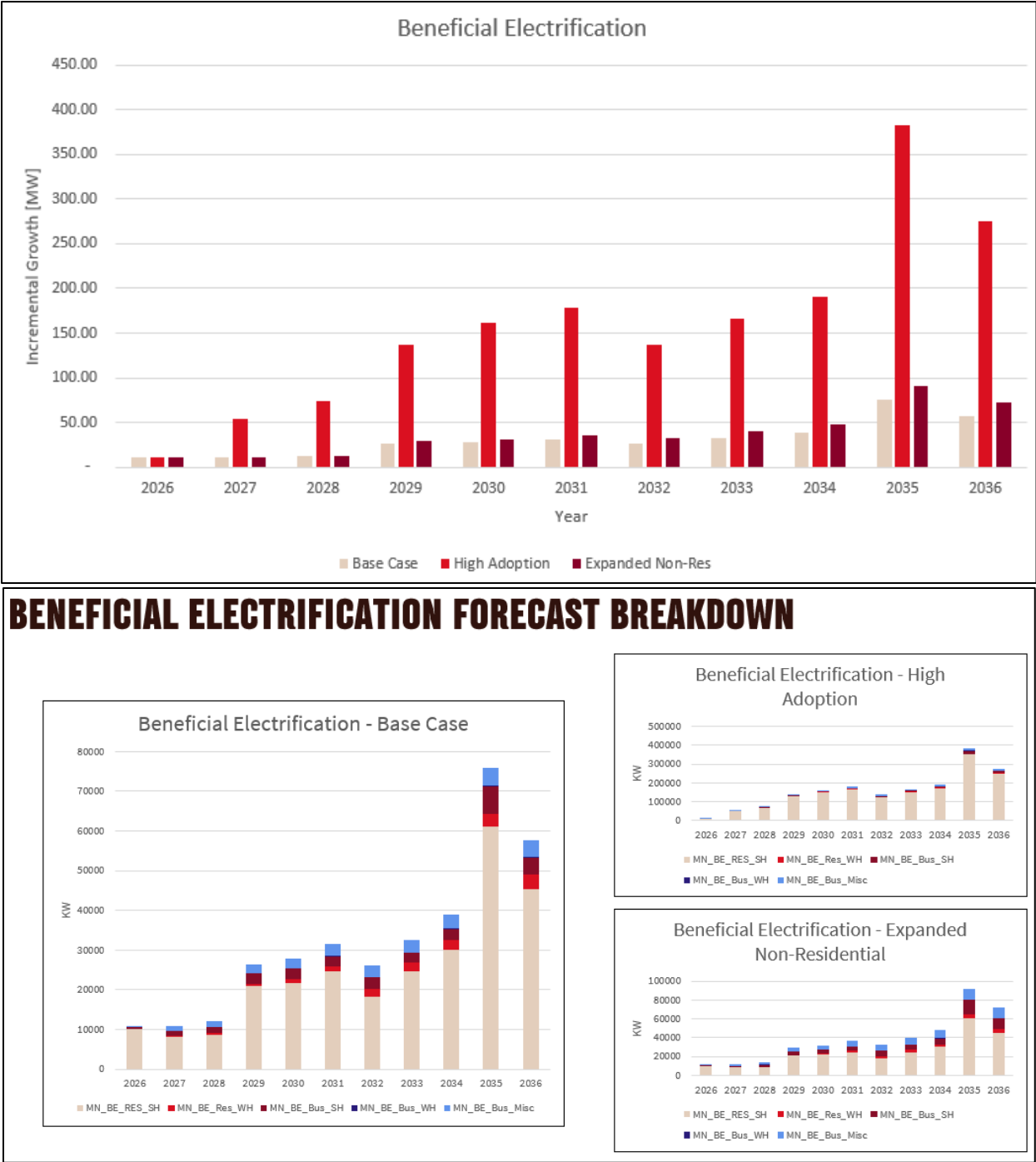
Beneficial Electrification (BE) has made a large step forward in this year's IDP compared to 2023. This year, the corporate-level BE forecast for Minnesota includes

non-residential customers. For BE, the IDP Base Case forecast is based on the Company's corporate-level July 2025 forecast. The Expanded Non-Residential scenario increases the anticipated BE load growth for non-residential customers. The High Adoption scenario builds off the Expanded Non-Residential forecast by also including high adoption of BE for residential customers. There are several discrete allocations for BE; Residential space heat and residential water heat, business space heat, business water heat, and business miscellaneous (such as businesses electrifying industrial processes, etc).

In regards to Order Point No. 3.a, while this year there are only two residential BE forecasts, those forecasts work together with the new C&I BE forecasts to create three distinct overall BE forecast scenarios. The three IDP scenarios were thoughtfully chosen to reflect a variety of forecast layers and ramping select ones up while keeping others steady to reflect meaningful variances in adoption rates. As a result of this, the Base Case and Expanded Non-Residential scenarios both use the same base case residential BE forecast values, but in the High Adoption scenario, the residential BE values are ramped up.

The allocation that was used in LoadSEER is shown in Figure 1-23 below.

Figure 1-23
Incremental Beneficial Electrification Growth Allocated in LoadSEER

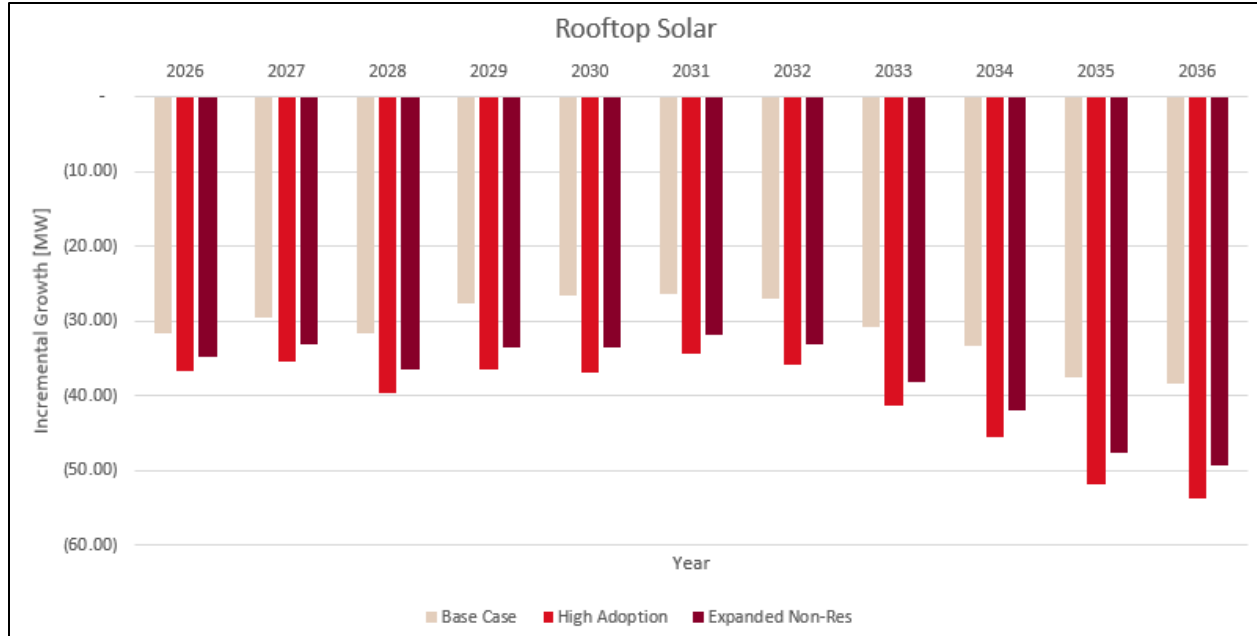


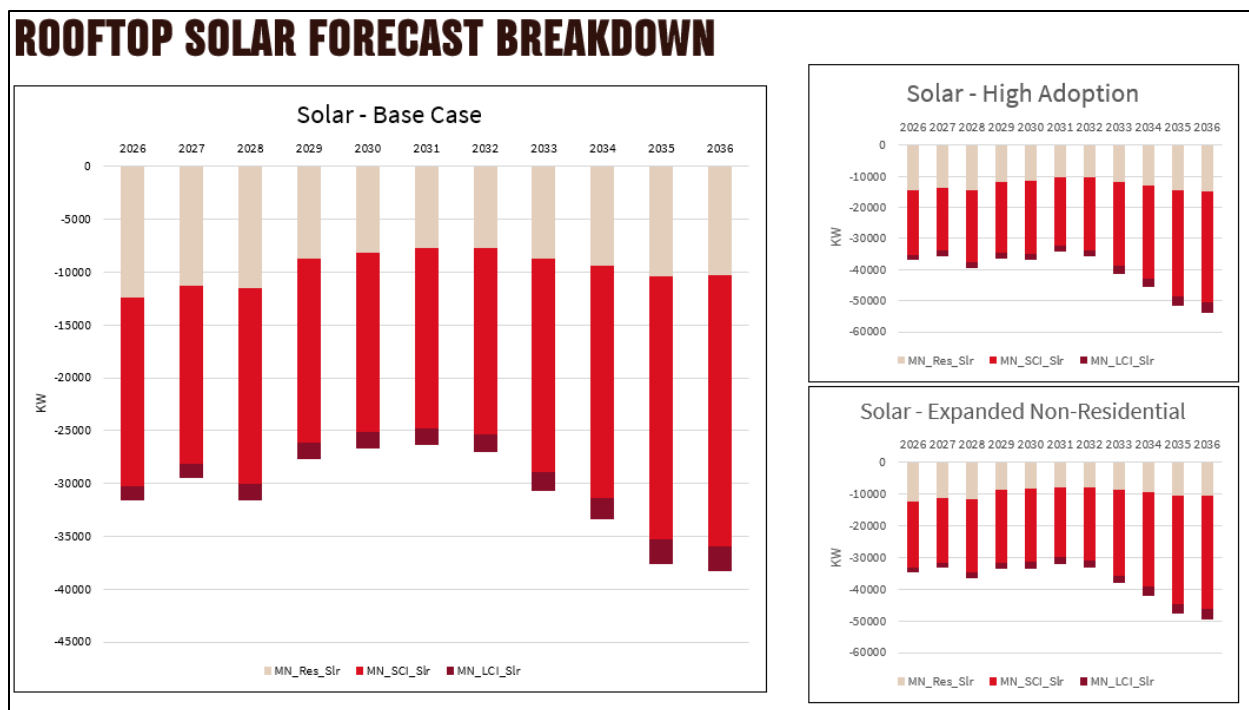
7. *Solar PV*

The Solar PV allocation in LoadSEER was divided into two components: rooftop solar, and front of the meter (FTM) solar. One of the improvements made this year was to further split up the rooftop solar component into three allocations – residential and non-residential (small CI and large CI). We also note that the solar forecasts were developed summer of 2025 for the Company’s July 2025 forecast, which was prior to the news of the Investment Tax Credit (ITC) ending at the end of 2025. Thus, any market impacts from this change that would cause fluctuation in this forecast data are not included.

For rooftop solar PV, the IDP Base Case forecast is based on the Company’s corporate level July 2025 forecast. The Expanded Non-Residential scenario increases the anticipated PV at non-residential locations. The High Adoption scenario builds off the Expanded Non-Residential forecast by also including high adoption of PV for residential customers. This allocation is shown in Figure 1-24 below.

Figure 1 - 24
Incremental Rooftop Solar PV Growth Allocated in LoadSEER





The FTM solar PV forecast includes two categories: CSG, and the required distributed solar for the Distributed Solar Energy Standard (DSES) established in the 2023 Minnesota legislative session.¹⁸ There is significant overlap in the potential future adoption points (i.e., locations) for both of these categories. Therefore, the two must be combined into one allocation.

We estimate that approximately 582 MW of nameplate solar will be needed by 2030 to meet the DSES target. To develop a forecast, we made assumptions about the timing of solar interconnections to our distribution system between now and 2030. In the first RFP issued in 2025, we targeted 200 MW, received proposals totaling 57 MW, and shortlisted 47 MW. Currently, 19 MW remain in negotiations following project withdrawals. We are required to issue additional RFPs every 18 months until our DSES obligations are met, with the next RFP scheduled for June 2026. The 582 MW target and associated timing assumptions are consistent across all three LoadSEER DER scenarios, which drive a significant increase in incremental front-of-the-meter (FTM) solar between 2026 and 2029.

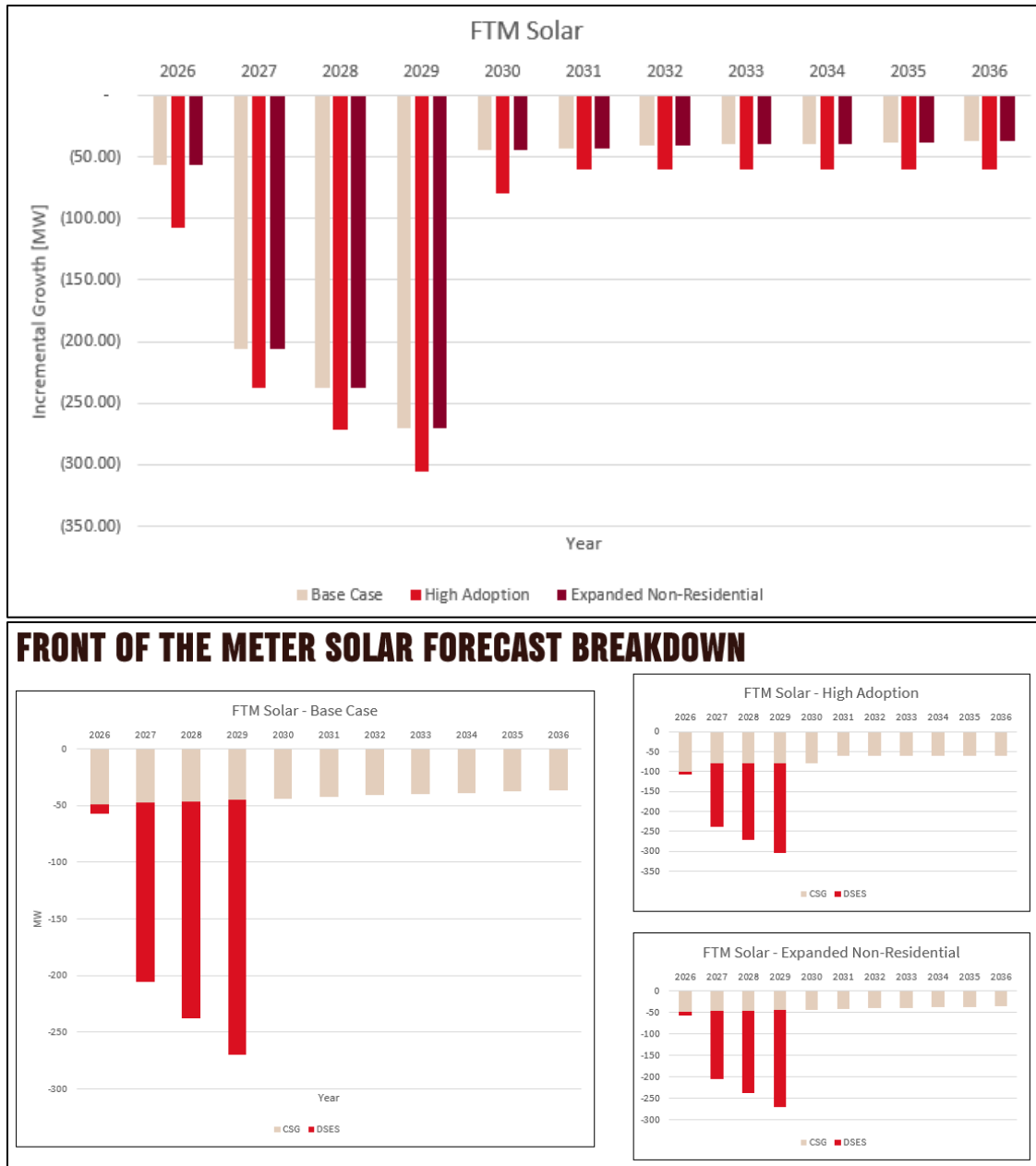
For the CSG category of the FTM forecast, the IDP Base Case forecast is based on the Company's corporate-level July 2025 forecast. The Expanded Non-Residential

¹⁸ Minn. Stat. § 216B.1691, subd. 2h, as added by 2023 Session Laws Chapter 60, Article 12, Section 16.

scenario is the same as the Base Case. The High Adoption scenario assumes high adoption of FTM solar.

The three LoadSEER allocations for FTM solar PV are shown in Figure 1-25 below.

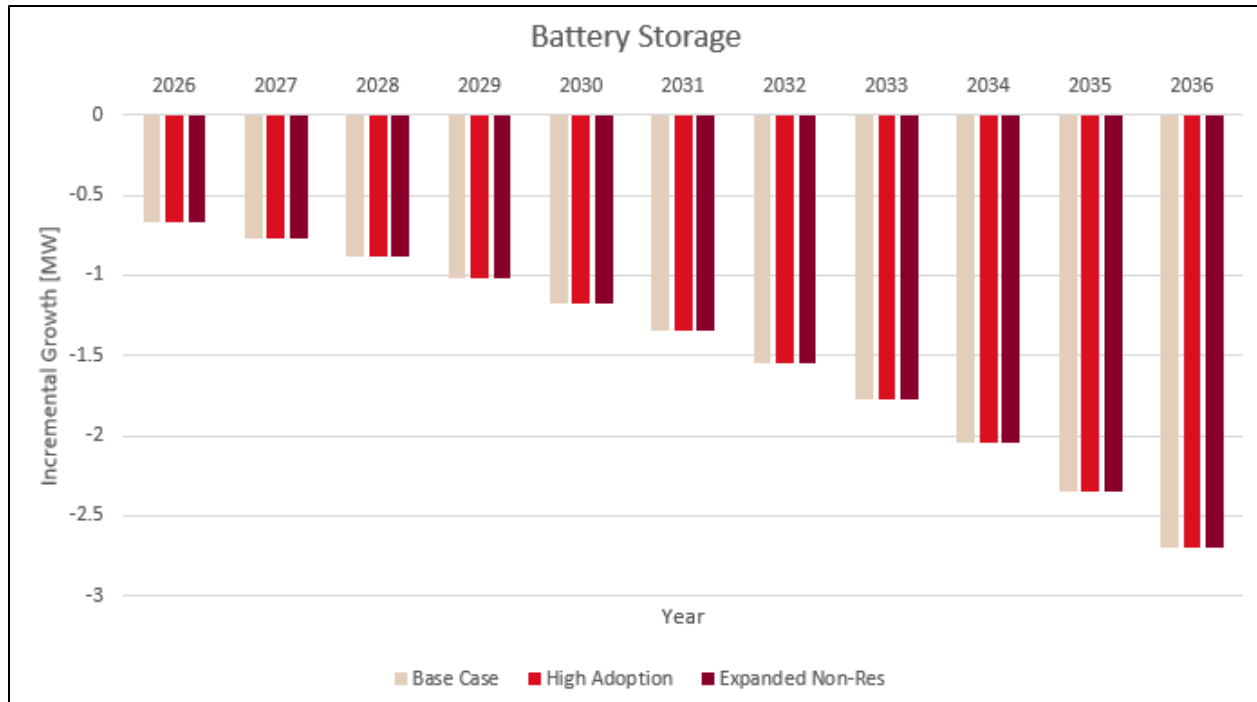
Figure 1 -25
Incremental FTM Solar PV Growth Allocated in LoadSEER



8. Battery Storage

For battery storage, all three IDP scenarios are the same and are based on the Company's corporate level July 2025 forecast. This allocation is shown in Figure 1-26 below.

Figure 1 -26
Incremental Battery Storage Growth Allocated in LoadSEER



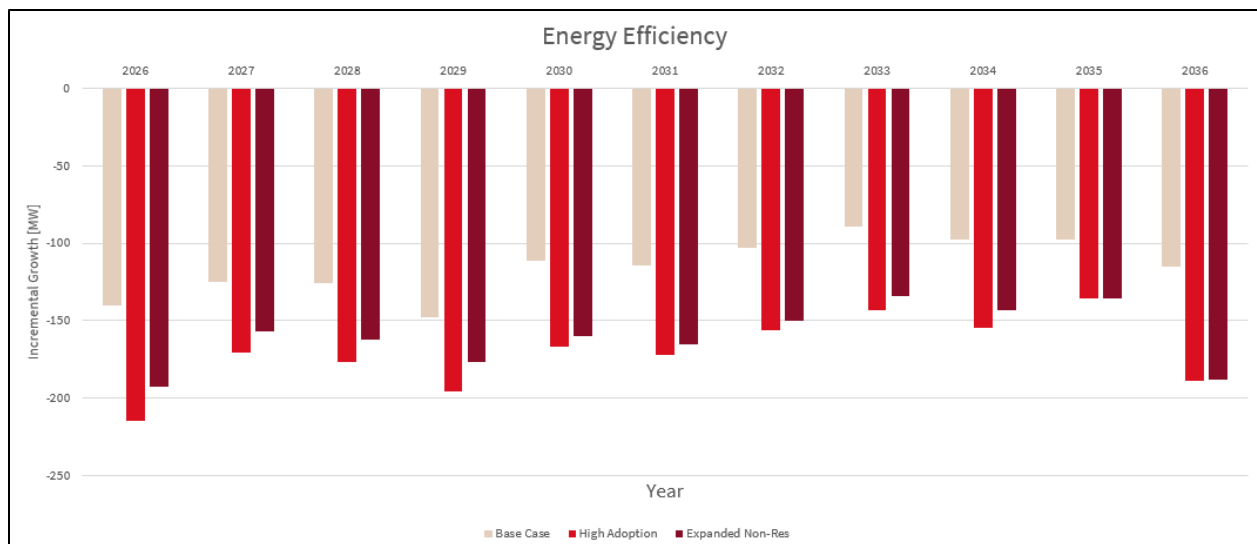
*Forecasts do not include Capacity*Connect, our proposed Distributed Capacity Procurement

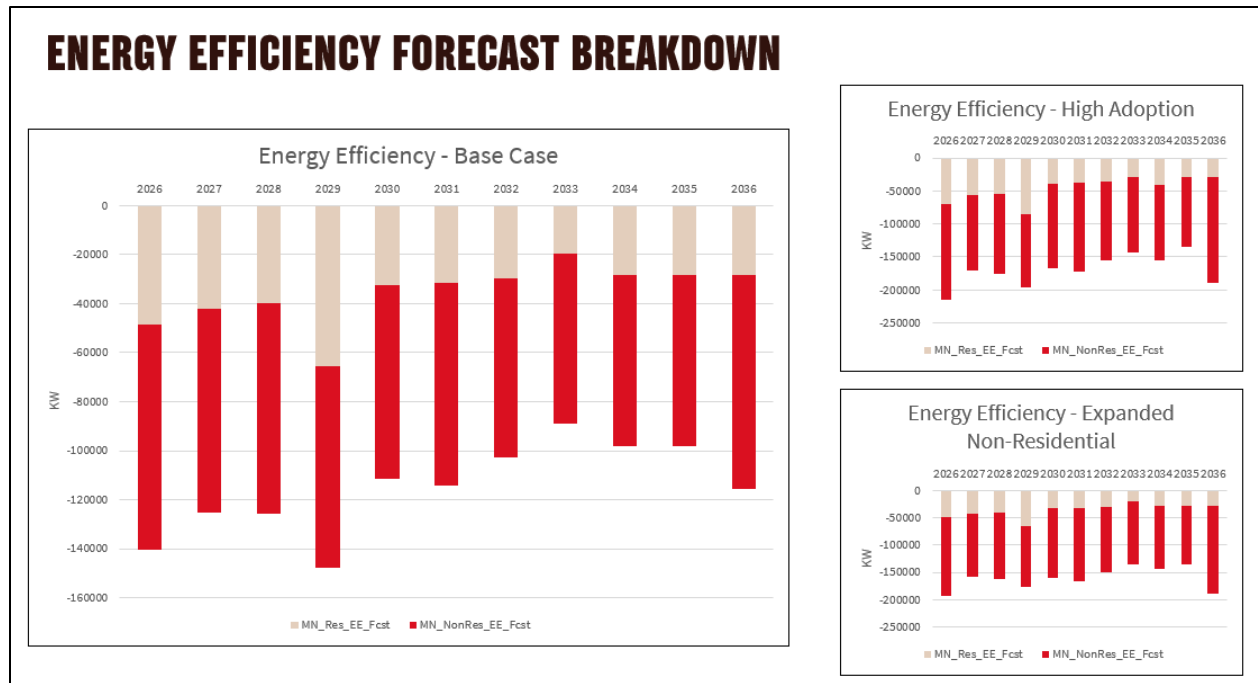
9. Energy Efficiency

This is the first year of including energy efficiency as a separate allocation in the LoadSEER forecast. Previously the impacts of energy efficiency had been embedded in the Corporate Energy Sales and Demand forecast totals. For Energy Efficiency, the Company's 2024-2026 ECO Triennial is the basis of the IDP Base Case scenario. The Expanded Non-Residential and High Adoption Scenario scenarios were developed using the IRP's high case (inclusive of Bundle 3 as described in section III B.5). Energy efficiency in LoadSEER was allocated to existing and future customers, and separate shapes were allocated for residential and non-residential customers.

Incorporating a separate allocation for energy efficiency impacts in LoadSEER within this IDP represents a meaningful advancement in our forecasting methodology. However, geospatially allocating these forecast adjustments presents distinct challenges compared to other forecast types. For example, the Company does not have comprehensive data on energy-efficient appliances, lighting, and other technologies already adopted by existing customers. As a result, assigning efficiency-driven load reductions to specific customer locations in the model may over- or under-represent the true energy efficiency potential at those sites. We recognize these limitations and will continue to refine this methodology moving forward.

Figure 1-27
Incremental Energy Efficiency Allocated in LoadSEER

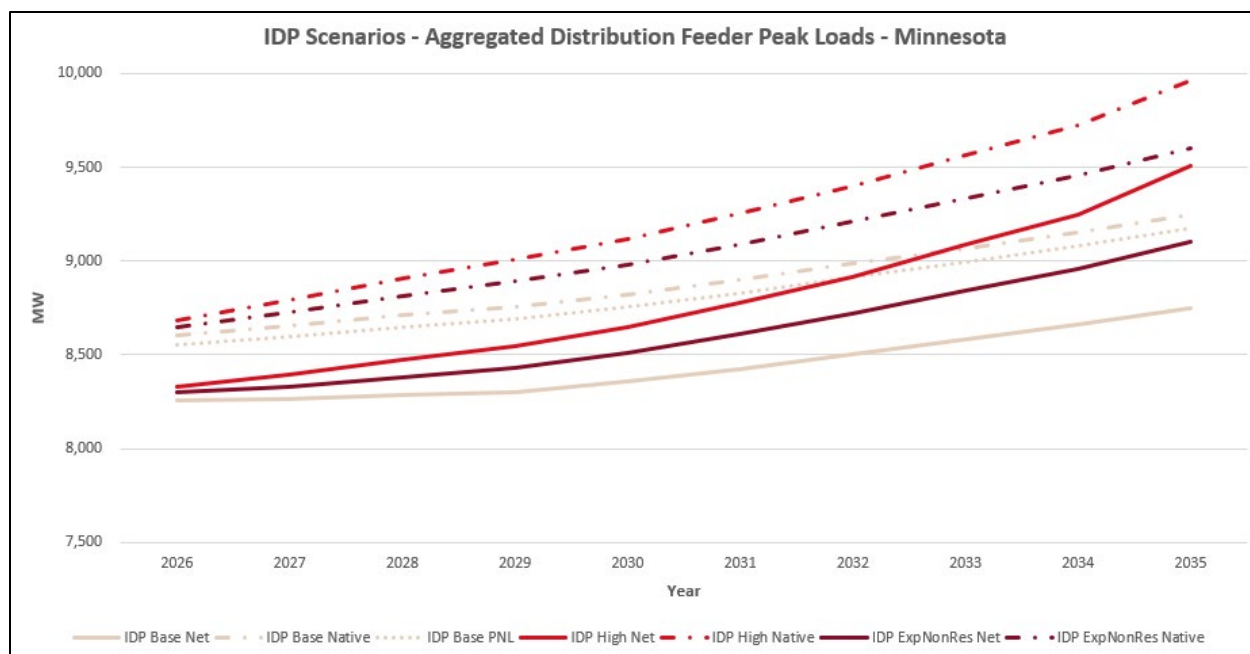




10. Results of LoadSEER Location-Specific Distribution DER Forecast Scenarios

After the allocations are executed in LoadSEER, the results are combined to compute the forecast for all distribution feeders and substation transformers as discussed in Section III.C.1 above. By aggregating the resulting feeder peak loads in the state of Minnesota for each year, we see the total non-coincident peak demand of the distribution system as shown in Figure 1-28.

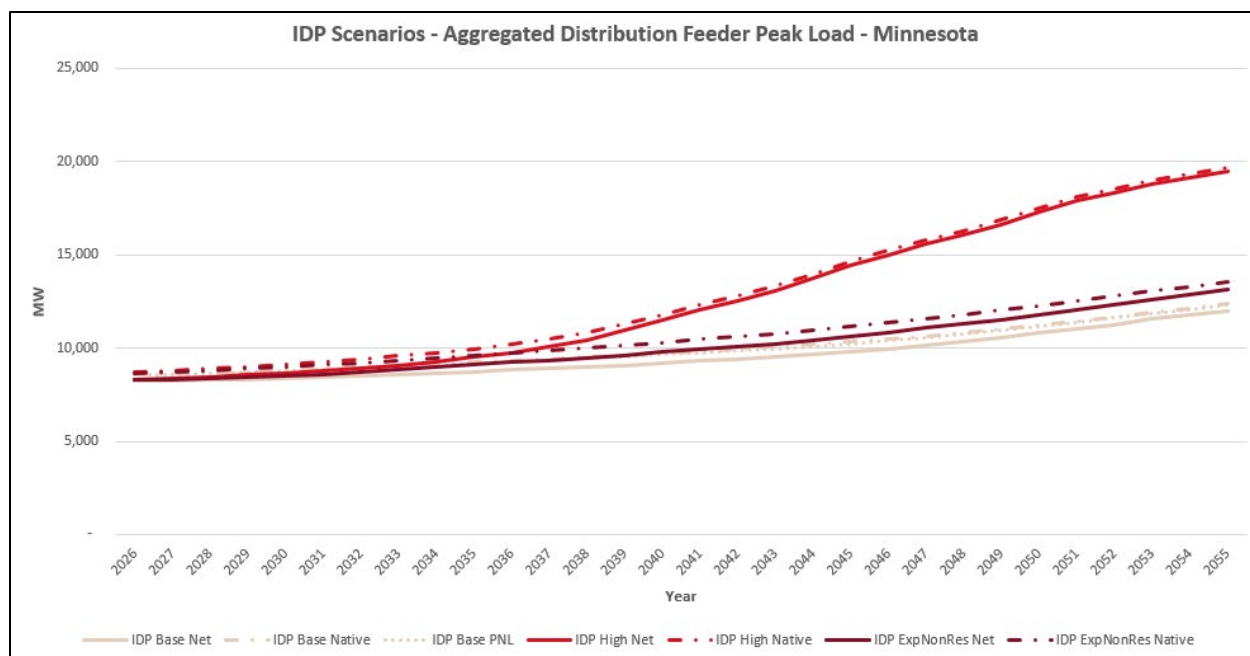
Figure 1 - 28
Total Non-Coincident Distribution Peak Demand Forecast – Aggregated Feeder Peak Load



Overall, the aggregate total of non-coincident feeder peak demands on the distribution system in Minnesota is expected to increase from around 8.5 GW today to over 9.3-10 GW by 2035. Both the net and native load for each scenario are also shown in Figure 1-28, where the native load does not include the load-reducing impact of the existing and forecasted generation on the distribution system but the net load does. The difference between the net and native peak load, in aggregate, is about five percent

LoadSEER is also capable of producing forecasts up to 30 years into the future. When 30-year DER adoption forecasts are allocated in LoadSEER (following the same methodology as described above), the resulting aggregate non-coincident feeder peak demand forecast can be seen in Figure 1-29.

Figure 1 - 29
Total Non-Coincident Distribution Peak Demand 30-Year Forecast –
Aggregated Feeder Peak Load



The 30-year forecast shows all three scenarios increasing from around 8.5 GW today to 12-20 GW by 2052. It also creates perspective, in that the growth from 8.5 GW today to 10 GW by 2035 is only the precursor to a more rapid rate of growth in the following 20 years.

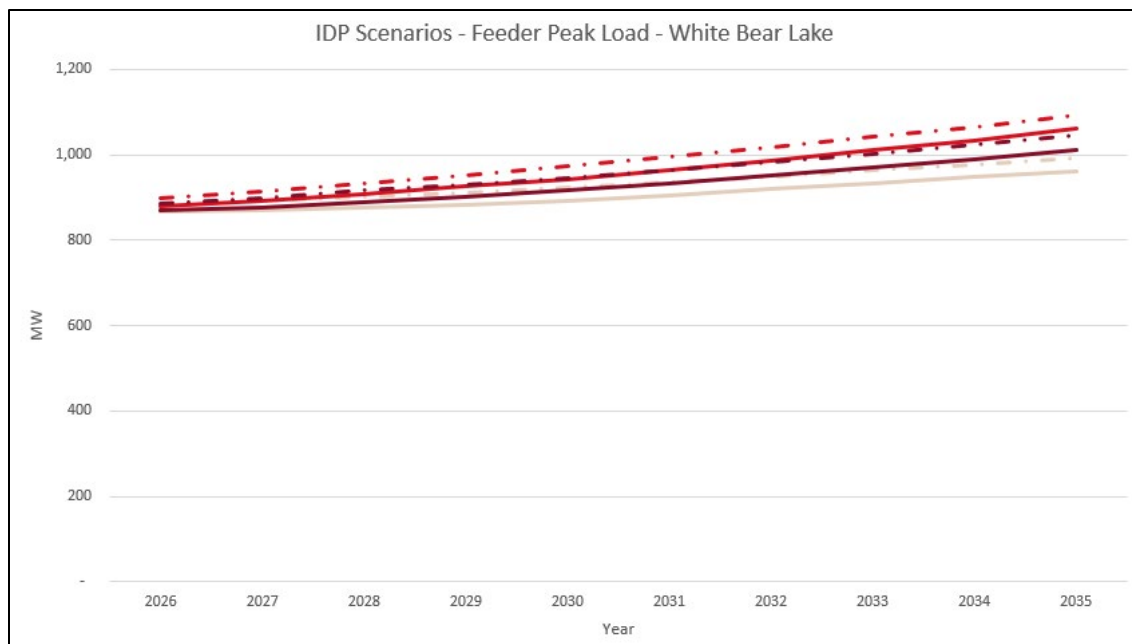
This is where we start to see the value in the three different scenarios chosen this year. In 2023, all three scenarios resulted in relatively similar values. This year the three different scenarios start to form upper and lower bounds of growth expectations.

A noteworthy observation is that the difference between the net load and native load, in aggregate, decreases slightly over the 30-year forecast. This is because, despite allocating several gigawatts of distributed solar PV during the 30-year forecast, the significant amount of EV and BE load allocated pushes many feeder peaks late into the evening, outside of the hours when solar PV is typically generating. Another interesting observation is that approximately between the mid-2040s and the early 2050s, a little over half of the system switches to a nighttime winter peak rather than an afternoon summer peak. This is again primarily driven by the managed EV charging forecast as well as beneficial electrification.

The 2025 forecast shows slightly slower load growth than the 2023 forecast—particularly in the Base Case and Expanded Non-Residential scenarios. This is largely due to an updated EV forecast. While EV adoption is still expected to grow, the 2025 forecast uses a more accurate method for assigning EV load to feeders. This improved approach better reflects how managed charging affects the distribution grid. Previously, we allocated by quantity of EVs and then used an assumed magnitude of kW charging demand for each EV. This year we allocated by kW to start, which leads to a better understanding of the actual loading impact that electric vehicles have, in aggregate, on the grid.

The LoadSEER forecast results can also be seen summarized by planning division in *Attachment L* (see “Planning Area Peak Load” tab). Most planning areas experience between six and eight percent growth between 2026 and 2035. Two outliers, however, are the Southeast and White Bear Lake planning areas. The growth in Southeast is lower than average during the same period, at about five percent growth; primarily driven by lower allocated growth from both EV Residential and BE forecast types. By contrast, the White Bear Lake planning area shows higher than average growth during the same period, at about twelve percent growth; primarily driven by higher allocated growth from the Corporate Energy Sales and Demand, EV Residential, and BE forecast types.

Figure 1-30
IDP Scenarios- Feeder Peak Load- White Bear Lake



In total, the forecasted impacts on the distribution system are significant and indicate the need to accelerate the rate of investment in distribution system capacity to be able to meet the needs of our customers over the coming decades. The location-specific forecasting results in LoadSEER do identify substations and feeders where this growth rate is higher or lower, but the upward trend in load-serving need is fairly common across most of the distribution system.

In the coming years, we will continue to refine the assumptions and inputs in our LoadSEER modeling. We will also continue investigating investments in technologies that may be needed to safely and reliably manage the grid of the future and could be used to reduce the need for traditional capacity upgrades. The impacts of this unprecedented load growth will reach beyond the distribution system, and we will be working collaboratively with our Transmission Planning, Gas Planning, and Resource Planning business groups to further align on forecast assumptions and plans.

Order Point 5 of the Commission's 2024 IDP Order requires:

Xcel shall provide a comparison of the forecast provided in the IDP to actuals in its next IDP.

Below is the comparison of the 2023 IDP forecast to actuals in Table 1-11. As anticipated, the results do not necessarily align. This can happen for multiple reasons, including:

- Weather impacts – cooler weather during the summer generally results in lower peak loads.
- New customers not coming online in the year expected
- New customer loads coming in less than the forecasted peak demand value
- Load switching – While we don't usually record abnormal peak load values that occur due to switching on the distribution system, in some cases it is difficult for engineers to distinguish between a switching event and permanent changes in a feeder's loading when reviewing historical loading data.
- Changes to aggregate distribution feeder peaks – While there are changes to the aggregate peaks, this is not particularly important for distribution planning purposes. We need to plan for all assets on the system annually, including each individual feeder and each substation bank (approximately 1,500 assets).

Table 1-11
Comparison of 2023 IDP Forecast to Actuals

Aggregate Distribution Feeder Peak Load- MN (MW)		
	2023	2024
Historic Actuals	8,205	7,996
2023 IDP Low Native	8,702	8,806
2023 IDP Med Native	8,708	8,819
2023 IDP High Native	8,715	8,837

The distribution system is constantly changing, and peak demand values can fluctuate yearly. The Company utilizes forecast data to inform its distribution system planning, ensuring infrastructure is designed to reliably serve the maximum load that could reasonably be encountered. While actual peak loads in a given year may fall below forecasted values, such deviations do not inherently indicate inaccuracies in the forecast. For example, cooler-than-average summer weather may suppress peak demand, but similar conditions to prior warmer years could result in those historic peaks being met or exceeded again. Additionally, it is not necessarily appropriate to rely solely on metrics such as average summer temperature, maximum temperature, or cooling degree days to determine whether a year's peak load should be considered indicative of typical system demand under design conditions. While such metrics may provide insight into overall energy consumption, peak load events are driven by a confluence of factors, including weather, customer behavior, energy prices, and broader economic conditions, that must be considered holistically in the planning process.

11. LoadSEER Forecast Accuracy

Order Point 3.c of the Commission's 2023 IDP requires:

In its next IDP, Xcel shall report on its progress to improve forecasting, including:

c) Evaluating the accuracy of LoadSEER forecasts.

LoadSEER does not currently have metrics or analytical capabilities related to evaluating the accuracy of its forecasts. However, in parallel, there's been substantial work done to improve the granularity of the system-level forecast provided as an input to LoadSEER. Specifically, the Company updated its bulk system peak demand forecast method (the "8760" forecast method described earlier) for use in the 2024-2040 Upper Midwest Resource Plan. Under this approach, each load component (Base load, DG Solar, DSM, Beneficial Electrification, new large customers, and Electric Vehicles) is modeled and forecast individually and at the hourly level. Further

segmentation within each component allows for more precise representation of unique demand profiles. For example, electric vehicle load is no longer modeled as a single series/impact; instead, our modeling incorporates the distinct impacts of residential light duty charging, public charging, workplace and general commercial charging, and medium- and heavy-duty vehicle charging. This improved granularity allowed the Company to develop more detailed and accurate distribution modeling within LoadSEER and improved scenario consistency.

We are also enhancing our use of machine learning to support propensity modeling in our load forecast. This approach helps identify the data inputs most strongly associated with customer adoption of technologies such as rooftop solar PV. While this work is being done in parallel with our LoadSEER forecasting, it will ultimately strengthen the Company's overall understanding of adoption indicators and improve forecast accuracy. Additional details on this effort are provided in Section I.B.3 above.

12. LoadSEER Forecasting Roadmap

As more iterations of load forecasting are completed in LoadSEER, forecast granularity and robustness improves over time as data and inputs improve. That being said, there are still key challenges and room for growth in the forecasting process. In our roadmap for improvements, the following main items have been identified.

- **Improving data integrity**, which is key to ensuring an accurate forecast. Higher granularity shapes and forecasting layers, as well as more accurate TLY creation, are essential to improving data integrity.
- **Improving the planning process via AMI data and automation enhancements.** Additional utilization of 8,760 data in the planning process as well as in applications such as the NWA analysis are also areas for improvement.
- **Continued collaboration with Integral Analytics** for developing enhancements in LoadSEER will help improve the forecast. We are collaborating to refine identification of future potential points and enhance LoadSEER to retain historical scenarios.
- **Integrated and inclusive planning for community needs.** The Company is advancing a holistic approach to community collaboration by prioritizing investments that benefit Disproportionately Impacted (DI) Communities, coordinating electric and gas system planning, supporting innovative local energy solutions, and deepening engagement with municipalities. These efforts include leveraging municipal development plans in forecasting, incorporating

local planner expertise, and maintaining flexibility in system capacity to accommodate emerging community-driven energy needs

D. Community-Based Climate Goals

IDP Requirement No. 3.C.1 regarding DER scenario analysis requires, in part:

Xcel must provide detail on how, in aggregate, the energy and climate goals of the Minnesota communities it serves, along with customer preference trends, are reflected. In particular, distribution generation planning should include consideration of local community generation goals and beneficial electrification.

In addition to IDP Requirement No. 3.C.1, the Commission's Order regarding our 2021 IDP required a stakeholder series that, among other things, covered the topic of how the Company should consider and incorporate local clean energy goals into our planning process.

An increasing number of Minnesota communities served by the Company have adopted their own energy, climate, and broader sustainability goals. These vary by community but often include goals for increasing the community's share of renewable generation, share of carbon-free generation (i.e., sum of renewable and nuclear), energy efficiency goals, and carbon or greenhouse gas reduction goals (usually a percent reduction below a specified baseline year by a specified target year; in some cases, net zero by 2050, with interim milestones). Some communities are also incorporating goals for EV adoption or other forms of beneficial electrification and building efficiency into their plans or as elements of broader sustainability or Climate Action Plans. Finally, some communities have adopted – in addition to a goal to use more renewable energy – a subsidiary goal that some specified amount of that renewable generation should come from local distributed resources (i.e., small-scale generation connected to the distribution system and sited within jurisdictional boundaries).

In response to stakeholder and Commission feedback on our 2021 IDP and our 2020-2034 IRP, in early 2023, we conducted a survey of the local jurisdictions we serve. Our community relations managers sent the survey via email to 415 cities, townships, and counties. The goal of the survey was to gather complete, detailed information on our communities' goals and specific plans so that we could aggregate and analyze the data compared to our forecasts and scenarios. This was necessary not only to attempt to gather a complete picture and holistic representation of our communities' goals but

also because each community's goal may, for example, use a different baseline year, count different types of technology or buildings differently toward a discrete goal, or have different geographic requirements or carbon accounting approaches.

We received 107 responses to the survey, 32 of which indicated that their community had a clean energy-related plan or goal; however, eight of those respondents did not identify the community or did not provide details on the plan. In some cases, we supplemented the information provided by the survey respondent by reviewing the community's plan document(s) or website. We also reviewed the information provided by the Cities of Edina, Richfield, Saint Paul, and St. Louis Park in their April 11, 2022 Letter in our 2021 IDP docket, in which they provided a helpful summary table of Minnesota communities' carbon and clean energy goals.¹⁹ Another source of data is the Company's Partners in Energy (PiE) program, which supports municipalities by helping them develop and implement energy plans – first assisting in developing a plan, then providing 18 months of assistance with plan implementation. These plans often include goals to increase renewable generation and reduce emissions.

Attachment K summarizes the community goals of the communities:

- For which we were able to find goal or plan information online;
- Identified in the April 11, 2022 Letter from the Cities of Edina, Richfield, Saint Paul, and St. Louis Park; and/or
- That participate in the PiE program.

As stated above, the goal of our survey was to gather enough detailed information from our communities so that we could compare their goals to our forecasts and plans and potentially model the goals. However, in most cases, we were not able to gather sufficient data at a level of detail required for resource plan modeling purposes. For example, most renewable energy goals did not have associated energy (kWh) requirements. In addition, we understand that some communities may set goals that are intentionally aspirational. Others may be speculative or evolving, without supportive policies, feedback loops, or specific implementation plans in place. These factors create challenges when it comes to system modeling. That said, we believe our decarbonization and clean energy plans as a whole will meet or exceed most communities' goals, which we will discuss further in our forthcoming resource plan.

¹⁹ See Appendix A of the Cities' April 11, 2022 Letter in Docket No. E002/M-21-694, at <https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={D0661A80-0000-C61C-BA5B-9ED57809F58A}&documentTitle=20224-184624-01>.

From a distribution system planning and forecasting perspective, incorporating community energy goals directly into LoadSEER is challenging. LoadSEER's spatial allocation functionality is based on the distribution system asset hierarchy at the node level. This hierarchy does not conform to local jurisdictional boundaries; that is, substations, transformers, and feeders may serve customers in multiple cities. Therefore, modification work needs to be done with the vendor. To the extent a community has specific sites identified for a DER or electrification project, in the future, that information can be manually added to LoadSEER as a map adjustment, as described further in Section III.C.1. As our distribution forecasting capabilities continue to grow, we will be able to reflect community goals in our modeling. That said, with respect to the DER forecast specifically, we believe the "High Adoption" DER forecast scenario would meet community goals in aggregate.

We are supportive of our communities' goals and aim to help them achieve their goals whenever possible. We encourage our communities to reach out to their community relations manager to discuss their objectives and ways we may be able to help. We also have an obligation to serve all of our customers with reliable, safe, and affordable electricity. We serve 415 cities, townships, and counties across Minnesota, and our integrated Upper Midwest system provides electricity to customers and communities across five states. Some customers and communities may have different priorities; indeed, most communities responding to our survey indicated that they did *not* have clean energy-related plans or goals. We cannot forgo responsible system planning and investments that ensure safe, reliable, affordable electricity for all, to favor individual communities' or jurisdictions' energy goals – some of which may be intentionally aspirational – at the expense of customers as a whole. That said, we are always eager to work with our customers and communities to find ways to help them meet their energy goals while minimizing cross-subsidization.

IV. RISK ANALYSIS

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



One deliverable of Distribution Planning’s annual analysis includes a detailed list of all feeders and substation transformers for which a normal overload or overutilization (N-0) has occurred or is likely to occur based on historic and forecast demand including the load modifying impacts of forecasted DERs. With regards to generation, we specifically use a Planned Net Loading methodology as described below. A normal overload is defined as a situation in which the real time load of a system element (conductor, cable, transformer, etc.) exceeds its maximum load carrying capability. For example, a 105 percent N-0 for feeder FDR001 means that the peak load on FDR001 exceeds the limit of the feeder’s limiting element by five percent. This could result in negative consequences: catastrophic failure of the element, damage and loss of life of the element, harm to nearby equipment and persons in the event of failure, loss of service for downstream customers, etc. It is important that these risks are resolved to uphold safety and reliability.

Additionally, Distribution Planning delivers an N-1 Contingency Analysis, which is a list of all feeders and substation transformers for which the loss of that feeder or transformer results in an overload on an adjacent feeder or transformer, or loss of service for customers. For example, a 1.5 MVA N-1 condition for feeder FDR001 means that for loss of FDR001, all but 1.5 MVA of FDR001’s peak load can be safely transferred to adjacent feeders without causing an overload. The remaining 1.5 MVA that cannot be transferred is then referred to as “load at risk.” This risk reflects the

ability of the system to be reconfigured to serve all the load. Any N-1 risk means that the N-1 analysis determined that there was not sufficient redundancy to supply the electricity demand once a given element has been lost. The Customers subjected to this N-1 outage would be without power until repairs are made, and the system is restored to an N-0 state.

Based on the risks developed during the risk analysis process, we then develop mitigations that address each of those risks.

The risk thresholds requiring mitigations are summarized in Table 1-12 below.

Table 1 - 12
Risk Thresholds Requiring Mitigations

	N-0 Threshold	N-1 Threshold
Feeder	15 kV: Loading exceeding 75%	Greater than 0 MVA at risk
	25 and 35 kV: Loading exceeding 50%	
Substation Transformer	Loading exceeding 100%	Greater than 0 MVA at risk

A. Risk Analysis Results

Our 2026 through 2030 annual planning process , analyzed forecasted 2026 loads and identified the following total risks across NSP Minnesota

- N-0 normal overutilization on 402 feeder circuits (>Planned Loading Limit)
- N-0 normal overloads on 70 feeder circuits (>100% loaded)
- N-0 normal overloads on 17 substation transformers
- N-1 contingency risks on 570 feeder circuits
- N-1 contingency risks on 189 substation transformers

This process of identifying N-0 overutilization/overloads and N-1 risks for feeders and substation transformers is referred to as Distribution Planning’s annual “risk analysis.” We enter these risks into WorkBook, an internal tool used to help rank projects based on levels of risk and estimated costs. We provide our risk scoring methodology and results from the 2026-2030 planning process as *Attachment D* (portions of which are not public). The total number of risks identified in the risk analysis consistently exceeds the number of risks that can be mitigated with available funds. There is always a balance that we must strike in mitigating risks, planning for new customers, and addressing the aging of our system – as well as preparing it for

the future. Budgeting to our system needs will become increasingly important as the pace of load growth increases and customers expect timely energization. We cannot wait until a customer asks about capacity before investing in system upgrades; we must prepare our system now so that capacity is readily available, and we are able to maintain safe, reliable service at the same time. We discuss how we strike this balance and prioritize projects below.

B. Planned Net Loading – Methodology

As noted in Section II.A and as required by the Commission’s July 26, 2022 Order IDP Order Point No. 6.f, the Company has developed a methodology for considering DER impact to peak loads on feeders and substation transformers. The methodology considers two different types of loading seen on the distribution system.

First, native loading is the actual demand when all DER generation impacts are excluded. This loading assumes that we cannot depend on any DER to lower peak demand due to the technology being non-dispatchable. For DER impacts to be considered, the technology should be available when peak conditions appear, which is not always true for DER generation. For feeders and substation transformers with DER generation, this native loading value is calculated via LoadSEER in the load forecast.

Net loading is the actual demand when all DER impacts are included. This loading considers all DER generation. This is the demand seen via SCADA at the substation for feeders and substation transformers with DER. While this value reflects 100 percent of DER generation impacts at that time, this value does not necessarily indicate whether peaks could be reliably lowered when necessary due to most DERs being non-dispatchable resources.

While 100 percent of DER generation on a given feeder or substation transformer might not reliably and consistently be available to lower peaks, we recognize that there is a certain percentage that can be assumed to be dependable. The amount of DER generation that is available to reduce peak is dependent on a variety of factors. For example, some DER may be offline at the time of peak load due to planned maintenance, equipment damage, or failure. Further, in the case of solar PV, it is a variable, non-dispatchable resource, and it is possible that the amount of incident solar irradiance at the time of peak load may be less than favorable or inconsistent with the amount of irradiance at the time of peak load in previous years.

The initial methodology to address this involves what we are labeling as Planned Net Loading (PNL) – the calculated demand when a certain percentage of DER generation is assumed to be dependable. For the initial development, only CSG and rooftop PV have been considered.

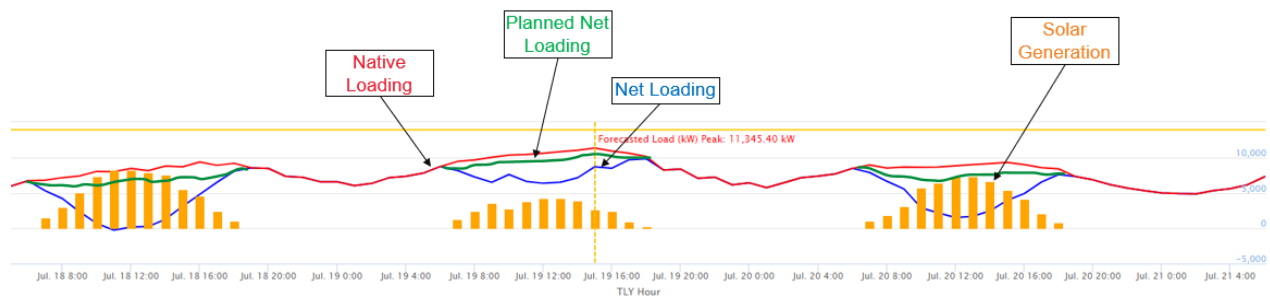
When planning the distribution grid, we must consider worst-case conditions to account for all outliers and to ensure grid reliability. If PNL is used for planning the grid, the grid becomes dependent on the DER technology to operate as expected during peak conditions and at all other times. If the DER technology is not available during peak conditions or is available at a lower level than the assumed dependability, grid reliability could deteriorate, and outages can occur.

Additionally, there are operational factors that must be considered in the planning process. Considering DER generation dependability and PNL concepts in relation to how the distribution system is operated during N-0 and N-1 conditions, we see that it is still vital to continue planning components of the grid using both native and net loading.

In the case of N-0 normal overloads on a feeder or substation transformer, solar would remain online and Operations would address the overload. In day-to-day operations, the Distribution Control Center uses net loading to identify these overloads, as that is reflected in the real-time SCADA data seen in the control center. In planning for an N-0 in the future, PNL could be utilized, assuming that a certain percentage of DER will be consistently and minimally available in the future.

An example of a peak load curve that considers a certain dependability of DER is shown in Figure 1-31 below.

Figure 1 - 31
Peak Load Curve Considering Solar Dependability



Whereas the net loading represents 100 percent of DER generation impact, the native loading is a calculated value that adds back the load that was masked by the DER generation to reflect loading with 0 percent DER generation impact. The PNL reflects that a certain percentage of DER can be dependable to lower the peak and the PNL loading falls between the native loading and the net loading.

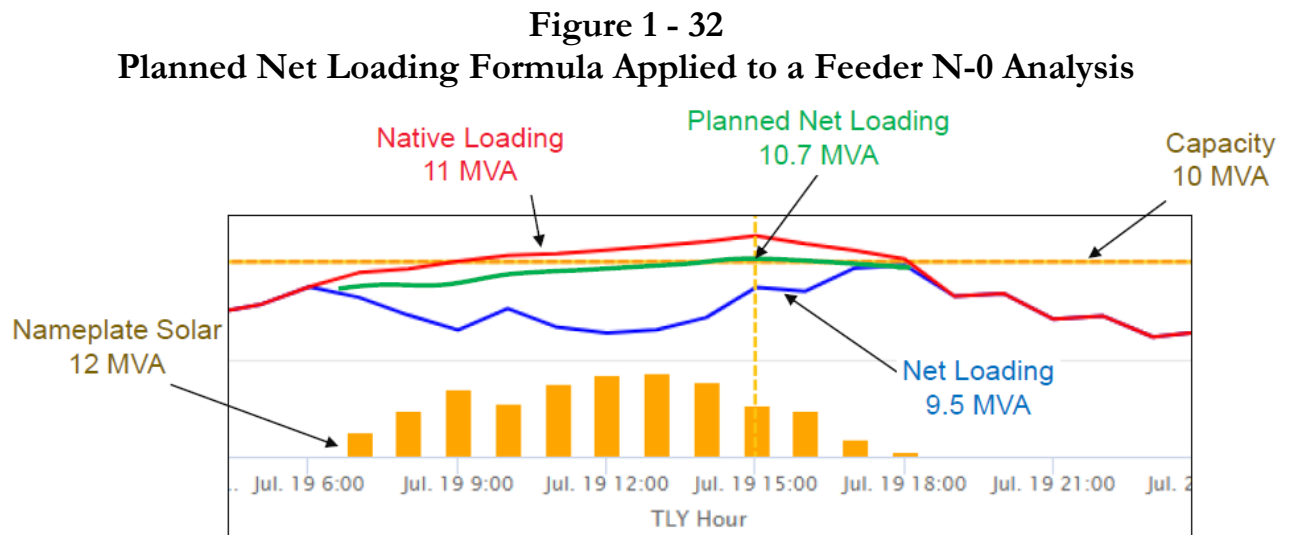
Applying the PNL concepts around DER generation dependability can be summarized into a single formula:

$$\text{Planned Loading} = \text{Native} - [(\text{Native} - \text{Net}) \times DF_{PV}]$$

Where:

$$DF_{PV} = \text{Dependability Factor of PV}$$

Figure 1-32 applies this formula to a N-0 analysis:



In this example, a 15 percent DF_{PV} is used. Keeping in mind that this is 15 percent of the DER generation impact (the difference between native and net load) and not of total nameplate DER generation, the PNL is calculated as such:

$$\text{Planned Net Loading} = 11 - [(11 - 9.5) \times 15\%] = 10.7 \text{ MVA}$$

In this case, the PNL of 10.7 MVA is 0.3 MVA lower than the 11 MVA native loading value that would otherwise be used in our current risk analysis process. It is also 1.2 MVA higher than net loading.

A 15 percent DF_{PV} was the initial proposed value to use in the PNL methodology. This assessment was based upon five years (2016-2021) of recorded PV generation as a percentage of nameplate capacity rating from our CSG program in Minnesota, as shown in Table 1-13 below. By taking the average PV output as a percent of nameplate for the specified time frame during each month of the year, we can compare and then select a DF_{PV} that would be safe to use in our PNL methodology. As the selected DF_{PV} can impact how much risk is seen and then considered for mitigations, we must use a conservative estimate to ensure system reliability. Based on the 08:00-18:00 Tracking row of data, we see the actual PV output as low as 12 percent during the month of December, with the next two lowest in January and November; averaging these three lowest months results in a value of 15.04 percent, leading to our initial DF_{PV} of 15 percent.

Table 1-13
Average Monthly Solar Generation Output as a Percent of Nameplate Capacity

Time Range	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
00:00-23:59 All Day	7.07%	11.27%	14.26%	15.16%	17.98%	20.23%	20.20%	17.90%	15.39%	11.50%	8.23%	5.40%
08:00-18:00 Tracking	15.44%	24.53%	30.24%	31.13%	36.12%	40.44%	40.93%	36.83%	32.06%	24.35%	17.90%	11.78%
10:00-16:00 Fixed	21.72%	33.09%	38.38%	37.69%	43.10%	47.93%	49.22%	44.93%	39.94%	30.70%	23.26%	16.34%

The above describes the PNL methodology that we have implemented since our 2023 IDP per the Commission’s September 16, 2024 Order, Order Point No. 18:

Xcel shall implement the 15 percent DF_{PV} in the next planning cycle for the N-0 risk analysis in the next IDP.

The remainder of this section presents the results of our risk analysis following the implementation of the PNL methodology, along with a summary of proposed refinements to the methodology informed by stakeholder engagement.

1. *Risk Analysis Results using PNL*

Planned Net Loading was implemented for N-0 risks in the risk analysis and mitigation cycle for this IDP. An evaluation was done to see the impact this had on our risk analysis. The net, native, and PNL peak value was listed for each node, and a comparison was done to see what level of impact the PNL methodology had on the effective peak loading percentage.²⁰

The table below reflects the nodes that experienced some amount of change to the effective peak loading percentage when using the PNL methodology. For example, when using native load for risk analysis there were 24 nodes that were over 100 percent loaded at peak, and when using PNL for risk analysis instead there were just 20 nodes over 100 percent, a change of four nodes. When a node is loaded over 100 percent, this means that that feeder or substation transformer is overloaded, and a capacity mitigation is needed; therefore, by implementing the PNL methodology there were four fewer overloaded feeders or substation transformers identified in the risk analysis process, and therefore four feeders or substation transformers with a slightly reduced need for a capacity mitigation.

Similarly, there were five fewer nodes identified between 75 percent and 100 percent loading when using the PNL methodology. There was no change in the amount of nodes identified as being loaded less than 75 percent when using the PNL methodology.

Table 1 - 14
Node Impacts from PNL

Percent Loading	Using Native	Using PNL	Difference
Over 100%	24	20	4
75%-100%	47	42	5
Under 75%	195	195	0

In addition to the nodes listed in Table 1-14, there were 996 nodes that included some level of distributed energy resources (DER) but showed no change in percent loading when analyzed using the PNL methodology. Additionally, 495 feeders had no installed

²⁰ In this context, a “node” refers to a feeder circuit or a substation transformer for which the planning team conducts capacity risk analysis.

DER and therefore no change in percent loading when analyzed using the PNL methodology.

For the nine nodes reflected in Table 1-14 that had the most significant change in percent loading, the risk scores for the capital projects associated with the N-0 risks were compared before and after the PNL methodology was applied. For these projects, there was little to no change in the risk score. This was primarily driven by the fact that most of the projects had other significant capacity risks also driving the need of the project.

The conclusion of the analysis is that while the PNL methodology changed the quantity and magnitude of N-0 risks observed on our distribution system, the associated capacity project risk scores did not change enough to defer any of the projects.

While the implementation of the PNL methodology did not result in the deferral of any capacity projects, a hypothetical reduction in risk scores sufficient to defer a project would warrant careful consideration of broader system impacts. The nine nodes evaluated in this analysis and that were most significantly impacted by the PNL methodology are located in outstate regions with relatively high solar penetration. Capacity projects in these areas not only address loading concerns but also increase hosting capacity, thereby supporting additional DER interconnections. In this hypothetical scenario, deferring a capacity project could limit future DER integration opportunities in the affected area. Although deferring capacity investment may offer near-term cost benefits, it may also constrain long-term system flexibility and preparedness for DER adoption.

2. Considerations For Proposed Changes to PNL

We held a series of PNL workshops to evaluate and improve our current methodology in response to stakeholder feedback and evolving system needs. The first workshop focused on explaining our distribution planning process and how our current PNL approach—using a conservative solar dependability factor (DF) of 15 percent—helps manage feeder and transformer risks. We demonstrated how this method balances native and net load by partially accounting for DER impacts, and why the DF must applied to the actual impact of the solar generation on system loading rather than nameplate capacity to ensure reliability.

In the second workshop, stakeholders proposed a range of refinements, including seasonal DFs, solar output shapes differentiated by solar type, and methods for evaluating PNL during Community Solar Garden outages. They also raised questions about emergency ratings, native load forecasting, and how to incorporate future PV interconnections into planning.

The third workshop presented our proposal to adopt seasonal DFs—one for summer and one for winter—for use in our 2027 IDP. We also committed to exploring additional refinements, such as using multiple solar profiles in LoadSEER to reflect geographic differences and investigating solar shapes by type.

Throughout the workshops, we emphasized a walk-jog-run approach to implementation, recognizing the need to balance improvements with available resources and system reliability. As we continue to evolve our planning processes, we are mindful of the trade-offs between effort and value, and the importance of maintaining system reliability. Getting this wrong could expose the system to risks we have not planned for, so we are taking a thoughtful, phased approach to ensure changes are both practical and effective.

V. MITIGATION PLANS

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



At this step, potential solutions are identified to provide necessary additional capacity to address the identified system deficiencies. Planning Engineers first consider distribution level alternatives including adding feeders, extending feeders, and expanding existing substations. If these typical strategies would not meet identified needs because they had already been exhausted or would not be sufficient to address the overloads, the engineers then evaluate alternatives that would bring new distribution sources into the area. We also evaluate certain projects for potential mitigation by an NWA. We discuss this analysis in *Chapter 8*.

If we conclude that distribution level additions and improvements would not meet the identified need, we consider the addition of new distribution sources (i.e., substation transformers with associated feeder circuits) to meet the electricity demands. Planning Engineers cluster and solve several risks to minimize the number of projects needed.

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

A. Long-Range Area Studies

IDP Requirement 3.A.30 requires the following:

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

We discuss our NWA analysis that is part of this IDP in *Chapter 8*.

IDP Requirement 3.D.2.o requires:

Long-range distribution studies conducted since the last IDP.

We have not completed or publicly published any long-range studies since submitting our last IDP. However, the Company regularly incorporates long-term considerations into its planning processes, including during the evaluation of mitigation options and project development, even if those efforts do not take the form of formal, standalone long-range studies.

B. Capacity Risk Project Prioritization

After mitigation projects are identified, projects are assigned a risk score based on their specifications, similar to a cost-benefit ratio; The methodology to developing this risk score is outlined in *Attachment D*. This score applies to the mitigation as a whole and not the individual risks that make it up. It is useful for comparing the merits of disparate projects. We then select and prioritize the actual solutions for which we intend to move forward. *Attachment E* contains a list of our capacity risks, their details, and the projects that mitigate them.

Once we have all the projects identified, we weigh each investment using a risk/reward model to determine which solutions should be selected and prioritized.

VI. BUDGET CREATE

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



The overall budget process recognizes that customers want reliable and uninterrupted power. To address this priority, we regularly evaluate the overall health of our system and make investments where needed to reinforce our system. This includes an asset health analysis of the overall performance of key components of the distribution system such as poles and underground cables. Key components are replaced with consideration for future needs, ensuring that investments not only support customers' requirements for reliable service today but also prepare the grid for tomorrow. Steps are taken to implement new systems and technologies that enhance operations and offer customers with more choices regarding their energy use. Examples of these kinds of investments include our SCADA system, our Advanced Distribution Management System, and AMI. Together, these systems will provide our engineers and operational staff with significantly improved data from which to monitor and

make decisions – all of which benefit our customers in both our planning and our ability to respond to events occurring on the system.

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

As capital spending is determined, and throughout the year as new issues are identified, each operating area brings risks and mitigations forward based on their knowledge of the assets and operations within their territory. The operating areas' focus is on building, operating, and maintaining physical assets while achieving quality improvements and cost efficiencies. All the risks and mitigations are submitted as project requests and entered into WorkBook (a database software) to track and rank projects based on the inputs provided – including their annual costs and benefits.

Budgeting personnel focus on the health and age of our existing assets, standardization, and mitigation of risk, and provide coordination and consistency in evaluating individual project requests with the Distribution organization. Engineering and operations personnel then work with budgeting personnel around each risk to evaluate and rank each mitigation. The factors generally considered in determining how to prioritize investments are as follows:

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

The analysis of these factors generates a ranked list of proposed projects. This ranking is determined by evaluating each project's assessment relative to others. Projects that must be executed within a specific budget year to fulfill regulatory and compliance requirements, as well as those needed to connect new customers, receive the highest priority. Engineering judgment is used during the prioritization process; projects with lower rankings may be included in the budget if other considerations—such as the magnitude, severity, or duration of the associated risk—warrant their inclusion. The process includes collaborative discussions with planning engineers to confirm and validate final priorities.

VII. PROJECT DETAILS

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



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

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

Once the five-year budget is determined, the Planning Engineers write Electric Distribution Planning (EDP) memos for at least the first two years of approved feeder capacity and asset health projects and the first three years of approved substation capacity and asset health projects; substation projects are released further in advance to account for the impact of long lead time materials such as substation transformers. An EDP memo is a high-level step-by-step description of the project that will mitigate an identified risk. The memos describe the problem, the substation design / construction steps to take (if any), and any distribution line design / construction steps to take. The memos provide maps and text specifying where to place switches, capacitor banks, or where to cut into another feeder to transfer load to a new feeder. These memos initiate the design and construction portion of the project and initiate the execution plan.

VIII. DESIGN AND CONSTRUCT



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

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

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

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

CHAPTER 2: STANDARDS, ASSET HEALTH, AND RELIABILITY MANAGEMENT

The health of our distribution system assets is essential to delivering safe, reliable, and cost-effective electricity to our customers. Each year, we invest in maintaining and upgrading our extensive network of overhead feeders and poles, underground cables, and substation equipment—critical components that make up the final mile of our electric system.

Many of these assets have reached or exceeded their expected useful life. To continue delivering excellent service, we are increasing our investments in Asset Health and Reliability. This includes replacing aging infrastructure such as overhead poles and substation transformers that are in deteriorated condition. Our goal is to proactively replace assets closer to the end of their useful life, while carefully balancing cost impacts for our customers.

These strategic investments not only help us maintain high levels of reliability but also strengthen our system’s resilience against extreme weather events. In this chapter, we outline the analyses and operational strategies that support the reliability and resilience of our distribution system—ensuring we continue to meet our customers’ expectations for excellent service.

I. ELECTRIC DISTRIBUTION STANDARDS

Utility distribution systems are inherently complex and must be resilient across challenging weather conditions, various geographies, rural and urban conditions while adapting to evolving customer needs. In Minnesota, we tailor our planning criteria and standards to meet these requirements- ensuring we deliver safe, reliable, and cost-effective service that meets our customers’ expectations for excellence.

Purpose of Electric Distribution Standards. Our Electric Distribution Standards guide the construction, repair, and maintenance of overhead, underground, and outdoor lighting systems. These standards ensure compliance with regulations, enhance safety, improve reliability, and support cost-effective operations. They are developed collaboratively and updated based on regulatory changes, field input, and industry best practices.

Standards Manuals. We maintain three core manuals—Overhead, Underground, and Outdoor Lighting—that document approved materials and configurations. These manuals streamline project design by embedding engineering and code compliance, reducing the need for custom engineering except in special cases. They also include

reference materials for transformer sizing and conductor lengths, incorporating voltage and thermal limits to support accurate and efficient system design.

Key Examples of Standards in Action. The following examples highlight how our Electric Distribution Standards evolve in response to field insights, industry collaboration, and changing conditions—demonstrating our commitment to innovation, reliability, and delivering excellent service to our customers.

- **Non-Wood Poles (2025–present):** Composite fiberglass and ductile iron poles have been introduced for specialized applications. These non-wood poles are used in areas affected by woodpecker damage, anti-cascading line designs, special equipment installations, unguyed light-angle and deadend poles, locations inaccessible to bucket trucks, environmentally sensitive areas, and Grade B Crossing applications.
- **Cable and Conductor Supply and Standards (2024–present):** To address supply chain challenges, we expanded our supplier base for both conductors and cables across low voltage (600 V and below) and primary distribution voltage (1 kV to 35 kV). New manufacturers were vetted for quality and compliance, improving material availability while maintaining safety and reliability standards.
- **Transformer Supply and Standards (2020–present):** To address supply chain challenges, we expanded our supplier base by vetting new manufacturers for quality and compliance. This increased equipment availability while maintaining safety and reliability. The expanded sourcing includes single-phase and three-phase overhead and padmount transformers, voltage regulators, step-down transformers, and underground network transformers.
- **Reclosers with Microprocessor Controls (2015–present):** We implemented advanced reclosers that consolidate multiple devices and offer flexible, software-based control. These are primarily used for system protection, enhancing safety, visibility, and uptime while lowering operational costs. In high-risk wildfire areas, communication devices and updated control programming have been added to allow the reclosers to adjust their operation based on local conditions.
- **Wood to Fiberglass Crossarms (2010–present):** In 2010, we transitioned to fiberglass crossarms, improving strength and longevity while reducing costs. Ongoing improvements include enhanced testing for extreme weather resilience and contributions to national standards updates.
- **Porcelain to Polymer Cutouts (2010–present):** Identified reliability issues with porcelain cutouts led to a transition to polymer alternatives. We collaborated with industry groups and contributed to Institute of Electrical and Electronics Engineers (IEEE) standards revisions. This change improved

reliability, expanded sourcing options, and reduced costs.

Common Engineering Standards. We apply a range of industry standards, primarily from IEEE, to ensure safety, voltage and thermal limits, interconnection, and power quality. Table 2-1 below shows a list of some of the most common industry standard documents applied in distribution engineering.

Table 2-1
Common Engineering Standards Summary

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

Regulatory Coordination. Northern States Power Company (NSPM) is registered as a Distribution Provider (#NCR01020) with North American Electric Reliability Corporation (NERC) and complies with all current and applicable Standards, including NERC Standard FAC-002-4 for interconnections to the Bulk Electric System. This includes coordination with its Transmission Planner and/or Planning Coordinator for reliability studies, planning criteria, and power flow analysis.

II. ASSET HEALTH

A. Overview

The Minnesota portion of the NSPM electric distribution system includes nearly 28,000 miles of distribution lines and 1,200 feeders that deliver electricity from substations to customer transformers and, ultimately, to homes and businesses. Maintaining and improving this extensive network is essential to delivering safe, reliable, and affordable energy.

To meet evolving customer expectations and ensure excellent service, we must continue investing in our aging infrastructure. Through our Asset Health and Reliability programs, we proactively maintain and upgrade the system to reduce outages, improve performance, and manage long-term costs.

Each year, we evaluate the condition and performance of our distribution assets to identify those in need of repair or replacement. We track the age of key components and analyze reliability data to prioritize investments in areas with the greatest impact on service quality and cost efficiency.

Our investments fall into two main categories:

- *Routine projects*: Ongoing replacements of aging infrastructure such as underground cables, poles, and substation equipment, as well as repairs due to storms or public damage.
- *Discrete projects*: Larger, targeted efforts to address specific reliability or asset health concerns.

In the sections that follow, we highlight examples of these programs and how they support our commitment to delivering excellent service while keeping customer bills as low as possible.

We also track several reliability metrics, which are reported annually in the Company's Reliability Performance Report. These metrics measure the frequency and duration of service interruptions—lower values indicate better reliability. Key metrics discussed in this chapter include:

- **System Average Interruption Duration Index (SAIDI)**: Measures the average total number of minutes a customer was without power during the calendar year.

- **System Average Interruption Frequency Index (SAIFI):** Measures the average number of sustained service interruptions per customer per year.
- **Customers Experiencing Lengthy Interruptions (CELI):** Indicates the number or percentage of customers who experienced an outage of a specified duration. For example, CELI-12 refers to customers who experienced at least one outage lasting 12 hours or more in a year.
- **Customers Experiencing Multiple Interruptions (CEMI):** Indicates the number or percentage of customers who experienced a specified number of outages. For example, CEMI-6 refers to customers who experienced six or more outages in a year.

B. Underground Distribution Assets and Reliability

For underground distribution assets, reliability is closely tied to the performance of both mainline and tap cables. We regularly analyze failure rates for each cable type and allocate budgets accordingly to maintain system reliability. Our analysis shows that cable age and material composition are strong indicators of failure risk, allowing us to prioritize replacements where they are most needed. These insights also inform our standards for selecting materials in new construction and replacement projects. By using both current and historical data, we strategically target cable replacements to enhance service reliability while balancing other system priorities and keeping customer costs in check.

C. Targeted Undergrounding Plan

The electrical distribution system is vital to modern infrastructure, yet overhead lines are increasingly vulnerable to severe weather and environmental challenges. Targeted Undergrounding offers a strategic solution by relocating high-risk segments underground, significantly improving storm resilience, reducing outages, and enhancing public safety. It also lowers operational costs by minimizing vegetation management and supports continuity of service for critical infrastructure.

Rather than full-scale undergrounding, which is often cost-prohibitive, this approach uses data-driven criteria—such as outage history and reliability metrics—to prioritize investments where they deliver the greatest impact. While implementation involves challenges like permitting and labor availability, these can be addressed through coordinated planning. Targeted Undergrounding aligns with regulatory goals and offers a cost-effective path to long-term grid resilience and community benefit.

1. *Project Overview*

The Company is launching a long-term reliability improvement initiative focused on targeted undergrounding of overhead distribution lines. This program is designed to address persistent outage issues, particularly in areas with aging infrastructure and elevated exposure to weather and vegetation-related risks.

Implementation will follow a phased investment strategy from 2025 through 2030, beginning with pilot projects and scaling up to full deployment. This approach allows for early learning, refinement of engineering practices, and alignment with stakeholder input. Planned capital investments total \$233.7 million:

Table 2-2
Planned Capital Investments (2025-2030)

Year	Capital Investment
2025	\$1,513,900
2026	\$8,000,000
2027	\$25,000,000
2028	\$62,000,000
2029	\$67,500,000
2030	\$69,727,500

Early investments will focus on areas with high outage volumes and lower construction complexity, providing a foundation for evaluating engineering methods, cost modeling, and community engagement. As the program progresses, investment levels will increase to support broader deployment across prioritized segments identified through system performance metrics and feasibility assessments. By the final years, the program will reach full-scale implementation targeting the highest-impact areas.

While technical criteria such as outage frequency, duration, and asset condition will guide early deployment, equity and demographic considerations will be informed by the results of an independent third-party evaluation.¹ In addition to reliability improvements, the program is expected to yield operational savings through reduced vegetation management, storm restoration, and infrastructure replacement costs. It

¹ In accordance with Order Point No. 46 in Order Accepting Reports and Setting Additional Requirements, Minnesota Public Utilities Commission, Docket No. E-002/M-24-27, issued January 13, 2025, In the Matter of Xcel Energy's 2023 Annual Safety, Reliability and Service Quality Report.

also supports broader goals such as electrification readiness and rooftop solar hosting capacity.²

The Company will continue refining its implementation strategy through engineering assessments, stakeholder engagement, and the results of the third-party evaluation. Further details, including project selection criteria and anticipated benefits, will be provided in this Integrated Distribution Plan and future filings.

2. Industry Background and Benchmarking

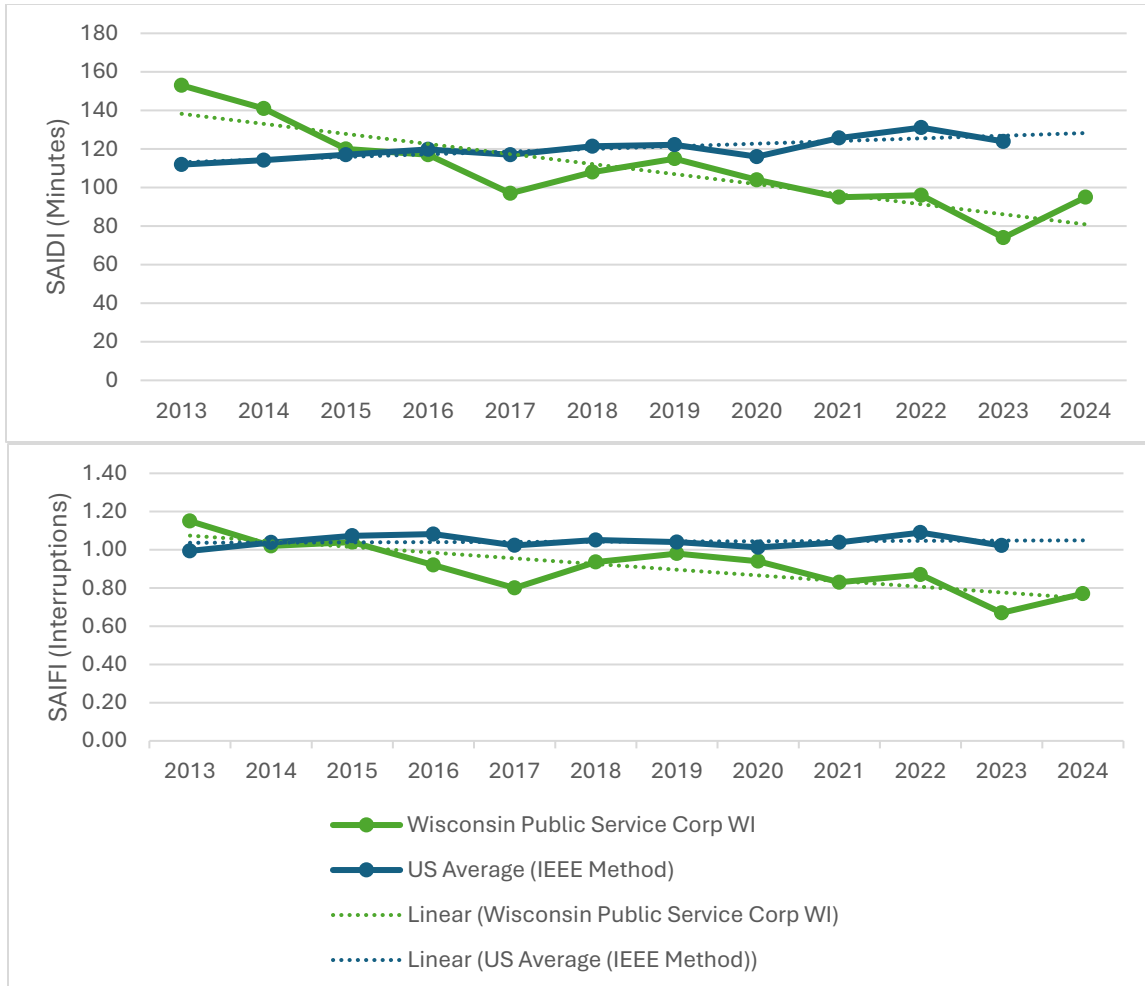
The Company's strategy incorporates a comprehensive benchmarking analysis of undergrounding programs across multiple U.S. utilities. This review informs the strategic direction, cost expectations, and reliability outcomes associated with undergrounding investments.

Wisconsin Public Service Corporation's (WPS) System Modernization and Reliability Project (SMRP) is a comprehensive undergrounding and automation initiative spanning over a decade. As of 2021, WPS has converted more than 1,718 miles of overhead distribution lines to underground and automated 386 miles of three-phase main lines. The program has delivered a 137-minute annual SAIDI improvement through undergrounding since 2014. With a total investment of \$431 million, SMRP has significantly enhanced reliability in forested outage-prone zones across Wisconsin.³ SMRP work had large portions devoted to rural lines, for which have a lower per-mile associated cost. WPS currently serves 469.2 thousand customers.

² Current Company design standards call for larger transformers and secondary conductors than those typically found in existing overhead installations. These upsized components not only support increased load capacity but also enhance rooftop solar hosting capability and improve readiness for residential electrification.

³ Wisconsin Public Service Corporation. (2022). Undergrounding Post-Construction Report. Public Service Commission of Wisconsin Electronic Records Filing System. Document ID: 430842. Retrieved from <https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=430842>

Figure 2 – 1
Wisconsin Public Service Normalized SAIDI and SAIFI History⁴

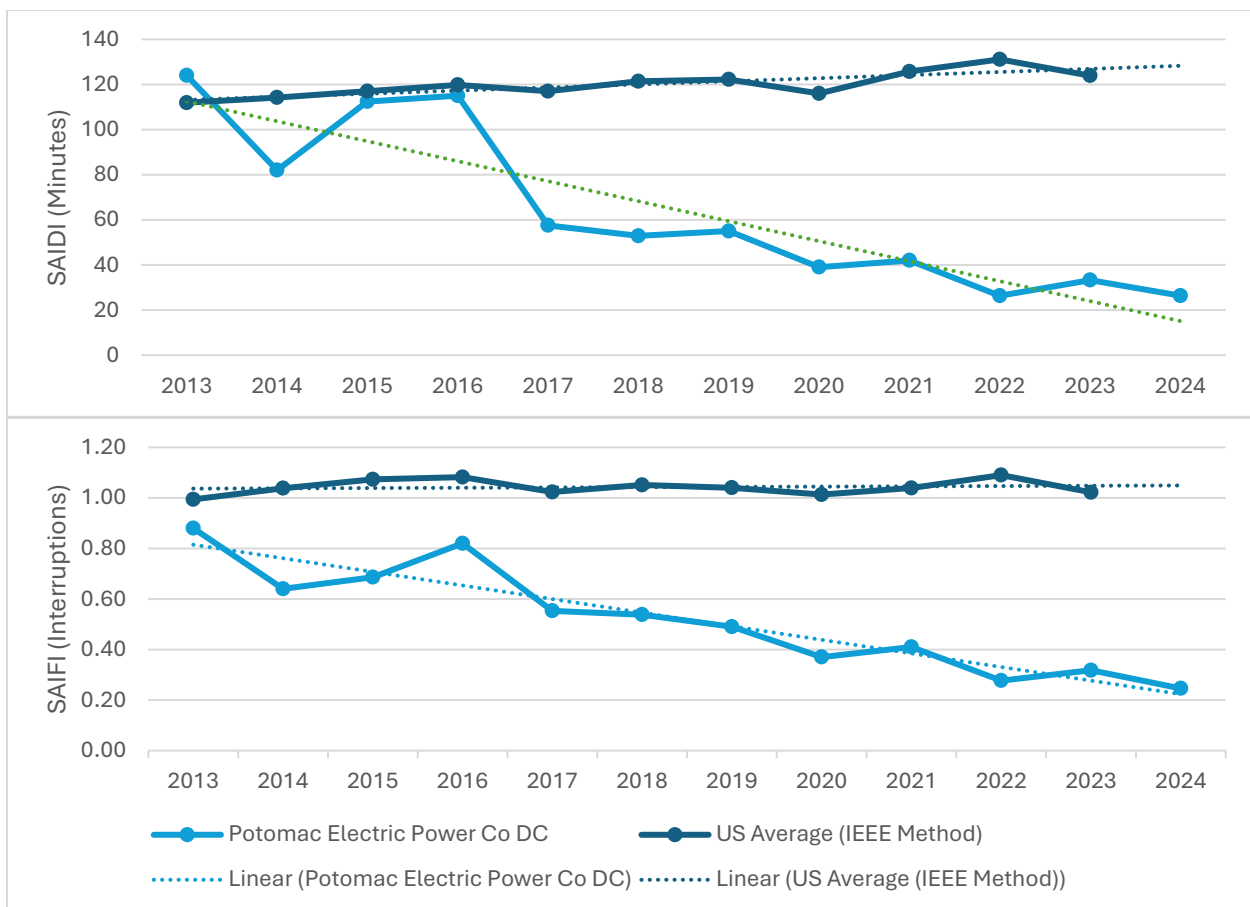


Potomac Electric Power Company’s (PEPCo) DC Power Line Undergrounding (PLUG) Program began in 2017 and is a \$500 million joint initiative with the District of Columbia Government to improve grid resiliency by undergrounding the most outage-prone feeders. Focused on five wards with dense overhead infrastructure, the program uses a data-driven feeder selection process based on SAIFI, SAIDI, and cost-effectiveness. The design incorporates radial loop systems, mid-line interrupters, and automated tie switches to isolate faults and restore service quickly. PEPCo anticipates a 95 percent reliability improvement on selected feeders, with undergrounding expected to eliminate most outage causes on primary lines and

⁴ U.S. Energy Information Administration (EIA). Electric Power Annual. Reports for the years 2013–2024. Available at: <https://www.eia.gov/electricity/data/cia861/>

significantly reduce restoration times. This program is unique in that significant public funds are included through the civil construction work performed by District Department of Transportation. Further, the DC PLUG Program differs from others in that the secondary voltage lines and services remain overhead, which results in lower initial construction costs and less disruption on customer property. PEPCo currently serves 342.5 thousand customers within its District of Columbia service territory.

Figure 2 – 2
Potomac Electric Power Company Normalized SAIDI and SAIFI History⁵

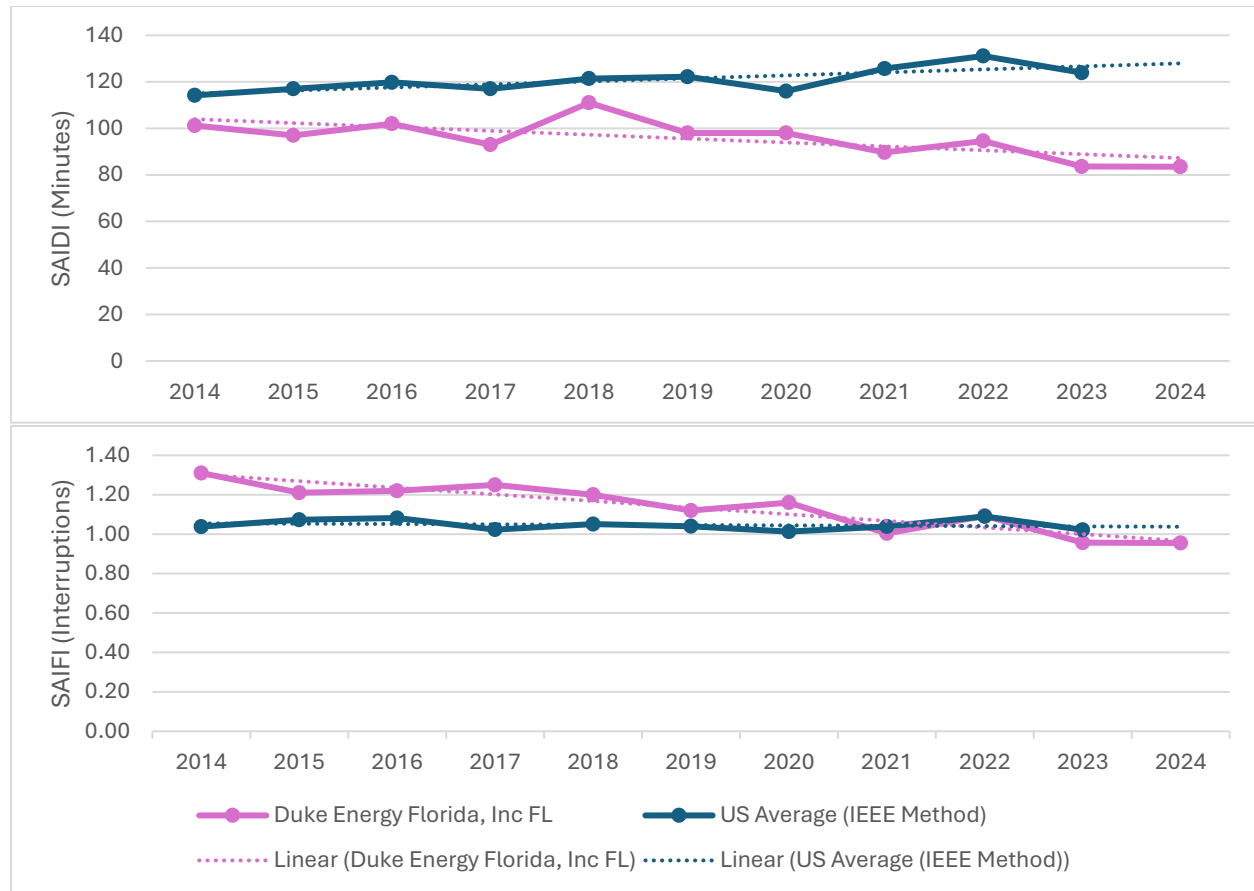


Duke Energy Florida’s (DEF) undergrounding initiative began as the Targeted Underground Program and evolved into the Lateral Hardening Program, aimed at reducing outages from wind and vegetation during extreme weather. From 2020 to 2022, DEF undergrounded approximately 200 miles of lateral distribution lines at a

⁵ U.S. Energy Information Administration (EIA). Electric Power Annual. Reports for the years 2013–2024. Available at: <https://www.eia.gov/electricity/data/cia861/>

cost of \$207 million, with plans to convert an additional 1,300 miles by 2032 at a projected cost of \$1.7 billion. The program prioritizes hard-to-access overhead lines with vegetation-related outages, using a 10-year outage history and metrics like SAIDI, SAIFI, and CEMI-6. Duke Energy Florida currently serves 2.0 million customers.

Figure 2 – 3
Duke Energy Florida Normalized SAIDI and SAIFI History⁶

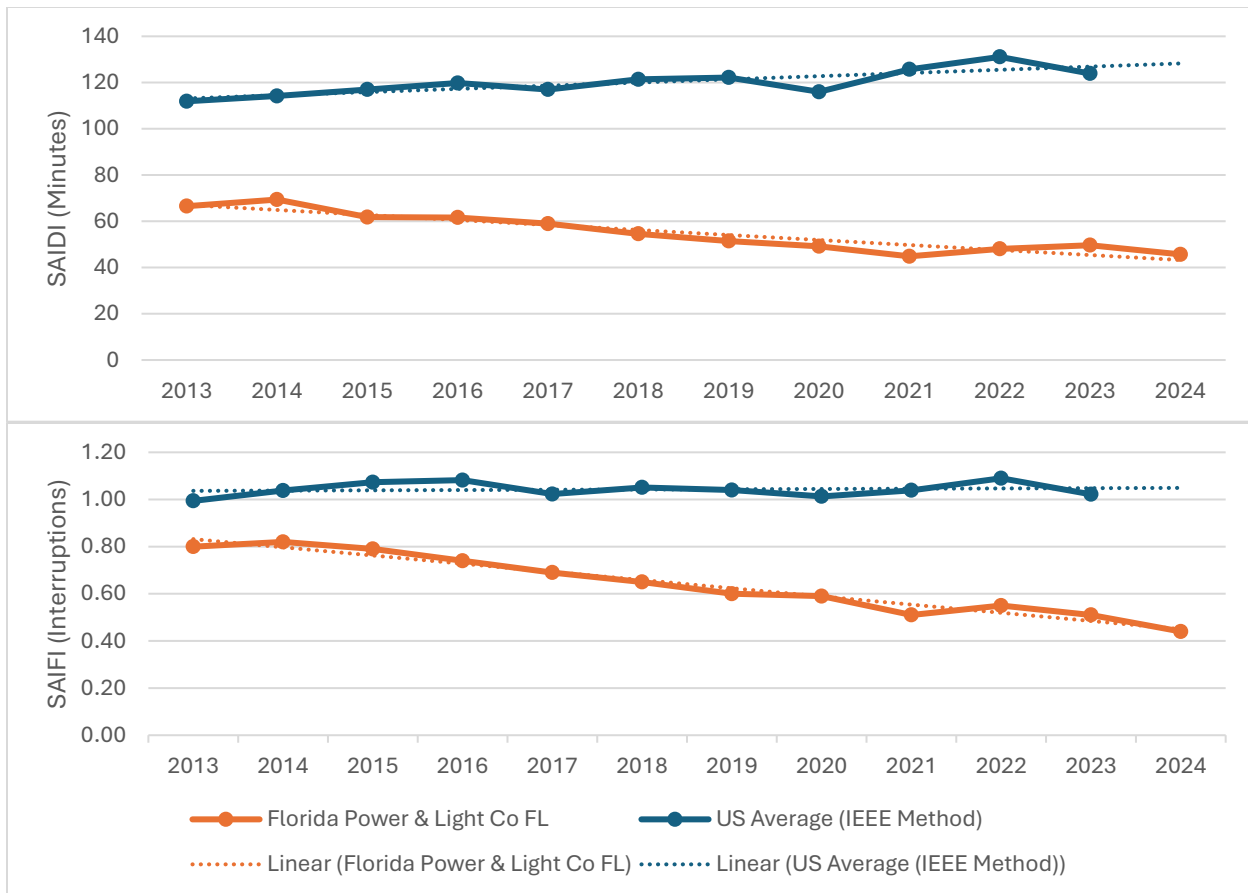


Florida Power & Light's (FPL) Storm Secure Underground Program (SSUP) began in 2020. It is a statewide initiative to improve grid reliability by converting overhead neighborhood laterals to underground lines, which perform 5 to 14 times better during hurricanes and 50 percent better day-to-day. As part of FPL's broader Storm Protection Plan, the Distribution Lateral Hardening Program alone is projected to cost \$9.39 billion over ten years. The program targets areas with vegetation-related

⁶ U.S. Energy Information Administration (EIA). Electric Power Annual. Reports for the years 2013–2024. Available at: <https://www.eia.gov/electricity/data/cia861/>

outages and storm vulnerability, using directional boring to minimize disruption. Florida Power & Light currently serves 6.0 million customers.

Figure 2 - 4
Florida Power and Light Normalized SAIDI and SAIFI History⁷



3. *Alternatives Considered*

In developing the Targeted Undergrounding strategy, the Company evaluated multiple alternatives to address persistent reliability challenges in outage-prone areas. These included overhead line rebuilds, enhanced vegetation management, and distribution automation technologies. Each alternative offers partial benefits but falls short of the comprehensive reliability and resilience improvements achievable through undergrounding.

⁷ U.S. Energy Information Administration (EIA). Electric Power Annual. Reports for the years 2013–2024. Available at: <https://www.eia.gov/electricity/data/cia861/>

- **Overhead Line Rebuilds** can improve reliability by replacing aging infrastructure but do not eliminate exposure to weather-related events—one of the leading causes of long-duration outages. Additionally, many overhead segments are in rear lot (backlot) areas, which present significant access restrictions for crews during routine maintenance and storm restoration. These segments often require manual entry through private property, increasing restoration time, labor intensity, and cost. Feeders with higher percentages of rear lot construction also correlate with longer incident durations and elevated cumulative customer minutes out (CMO), particularly during storm events. These access limitations contribute to slower recovery and reduced effectiveness of overhead rebuilds as a long-term reliability strategy. The Company's analysis of overhead line rebuilds reported in Docket No. E-002/M-25-27 indicates that only marginal improvements can be expected to the frequency of outages lasting 12 hours or more. In a subset of cases, backlot lines could be relocated to front lot overhead lines and obtain as much as 50 percent reductions in total outage durations. However, this rerouting adds to construction costs and requires significant disruptions to customers' property such as additional poles and new tree clearing.
- **Enhanced Vegetation Management** can reduce outage risk but does not eliminate it. While trimming programs are essential for maintaining clearance around overhead lines, they are inherently reactive and cyclical. Vegetation management costs vary considerably based on the accessibility of electrical infrastructure and the surrounding vegetation density. Rear lot segments typically incur higher costs than roadside lines due to restricted access, which often necessitates manual trimming or specialized equipment. These costs accumulate over time and are exacerbated by storm events, which often require emergency trimming and manual restoration efforts. Additionally, stakeholders have raised concerns about the potential for increased vegetation management to worsen urban heat island effects, particularly in densely populated areas. The Company currently does not have data to quantify the reliability benefits or duration of impact from enhanced vegetation management. Example of a typical situation found in vegetation management below in Figure 2-5:

Figure 2-5
Example of Vegetation Management Function (Tree and Powerlines)



- **FLISR (Fault Location, Isolation, and Service Restoration)** technology is effective for managing short duration outages where there are switch points to alternate source lines. It can quickly reroute power around the faulted section and avoids the need for manual line patrol and switch operation. However, it was not designed to resolve long-duration outages caused by severe weather or physical infrastructure damage. In such cases, FLISR cannot restore power until physical repairs are completed.

In contrast, Targeted Undergrounding offers a more comprehensive and cost-effective solution. By converting high-risk overhead segments to underground, the program significantly reduces outage frequency and duration and supports broader system goals such as electrification readiness and distributed energy resource hosting capacity. Undergrounding provides the opportunity to relocate distribution infrastructure out of rear lot (backlot) areas, which are notoriously difficult to access for routine maintenance and storm restoration. This shift improves operational efficiency, reduces vegetation management and emergency response costs, and accelerates outage recovery by enabling safer and more direct access for crews. Over time, these improvements contribute to lower O&M expenditures and enhanced service reliability, especially in areas with historically high restoration times due to access constraints.

4. *Indication of Benefits*

To ensure cost-effectiveness and strategic deployment, the Company's site selection criteria will follow the structured methodology outlined in the next subsection. However, to illustrate the potential value of this approach, the Company conducted two hypothetical analysis scenarios.

First Targeting Method Scenario:

This method incorporated the top 49 feeders from the 171 identified in Docket No. E002/M-24-27.⁸ These feeders were selected based on the amount of overhead infrastructure that could have been converted to underground using the full \$235 million program investments. Assuming overnight implementation, using outage data from the two years following the data used for Docket No. E002/M24-27, the Company estimated that undergrounding these 49 feeders would have avoided approximately 10.5 million CMO annually.⁹

Further analysis of the outages on these same feeders revealed that undergrounding could have avoided 46 events lasting 12 hours or longer (CELI-12) over the past two years—averaging 23 lengthy outage events per year. Which are particularly disruptive to customers and challenging to restore. Notably, 40 of the 46 CELI-12 events occurred on major event days driven by extreme weather, highlighting the vulnerability of overhead infrastructure during severe conditions. These events accounted for approximately 28 percent of the total 10.5 million CMOs avoided annually.

Using the Interruption Cost Estimate (ICE) tool developed by Lawrence Berkeley National Laboratory,¹⁰ the Company estimates an average customer value of \$3.05 per minute of avoided interruption. This metric allows for a direct comparison between the reliability benefits of undergrounding and the associated customer costs. Applying the ICE tool's valuation of \$3.05 per minute to the 10.5 million CMO savings, translates to an annual customer benefit of over \$31.9 million. This represents the

⁸ In the Matter of Northern States Power Company's Annual Report on Safety, Reliability, and Service Quality for 2023; and Petition for Approval of Electric Reliability Standards for 2024, Docket No. E002/M-24-27, Minnesota Public Utilities Commission, p. 97.

Note: The 171 feeders were identified using 2018-2022 data of customer interruptions on overhead distribution lines.

⁹ For comparison, the 10 year average for these 49 feeders is 7.5 million CMOs, and 11.8 CELI-12 events annually (using 2015-2024 data).

¹⁰ Lawrence Berkeley National Laboratory. ICE Calculator 2.0: Final Report for Phase 1 of the National Initiative to Update the Interruption Cost Estimate (ICE) Calculator. Energy Analysis and Environmental Impacts Division, June 2025. Available at: <https://eta-publications.lbl.gov/publications/ice-calculator-20-final-report-phase>

economic value of increased reliability to the customers directly served by the undergrounded assets.

Other customers would also benefit from reduced outage durations as a result of shorter work queues for the crews responding to outages. Additional analysis was performed to estimate the impacts of these other potentially shortened outages. The crews assigned to the outages prospectively avoided by undergrounding in this scenario subsequently responded to separate concurrent outages affecting over 18 thousand customers annually. These potentially shortened outages' actual durations averaged 12.6 hours per customer. Assumptions are required to estimate customer benefits in this case. If the average duration reduction is conservatively set at 30 minutes, this would result in an estimated 0.57 million CMO savings. Applying the same \$3.05 per minute value translates to an additional annual customer benefit of \$1.7 million.

Ongoing operation costs of underground lines are significantly lower than overhead lines due to reduced needs for inspection, outage response and repairs. However, the current undergrounding project approach retains existing overhead service spans and poles. This complicates estimation of resulting operational savings since a portion of the overhead facilities and their associated costs will remain. Because of those uncertainties, the company intends to incorporate estimates of operational cost savings estimates in future analysis when more data is available.

The prioritization method of this scenario was performed at a level significantly less granular than ultimately planned for implementation. However, this scenario affords a unique opportunity to use outage data from the two-year period entirely after a candidate selection process. This establishes a highly realistic representation of selection method effectiveness in identification of future outage risks and illustrates the level of reliability improvements that are achievable with this level of investment. The estimated annual cost impact to customers—based on planned program capital expenditures and rate recovery—is calculated at \$22.4 million annual revenue requirement at completion of this scenario.

The resulting benefit-cost ratio of 1.5 demonstrates that the reliability improvements in this scenario provide net economic value to customers, supporting the cost-effectiveness of the Targeted Undergrounding Program and its alignment with long-term grid modernization and customer service goals.

Second Targeting Method Scenario:

The Company also analyzed feeders located within 27 census block groups (CBGs) identified in Docket No. E002/M-25-27 as having elevated CELI-12 rates. These CBGs were highlighted in the TRC Study due to their disproportionate exposure to long-duration outages, primarily driven by vegetation-related interactions with overhead infrastructure. To ensure a direct comparison, an analysis was done on 13 of the 171 feeders identified in Docket No. E002/M-24-27 that have segments that fall within the 27 CBGs. The analysis found that undergrounding these 13 feeders would have hypothetically cost \$208 million and avoided approximately 4 million CMOs annually, resulting in an estimated annual benefit of just over \$12 million. Further analysis of CELI-12 outages on these feeders revealed that undergrounding would have avoided 25 CELI-12 events over the past two years—averaging 12.5 lengthy outage events per year.¹¹ These events accounted for approximately 49 percent of the total four million CMOs avoided annually.

The estimated annual cost impact to customers—based on program capital expenditures and rate recovery—is calculated at \$19.9 million annual revenue requirement at completion of this scenario.

The resulting benefit-cost ratio of 0.6 demonstrates that the reliability improvements in the second scenario, focused on the CELI metric, are more difficult to justify in simplified analysis. However, these feeders still contain high impact line segments that can be identified with more granular analysis described in the following section. An example project from this feeder set is also detailed.

5. Site Selection Criteria

The Company will employ a structured, data-driven methodology to identify and prioritize overhead distribution segments for underground conversion. This approach is designed to maximize reliability improvements, operational efficiency, and equitable investment across the service territory.

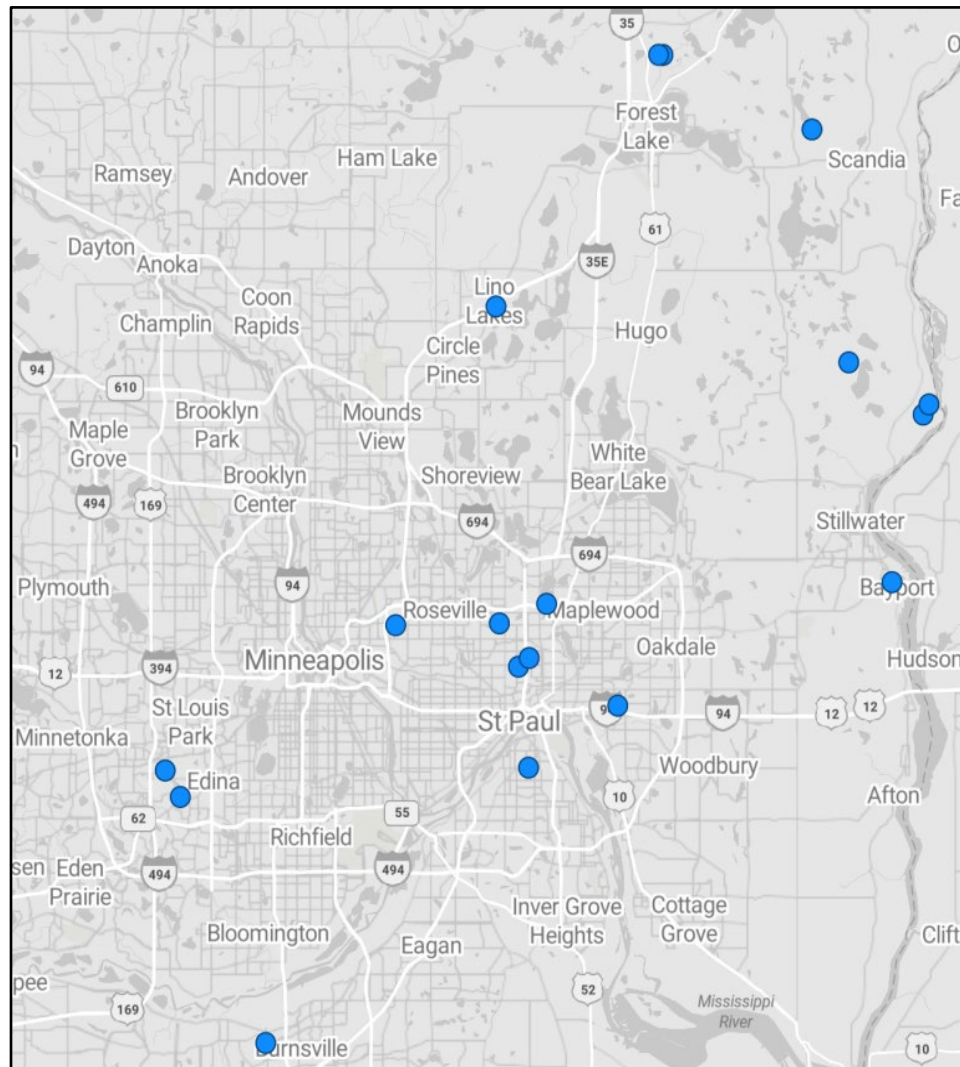
During the initial phase, the program will target segments where customers and/or devices have experienced multiple service interruptions (CEMI/DEMI) within a rolling 12-month period. Segments meeting certain CEMI or DEMI thresholds will be flagged for engineering review. The thresholds will remain flexible to account for evolving system performance, regional outage patterns, and the need to balance

¹¹ For comparison, the 10 year average for these 13 feeders is 3 million CMOs, and 6.4 CELI-12 events annually (using 2015-2024 data).

engineering precision with practical deployment considerations. These thresholds serve as a trigger for formal investigation by distribution engineers to assess root causes and evaluate the feasibility of undergrounding.

Each candidate segment will undergo a comprehensive technical assessment. This includes analysis of historical outage trends, asset condition (such as pole age, conductor type, and vegetation exposure), access constraints (including rear-lot construction), and restoration challenges measured by construction man-hours during prior events. Engineering judgment, informed by field validation and design feasibility, will guide final determinations. Due to these needs for rigorous review of site suitability, the company is currently not able to provide information on specific locations beyond the near-term projects that have been identified. To date, over 180 such projects have been selected for Design and Construction. An initial focus on small projects addressing CEMI allows for shorter durations needed to incorporate process and operational learnings and realize reliability improvements. These initial projects are distributed across 59 cities or townships. Most projects replace single phase primary in back lot lines. This geographic diversity reflects the program's commitment to broad investment and responsiveness to localized reliability challenges. Figure 2-6 below is a map showing the locations of identified potential Targeted Underground projects, as described above. These represent projects in the late stage of design where there is a high likelihood of feasibility.

Figure 2-6
Map of Potential Undergrounding Projects



As an example of current work, Figures below show portions of the existing overhead lines for an undergrounding project that began design scoping in February 2025. The project is on a line section serving 166 customers located in St Paul within CBG 271230306013. This CBG was reported in the Company's service quality map to have CELI-12 rates of 77.3 percent and CEMI-6 rates of 30.45 percent based on the most recent 3 year averages. The targeted line has approximately 1 mile of single-phase primary conductor and is at risk of impacts from large mature trees outside the right-of-way. A lack of vehicle accessibility has also extended the time required to perform repairs and service restoration. In 2023 and 2024, the lines and equipment targeted for undergrounding in this location were directly associated with 0.78 million CMO in total.

Figure 2-7
Location of Project in St Paul, MN

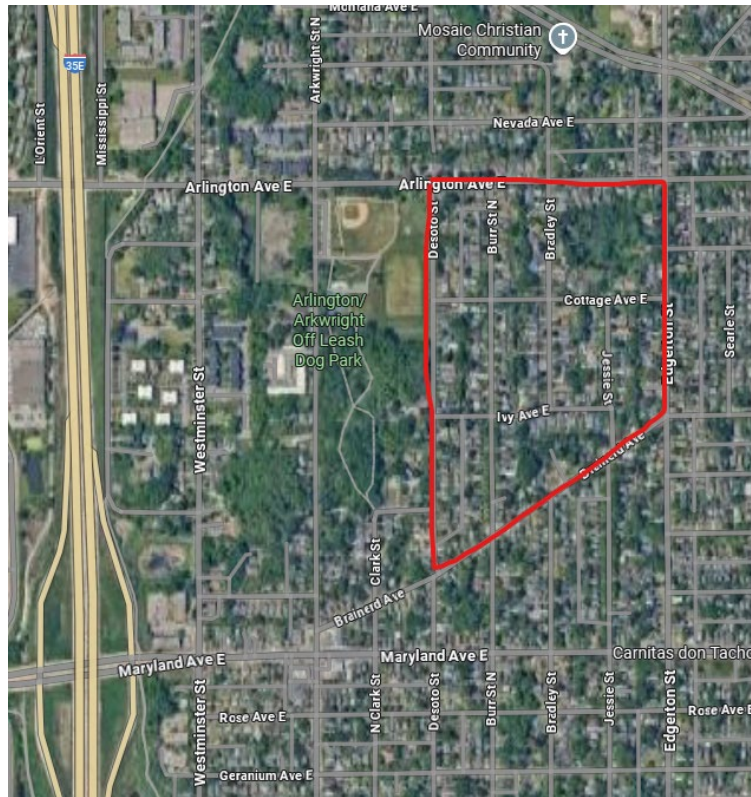


Figure 2-8
Existing Overhead Lines for an Undergrounding Project

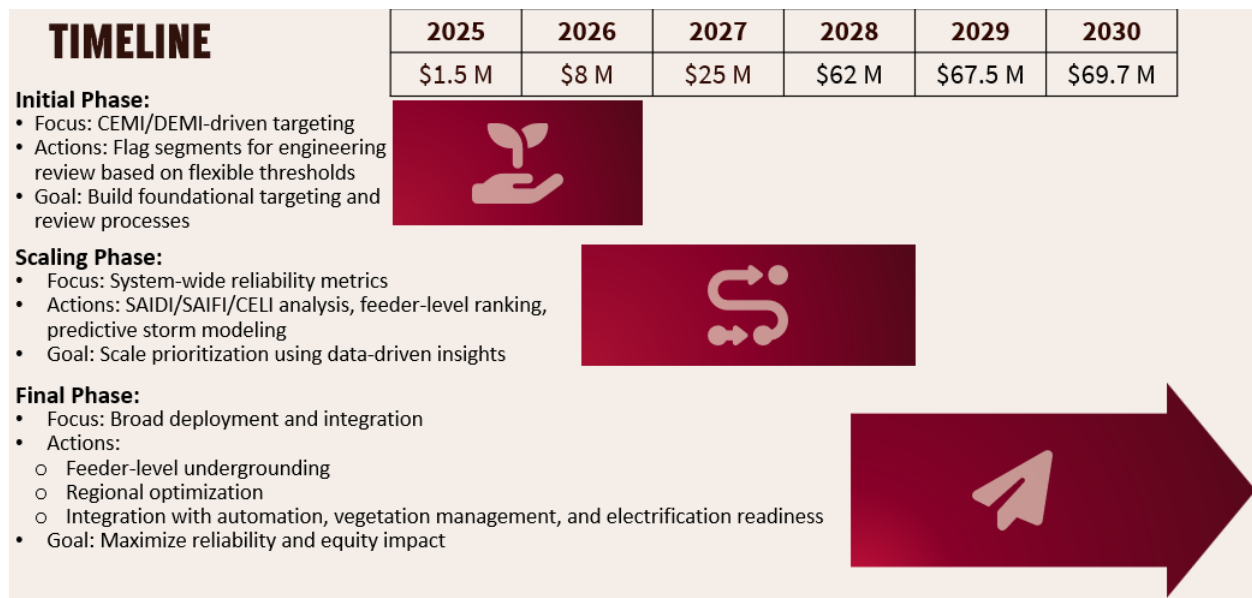


As the program scales, prioritization will be informed by system-wide reliability metrics and operational data. This includes SAIDI, SAIFI, and CELI analysis¹² to identify segments contributing disproportionately to reliability indices, feeder-level ranking integrated with hardening and automation strategies, and predictive storm impact modeling to identify high-risk areas.

To ensure equitable investment, the Company will incorporate findings from an independent third-party evaluation.¹² This evaluation will inform demographic analysis to identify underserved or vulnerable communities, and community engagement strategies coordinated with local stakeholders and municipalities.

In the final phase, the program will transition to broader deployment across prioritized segments. This will include feeder-level undergrounding based on cumulative performance and reliability impact, regional optimization targeting high-density areas with recurring outages and restoration delays, and integration with complementary programs such as distribution automation, vegetation management, and electrification readiness initiatives.

**Figure 2-9
Project Timeline**



¹² In accordance with Order Point No. 46 in Order Accepting Reports and Setting Additional Requirements, Minnesota Public Utilities Commission, Docket No. E-002/M-24-27, issued January 13, 2025, In the Matter of Xcel Energy's 2023 Annual Safety, Reliability and Service Quality Report.

6. *Technical Design*

Following the completion of the site selection process, the engineer initiates a formal request to Design and Construction to develop undergrounding plans for the identified segments. These plans encompass the conversion of overhead primary conductors, distribution transformers, and secondary lines to underground configurations.

Some secondary lines will be undergrounded as part of the standard design scope. However, the final service drop to the customer premises will generally remain overhead. This approach is designed to optimize both reliability and cost-effectiveness, allowing the program to achieve broader coverage while maintaining expedient construction timelines. Retaining the overhead service drop reduces the need for customer-side modifications, avoids unnecessary disruption, and supports efficient deployment.¹³

Where feasible, facilities will be relocated from rear-lot (backlot) alignments to front-lot locations. This relocation is the preferred design approach due to its operational advantages, including improved accessibility for maintenance personnel, reduced restoration time, and enhanced safety for both crews and the public. Rear-lot construction has historically contributed to longer restoration durations and elevated outage costs, particularly during storm events. Front-lot placement mitigates these challenges and supports more efficient deployment of underground infrastructure. The design will incorporate looped system configurations to enhance reliability and restoration speed. Looping enables fault isolation and sectionalization, allowing service to be restored to unaffected areas while repairs are underway.

Directional boring will be employed as the primary construction method to minimize surface disruption and reduce permitting complexity. This technique has proven effective in urban and suburban environments and supports efficient installation of underground facilities with minimal impact to property owners. Figures of Xcel Energy directional boring operations and equipment are shown below:

¹³ The Company notes that the approach of retaining overhead services has been utilized by PEPco, a peer utility that has achieved one of the most dramatic improvements in reliability metrics.

Figure 2-10
Directional Boring Equipment



Figure 2-11
Directional Boring Operation Begins



Figure 2-12
Directional Boring Operation Process



Design packages will be developed in coordination with Distribution Planning to ensure alignment with long-term grid modernization objectives, including electrification readiness, distributed energy resource hosting capacity, and aesthetic improvements. All designs will comply with applicable codes, standards, and permitting requirements, and will be reviewed for constructability, cost-effectiveness, and restoration efficiency.

7. Customer and Community Engagement

Customer and community engagement will be a critical component of the Targeted Undergrounding Program, particularly as the initiative transitions from pilot deployments to broader implementation. The Company recognizes that successful execution depends not only on technical feasibility and cost-effectiveness, but also on proactive communication, transparency, and responsiveness to stakeholder concerns. During the initial phases, engagement efforts will focus on neighborhoods selected for pilot projects. Customers in these areas will receive advance notice of planned construction activities, including information on project scope, anticipated timelines, and potential impacts. The Company will provide dedicated points of contact for

inquiries and will coordinate with local municipalities to ensure alignment with permitting, traffic control, and public safety requirements.

As the program expands, the Company will implement a standardized outreach protocol that includes direct mail, digital communications, and community meetings. These efforts will be tailored to reflect the unique characteristics of each service area, including language accessibility, cultural considerations, and local governance structures. Particular attention will be given to areas identified through the third-party equity evaluation as underserved or historically disadvantaged, ensuring that engagement is inclusive and equitable.

The Company will also develop educational materials to explain the benefits of undergrounding, including improved reliability, reduced vegetation-related outages, and enhanced restoration speed. These materials will address common questions regarding service drops, property access, and construction methods such as directional boring. While the final service drop will generally remain overhead to support cost efficiency and expedient deployment, customers will be informed of this design choice and its rationale.

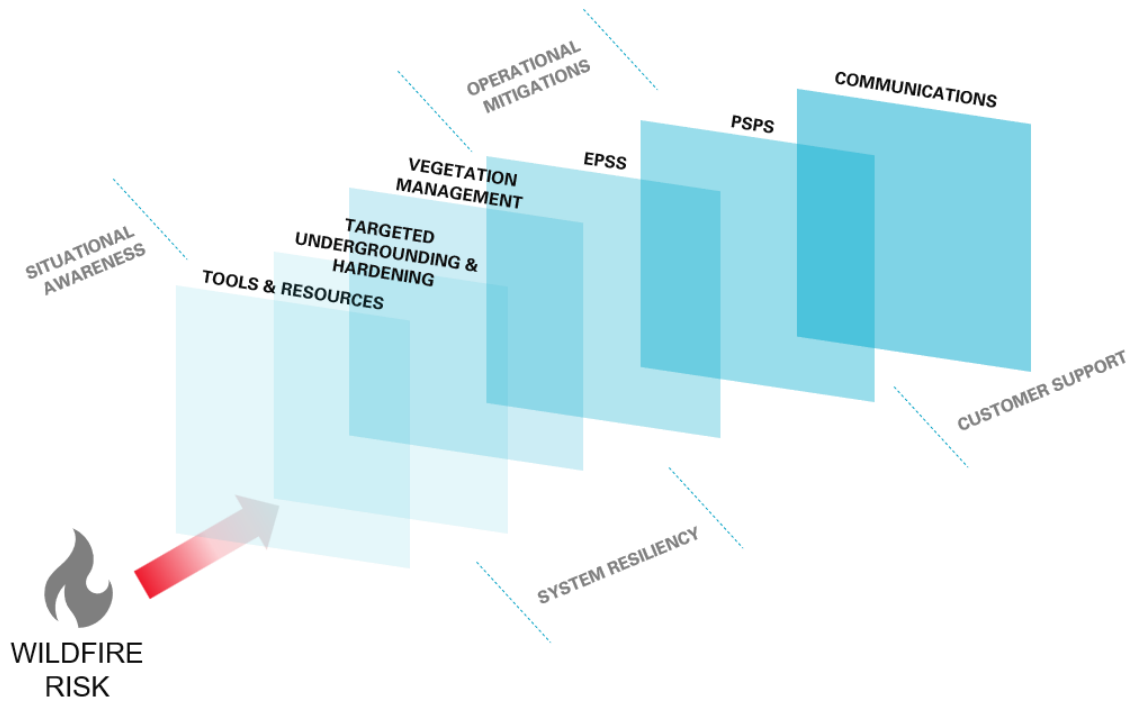
Feedback mechanisms will be incorporated throughout the program lifecycle, allowing customers to provide input before, during, and after construction. Lessons learned from early deployments will inform refinements to engagement practices, and the Company will report on outreach effectiveness in future regulatory filings.

D. Wildfire Mitigation Strategy

The Company's wildfire mitigation efforts are a critical part of its commitment to delivering clean, safe, reliable, and affordable electric service. While Minnesota's wildfire risk is generally lower than in western states, changing climate patterns, increased vegetation stress, and extreme weather events—such as higher temperatures, stronger winds, and more frequent droughts—require a proactive and comprehensive approach.

There is no single solution to managing wildfire risk. Instead, the Company employs a layered defense strategy that combines situational awareness, system hardening, operational protocols, and community engagement. This multifaceted approach is designed to reduce ignition risk, enhance system resilience, and protect public safety, all while maintaining the high standards of excellent service that customers expect. Our layered approach is shown in Figure 2-13 below.

Figure 2-13
Wildfire Risk Layered Mitigation Strategy



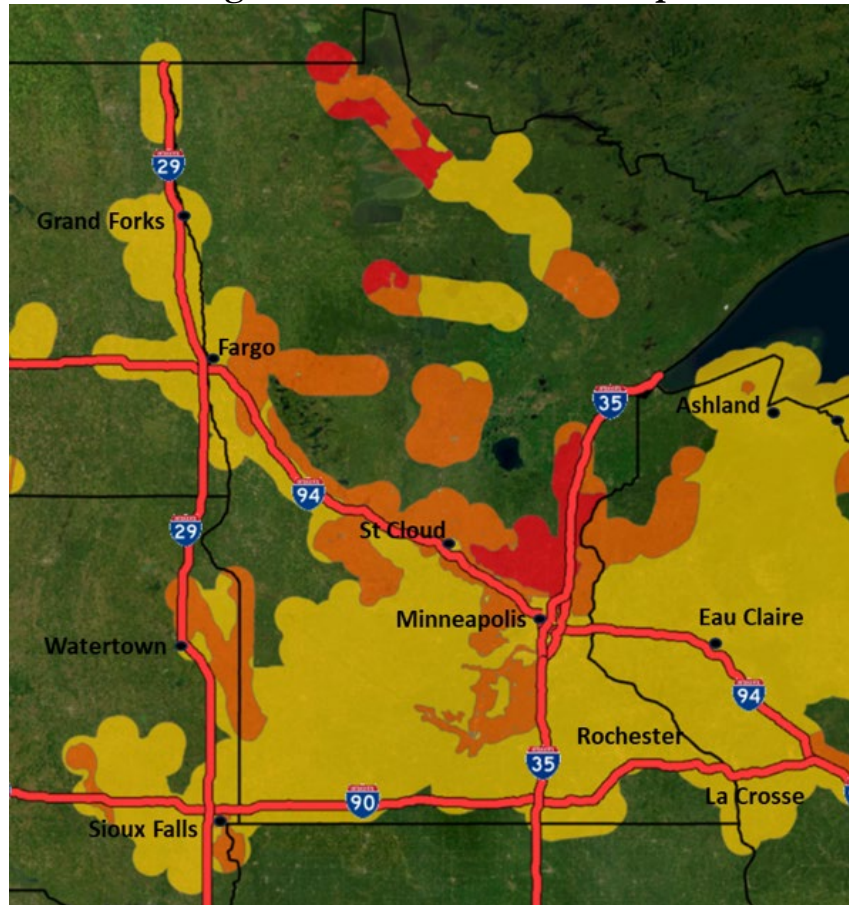
This section outlines the key components of the Company's wildfire management strategy.

1. Wildfire Risk Tier Mapping

The Company employs a three-tier Wildfire Risk Map, shown in Figure 2-14 below, to classify geographic areas based on their relative wildfire risk:

- Tier 1 (Yellow): Low risk
- Tier 2 (Orange): Moderate risk
- Tier 3 (Red): High risk

Figure 2-14: Wildfire Risk Map



Developed through Geospatial Information System (GIS) analysis, expert judgment, and local operational insights, the map identifies approximately 107,000 poles in Tier 2 and 4,700 poles in Tier 3, enabling feeder-level planning and targeted mitigation. This refined mapping supports more accurate budgeting, better coordination across programs, and prioritization of resources—key elements in delivering excellent service.

The map incorporates data layers such as vegetation type, historical fire data, topography, and infrastructure density. While relatively static, it provides a foundational tool for long-term planning and risk prioritization. It reflects average risk levels and helps ensure that mitigation efforts are strategically aligned with customer safety and system reliability. The wildfire risk maps are based on the best available information at the time of development. As new data becomes available, it will be incorporated into future versions. These maps are reviewed annually to determine whether updates are necessary.

2. *Situational Awareness Tools*

To improve real-time monitoring and decision-making, the Company integrates several advanced technologies:

- *Advanced Fire Modeling Software:* Simulates fire behavior under various environmental conditions to predict spread and intensity.
- *Weather Stations:* 45 stations will be deployed in 2025 and 64 more in 2026 to collect localized data on temperature, humidity, wind speed, and other fire-relevant metrics.
- *AI-Enabled Cameras:* Detect smoke and fire signatures, enabling early warning and rapid response. 38 cameras will be installed in both 2025 and 2026.
- *High Impedance Fault Detection:* Identifies downed conductors or vegetation contact that may not trigger traditional fault protection systems.
- *Non-Traditional Fault Detectors* Detect abnormal electrical activity—such as arcing or intermittent faults—that may go unnoticed by conventional monitoring systems. They support early identification of potential ignition sources and are planned for installation on 14,225 poles in 2026.

These tools support early identification of ignition risks and enable precise fault location, improving both safety and restoration times.

3. *System Resiliency Enhancements*

Infrastructure upgrades are essential to reducing wildfire risk and improving reliability:

- *Asset Inspection and Repair/Replacement:* Includes drone-assisted inspections and manual assessments to identify and remediate defects.
- *Pole Loading & Clearance (PLEC):* Uses LiDAR to create 3D models of distribution lines, analyzing structural integrity and clearance under various weather conditions.
- *System Hardening:* Involves replacing vulnerable components with fire-resistant materials and designs.
- *Non-Expulsion Equipment Replacement:* Transitioning to Cal Fire-rated fuses and arresters that minimize the risk of sparks during fault conditions.

These measures not only reduce fire risk but also improve system performance during storms and other disruptive events.

4. *Vegetation Management*

Vegetation contact is a leading cause of utility-related wildfires. The Company's vegetation management strategy includes:

- *Conductor Clearance Programs*: Ensures safe distances between power lines and surrounding vegetation.
- *Defensible Space Around Poles*: Clears flammable materials near poles to prevent ignition from electrical faults.
- *Wildfire Hazard Tree Activities*: Includes inspection and execution of hazard tree work, criteria and qualifications for personnel responsible for identifying and assessing hazard trees, and processes for identifying high-priority trees.

These practices are tailored to local vegetation types and growth patterns, with a focus on high-risk areas identified through tier mapping.

5. *Operational Mitigations*

Operational protocols are adjusted during elevated fire risk periods to reduce the likelihood of ignition:

- *Enhanced Powerline Safety Settings (EPSS)*: Modifies protection schemes to detect faults more quickly and block automatic reclosing.
 - Devices are supervisory control and data acquisition-controlled (SCADA)- for remote operation.
 - Faults are cleared in under 30 cycles (0.5 seconds), significantly faster than traditional settings.
 - Nontraditional fault detectors and Wildfire Fault Indicators assist with patrol and restoration.
- *Public Safety Power Shutoffs (PSPS)*: Temporarily de-energizes lines in extreme fire weather conditions to prevent ignition.
 - These measures are coordinated with local emergency services and communicated to affected communities to ensure safety and minimize disruptions.

6. *Distribution System Upgrades*

The Company is investing in targeted upgrades to reduce ignition risk and improve system durability:

- *Small Wire Conductor Replacements*: Targets the replacement of conductors smaller than #4awg in high-risk areas with modern, more durable materials. Often requires pole and hardware upgrades.

- *Covered Conductor Installations:* Uses insulated conductors with UV- and erosion-resistant coatings. These are less likely to ignite fires from vegetation contact but are heavier and require structural reinforcement.
- *Nontraditional Fault Detectors:* Includes advanced sensors that detect faults not captured by conventional protection systems, improving detection of downed lines and vegetation contact.

These upgrades are prioritized in Tier 2 and Tier 3 areas and are aligned with broader reliability and resiliency goals.

7. Budget

We include our wildfire capital expenditures for the next five years in Table 2-3 below.

Table 2-3¹⁴
Wildfire Expenditures (2025-2030)

Year	2025	2026	2027	2028	2029	2030
Capital	\$92,135,000	\$232,966,000	\$214,463,003	\$137,900,002	\$124,500,003	\$124,500,003
O&M	\$2,637,000	\$4,697,000	\$6,190,000	\$2,616,000	\$2,749,000	\$2,749,000

E. Overhead Distribution Assets and Reliability

The reliability of our overhead distribution system is influenced by several factors, including vegetation, weather conditions, and the condition of system components. To maintain excellent service and minimize outages, we implement targeted programs that address these key areas.

1. Vegetation Management Program

Vegetation is a leading cause of service interruptions. Our Vegetation Management Program helps reduce outages, protect public safety, and support efficient maintenance and restoration efforts. Activities include pruning, tree and brush removal, mowing, and herbicide application along and near our rights-of-way.¹⁵ These proactive efforts help prevent vegetation-related outages and ensure safe, timely

¹⁴ Table 2-3 presents the most current wildfire expenditures, which are also included in the rate case. These figures differ slightly from the wildfire allocations in our five-year capital budget because they were captured at different points in time. The capital budget reflects our July 2025 budget load, which has not yet been trued up.

¹⁵ Please see Chapter 3, Section III.A for more details on our vegetation management practices.

access for line crews.

2. *Arrester Replacement Program*

To improve reliability and reduce outage duration, we target the replacement of arresters on overhead feeder lines with high failure rates. Our analysis reveals that less than 30 percent of the arrester population is responsible for over 90 percent of the SAIDI impact from arrester failures. We prioritize replacements based on feeder performance and outage history, with a focus on feeders identified through our Feeder Performance Improvement Program. This targeted approach helps us deliver more reliable service while managing costs effectively.

3. *Low Cost Recloser Program*

The Low-Cost Recloser Program offers an economical way to supplement our standard recloser devices. Following the conclusion of the pilot program in 2021, a new cutout-mounted recloser model was approved for company-wide use. We continue to evaluate alternative low-cost recloser technologies to further enhance system reliability.

The approved device is a unique, single-phase, electronically controlled recloser that mounts directly to a cutout. It can be programmed with time-current curves to emulate traditional reclosers or fuses and supports both fuse-saving and fuse-blowing protection schemes. During the pilot, installation practices focused on areas prone to transient outages—such as treed taps or locations with high exposure—where traditional fuses had caused repeated service interruptions. During the pilot, the cutout-mounted reclosers performed reliably and contributed to improved customer service in those areas.

Building on the success of the pilot, cutout-mounted reclosers are now being deployed as part of our standard reliability improvement programs. Installations have continued at a steady pace, with 199 units added in Minnesota in 2023 and 299 in 2024.

4. *Feeder Performance Improvement Program*

The Feeder Performance Improvement Program (FPIP) is designed to identify opportunities to enhance the reliability of electric service at the feeder level. Feeders are evaluated based on their outage performance, with a focus on reducing service interruptions and addressing feeders that significantly contribute to customer

interruption counts.

FPIP assessments are conducted at the feeder level, which is the most practical and consistent unit for measuring reliability across groups of customers. The program targets improvements in the distribution system's outage performance, aiming to reduce both the frequency and duration of electric service interruptions.

Only feeders serving 10 or more customers are included in the FPIP. Feeders selected for review often have a notable impact on the CEMI4 metric (Customers Experiencing Multiple Interruptions—four or more). Each feeder identified through the FPIP is thoroughly reviewed to determine potential corrective actions.

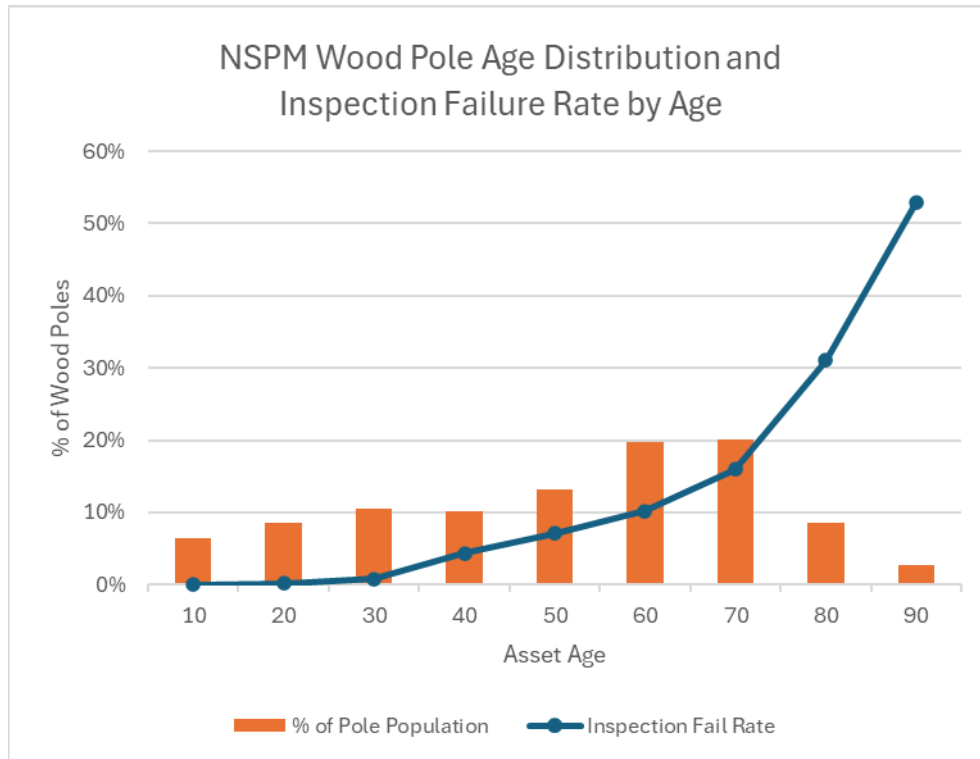
F. Maintaining Wood Pole Health

Maintaining the health of our wood poles is a critical part of asset management. Over time, wooden poles naturally degrade due to exposure to weather, wildlife, and aging. Like many utilities across the country, the Company has a substantial number of poles that are 50 years old or older. This is largely due to the extensive distribution system buildout during the 1950s and 1960s, driven by population growth and suburban expansion.

While these poles have served reliably for decades, many are now approaching the end of their useful life. Given their advanced age, it is essential for Distribution to maintain a consistent inspection and replacement schedule to proactively identify and address potential issues before failures occur.

Groundline Pole Assessment. Figure 2-15 illustrates inspection failure rates by pole age. Poles that no longer meet required strength standards are either replaced or reinforced. One common failure point is rot at the base, which can lead to pole collapse—especially during storms. To mitigate this risk, we inspect poles on a 12-year cycle.

Figure 2-15
NSPM Wood Pole Inspection Failures by Age



G. Porcelain to Polymer Cutout Replacement Program

This program, launched in 2022, focuses on improving reliability by replacing porcelain cutouts with polymer cutouts on overhead feeders. Cutouts are mounting devices that hold protective fuses and provide overcurrent protection. Porcelain cutouts are prone to developing small cracks that can collect moisture. When this moisture freezes, it can cause fractures and ultimately lead to equipment failure.

Failures often occur when a fuse is reclosed during power restoration, potentially causing or prolonging outages for affected customers. Additionally, a failed porcelain cutout can damage other feeder equipment, compounding the impact.

To address these issues, the Company began installing polymer cutouts in new feeder installations starting in 2010. Polymer cutouts offer several advantages over porcelain, including:

- Improved cold weather reliability
- Greater durability during transport and installation
- Superior mechanical toughness

Despite this transition, approximately 100,000 porcelain cutouts remain in service. Prior to the replacement program, these cutouts were experiencing an increasing rate of premature failures.

The program has since expanded from its pilot phase to a larger-scale implementation. While it's not yet clear whether observed improvements are directly due to replacements or changing failure patterns, the program has correlated with a reduction in failure and outage rates.

Figures 2-16 and 2-17 show a 10-year historical trend of IEEE OpCo Normalized SAIDI and SAIFI metrics related to fused cutout failures. These figures help illustrate the reliability impacts before and after the program's implementation. In 2024, the SAIDI impact from fused cutout failures was 0.95 minutes—an improvement compared to the three-year average of 1.39 minutes since the program began in 2022. Similarly, the SAIFI impact in 2024 was 0.009 interruptions, down from the three-year average of 0.014 interruptions. These results indicate continued progress in reducing outage impacts associated with fused cutout failure

Figure 2-16
NSPM Fused Cutout SAIDI Impact 2015-2024

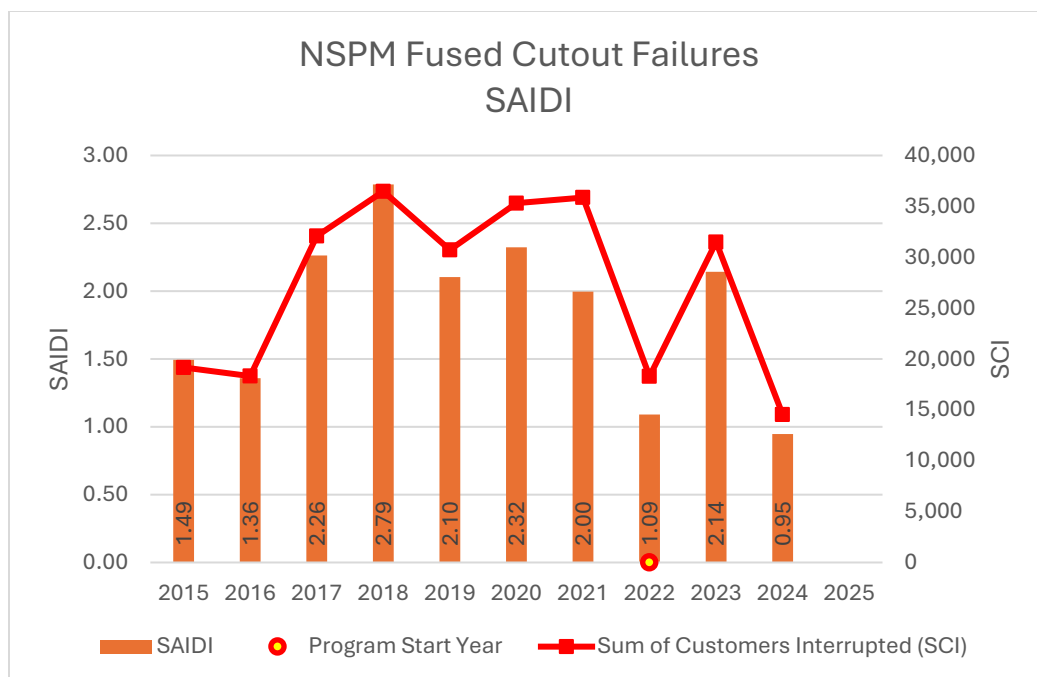
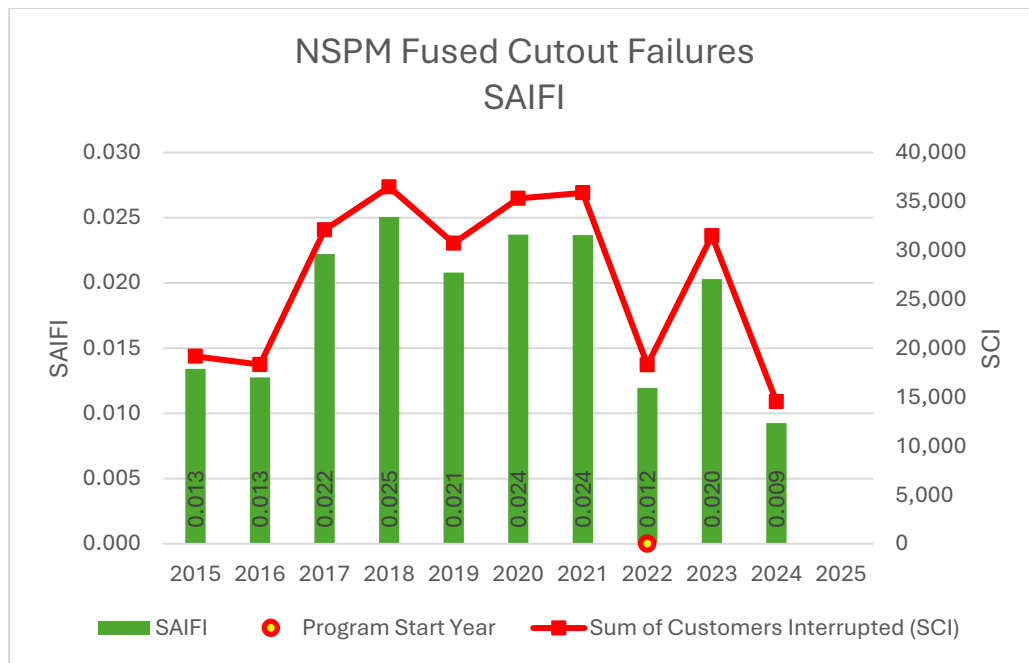


Figure 2-17
NSPM Fused Cutout SAIFI Impact 2015-2024



H. Substation Renewal Program

We anticipate increased near-term investment in the Substation Renewal Program, which focuses on replacing aging substation assets nearing the end of their useful life. The goal is to improve reliability and resiliency across Minnesota by upgrading key components—especially substation transformers.

Transformers are critical to the distribution system and among the most expensive substation assets. While failures are uncommon, they can result in outages affecting 5,000 to 15,000 customers. Many transformers in service have exceeded their expected 55-year lifespan, increasing the risk of failure and customer impact.

In addition to transformers, substations contain other essential components such as switches, breakers, relays, fences, and regulators, all of which require ongoing maintenance. The program also includes replacing mobile transformers that have reached the end of their service life. These mobile units are vital for performing upgrades and maintenance and allow for quicker restoration when permanent transformers fail—a process that can take weeks, especially under current supply chain constraints.

III. DELIVERING EXCELLENT SERVICE THROUGH SYSTEM RELIABILITY PROGRAMS

Each year, the Company develops and manages a range of programs aimed at maintaining and improving the performance of its transmission and distribution assets. These efforts are central to our commitment to delivering excellent service to our customers by ensuring a reliable and resilient electric system.

Our programs are designed to proactively manage system performance, reduce the frequency and duration of outages, and enable effective response when service interruptions occur. Through these initiatives, we strive to meet and exceed customer expectations for reliability and service quality.

We provide a detailed discussion of our reliability indices, performance results, and program activities in our annual service quality filings, as required under our tariff and the Minnesota Rules.¹⁶ Below is a brief summary of key sections from those reports, highlighting the programs and initiatives that support our reliability goals.

A. Reliability Indices

This section provides a snapshot of our 2024 reliability performance and highlights how we deliver excellent service through continuous system improvements and customer-focused tools.

In 2024, we achieved a SAIDI of 108.23 minutes, outperforming our Quality of Service Plan(QSP) tariff goal of 133.23 minutes. Similarly, our SAIFI was 1.05 outage events, outperforming the QSP goal of 1.21 outage events. These results reflect our commitment to delivering reliable service and minimizing disruptions for our customers.

To provide the Commission with a comprehensive view of our reliability trends, we normally include three tables that show historical performance, storm day impacts, and 2024 targets under three methodologies:

- All Days: Includes all days, levels, and causes, based on meter-level customer counts.

¹⁶ The QSP Tariff is filed annually in Docket No. E002/CI-02-2034. Additional reliability data is submitted each year through the Electric Annual Safety, Reliability, and Service Quality Performance Report and a corresponding Petition, which is filed in a new docket annually—the most recent being Docket No. E002/M-25-27.

- MN Tariff: Normalized using IEEE 1366 at the regional level, excluding transmission-level events.
- Annual Rules: Normalized using IEEE 1366 at the regional level, including all levels and causes.

This year, the Commission granted an extension to allow the Company to submit the tables in a supplemental filing by November 6, 2025. Please refer to our upcoming filing in Docket No. E002/M-25-27 for the Historical Reliability Indices and Performance tables.

B. Enhancing Customer Experience with CEMI Tools

To further our goal of delivering excellent service, we have developed advanced tools to better understand and address the experiences of customers who face multiple outages. Our Customers Experiencing Multiple Interruptions (CEMI) tools allow us to:

- Track customers with multiple outages over a rolling 12-month period.
- Visually map outage patterns across our service territory.
- Analyze outages from the customer's perspective, regardless of the root cause.

While the CEMI metric historically focused on customers with six or more sustained outages during non-storm days, our tools are flexible and can be adjusted to different thresholds for specific cases or QSP-level reporting. This customer-centric approach enables us to proactively identify and address reliability concerns before they escalate. By shifting the focus from equipment-based analysis to customer impact, we gain a more holistic view of service quality. Whether the cause is equipment failure, vegetation, animal contact, vehicle accidents, or weather events, our tools help us understand how these incidents affect individual customers. This insight supports our long-term efforts to reduce repeated outages and enhance overall customer experience.

C. Reliability Management Programs

To deliver excellent service, we actively monitor and analyze the causes and trends of historical outages to identify opportunities for improving system reliability. These insights guide targeted investments in reliability enhancements, which complement broader capital programs designed to ensure sufficient capacity to meet customer needs.

Our Reliability Management Program integrates these improvement efforts into a structured approach focused on proactive system performance. A dedicated reliability core team, composed of experts from both field operations and system planning, regularly reviews performance data and progress toward established targets. This cross-functional team takes timely, data-driven actions to address emerging issues and ensure optimal system reliability.

By continuously refining our strategies and investing in system resilience, we remain committed to minimizing service interruptions and enhancing the overall customer experience.

1. Reliability Management Programs – Key Initiatives

After analyzing the most common failure types, their root causes, and identifying at-risk equipment, we developed targeted work plans—summarized in Table 2-4, the “Star Chart” on the following page.¹⁷ These programs represent proactive investments in our transmission and distribution systems that are most likely to enhance overall reliability, improve asset health, and strengthen contingency preparedness.

By prioritizing these initiatives, we aim not only to improve system performance but also to deliver excellent service to our customers—minimizing outage impacts and ensuring a more resilient and responsive energy infrastructure. These efforts complement other capital investments that support adequate system capacity and enable load switching during outage response to further reduce customer disruptions.

¹⁷ The information in Table 2-4 reflects current plans and is subject to change. Funding in prior years included both Capital and O&M (Operations and Maintenance) expenditures. Equipment replacement costs were primarily capital-funded, while inspection and testing programs were supported through O&M. Estimates for pole replacements and the Feeder Infared Evaluation Program (FIRE) program include a mix of capital and O&M funding, as these activities are integrated into broader work programs—such as overhead rebuilds and maintenance accounts.

Table 2-4
Reliability Management Program Impacts (Star Chart)

NSPM Program Summary									
	Funded Programs		2022 Actuals (k\$)	2023 Actuals (k\$)	2024 Actuals (k\$)	IMPACTS			
		Description				SAIFI	CAIDI	CEMI	Complaints
Reliability	Feeder Perf. Improvement Program (OH & UG)	FPIP evaluates and implements improvements for feeders experiencing an increased number of outages based on prior year information.	3,271	6,501	1,866	★		★	★
	Outage Exception Reporting Tool (OH & UG)	OERT process provides automatic notification to area engineers when repeating outage criteria have been met and engineering solutions are implemented to eliminate recurring problems.	668	1,548	726			★	★
	Mainline Cable Replacement, (UG)	Deteriorating non-jacketed cable is failing and causing repeat outages. Proactive and reactive replacement of this cable reduces the outages.	4,448	2,207	4,268	★			★
	Tap (URD) Cable, (UG)		31,980	25,628	31,936	★	★		★
	Feeder Infrared Evaluation (OH)	Many pieces of equipment show excess heating prior to failure. The FIRE program provides infrared scans of overhead mainline which reveal specific equipment that is likely to fail so it can repaired prior to causing an outage.	45	67	103	★			
	Vegetation Management (Transmission & Distribution)	Cost benefit prioritized circuit trimming in NSPM. Continued reactive "Hot Spot" trimming.	35,522	27,067	27,713	★		★	★
Integrity	Pole Assessment & Replacement (Distribution)	Pole Assessment include an above groundline visual inspection. Groundline inspections are based on age and environment and may include visual, sound and bore and excavation. Life extension preservative treatments occur on majority of poles starting in 2021.. Based on results poles may be tagged for replacement.	25,621	29,254	80,857	★	★		
	Transmission Substation	Replaces end-of-life equipment in order to reduce maintenance costs and improve reliability.	15,373	33,763	36,448	★			
	Line ELR Work (Transmission)	Identifies lines that have components that have reached their end of life or where significant refurbishment work is needed to enhance system performance and reliability. Project focus may be to extend life of existing asset 20 + years or to replace and address future capacity upgrade concerns.	5,200	6,289	1,965	★			★

We have marked the primary performance impacts of each program with a red star in Table 2-4, where applicable. These impacts include improvements in SAIFI, Customer Average Interruption Duration Index (CAIDI), CEMI, and reductions in customer complaints. Additional details on estimated spending for reactive versus proactive cable replacements can be found in Chapter 6: Distribution Financial Information and Action Plans.

Table 2-5 outlines the key indicators for each of our major initiatives. The amount of work completed under each program may vary from year to year, depending on the areas identified as needing the most attention and the results of our condition assessments (i.e., the number of deficiencies requiring corrective action).

For more information on the initiatives listed in Table 2-5, please refer to the “Star Chart” in Table 2-4.

Table 2-5
Reliability Management Key Initiatives

	2024	2023	2022	2021	2020	2019	2018
Vegetation Management Program							
Total Overhead Distribution miles completed	1,050	1,128	2,239	2,019	1,606	2,647	2,307
Total Overhead Transmission miles completed	641	670	807	754	762	896	768
Normalized Tree-coded Sustained Cust Ints.(W/O Storms)	350,300	247,376	231,463	168,848	184,302	170,994	214,299
Non-normalized Tree-coded Sustained Cust Ints.(With Storms)	747,861	444,037	405,731	285,454	286,735	242,158	243,867
Underground Cable Replacement Program							
# of Segments That Have Been Replaced (est.)	2,541	2,526	2,591	2,252	2,579	1,158	1,504
# of Failures(Only on Primary Cable)	1,197	1,269	1,429	1,656	1,459	1,301	1,366
Feeder Infrared Evaluation (FIRE)							
# of Feeders Scanned	272	126	270	276	259	280	209
# of Hot Spots Corrected	17	18	16	28	66	55	67
Feeder Performance Improvement Plans (FPIP)							
Investigations Completed	150	109	91	97	112	111	108
Wood Pole Inspection Plan							
Total Distribution Wood Poles Inspected	53,626	54,642	42,330	39,045	40,179	10,312	33,720
Total Transmission Wood Poles Inspected	4,547	1,915	4,329	4,945	3,124	3,381	2,464

2. *Reliability Management Programs – Work Practices*

Improvements to existing work practices—identified and implemented by members of the Reliability Core Team and their staff—are a key contributor to both our reliability performance and the overall customer experience. These enhancements involve operational and procedural changes designed to either reduce the duration of outages when they occur or decrease their frequency altogether.

As shown in Table 2-6: Reliability Management Work Practices,¹⁸ we assess and prioritize each action based on two factors:

¹⁸ As filed in our 2024 Annual Report and Petition Safety, Reliability and Service Quality Performance and Proposed Reliability Measures, Docket No. E002/M-25-27 (Part 2, Attachment J, Page 8 of 9).

1. Its potential impact on reliability (rated as high, medium, or low), and
2. Its feasibility for integration into standard work practices—often occurring in parallel.

Many of these improvements require no additional funding and are implemented through ongoing employee training and updates to standard procedures. We continuously monitor these actions and update our plans as needed to ensure sustained progress.

Table 2-6
Reliability Management Work Practices

Areas of Opportunity	Key Initiative	Action/Program	Description	Reliability Impact
Resource Management	Duration	Work Coordination	Introducing a full-time work coordinator to support and schedule all appointment work when able. The coordinator will be in contact with customers prior-to, during and following their scheduled appointment. This will optimize use resources in support our customers. Better customer service for appointments and resource availability for outage restoration work will result.	Medium
Substations	Frequency	System Integrity	Substation inspection done on every substation specific to identifying vegetation issues, in addition moving to an electronic work collection APP to track and prioritize timely maintenance.	High
	Duration	Equipment Failure Response	Install Mobile subs and connection cables as quickly as possible when customers are out due to equipment failure.	Medium
Feeders	Duration	Restore before repair	During a feeder event Control Center personnel restore service to as many customers as possible before making temporary/permanent repairs.	Medium
	Duration	Patrol Optimization	Use of application software to assist manual patrol of outages and momentary outages. This will allow for quicker response and permit a single resource to respond to a greater number of outages or appointments.	Medium
	Frequency	Intentional Outages	Reduce impact of intentional outage to ensure all steps are being taken to keep the maximum number of customers on. Verify switching to reduce customer counts. Repair while hot instead of taking outage.	Medium
	Frequency & Duration	VM Partnership	Partner with Vegetation Management leadership to prioritize trimming of circuits that are scheduled to be trimmed. Substations to be trimmed with associated feeders.	High
	Frequency & Duration	Feeder Patrol Program	Looking for unfused taps and animal protection. Continued use of IR/thermo imaging to identify problems.	Medium
	Frequency	Condition Assessment & Correction	Utilizing UAS (Drone) technology to complete a comprehensive inspection of our worst performing feeders upon request.	High
Control Center	Duration	Restore before repair	Advanced technology going into the control centers and the field.	High
	Duration	Distribution Operations Model	ADMS (Advanced Distribution Management System) application is live in all NSP Control Centers (4); as the application matures, we are working to locate the fault on the circuit to cut down on the response time.	High
	CAIDI	Model 1/0 Switching	Standard operating procedure to model 1/0 URD as close to real time so the OMS model will reflect the configuration of the URD circuit after it has been switched.	Medium
	CAIDI	Validate Restoration Times	Tighten up existing process on actual restoration times, utilize approver process to ensure outage times are correct.	High
COM	CAIDI	COM Saturday Crews	Assigned crews for weekend response; 3 Metro East crews and 3 Metro West crews	Medium

Areas of Opportunity	Key Initiative	Action/Program	Description	Reliability Impact
	CAIDI	Backup Crews	Currently negotiating on-call crews for outage response, Friday-Monday to enhance response time to customer outages.	Medium
	SAIFI & CAIDI	Underground Cable Repair	Repair and/or replace cables as directed by engineering	High
	SAIFI	REMS/CEMI Work	Complete work referred by engineering in a timely manner	Low
Reliability Team/ Communications	SAIFI & CAIDI	On-going Regular Reliability Meeting	Meet regularly to review reliability and share ideas to improve reliability performance.	Low
	CAIDI	Continuous Improvement	In 2021, Control Center Leadership is producing a detailed CAIDI report on a monthly basis, the purpose and impact of the report is to call out opportunities for improvement on response, meet with the first responders to develop plans to remove obstacles to response and holding employees accountable to timeliness of response using the data and operator comments.	Medium

CHAPTER 3: DISTRIBUTION OPERATIONS

In Chapter 3, we discuss key aspects of our distribution operations, with a focus on how we uphold our commitment to deliver excellent service to our customers. Section I focuses on our escalated operations—how we plan for, manage, and respond to unplanned events that impact our system and customers, most commonly due to storms or severe weather. Section II highlights major components of our routine operations that support reliable electric service. These include Vegetation Management, Damage Prevention and Locating, and Fleet and Equipment Management.

I. POWERING THROUGH THE STORM: OUR EMERGENCY RESPONSE

While we take many proactive steps to plan and maintain a reliable electric system, unexpected events—such as severe weather—can still cause customer outages and infrastructure damage. In this section, we describe how we prepare for such events, our approach to outage restoration, and provide an overview of storm-related costs.

The Company is recognized as an industry leader in storm response. For example, in March 2025, a powerful winter storm swept across Minnesota, affecting approximately 50,000 customers, primarily in the Twin Cities metro area. Despite challenging conditions, the Company deployed 500 workers and restored power to over 90 percent of customers by 4 p.m. the same day, prioritizing public safety hazards and demonstrating the effectiveness of our rapid response protocols.

This builds on our award-winning performance in 2023, when the Company received the Edison Electric Institute Emergency Recovery Award for our response to the April Fools’ Day snowstorm. That storm impacted approximately 300,000 customers across Minnesota and Wisconsin. Over 1,200 employees and contractors from 10 states were mobilized to restore power to 180,000 customers who experienced sustained outages.

These examples highlight the Company’s strong commitment to deliver excellent service to our customers. They demonstrate the value of our pre-storm planning, rapid workforce mobilization, and coordinated communication strategies. By continuously refining these processes and investing in readiness, we reduce outage durations and enhance the customer experience.

A. Storm Preparedness and Response: A Coordinated, Customer-Focused Approach

The Company's ability to respond effectively to severe weather events is built on a foundation of proactive planning, cross-functional coordination, and a strong commitment to deliver excellent customer service. The following sections outline the key phases of our storm response strategy—from early planning and logistics to real-time mobilization and on-the-ground restoration.

1. Planning Before the Storm: Building a Foundation for Rapid Response

Our readiness begins long before a storm appears on the radar. At the core of our strategy is the Distribution Incident Response Plan, which outlines how we plan, execute, and communicate during escalated operations. This plan is not static—we regularly test and refine it through drills and readiness assessments to ensure we are always prepared.

As a storm approaches, our entire organization mobilizes to ensure a safe and effective response. Internal teams proactively assess risks and begin positioning field crews, troublemen, and contractors based on those assessments. Crews may be redeployed to strategic service centers or placed on standby to enable a rapid and coordinated response once the storm arrives.

But restoration is far more than boots on the ground. Behind the scenes, back-office support, managers, warehouse personnel, contracting services, damage assessors, customer-facing teams, safety professionals, and workforce relations staff all play critical roles. Their coordination ensures that crews have the tools, information, and support they need to work efficiently and safely.

In parallel, we activate foundational agreements with contractors and mutual aid partners, enabling us to quickly scale our workforce. These trusted partnerships are essential to maintaining speed and efficiency during large-scale restoration efforts.

One key indicator of our improved readiness is the increasing number of storm events that no longer qualify for Major Event Day (MED) exclusions.¹ Thanks to detailed

¹ A Major Event Day (MED) is a term used in the electric utility industry—particularly in reliability reporting—to describe a day when service interruptions are significantly higher than normal due to extraordinary circumstances. These events are typically caused by factors outside the utility's control, such as severe weather (e.g., hurricanes, ice storms, tornadoes), natural disasters (e.g., wildfires, earthquakes), widespread equipment failures, or large-scale external disruptions (e.g., cyberattacks or regional grid failures).

planning, pre-staging of crews, and early mobilization, we are restoring power faster—often before events reach the MED threshold. This shift reflects our commitment to delivering a better customer experience, even during challenging conditions.

2. *Logistics in Motion: Preparing the People and Places That Power Restoration*

Behind every successful restoration effort is a well-coordinated logistical operation. We maintain detailed lists of hotel accommodations and conference facilities across our service area to house crews, serve as dispatch centers, or host safety briefings. We also track available transportation options, such as buses and vans, to move crews and support staff efficiently.

To support large-scale mobilization, we have pre-identified over 100 staging sites within our service territory. Each site is equipped with street and feeder maps to help crews navigate quickly. Our planning also includes less obvious but essential needs: restrooms, waste containers, and security. These details ensure our crews can work safely and effectively for extended periods.

To accelerate crew deployment, we use automated call-out systems that notify and assign personnel based on availability and location. This technology enables us to quickly assemble the right teams and get them where they are needed most—reducing response time and maximizing operational efficiency.

Additionally, during normal working hours, we pre-stage crews and contractors in anticipation of potential weather threats, allowing for quicker mobilization when conditions change.

3. *As the Storm Approaches: Monitoring, Mobilizing, and Communicating*

When a weather event is on the horizon, our teams begin closely monitoring forecasts, system conditions, and customer call volumes for early warning signs. As the picture becomes clearer, we notify internal teams—including field crews, operations, call centers, communications, and regulatory affairs—and begin sending regular updates to predefined internal distribution lists.

Employees in storm support roles are alerted to prepare for extended shifts. We also inform support functions such as supply chain, fleet, safety, and workforce relations, as well as local labor unions. If necessary, we begin strategically moving crews and equipment to areas expected to be hardest hit—especially where access may be limited during the storm.

4. *Activating the Response: Coordinated Action Across the Organization*

Once operations leadership determines that the storm poses a risk to the distribution system, we hold an operational readiness call to review conditions, staffing, and preparations. If system impact is confirmed and the severity of the incident warrants it, we activate Everbridge, our internal alert system, to notify key personnel across the organization.

We then initiate a regular cadence of escalated operations calls, following a standardized agenda and checklist. These calls ensure alignment across all teams, communicate key facts about the event, and gather updates from support functions and customer-facing groups such as the call center, community relations, and large managed accounts.

5. *On the Ground: Responding to Outages with Speed and Safety*

As outage reports come in and conditions become safe for crews to respond, our systems analyze the data to determine the scope and scale of the disruption. Crews are then dispatched to investigate. Upon arrival, the crew assesses the situation and begins repairs. Given the complexity of our electric system and the variety of potential outage causes, this process can take time—especially when public safety issues, such as downed live wires, must be addressed first.

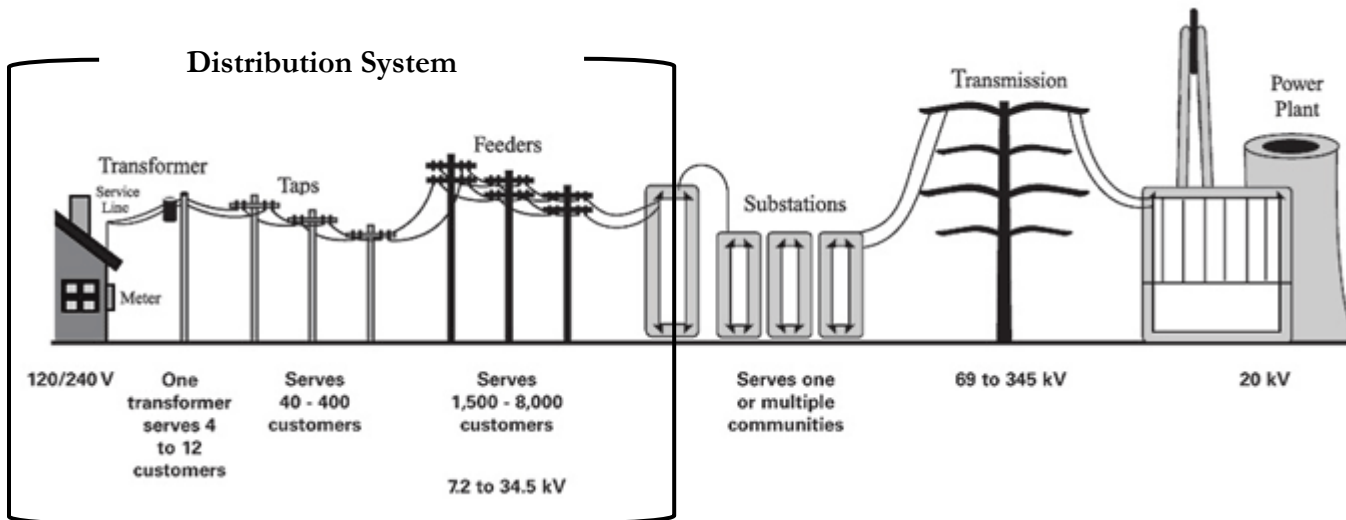
Our restoration process prioritizes safety and efficiency. We focus first on hazards—such as downed power lines or damaged equipment—because they pose immediate risks to public safety. Once those hazards are mitigated, we prioritize repairs that will restore power to the greatest number of customers as quickly as possible.

Crews work around the clock until service is fully restored. Restoration time estimates are updated in real time within our control center systems, based on data transmitted from mobile data terminals in crew vehicles.

6. *Understanding the Impact: How the Grid Responds*

The number of customers affected by an outage depends on the level at which the issue occurs on the electric grid. Figure 3-1 (below) provides a high-level overview of the major grid components involved in restoring power—whether during a major storm or a more localized event.

Figure 3 - 1
Major Grid Components



B. Restoring Service Safely and Quickly

This section outlines our strategic approach to outage restoration, emphasizing our commitment to deliver excellent service through safe, efficient, and customer-focused operations. It explains how we prioritize restoring power to the greatest number of customers as quickly as possible, beginning with critical infrastructure such as transmission lines and substations that serve entire communities. The section also details the hierarchy of the distribution system—from substations to service wires—and how this structure guides our restoration efforts.

Additionally, we highlight the role of Advanced Metering Infrastructure (AMI) in enhancing our ability to detect outages, track restoration progress, and reduce unnecessary truck deployments. These capabilities enable faster, more accurate responses, ultimately improving the customer experience during service interruptions.

1. Prioritizing the Backbone: Transmission and Substations

Restoration begins with the transmission system and substations, which are essential to delivering power across wide areas and serving large numbers of customers. Although outages at the transmission level rarely cause direct customer interruptions due to the grid's interconnected design, any damage or failure reduces system resilience and creates vulnerabilities. That is why transmission repairs are a top priority.

Transmission and substation repairs are handled by dedicated teams, allowing our distribution crews to focus on restoring service to customers more directly. Substations can serve either the transmission or distribution system. Distribution substations feed power to distribution feeders, each of which can serve between 1,500 and 8,000 customers.

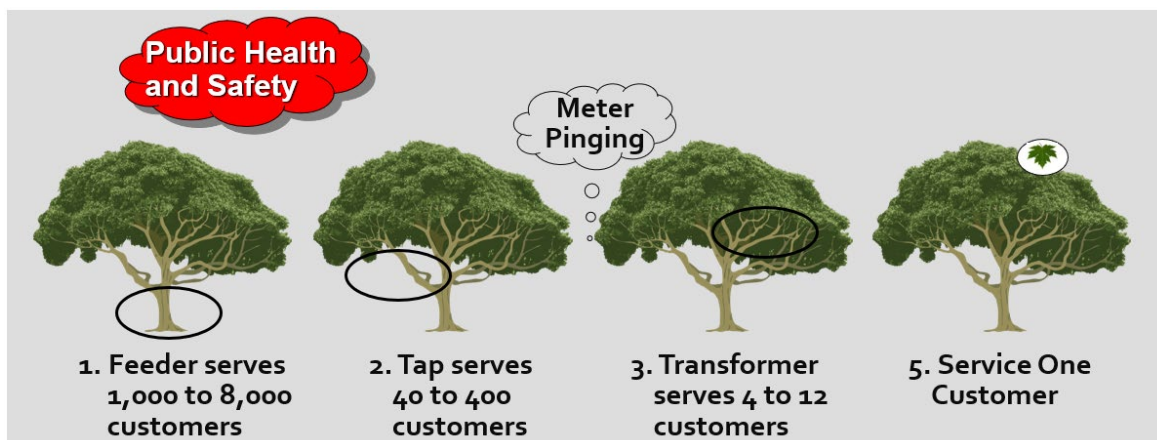
2. *From Feeders to Homes: The Distribution Path*

The distribution system for electricity restoration can be thought of like a **tree**, with each part playing a distinct role in delivering power from the source to individual homes. We follow a clear hierarchy for restoration:

- **Feeders** are the **trunk**, carrying electricity from substations to large areas (1,500–8,000 customers).
- **Tap lines** are the **branches**, distributing power to neighborhoods (40–400 customers).
- **Transformers** are the **twigs**, serving small groups or buildings (4–12 customers).
- **Service lines** are the **leaves**, connecting power directly to individual homes and businesses.

This structure means that a single issue at the feeder or tap level can affect hundreds or thousands of customers, while a problem at the transformer or service level may impact only one or a few. See the figure below, which illustrates the electricity restoration system as a tree.

Figure 3-2
Restoration Progression



3. *Isolated Outages and the Role of AMI*

In some cases, a feeder or tap line may be restored, but individual customers remain without power due to issues at the transformer or service connection. Historically, these isolated outages may not have been immediately visible to our systems—especially if the customer receives a restoration notification based on upstream repairs.

This is where AMI plays a critical role. AMI enables us to:

- **Detect outages at the individual customer level** – Smart meters send real-time signals when power is lost, allowing us to identify outages that would otherwise go unnoticed until reported by the customer.
- **Confirm restoration with precision** – Instead of relying solely on system-level indicators, AMI lets us verify that power has been restored to each meter, reducing uncertainty and improving customer communication.
- **Reduce unnecessary truck rolls** – AMI helps avoid “OK on arrival” scenarios by confirming whether power is truly out before dispatching a crew, saving time, fuel, and operational costs.
- **Improve restoration prioritization** – By pinpointing exactly which customers are still without power, we can better allocate resources and sequence repairs based on impact and need.
- **Enhance customer trust and transparency** – With more accurate outage and restoration data, we can provide timely, personalized updates and reduce frustration during extended outages.

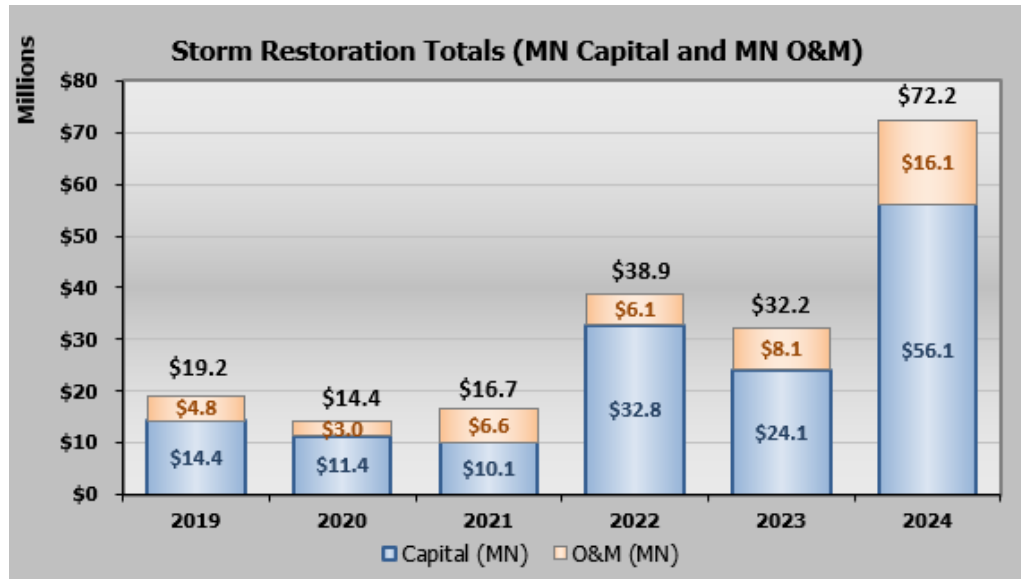
We discuss the broader benefits of AMI in Chapter 5: Grid Modernization and in our AMI Annual Report, submitted October 31, 2025 with our Transmission Cost Recovery Rider filings (see Docket No. E002/M-21-814).

C. **Storm Response Budgeting: Balancing Preparedness and Flexibility**

Our annual capital and operations and maintenance (O&M) expenditures are significantly influenced by the frequency and severity of storm restoration activities across our service territory. Because severe weather is inherently unpredictable, it presents ongoing challenges for accurate budgeting.

Figure 3-3 below illustrates the variability of our capital and O&M expenditures related to storm response in Minnesota from 2019 to 2024. This variability underscores the need for flexible financial planning.²

Figure 3 – 3
Storm Restoration – State of Minnesota Electric Capital and O&M Expenditures 2019 to 2024 (Millions)



To manage this uncertainty, we allocate funds for storm restoration through a working capital reserve rather than assigning them to specific projects or programs. When emergent events—such as major storms—occur, we reallocate these funds as needed, while maintaining alignment with our overall annual budget.

For O&M, we take a similar approach. We include a base level of funding in key labor accounts, such as productive labor and overtime, to ensure we have the flexibility to respond to unplanned events without compromising other operational priorities.

D. Ensuring Reliable Service for Critical Customer Loads and Vulnerable Populations

This section addresses Order Point No. 9 from the September 24, 2024 ORDER:

² Figure 3-3 shows escalated operations events significant enough for a work order to be established.

Order Point No. 9: *Xcel shall provide a discussion of how it tracks, protects, and considers the restoration of vulnerable populations and critical customer load, such as hospitals and first responder sites, during extended outage events in its next IDP.*

1. Prioritizing Critical Customer Loads

The Company is committed to ensuring that critical customer facilities—such as hospitals, emergency response centers, and essential infrastructure—receive top priority during extended outage events. Our approach combines proactive system planning, operational readiness, and close coordination with emergency partners to maintain continuity of essential services when they are needed most.

Identification and Tracking of Critical Customers. We maintain a comprehensive, regularly updated registry of critical customer loads, including hospitals, emergency response centers, water treatment plants, and other essential services. These customers are flagged in our outage management and distribution systems, allowing our teams to quickly identify and prioritize their restoration during outages.

Many of these critical customers consume over 500 kW and are assigned dedicated account managers, allowing them to bypass the standard customer service line during outages. Additionally, every city and county the Company serves has an assigned community relations manager who maintains regular contact with local officials and stakeholders, complementing the support provided by account managers.

Protection and Prioritization Protocols. Our grid planning strategy includes targeted investments to safeguard circuits that serve critical loads. These circuits are often reinforced with upgrades such as proactive pole replacements and automated switching devices. These enhancements help reduce the risk of outages and enable faster restoration when disruptions do occur.

Coordination with Emergency Management Agencies. We work closely with local and state emergency management agencies to align our restoration priorities with broader public safety goals. This includes participating in emergency preparedness exercises, real-time coordination during major events, and sharing outage and restoration updates with emergency response partners. These relationships are essential to delivering a unified and effective response.

The Company is committed to prioritizing our critical customer loads. These efforts are part of our broader commitment to resilience and community well-being.

2. Informing and Supporting All Customers, Including Vulnerable Populations

The Company delivers excellent service by restoring power to the largest number of customers as quickly and safely as possible. We do not track “vulnerable” customers but our restoration protocols, advanced tools, and outage communications assist all our customers, including vulnerable customers. We begin by prioritizing repairs to large feeders, which helps restore service to entire neighborhoods or communities efficiently. This approach benefits all customers, including those who may face greater risks during outages. As restoration efforts progress and we reach the stage of individual home restoration, we also consider registered medical needs to prioritize those homes whenever possible.

Smart Technologies that Improve Response Time. We use advanced tools such as our automated Outage Management System (OMS) and AMI to detect outages in near real-time—often before they are reported. This is particularly helpful in low-income areas, where fewer reports may come in due to limited phone access or vacant homes. AMI helps us identify broader outages and prioritize restoration more effectively.

We are also expanding the use of technologies to help improve our service, including:

- AGIS (Advanced Grid Intelligence and Security): Combines smart meters, communication networks, and analytics to give us real-time visibility and control of the grid.
- FLISR (Fault Location, Isolation, and Service Restoration): One of the AGIS projects, which automatically detects and isolates faults, then reroutes power to restore service—often within seconds.

Keeping Customers Informed. Clear, timely communication is a key part of excellent service. We use multiple channels to keep customers updated about outages and estimated restoration times, including:

- Social media and website updates
- News outlets and mainstream media
- Interactive text messaging³
- Call center agents equipped with real-time outage and restoration information

These tools help ensure that all customers—especially those with critical needs—receive timely, accurate information to stay informed during an outage.

³ We are piloting interactive text messaging with customer service representatives and will evaluate its effectiveness based on customer engagement and satisfaction.

Notifications for Customers with Medical Needs. Customers who have registered a medical need with us receive updates via automated calls and emails with information on outage duration. This ensures they can take timely action to safeguard their health and access necessary resources.

Helping Customers Plan Ahead. We also provide customers with estimated restoration times, both at a system-wide and neighborhood level. This helps all customers, including those with critical needs, make informed decisions and prepare during an outage. For instance, a household with an adult who uses a ventilator can use this information to determine whether to relocate temporarily or activate a backup power source. Similarly, an elderly person living alone who relies on an electric-powered stair lift can use estimated restoration times to decide whether to receive additional help during an outage, ensuring they maintain safe mobility at home.

Mobile Transformers and Substation Equipment. Xcel Energy, including its Minnesota operations, maintains a fleet of mobile transformers and other mobile substation equipment to support planned maintenance outages and to restore service following major equipment failures.

When a substation transformer or other critical substation component fails, replacing it can take weeks or even months—even if spare equipment is available in the Company’s inventory. In contrast, mobile equipment enables restoration of service within hours or days, allowing time for permanent repairs or replacements to be completed.

Mobile substations are typically self-contained units mounted on trailers, including a transformer and essential protective devices such as breakers and relays. Mobile transformers, also trailer-mounted, consist solely of the transformer and may have either fixed high-side and low-side voltages or adjustable taps to accommodate variable voltage requirements.

This mobile capability is essential for rapid restoration of power when permanent substation equipment fails. In cases where spare equipment is unavailable, lead times for new substation transformers can exceed three years. Therefore, maintaining a robust and strategically deployed fleet of mobile and spare transformers is critical to ensuring reliable service across our Minnesota territory.

We are constantly working to restore service as quickly and safely as possible to as many customers as we can. Delivering excellent service means strengthening the grid and ensuring that all customers are informed and supported during outages.

II. ESSENTIAL OPERATIONS THAT POWER OUR COMMUNITIES

This section highlights several essential—but often less visible—aspects of the Company’s Distribution operations that are fundamental to delivering excellent service through safe and reliable energy. While high-profile efforts like storm response and the construction of new feeders and substations often take the spotlight, the following functions are equally critical to our day-to-day operations and our commitment to customers:

- *Vegetation Management*, which helps prevent tree-related outages and supports public and employee safety.
- *Damage Prevention and Locating*, which protects underground infrastructure and promotes safe excavation practices.
- *Fleet and Equipment Management*, which ensures our crews have the tools and vehicles needed to maintain and restore service efficiently.

A. Vegetation Management

For the Company, delivering excellent service means more than just providing electricity—it means ensuring that service is safe, reliable, and responsive to customer needs. The Vegetation Management program is a key part of this commitment, helping to protect the electric grid from outages, safeguard the public, and support efficient operations.

By proactively managing vegetation near power lines, the program helps prevent service disruptions, reduces the risk of accidental contact with energized equipment, and ensures that crews can safely access infrastructure for maintenance and emergency response. These efforts are essential to maintaining the high standards of service that customers expect.

1. *Comprehensive Vegetation Management Activities*

Vegetation management includes a variety of field operations designed to control vegetation growth in and around our facilities. These activities include:

- *Pruning*: Trimming tree limbs to maintain safe clearances from power lines. This category accounts for most of our vegetation management work.
- *Tree Removal*: Eliminating trees that pose a risk of falling onto electrical infrastructure.
- *Mowing*: Clearing brush and small trees to reduce fire hazards and improve access to our distribution and transmission infrastructure.

- *Herbicide Application*: Using targeted treatments to control regrowth and maintain clear zones around our distribution and transmission infrastructure.

These activities are organized into four key categories:

- *Outage Response*: Emergency vegetation work to restore service quickly and safely after storms or other disruptions.
- *Customer-Requested Work*: Responsive service to address vegetation concerns raised by property owners.
- *Proactive Maintenance*: Proactive efforts to prevent outages and maintain system health.
- *Construction Clearance*: Ensuring access and safe working conditions for our infrastructure projects.

2. *Proactive, Customer-Focused Vegetation Management*

Across all categories of our work, it is essential that we prioritize clear communication and collaboration with our customers. This is especially important because the majority of the trees we prune or remove are located on private property. To inform landowners about upcoming work, we may use various communication methods such as outbound calls, automated emails, and door cards. Each of these will include our company's general customer service number, as well as the name and direct phone number of the representative overseeing the work. This ensures that landowners can speak directly with someone familiar with the project, ask questions about what will take place on their property, and, if necessary, arrange an on-site meeting to help make decisions regarding potential tree removals.

Specific to the proactive maintenance category of work, the scheduling of our vegetation management work is guided by a hybrid strategy that combines:

- *Time-Based Cycles*: Vegetation Management is scheduled based on when a circuit was last serviced, with work repeated at a fixed interval—such as every five or six years.
- *Risk-Based Modeling*: Advanced tools—including satellite imagery, GIS, past reliability performance, and AI analytics—help identify and prioritize areas where vegetation poses the greatest risk.

This data-driven approach ensures that vegetation work is performed efficiently and effectively, minimizing disruptions and enhancing service reliability. By combining traditional maintenance cycles with advanced tools like satellite imagery and AI analytics, we are working to better anticipate and address potential issues—

demonstrating our ongoing commitment to delivering excellent service and improving reliability for our customers.

B. Damage Prevention and Locating

The Damage Prevention program supports public safety and system integrity by helping customers and contractors avoid accidental contact with underground electric infrastructure. This includes compliance with the statewide “Call 811” or “Call Before You Dig” program, which requires utility locates before excavation.

The Company tracks and responds to hundreds of thousands of locate requests each year. Table 3-1 below shows historical and projected volumes of electric facility locate requests from 2018 through 2028:

Table 3 - 1
NSPM Electric Locates Volumes (2018-2028)

2018 Actuals	2019 Actuals	2020 Actuals	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast
459,904	470,697	502,348	489,115	471,205	472,921	484,797	498,421	508,389	518,557	528,928

The Damage Prevention budget is based on historical locate volumes, regional economic indicators (such as new housing starts), and contract pricing with service providers.

C. Fleet and Equipment Management

This function supports the entire Distribution operation by providing and maintaining the vehicles, tools, and equipment needed to build, operate, and maintain the electric distribution system.

Capital investments in fleet and equipment ensure our crews have safe, reliable resources to perform their work. This includes replacing vehicles and tools that have reached the end of their useful life. O&M costs cover fuel, repairs, and support services for the existing fleet.

Fleet vehicles are the largest cost driver in this category. The annual fleet budget is developed based on the number and type of vehicles scheduled for replacement, along with current pricing. We use a data-driven approach to manage fleet investments, including:

- Tracking vehicle maintenance costs
- Identifying optimal replacement timing
- Prioritizing replacements based on cost-benefit analysis
- Conducting condition assessments with mechanics
- Gathering input from field users on operational needs

CHAPTER 4: DISTRIBUTION SYSTEM STATISTICS

In this Chapter, we provide a snapshot of distribution system statistics for the Company in compliance with various IDP requirements for distribution system statistics.

I. SYSTEM VISIBILITY, MEASUREMENT, AND CONTROL CAPABILITIES

Delivering excellent service requires a deep understanding of our electric distribution system's performance and the ability to respond quickly and effectively to changing conditions. Our system visibility, measurement, and control capabilities are central to this mission. The following section addresses the following IDP requirements:

- Requirement No. 3.A.2: *Percentage of substations and feeders with monitoring and control capabilities, planned additions.*
- Requirement No. 3.A.3: *A summary of existing system visibility and measurement capabilities (feeder-level and time-interval) and planned visibility improvements; include information on percentage of system with each level of visibility (e.g., max/min, daytime/nighttime, monthly/daily reads, automated/manual).*

Because these requirements are closely related, we have combined them into a single, comprehensive discussion.

A. System Monitoring and Control Capabilities (Requirement Nos. 3.A.2 & 3.A.3)

Our Supervisory Control and Data Acquisition (SCADA) system is the backbone of our monitoring and control infrastructure. It enables real-time visibility into system conditions and supports rapid response to outages and disturbances—key to delivering reliable and responsive service. We have combined the relevant data into a single summary table, Table 4-1, which outlines the current state of Feeder Load Monitoring (FLM) across Minnesota.

Table 4 - 1
Feeder Load Monitoring (FLM) – State of Minnesota

FLM Type	% of subs ¹	Measurement	Interval	Automated/ Manual	Frequency of reads	Min/ Max	Daytime/ Nighttime
Full FLM	67%	3 phase Amps, MW, MVar, MVA, kV	Hourly	Auto	Continuous ₂	Yes- <i>Manual effort</i>	Both
Partial FLM	17%	Has some or most of the above data points, varies by location	Hourly	Auto	Continuous ₂	Yes- <i>Manual effort</i>	Both
No FLM	16%	Only manual reads available (provides 3 phase Amps)	Varies	Manual	Varies	No	Neither

¹ Based on 240 total substations in Minnesota.

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

More than 95 percent of our customers are served by substations and feeders with either full or partial FLM. Additionally, approximately 84 percent of substations have control capabilities, and these also serve over 95 percent of our customers. This high level of coverage ensures we can maintain system reliability and deliver excellent service across our service territory.

1. *Visibility and Measurement Capabilities*

Our SCADA system collects hourly load data at the feeder and substation transformer levels, including three-phase Amps, MW, MVar, MVA, and Volts. When all key data points are available, we classify the site as having full FLM. Sites missing one or more data points are classified as partial FLM. Sites without SCADA fall under no FLM. To support DER integration and system planning, we calculate Daytime Minimum Load (DML) using SCADA data. This process involves manual filtering of hourly data to remove anomalies caused by switching events. Engineers derive:

- Absolute Minimum Load (24-hour window)
- DML for Solar PV (8 a.m. – 6 p.m.)
- DML for Fixed Solar PV (10 a.m. – 4 p.m.)

This process is repeated for over 1,000 feeder circuits, demonstrating our commitment to data-driven planning and service reliability. For substations without

full FLM, field personnel collect peak demand data monthly. While this manual process may introduce data gaps, it supports planning efforts and ensures continuity of service in areas not yet fully automated.

2. *SCADA Expansion and Future Improvements*

Since 2016, we have pursued a long-term SCADA expansion plan, installing SCADA at three to five substations annually. New feeders and transformers are equipped with SCADA by default. Our Feeder Load Monitoring Program aims to complete SCADA deployment across most remaining substations in Minnesota, further enhancing our ability to deliver excellent service.

II. NUMBERS OF AMI CUSTOMER METERS AND AMI PLANS

IDP Requirement No. 3.A.4 requires the following:

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

As of September 30, 2025, we have installed approximately 1,395,000 advanced metering infrastructure (AMI) meters in Minnesota. We plan to mostly complete the deployment of approximately 1.41 million AMI meters by the end of 2025.

Additional details on current and planned AMI functionality, as well as our broader AMI deployment strategy, are provided in *Chapter 5: Grid Modernization* of this IDP. We are also filing our third AMI Annual Report on October 29, 2025 in Docket Nos. E002/M-21-814 and E002/M-25-386.

III. ESTIMATED SYSTEM LOSSES

IDP Requirement No. 3.A.8 requires the following:

Estimated distribution system annual loss percentage for the prior year.

The Edison Electric Institute (EEI) defines electric losses as the energy (kilowatt-hours) and power (kilowatts) lost during the operation of an electric system. These losses primarily occur when energy is converted into waste heat in conductors and equipment.

1. *Types of Losses*

Losses in electrical systems are typically grouped into a few key categories, with one of the most prominent being demand losses. These losses represent the power lost during the operation of the system and are often easier to quantify, thanks to the availability of well-established equations and accessible data.

Within demand losses, there are several subtypes:

- *Coincident Demand Loss* occurs when the system experiences its peak demand. This is the moment when the entire network is under the greatest load, and losses are at their highest due to the cumulative effect of all active components.
- *Non-Coincident Demand Loss*, on the other hand, happens during the peak usage of a specific piece of equipment or a particular subsystem. Unlike coincident demand, this type of loss is localized and does not necessarily align with the system-wide peak.
- *Class Peak Demand* refers to the maximum demand recorded for a specific class of customers, such as residential, commercial, or industrial users. This classification helps utilities analyze and manage demand patterns more effectively across different user groups.

Losses are further classified into *load losses* and *no-load losses*, depending on the subsystem. Table 4-2 below summarizes where these losses occur:

Table 4 - 2
Categories of Load and No-Load Losses

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

For example, transformers experience both types of losses:

- *Load losses* (also called copper losses) are a function of winding resistance and load current.

- *No-load losses* (also called iron or excitation losses) are a function of voltage, which remains relatively constant in U.S. power systems—making these losses relatively stable.

2. *Loss Estimation Methodology*

We estimate losses using engineering calculations and customer load profiles derived from load research. While advanced technologies to directly measure losses across the distribution system exist, they have historically been cost-prohibitive to implement at scale.

Recent advancements in transmission system technologies have made direct loss measurement more feasible. However, similar progress at the distribution level has lagged due to the need for widespread deployment. As part of our grid modernization efforts, investments in AMI, Field Area Network (FAN), and grid sensing and control technologies will enhance our ability to refine loss analysis over time.

3. *Engineering Analysis Approach*

Our engineering analysis uses equipment records and system models to estimate losses based on average loadings. The process includes:

- Identifying the number and size of distribution lines and transformers.
- Using metered sales data to estimate average loading across system components.
- Calculating losses based on the ratio of average to maximum loading for:
 - Distribution substation transformers
 - Primary lines
 - Primary-to-primary voltage segments
 - Distribution line transformers
 - Secondary distribution lines

Using this analysis, we update loss percentages monthly using the following steps:

1. Gather five years of monthly MWh energy and sales by state.
2. Calculate the difference of energy and sales for each of the months in the 5-year timeframe.
3. Calculate a MWh loss percentage from the original MWh energy values by month in the 5-year timeframe.
4. Use the values from step 3 to calculate a 5-year average by month.
5. Use the values from step 4 to calculate a 5-year annual average.
6. Use the values from step 5 to represent current loss by state.

7. Apply state-level loss percentages from step 6 to update losses at each voltage level in the engineering model.

This methodology produced the 2025 system loss percentages for Minnesota, shown in Table 4-3 below.

Table 4-3
2025 System Loss Percentages- MN

Minnesota	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bulk(UT)	0.976	0.975	0.972	0.973	0.978	0.981	0.979	0.979	0.979	0.977	0.976	0.975
Bulk(T)	0.967	0.966	0.963	0.964	0.970	0.972	0.971	0.971	0.971	0.969	0.967	0.966
Tran(UT)	0.958	0.958	0.954	0.956	0.962	0.964	0.962	0.963	0.964	0.962	0.958	0.958
Tran(T)	0.956	0.955	0.952	0.953	0.960	0.962	0.960	0.961	0.962	0.960	0.956	0.955
Subtran(UT)	0.943	0.943	0.939	0.941	0.950	0.951	0.948	0.950	0.951	0.950	0.944	0.943
Subtran(T)	0.934	0.934	0.930	0.932	0.940	0.941	0.938	0.940	0.942	0.941	0.935	0.933
Primary	0.913	0.915	0.912	0.914	0.918	0.912	0.905	0.910	0.919	0.921	0.914	0.912
Large Secondary	0.893	0.894	0.890	0.891	0.897	0.891	0.884	0.889	0.897	0.898	0.893	0.892
Small Secondary	0.879	0.879	0.875	0.876	0.878	0.869	0.860	0.869	0.878	0.882	0.878	0.877

IV. OTHER DISTRIBUTION STATISTICS

This section addresses IDP Requirement Nos. 3.A.10 through 3.A.14, which request key distribution system statistics for the NSPM operating company.

A. Total Distribution Substation Capacity in kVA

IDP Requirement No. 3.A.10 requires the following:

Total distribution substation capacity in kVA.

As of July 1, 2025, the total distribution substation capacity in Minnesota is 13,747,242 kVA (or approximately 13,747 MVA). This figure reflects the sum of

nameplate power ratings for all active, functional, and Company-owned distribution transformers across our Minnesota service area.

B. Total Distribution Transformer Capacity in kVA

IDP Requirement No. 3.A.11 requires the following:

Total distribution transformer capacity in kVA.

Consistent with our prior IDP filings, we interpret this requirement to mean the total distribution substation transformer kVA. Accordingly, please refer to the response provided under Requirement Nos. 3.A.10 above.

C. Total Miles of Overhead Distribution Wire

IDP Requirement No. 3.A.12 requires the following:

Total miles of overhead distribution wire.

As of October 2025, the NSPM operating company has approximately 14,912 circuit miles of primary overhead conductor.

D. Total Miles of Underground Distribution Wire

IDP Requirement No. 3.A.13 requires the following:

Total miles of underground distribution wire.

As of October 2025, the NSPM operating company has approximately 12,529 circuit miles of primary underground cable.

E. Total Number of Distribution Premises

IDP Requirement No. 3.A.14 requires the following:

Total number of distribution premises.

A premise is defined as a unique combination of meter number and address. As of August 31, 2025, the NSPM operating company served 1,582,230 electric premises, of which 1,378,084 were located within our Minnesota service area.

CHAPTER 5: GRID MODERNIZATION

The Company is committed to continuing its long history of providing customers and communities with safe, reliable, affordable, and clean energy. Making energy work better for our customers means embracing innovative technologies across our system to deliver excellent service, now and in the future. To that end, we have been taking a measured and thoughtful approach to maximize customer value, ensuring the fundamentals of our distribution business remain sound, and maintaining the flexibility needed as technology and our customers' needs and expectations continue to grow.

This chapter discusses our overall grid modernization strategy that includes our Grid Modernization initiative (also known as Advanced Grid Intelligence and Security, or AGIS), which is a distinct, long-term strategic plan to transform our electric distribution system to update foundational system technologies and capabilities.¹ We are modernizing our grid planning and operations each day as we strive for continuous improvement and to deliver excellent service; the Grid Modernization initiative includes important building blocks that enable us to plan, build, and operate a modernized, hardened, and expanded electric delivery system. Overall, the Grid Modernization initiative consists of multiple foundational elements, as shown in Figure 5 - 1, that work together to create a more modern and advanced distribution grid.

¹ For the financial forecasts associated with our grid modernization plans, please see *Chapter 6: Distribution Financial Framework and Information*.

Figure 5 - 1
Foundational Elements of the Grid Modernization Initiative

Grid Visibility and Control		Network	Meters
Advanced Distribution Management System (ADMS)	Fault Location, Isolation and Service Restoration (FLISR)	Field Area Network (FAN)	Advanced Metering Infrastructure (AMI)
 • Advanced centralized software or the “brains,” enhances the operation of the distribution grid • Enables improved reliability, management of DERs, and improved efficiency when operating the grid • Enables enhanced visibility and control of field devices (including customer meters via AMI)	 • ADMS provides fault location prediction and the automatic operation of intelligent grid devices • Reduces outage durations and the number of customers impacted by an outage • Enabled by intelligent field devices, FAN, and ADMS	 • Two-way communications network • Connects intelligent grid devices and smart meters with software • Enables enhanced remote monitoring and control of intelligent field devices and advanced meters	 • Focused on the deployment of smart meters and software • Provides near real-time communication between software and meters • Data and AMI functionality enable new products and services and improves customer experience

We have made significant progress in deploying these foundational elements and planning to build upon them with more advanced technologies: the Advanced Outage Management (AOM) and Distributed Energy Resources Management System (DERMS) projects. In this chapter, we discuss these technologies and our overall grid modernization roadmap. We also outline our customer strategy and roadmap related to present and future grid modernization efforts in Section V, and the ways we intend to leverage the data for operational and planning purposes. Finally, we discuss our approach to data security and note that protective cyber security controls and protocols are built into every step and technology underlying our overall plan, and are essential to operating a secure, technologically advanced grid, today and tomorrow.

I. DRIVERS OF THE GRID MODERNIZATION INITIATIVE

Customers have high expectations of their energy providers, and the Company is making energy work better for them by offering more choices, delivering excellent service, and giving them greater control over their energy sources and their energy use. Technologies that customers can use to control their energy usage, such as smart thermostats, EV chargers, smart home devices, and smart phones and apps, continue to evolve. The expansion of cloud computing and artificial intelligence, while creating new challenges as new data center load comes online, also presents opportunities to improve our operations and make customers’ interactions with us easier and more dynamic.

We have been modernizing the grid at a more rapid pace in response to customer usage patterns, policies, and technical developments – and we have made significant progress in deploying grid modernization technologies, building the foundation for further modernization.

At the same time, new challenges and opportunities are arising that create new drivers and strategies for grid modernization. One such growing challenge is the threat of wildfire. Minnesota is not immune to wildfire risk, and we discuss our wildfire mitigation efforts in *Chapter 2: Standards, Asset Health, and Reliability*. The relationship between our wildfire mitigation efforts and grid modernization strategies continues to evolve as we work to balance two key priorities: enhancing reliability for our customers and protecting communities from wildfire risks. This Chapter explores how these efforts intersect and support one another.

Drivers of our Grid Modernization strategy include:

- The Company's commitments to delivering excellent service, making interactions easier, guiding with expertise, and leading the clean energy transition,
- Current and future distribution system needs – in consideration of increasing integration of the grid as well as emerging risks such as wildfire, and
- Legislative and Commission policy and direction, and stakeholder input relative to customer offerings, performance, and technological capabilities of the grid.

The modernized grid goes beyond infrastructure upgrades alone – it requires a transformation of the energy system from a one-directional service model where utilities provide energy and customers passively consume it, to a more interactive and collaborative model. In this new paradigm, customers play an active role in the energy ecosystem, adopting behaviors and technologies that contribute to a sustainable and resilient energy grid while ensuring their energy needs are met now and for generations to come. Our grid modernization plans put this philosophy into practice. As we discuss below, deployment of our foundational grid modernization technologies – Advanced Metering Infrastructure (AMI), Field Area Network (FAN), Advanced Distribution Management System (ADMS), and Fault Location, Isolation, and Service Restoration (FLISR) – is well underway. Building on that solid foundation, grid modernization will be a continual, iterative process as we maximize customer value and continuously improve all facets of our service, meeting and exceeding customer expectations.

We plan to build on these foundational technologies through the Advanced Outage Management (AOM) project, Distributed Intelligence (DI), and a Distributed Energy Resources Management System (DERMS). We discuss these projects in this Chapter.² AOM, DI, and DERMS are natural and necessary next steps on our grid modernization roadmap. These projects will expand our operational capabilities, making them more efficient.

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

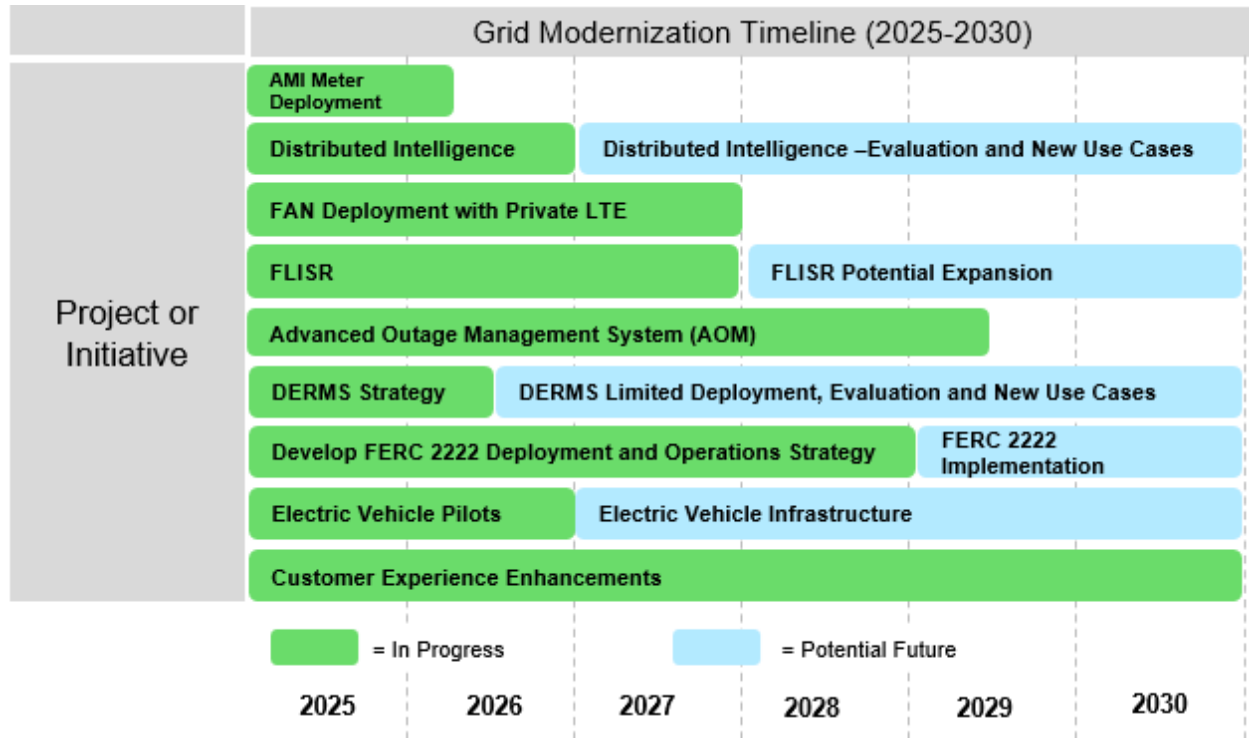
All of these circumstances helped to drive and form the Company’s Grid Modernization initiative. We will continue to evolve our plans and leverage new technology, platforms, and optionality as appropriate over time. We are excited to modernize our system in a measured way, bringing the Company’s expertise to bear as we deliver excellent service and make interactions easier for our customers.

II. GRID MODERNIZATION ROADMAP

Our implementation of the foundational components of modernizing our grid is well underway and we have continued to develop plans for new technologies on our grid modernization roadmap. We now have plans in place to implement the AOM project, a limited deployment of Grid DERMS, and continue building on DI capabilities, as discussed further below.

² *Chapter 11: DERMS* provides the Company’s DERMS roadmap and addresses Order Point Nos. 22 and 23 of the Commission’s September 16, 2024 Order in our 2023 IDP docket (Docket No. E002/M-23-452). DI and DERMS have been discussed in prior IDPs.

**Figure 5 - 2
 Illustrative Grid Modernization Plan**



Order Point No. 128 of the Commission’s Order in our most recently approved rate case adopts the Department’s recommended grid modernization filing requirements, which suggest the Company include

[T]he following standardized information in all future [grid modernization] proposals: a road map with all planned and contemplated future grid modernization investments and a complete accounting of all historical grid modernizations costs and all anticipated future grid modernization costs.^[3]

We present our grid modernization roadmap above. For technologies that have specific capital expenditure or O&M forecasts, these anticipated future grid modernization costs are presented for each technology below. Historical grid modernization costs are included in *Attachment I*.

IDP Requirement No. 3.D.2.b requires:

Description of steps planned to modernize the utility’s grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what

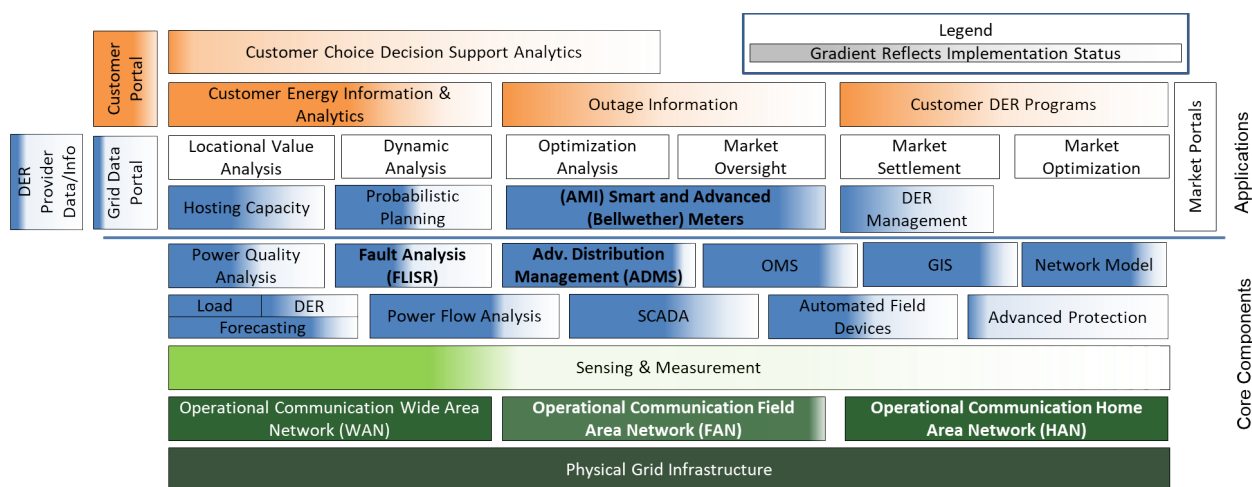
³ FINDINGS OF FACT, CONCLUSIONS, AND ORDER, Docket No. E002/GR-21-630 (July 17, 2023). Page 146 of the Order references the Department’s recommendation quoted here. Order Point 128 states, “The Commission adopts the Department’s recommended grid modernization filing requirements.”

utility and customer benefits that could or will arise. [Footnote: See <https://gridarchitecture.pnnl.gov/>]

Our overall approach to a grid modernization framework has been informed by (1) the U.S. Department of Energy’s (DOE’s) Next Generation DSPx, Volume III, in alignment with the footnote reference in IDP Requirement No. 3.D.2.b; and (2) the Company’s own grid architecture. DSPx provides a good reference for how to consider both the elements of a modern grid and their costs.⁴ The DSPx report was sponsored by the U.S. DOE’s Office of Electricity Delivery and Energy Reliability. This report was developed at the request of, and with guidance from, the Minnesota Commission among others like the California Public Utilities Commission, the New York Public Service Commission, and the Hawaii Public Utilities Commission.

We portray our current state systems and processes against the DSPx framework as shown in Figure 5 - 3 below – developing “core components” as the foundation for our grid modernization roadmap first and subsequently building on that foundation to enable advanced applications, which is well aligned with the DSPx framework. Although the framework is nearly 10 years old, it was developed by industry experts and still provides a useful and consistent way to portray our grid modernization implementation.

Figure 5 - 3
Estimated Status of Grid Modernization Implementation



⁴ See *Modern Distribution Grid, Volume III: Decision Guide*, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017). Available at <https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf>.

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

- Applying grid architecture principles in implementing new technology
- Identifying and addressing operational and functional gaps,
- Identifying and managing competing priorities, and
- Identify innovative opportunities that add to our business value and improve efficiencies.

GridWise® Architecture Council (GWAC) was formed in 2004 by the DOE to propose principles for and accelerate the development and adoption of interoperability concepts and standards across all applications operating and interfacing with electric systems. Recognizing the importance of grid architecture principles and interoperability in successfully implementing and scaling new technologies, the Company has adopted the GWAC Interoperability Stack. Beginning in 2025, we are proud to have a Company representative serving a two-year term as one of the 13 members of the council.

The GWAC Interoperability Stack defines the critical pathways needed to integrate and align devices, systems, use cases, business processes, contracts, and stakeholder organizations. This alignment is essential to achieving both regulatory policy goals and business objectives in a modern electric system. Within this framework, organizational structures, business processes, and technology requirements must be developed in concert and aligned with policy and customer needs. Likewise, new devices and systems must be integrated thoughtfully with existing infrastructure, guided by grid architecture principles. This ensures that all components function cohesively, in a scalable and streamlined manner.

III. GRID MODERNIZATION IMPLEMENTATION SUMMARY AND STATUS – FOUNDATIONAL TECHNOLOGIES

As discussed above, our investments in ADMS, AMI, FAN, and FLISR have been foundational initial components in our efforts to advance the grid. These foundational elements, in concert with other future investments, will provide cumulative benefits over time and transform the customer experience by providing new, innovative

customer programs and service offerings, developed internally and in concert with partners. In this section, we provide an overview of the four foundational grid modernization projects, including updates on implementation and financials.

A. Implementation Snapshot

The Grid Modernization foundational investments include ADMS, AMI, the FAN, and FLISR. The Commission certified ADMS in 2016, and we completed in-servicing in 2021 and filed our final Annual Report in January 2025. The Commission certified AMI and FAN as an outcome of our 2019 IDP in Docket No. E002/M-19-666,⁵ and we began deploying AMI meters in April 2022. The Commission approved initial cost recovery of FLISR program costs in its July 17, 2023 rate case Order in Docket No. E002/GR-21-630. Table 5 - 1 shows provides an overview of these foundational technologies and their deployment timelines.

Table 5 - 1
Grid Modernization Foundational Technologies and Initiatives Deployment Timeline

Program	Implementation Timeline
ADMS	Implementation is now complete. Our ADMS was deployed in the first two Minnesota control centers in April 2021 and deployed in the final Minnesota distribution control center in September 2021.
AMI	Meter deployment began in 2022, with substantial completion in 2025 and a relatively small number of installations to be completed in 2026.
FAN	The initial network and security design was completed in 2020. The first FAN device was installed and programmed in May 2021 and the installation and programming of additional FAN devices will continue through 2025, with Network Optimization in 2026. FAN deployment is nearly complete, and we are making progress upgrading the backhaul technology to private LTE.
FLISR	Installation of automated field devices (reclosers and switches) and substation upgrades began in 2021 on select feeders and will continue to be expanded to other feeders through 2027. The ADMS FLISR functionality is available in Minnesota control centers use on select feeders and will be continued to be expanded to other feeders through 2027.

We address our grid modernization projects in turn below, and we provide financial information for the four ongoing projects shown in Table 5 - 1. Once major grid modernization projects are completed, their ongoing costs will be reflected in other

⁵ ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, AND CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS, Docket No. E002/M-19-666 (July 23, 2020).

budget categories. For example, when the initial, project-based deployment of AMI meters is complete, those ongoing costs will be reflected in the distribution budget metering category.

B. Advanced Distribution Management System

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

The Commission certified ADMS in 2016, and we are recovering the costs of ADMS through the Transmission Cost Recovery (TCR) Rider, beginning in Docket No. E002/M-17-797. Initial implementation is now complete, and we submitted our final Annual Report in January 2024;⁶ therefore, we will not include this foundational ADMS project-level information in future IDPs.

1. Implementation

The Company completed the deployment of ADMS to all Minnesota Distribution Control Centers (DCCs) in 2021. Deploying ADMS to all DCCs was the culmination of all necessary efforts to implement an operational system. Specifically, this is when our control center operators began using the ADMS system as designed – which for the first control center go-live included monitoring and control of substations, field devices, and feeders. Since the first DCC go live in April 2021, the system has

⁶ Annual Report, Docket Nos. E002/M-23-452 and E002/M-23-467 (January 25, 2024).

performed very well and has been extremely stable. Additional data collection, validation, and testing of feeders to support distribution grid operations from the ADMS was completed in 2023.

2. Benefits

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

The current version (3.7) of the ADMS will be at end of life in mid-2026, so we are actively planning for our next phase of distribution management through a project called AOM. We discuss AOM further in Section IV below.

C. Advanced Metering Infrastructure

AMI is the Company's metering solution, consisting of an integrated system of advanced meters, communication networks, and software that enables the AMI functionality and secure two-way communication between the Company's data systems and customer meters. The AMI meters we are currently deploying, the Itron Riva 4.2, include Distributed Intelligence (DI) capabilities. We discuss our DI plans further in section IV below.

The Commission certified AMI in our 2019 IDP proceeding, and we are currently recovering costs through the TCR Rider. The Company files an AMI and FAN Annual Report in Docket Nos. E002/M-21-814 and the most recent TCR docket (Docket No. E002/M-25-386). The Annual Report was filed October 31, 2025.

1. Implementation

Installation of AMI meters in Minnesota began in April 2022. As of September 30, 2025, we have installed approximately 1.39 million AMI meters total in Minnesota, and plan to complete deployment of approximately 1.41 million total meters largely by the end of 2025.

We anticipate that a small number of meters will still need to be replaced in 2026. We have encountered a relatively small number of premises at which installers have been unable to gain access to replace the meter or have encountered other complexities with installation. In these instances, we are continuing to escalate these issues. We will

attempt to read the legacy meters in 2026, and/or estimate bills as needed while we continue to work toward completion of these meter exchanges. As we have noted previously, some of these customers have meters with ‘KYZ’ contacts, which provide energy pulses or load control signals for energy management purposes. These meters will not be commercially available from Itron until late 2027.

Table 5 - 2 provides the most recent deployment timeline.

Table 5 - 2
Latest Available Meter Deployment Schedule – Minnesota

Year	Approximate Deployment Volume
2022	128,000 (actual)
2023	540,000 (actual)
2024	530,000 (actual)
2025*	Target: 202,000
Total	1,400,000

**Actual 2025 installs as of 9/30/25 was approximately 197,000*

2. *Benefits*

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

AMI deployment is nearly complete; realizing the benefits of AMI and its capabilities will be an ongoing process that continues to evolve as we expand and enhance our own capabilities and continue to enhance the customer experience through new tools. The AMI Annual Report filed October 31, 2025 in Docket Nos. E002/M-21-814 and E002/M-25-386 includes additional discussion of AMI benefits.

3. Financials

For AMI, we expect \$14.4 million in capital costs through 2027.⁷

Table 5 - 3
AMI Capital Expenditures Budget
Minnesota Electric Distribution (Millions)

Project Component		2026	2027	2028	2029	2030
AMI	Dist	\$4.4	\$10.0	-	-	-
Total		\$4.4	\$10.0	-	-	-

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

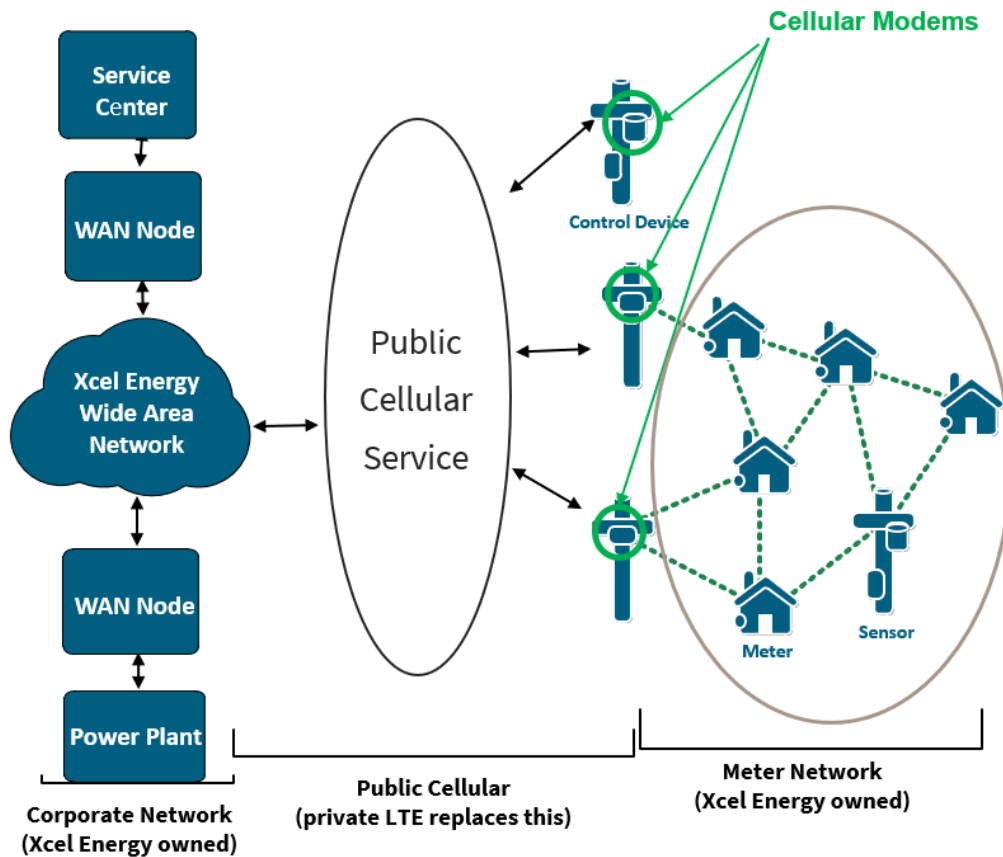
D. Field Area Network

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

The FAN consists of two separate wireless technologies. The first is a lower-speed, private mesh network. The second is a high-speed network backhaul. The relationship between the mesh, backhaul, and the Company's corporate Wide Area Network (WAN) are illustrated in the diagram below.

⁷ The budget for AMI is included in the budget totals presented in *Chapter 6*.

Figure 5 - 4
Field Area Network Illustration



1. *WiSUN Mesh*

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

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

2. Backhaul and Private LTE

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

3. Implementation

We started the initial network and security design for the FAN in 2020 and installed and programmed the first FAN device in May 2021; we completed all FAN devices installations in 2025 pending any new devices that need to be installed as part of an optimization phase. The FAN implementation includes the network design, the security of these networks, configuring the software and hardware components of the FAN, and the installation of FAN devices that are located primarily on distribution poles. The physical installation of FAN devices is performed by field crews. For any given geography, FAN deployment precedes AMI meter deployment by approximately six months, to ensure the communication network is immediately available for the meters to communicate with.

FAN deployment is nearly complete, and Itron – the FAN technology vendor – is undertaking an optimization analysis in which it evaluates the network design to identify any bottlenecks or other areas of improvement. Based on that analysis and Itron's recommendations, the Company may add devices to alleviate bottlenecks and improve service; that work may continue into 2026.

In addition to public LTE service, the Company is currently deploying a private LTE network for the backhaul. The Company's private LTE network will be deployed initially in 27 counties within our operating regions in Minnesota, Colorado, Wisconsin, and Texas. We will add cellular towers primarily at Company-owned and maintained locations, with the private LTE cellular headend located at the Company's data centers in Minnesota and Colorado in a redundant state. Our private LTE will

provide backhaul for the WiSUN network, similarly to Verizon, but on a cellular network that is maintained end-to-end by the Company, which increases the reliability and resiliency of the communication network. The current LTE cellular modems support dual SIM cards. As the Company's private LTE SIM cards are added, some locations will have a secondary, backup option for cellular communications, increasing system resilience.

The private LTE project is on schedule for the initial deployment of 27 counties by the end of 2027. We have installed and are currently operating the pLTE core, which is a series of network management systems that are co-located in separate data centers to increase resiliency and availability.

As new cellular towers are constructed and brought online, the teams are beginning to add devices and test them for accuracy and resiliency. Over time the private LTE will begin to be the primary backhaul solution for AMI and automated field devices (in areas it is available) with public cellular and other options as backup.

4. Benefits

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

5. Financials

For FAN, we expect \$12.0 million in capital costs over the five-year budget period in Technology Services.

Table 5 - 4
FAN Capital Expenditures Budget
Minnesota Electric Technology Services (Millions)

Project Component		2026	2027	2028	2029	2030
FAN	Tech Svcs	\$6.5	\$4.4	\$1.1	-	-
Total		\$6.5	\$4.4	\$1.1	-	-

E. Fault Location Isolation and Service Restoration (FLISR)

FLISR is an integrated technology that consists of an advanced application in ADMS, two-way communication, and automated field and substation (reclosers, switches, substation relays) equipment. FLISR improves customers' reliability experience, reducing the duration of outages and number of customers affected by them. FLISR takes the form of distribution automation and involves the deployment of automated switching devices that work with ADMS to detect issues on our system, isolate them, and automatically restore power.

The Commission approved the Company's FLISR deployment strategy, cost allocation, and recovery of 2022-2024 costs in its July 17, 2023 rate case Order in Docket No. E002/GR-21-630. The Company requested recovery of additional FLISR costs in its currently pending rate case, Docket No. E002/GR-24-320.

1. Implementation

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

The work for the installation of automated field devices (reclosers and switches) and substation upgrades began in 2021 on select feeders and will continue to be expanded to other feeders through 2027. Through 2027, we plan to deploy approximately 600 devices on 200 feeders. The total number of feeders and devices deployed is subject

to change as we continually refine our deployment plan. Each year, feeders will be reevaluated and selected for the FLISR deployment primarily considers the five-year reliability performance, number of customers per feeder, and the number of feeder level outages. The Company also considers other factors like recently completed capital projects, feeder length and topology, and if a feeder is in a high wildfire risk area. This approach allows for feeder selection based on the most up-to-date analysis and can account for any other relevant factors. This agile approach allows for feeder selection based on the most up to date analysis and can account for any other relevant load or constructability changes for prospective feeders. Based on the actual costs to deploy FLISR on each feeder, the overall program may deploy devices on more or fewer than 200 feeders, though we do not expect a significant deviation from that figure.

Wildfire mitigation is another important use of FLISR technology, and a new use case developed since our last full IDP filing in 2023. As discussed above and in *Chapter 2*, Minnesota is facing elevated wildfire risks. Automated field devices such as reclosers can be operated in Wildfire Safety Operating (WSO) modes during high-risk days; in essence, operating more quickly de-energizing distribution lines and causing an outage with the aim of preventing a wildfire ignition in order to protect public safety.

2. *Benefits*

The most significant quantifiable benefit of FLISR is improved reliability for our customers. We discuss FLISR's impact on reliability further below. We are already seeing examples of improved reliability for customers, as discussed below.

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

3. *Financials*

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

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

Table 5 - 5
FLISR Capital Expenditures Budget
Minnesota Electric Distribution (Millions)

Project Component		2026	2027	2028	2029	2030
FLISR	Dist	\$12.0	\$19.6	-	-	-
Total		\$12.0	\$19.6	-	-	-

Table 5 - 6
FLISR O&M Expenditures Budget
Minnesota Electric Distribution (Millions)

Project Component		2026	2027	2028	2029	2030
FLISR	Dist	-	\$0.2	-	-	-
Total		-	\$0.2	-	-	-

Table 5 - 7
Approved FLISR Additions Budget
Minnesota Electric (Millions)

	MYRP Period			Forecast			
	2022	2023	2024	2025	2026	2027	2028
Approved FLISR Additions Budget	\$3.4	\$7.8	\$7.8	\$8.2	\$20.0	\$15.3	-
Actual Additions	\$0.1	\$6.0	\$6.9	\$1.1*	-	-	-
Latest Forecasted Additions Budget	\$0.1	\$6.0	\$6.9	\$5.8	\$12.5	\$22.9	-

**Actual additions through June 2025.*

4. Reliability

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

Xcel must report [...] a summary of FLISR's reliability results in its Integrated Distribution System Plan.

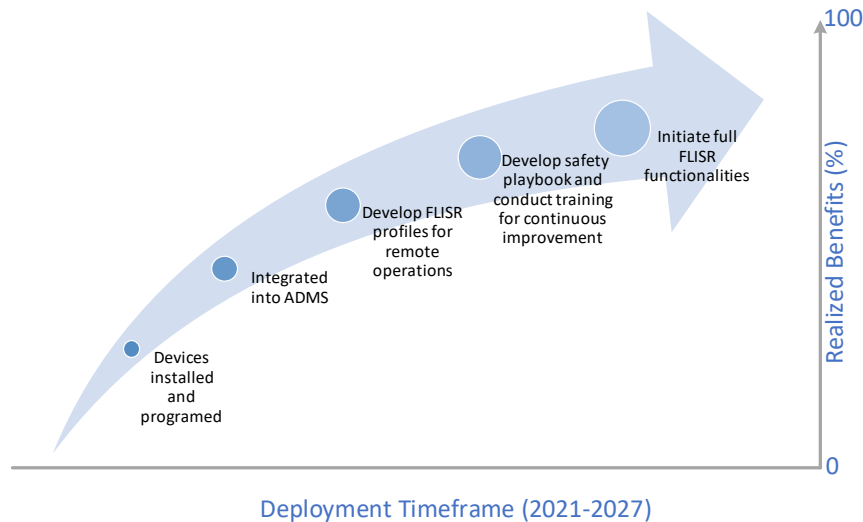
We expect that FLISR will improve our overall reliability performance and a customer's overall outage experience. However, our performance in certain reliability metrics may decline after FLISR is installed. For instance, FLISR will help some customers avoid sustained outages. Sustained outages are tracked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

As a result, we expect that customers will experience fewer sustained outages, improving our SAIFI performance, while our MAIFI performance may decline. We also expect that FLISR may cause our Customer Average Interruption Duration Index (CAIDI) performance to decline. CAIDI is a measure of the length of time the average customer can expect to be without power during an interruption. CAIDI performance declines when the outages are more heavily concentrated on problems that take a longer time to fix. As FLISR's automatic switching will restore power quickly to customers not along the faulted section, the result will be a sustained outage that impacts fewer customers. This may negatively affect our CAIDI performance, as longer-duration outages could represent a larger share of the metric. However, FLISR will improve the overall customer experience by reducing both the duration of outages and the number of customers impacted.

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

The outright reliability benefit of FLISR feeders is not easily quantifiable with minimal years and events available for data collection and analyzing. Figure 5 - 5 is an illustrative representation of the benefits as we enable FLISR functionality across the different phases and as we expand the functionality to a greater number of feeders.

Figure 5 - 5
Phases of FLISR Functionality and Benefits



Even without years of system trend data for FLISR feeders, we have still observed a reduction in sustained outages. As an example, a tree in a distribution feeder line caused a feeder-level outage on February 28, 2025. A recloser had been installed towards the middle part of the feeder as part of the FLISR project. The recloser was operational in “local mode” on the feeder; that is, the recloser functionality had not yet been integrated into ADMS. When the tree contacted the distribution lines, the recloser opened instead of the feeder breaker, avoiding an outage for 1,020 customers, totaling approximately 54,000 avoided customer minutes out. As the Company expands the use of automatic FLISR in ADMS, it could result in even greater reliability benefits. As an example, on July 26, 2025, a feeder breaker opened due to a failed cable splice near the start of the feeder, causing an outage for 3,987 customers. In this case, the FLISR installation was integrated in ADMS, which automatically sent a command to operate the devices to restore power. 3,047 customers – over 75 percent – were restored within seconds, experiencing a momentary outage. 940 customers experienced a sustained outage of 122 minutes while the cable splice was repaired. The result was a reliability improvement of approximately 370,000 customer minutes out (CMOs).

IV. BUILDING ON THE FOUNDATION: PLANNED FUTURE GRID MODERNIZATION TECHNOLOGIES

Since our last full IDP filing, we have continued to develop plans for new technologies on our grid modernization roadmap. We now have plans in place to

implement the AOM project, a limited deployment of Grid DERMS, and continue building on DI capabilities, as discussed below.

A. Advanced Outage Management

The Advanced Outage Management (AOM) project will enhance the Company's management of the distribution system by consolidating multiple software platforms into a single distribution management platform. The project consists of upgrading the current ADMS from version 3.7 to the newer version 3.9, a hardware refresh at data center locations, and the implementation of a new outage management system. Consolidating functions into a single platform is an important step in the company's vision for managing a more complex electric grid that enables increasing levels of DER and meets multiple business objectives. It also supports the Company's advancement of visibility and control of the distribution system through more advanced outage management that includes the deployment of fire mitigation application.

AOM will transform current outage management tools and create a "single pane of glass" for control rooms, which currently have multiple systems to navigate during the life of an outage. The AOM project includes:

- ADMS upgrade
 - Upgrade from v3.7 to v3.9, the first major upgrade to this foundational software, providing a platform for continual improvement of integrated operations within Distribution and allowing for the ability to advance our DER capabilities
- Deploy the fire mitigation application within ADMS
- The Wildfire Mitigation Advanced Application coordinates with other ADMS applications, including FLISR. This application automates the implementation of Enhanced Powerline Safety Settings Enablement (EPSS) and provides more situational awareness in ADMS such as the wildfire high areas to the Distribution Control Center and field to help reduce the risk of wildfire threats to our communities. Hardware upgrades
 - Upgrade and optimize the footprint to simplify the technology environment and improve system resiliency.
 - Transition the outage management system (OMS) from information technology (IT) to operational technology (OT) to security zone.
- Outage Management System and Field Client deployment
 - Retire the Oracle network management system.

- Deploy Schneider Electric’s outage management system to improve outage and storm response and coordination through a consolidated platform.
- Deploy the Field Client, providing field crews with visibility into the as-operated system for the first time.

The hardware upgrades were completed in 2024 and the ADMS upgrade to v.3.9 was successfully completed in October 2025, paving the way for the other components of AOM. The Fire Mitigation application is planned for 2026 and the OMS and Field Client deployment is in earlier stages of the project lifecycle– we are currently gathering requirements and anticipate these components to be completed in late 2027.

AOM costs are included in the currently pending rate case.

1. *Financials*

For AOM, we expect \$54.8 million in capital costs over the five-year budget period in Technology Services.

Table 5 - 8
AOM Capital Expenditures Budget
Minnesota Electric Technology Services (Millions)

Project Component		2026	2027	2028	2029	2030
AOM	Tech Svcs	\$22.9	\$19.6	\$9.4	\$2.9	-

B. Distributed Energy Resources Management System

Distributed Energy Resources Management System (DERMS) is not a single system, but rather can be viewed as an ecosystem of software platforms, business processes, and policy frameworks. It is important to establish clear definitions around DERMS:

- **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 do not impact the safety and reliability of the distribution grid.

- **Aggregator DERMS:** Primarily behind-the-meter resources, such as battery storage 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 DERMS solution is not an “off-the-shelf” product due to the complex integration requirements and the unique needs and priorities of utilities. We view the journey toward enterprise DERMS as one driven primarily by people and process changes, with technology serving to support and enhance the overall strategy.

Planning and implementing our Aggregator DERMS and Grid DERMS platforms are progressing through defined phases through 2027 and beyond.⁸ 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.

Chapter 11 provides further information on DERMS and our approach.

1. Financials

For the limited deployment of Grid DERMS, we expect \$2.9 million in capital costs.

C. Distributed Intelligence

Distributed Intelligence (DI) describes the capability of AMI meters to perform data processing on-site via Edge Chip hardware and software programs known as Agents.

⁸ We have requested approval of a limited deployment of grid DERMS as part of our pending Distributed Capacity Procurement (DCP) proposal, Capacity*Connect (Docket No. E002/M-25-378).

High Impedance Detection. This grid-facing DI-enabled capability will allow the meters to detect deteriorating or loose connections. Without those capabilities, such issues on the secondary system, which carries power from transformers to meters, might only be detected if a customer notices a problem, such as flickering lights, or when they cause outages. By proactively identifying high impedance situations, the Company can promptly dispatch crews to proactively address the issue. A significant benefit of this capability is the prevention of outages, which enhances service quality for our customers and reduces the Company's outage response costs. The Company currently has High Impedance Detection deployed on approximately 62,000 meters in Minnesota.

EV Detection. DI capabilities can provide the Company with insights into where EVs are located and charging patterns of customers. This information can be leveraged to support system planning, load balancing, and infrastructure upgrade efforts based on awareness of EVs being added to a customer's load profile. This grid-facing use case will also enable the Company to become aware and proactively respond to possible service quality issues and encourage customers to participate in managed charging programs. The Company is currently in the process of completing meter testing and will be starting a limited deployment in Minnesota to approximately 1,000 meters.

Location Awareness.

This grid-facing DI application can improve accuracy in outage management and notifications, as well as planning and operational modeling. The Location Awareness application will also help to correct the connectivity to mis-mapped customers, reducing this source of error. All processes that rely on the connectivity model in our GIS, including outage management, will benefit from the improved data. Going forward, this use case can also be used to maintain the accuracy of our GIS mapping after modifications to the secondary system. The Company currently has Location Awareness deployed on approximately 146,000 meters in Minnesota.

Section V below discusses customer-facing DI tool, My Energy Connection (MEC).

1. Financials

For DI, we expect \$0.3 million in capital costs over the five-year budget period in Technology Services.

Table 5 -9
DI Capital Expenditures Budget
Minnesota Electric Technology Services (Millions)

Project Component		2026	2027	2028	2029	2030
DI	Tech Svcs	\$0.1	\$0.1	\$0.1	-	-
Total		\$0.1	\$0.1	\$0.1	-	-

V. CUSTOMER STRATEGY AND ROADMAP

The Commission’s IDP Planning Objectives include:

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

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

Our overarching customer strategy remains unchanged since our last full IDP filing in 2023. At its core, our strategy recognizes that enabling our customers to embrace new technologies, participate in the clean energy transition, and support Minnesota’s policy objectives requires us to build a seamless customer experience. For example, customers who want to purchase an electric vehicle should have a clear, smooth, and quick experience from the moment they are considering the purchase to their first time charging their vehicle at home. That means no long wait times, no inefficient processes, and no insurmountable costs. This is not only a matter of having a safe, reliable grid with enough capacity to meet those demands, but also having a system in place that allows our team to provide timely support throughout the process.

The Company is committed to ensuring that our customers will be able to pursue their preferred energy options. In total, nearly 1.4 million AMI meters have been installed in Minnesota as of September 30, 2025. The rollout of the new meters enables customers to view 15-minute energy usage, via the Xcel Energy web portal. We have also made strides in executing on our customer strategy, developing the foundation for future offerings. We have built a platform that will enable data to be shared with customers and customer-authorized third parties, promoting innovation

and the expansion of technologies that will enable the Company to lead the clean energy transition, enhance the customer experience, and keep bills low.

A. Customer Strategy

Our grid modernization efforts aim to transform the customer experience by implementing capabilities, technologies, and program management strategies to enable the best-in-class customer experience that our customers now expect, as shown in Figure 5 - 6.

Figure 5 - 6
Customer Strategy Informed by Customer Expectations



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

In order to know our customers, inform, advise, and enable them, and deliver seamlessly, we are taking time to understand the customer's journey and experience in our program design and execution. This process starts with a commitment to understanding customers' preferences, considerations, and motivations regarding the benefits and value of an advanced grid investment from their point of view. To ensure our strategy resonates with customers and meets their evolving expectations, we conduct customer research across key touchpoints. This includes transactional surveys that capture customer experiences with programs and rebates, outage communications, and digital tools. We also engage in user experience (UX) research and concept testing to evaluate whether our strategies align with customer needs, preferences, and perceptions of value. These insights inform program design and help us deliver more personalized, seamless, and empowering customer experiences.

Delivering an excellent customer experience also requires our organization to improve the skills and competencies needed to continuously evolve and iterate our programs more quickly and leverage technology to make interactions more streamlined and enjoyable.

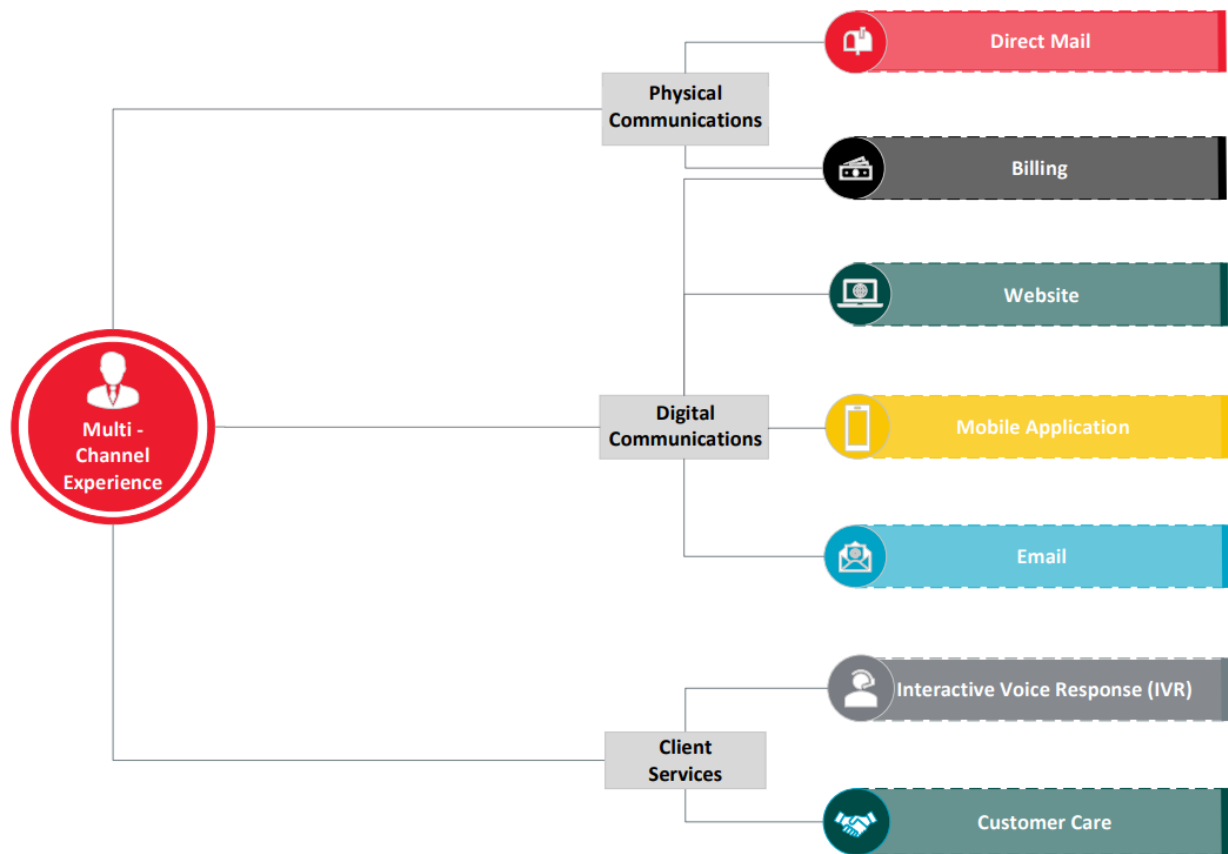
B. A Multi-Channel Experience

Today, the Company's customers have access to numerous energy efficiency and demand management programs, renewable energy choices, electric vehicle and charging options, billing options, a mobile app, a variety of notification options, and many ways to access and share their own data. For example, customers receive confirmations when our records reflect that the outages have been resolved – and they receive these via their preferred communication channel – text, email, or phone. We continue to make advances on our grid and how that shapes the service we offer our customers – and these and other products and services have provided our customers with significant value over many years.

A multi-channel approach to providing information to customers, shown in Figure 5-7 enables the Company to broaden the reach and impact of our programs while laying the foundation for future innovation. This enables the Company to continue to offer new and effortless methods for customers to engage with the utility, gain insights into how and when they use energy, and be directed to other programs that will benefit them.

The Company's communications and customer awareness strategies are continually evolving to align with customer preferences and expectations. As the grid advances, we will continue to use the latest technologies and data to inform our customers of how and when they use energy, new product and rate designs, and events that impact them such as outages.

Figure 5 - 7
Multi-Channel Communications Strategy



C. Customer Tools, Products, and Services

The Company has created a variety of products and services that leverage the AMI data and provide direct benefit to customers, the Company, and society. In the following sections, we provide more details on the types of products and services we offer today. The Company plans to continue to build and expand our portfolio of products.

The customer journey with their new smart meter starts with the post installation experience, which is nearly complete as we reach the conclusion of AMI deployment. The Company provides a personalized multichannel (email and direct mail) campaign after a smart meter installation. As new products are developed, we will notify customers of the products through the post-installation experience as well as a variety of other channels, depending on the customer's preference. Table 5-10 shows the AMI- and DI-enabled products and services, approximate availability, and end-user.

Table 5 - 10
AMI and DI Products & Services

Product / Service	Available	Target End User	Available before AMI	Enabled by AMI	Enhanced or Enabled by DI
My Energy Portal	Current	Customer	Y	Y – Additional Information Available	N
On Demand Meter Reads	Current	Customer	N	Y	N
Green Button Connect My Data	Current	Third Party Access (Customer and Third Party)	Y	Y – Additional Information Available	N
Green Button Download My Data	Current	Third Party Access (Customer)	Y	Y – Additional Information Available	N
Software Development Kit	Current	Third Party Access (Third Party)	N	Y	Y
Outage Notifications to Company Systems	Current	Customer	N	Y	N
Advanced Rates	Coming in 2026	Customer	Limited	Y	N
High Bill Alerts	Summer 2026	Customer	N	Y – Additional Information Available	N
Budget Alerts	Summer 2026	Customer	N	Y – Additional Information Available	N
Energy Action Days	Current	Customer	Y	Y	N
My Energy Connection	Current	Customer	N	Y	Y
Xcel Energy Launchpad	Current	Third Party Access (Customer)	N	Y	Y

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

- **My Energy Connection (MEC)** - My Energy Connection is a mobile application that provides customers with detailed information on their energy usage. It uses the DI-enabled Home Area Network (HAN) to display real-time energy usage, while in their home, enabling customers better control of their

energy usage while providing insights to energy savings and to more Xcel Energy programs that can help them accomplish their energy goals. If customers are away from their homes, data in the app is updated every 15 minutes. Future enhancements will focus on providing customers with appliance-specific usage and cost breakdowns. Having detailed usage and cost by appliance will allow customers to understand where and when they are using the most energy and will provide focus for their energy savings goals

- **Mobile App** - New features will be added to the Xcel Energy mobile app that will provide customers with forecasted usage, category level disaggregation and cost breakdowns. Customers will be able to see their forecasted usage and be able to set a goal for their energy cost over a period of time. Having detailed usage and cost by main categories in their home will allow customers to understand where and when they are using the most energy.
- **AMI Energy Usage Dashboard in My Energy Portal.** Within My Energy Portal linked to My Account, customers can view their 15-minute interval, hourly, daily, monthly, and yearly usage data. For Colorado customers on Time of Use (TOU) rates, the data is broken out by TOU peak periods (off-peak, mid-peak, and on-peak); this view will also be available for Minnesota customers when TOU rates are available. Customers can toggle between kilowatt-hour usage and cost for each view. Using this presentment tool provides customers with information they previously have not had available that allows them to better control their energy usage.
- **On Demand Meter Reads.** The On Demand Read functionality in My Account provides customers the ability to see their 15-minute interval kilowatt-hour usage for the last eight hours. The On Demand Read functionality provides customers options to experiment with turning appliances and other equipment on and off to identify their energy usage patterns.
- **Rate Comparison Tool** - A rate comparison tool will be available along with the TOU rate launch to allow customers to compare energy bills under different rate options using their energy usage profile. Customers choosing to enroll in TOU will have the option to submit the request online.

In addition to the functionalities listed above, customers have access to several tools that allow them to share data with customer-authorized third parties. Customers must provide consent prior to sharing their data. This access gives the customer freedom of choice over how they view and use their data. In addition to the tools listed below, the

Company also offers Green Button Connect my Data and Green Button Download my Data, which are certified by the Green Button Alliance.⁹

- **Xcel Energy Launchpad.** Xcel Energy Launchpad allows customers to connect applications or devices developed by third parties to the AMI meters through the customer's home Wi-Fi network over the DI-enabled HAN. This permits the customer and third-party to directly gather 1-second energy consumption information from the meter. Customers can enroll in Xcel Energy Launchpad through their My Account. The Xcel Energy Launchpad includes a web application that walks the customer through the connection process. As part of the application process, customers are asked to provide consent to connect the meter to their Wi-Fi network. Customers must also provide consent to connect third party devices to the meter via their Wi-Fi network and the HAN.
- **Software Development Kit.** Software Development Kits (SDKs) for Bring Your Own Device (BYOD) and gateway solutions allows third parties to develop hardware and software products that connect to the customer's AMI meter via the HAN. Devices can be energy-related (thermostats, smart appliances) or non-energy-related (security systems, mobile devices). The uses vary depending upon the devices and the functionality enabled.

Through our grid modernization efforts, we are also enhancing the customer experience through more timely outage communications, advanced rates, and enhanced behavioral demand-side management options:

- Outage notification alerts allow customers to be notified with important information in a timely, relevant way. These could include proactive messaging about an outage, estimated restoration, and restoration confirmation. Year-to-date customer satisfaction scores for outage communications have improved year over year, from 2024 to 2025. We remain committed to enhancing how, when, and what we communicate to customers before, during, and after outage events. Our current priorities include advancing data analytics, refining processes, and enhancing technology. The impact of our efforts will continue to be measured by customer satisfaction with outage communications.
- AMI meters' remote capabilities enable the Company to reprogram meters to roll out new rates. Energy consumption data for billing purposes can be recorded by AMI meters in intervals as short as five minutes, but in most cases, is configured for 15-minute intervals. With more granular consumption data

⁹ See <https://www.greenbuttonalliance.org/> for further information on Green Button and certification requirements.

and more sophisticated meters, rate schedules can be created to better reflect the actual costs on the system at specific times of day. Customers will be able to take advantage of these price signals to manage costs. Time-of-day rate structures also encourage load shifting from peak periods to off-peak periods, resulting in emission reductions. The Company is actively engaged in preparing to launch residential TOU rates in mid-2026.

- Behavioral demand side management is a mechanism to encourage customers to reduce or shift load via energy awareness. Small adjustment to customer behaviors by large numbers of customers has the potential to have a sizeable impact on the grid. AMI meters enable the Company to create new and expand existing behavioral DSM programs. The Company is consistently looking to expand the behavioral DSM portfolio. The AMI meters enable the company to provide personalized insights and tips to customers using the data collected by and analyzed on the meter. The Company plans on making the insights available to customers through a variety of channels including web, mobile, and email. Behavioral DSM products we have created or are developing as a result of or enhanced by the AMI meters include:
 - **Energy Action Days.** Energy Action Days uses digital communications and behavioral science messaging to encourage residential customers to reduce energy consumption during peak events. Participation is voluntary, and there are no incentives or penalties for participation or non-participation. Customers with AMI meters receive a follow up email within a couple days of peak events, showing customers how they performed and comparing their performance to their neighbors. This feature is only available to customers with AMI meters.
 - **High Bill Alerts.** With this future tool (planned for 2026), electric customers will be automatically enrolled in the High Bill Alert program. This product will notify customers halfway through the billing cycle if their bill is trending higher than historically normal, allowing the customer time to adapt their energy usage or prepare financially for the additional costs.
 - **Budget Alerts.** When released in the future (planned for 2026), Budget Alerts will enable customers to set a dollar threshold and be alerted if their bill is projected to exceed their set amount. Customers will be able to sign up for Budget Alerts in the My Energy Portal and set their budget threshold. The system will check customers' bills daily between the 5th and 28th day of their billing cycle. If the projection for the current bill will be higher than their budget amount, customers will

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

As we continue to lead with expertise and work to provide a seamless experience for our customers, we will continue to develop new products and services and continuously improve existing tools. As the Company's grid modernization journey continues, we will leverage our foundational investments and future technologies to make energy work better for our customers.

VI. SECURITY AND PROTOCOLS FOR GRID MODERNIZATION

IDP Requirement No. 3.D.2.h requires:

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

Earlier in this Chapter, we discussed the ways customers can access and share their own data. In this section, we discuss our approach to data security for our grid modernization plans.

A. Overall Approach to Security

Overall, our approach to security has remained consistent since our 2023 IDP filing. The Company has a dedicated Enterprise Security Services (ESS) business unit that encompasses cyber and physical security, security governance and risk management, and enterprise resilience and continuity services. This combination of services is designed to cover analysis of vendor risks, alignment of technologies with security standards, secure solution design and deployment, integration with Company solutions (including user access management, system monitoring, and incident response), as well as threat analysis and planning for continuity of business operations in the event of a disruption. The Company's security risk management program provides Company leaders with information about threats and the level of security risks, so that proportional mitigations and responses can be planned.

Generally, our security practices include a security controls governance framework, which leverages industry best practices including the National Institute of Standards and Technology (NIST) Cyber Security Framework. The Company's security policies and standards incorporate regulatory compliance requirements and security controls designed to protect the Confidentiality, Integrity, and Availability of information and systems. A rigorous vendor security risk assessment process helps to reduce supply chain risk. Figure 5 - 8 shows the key security components.

Figure 5 - 8 Key Security Components



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

Our cyber security program may best be described in terms of the six categories of controls outlined in the NIST CSF: identify, protect, detect, respond, recover, and govern. Controls within these layers include:

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

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

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

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

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

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

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

B. Physical Security

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

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

C. Grid Modernization to Security Approach

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

rely on other controls. For example, detective controls at strategic locations to provide early notification of suspicious behavior or anomalous activity.

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

We have based our controls on a security controls governance framework that leverages industry best practices including the National Institute of Standards and Technology (NIST) and Cyber Security Framework (CSF). The Company's security policies and standards incorporate regulatory compliance requirements and security controls designed to protect against CIA (Confidentiality, Integrity, and Availability) breaches. This framework serves as the basis for project security requirements as well as periodic internal security technology control assessments.

D. AMI Infrastructure and Communications Overview

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

- The meter sits at the customer premise, gathering metrology data to be sent to the headend for billing purposes. The meter may also employ DI agents, to gather information for electric grid optimization, or to provide the customer with additional information and capabilities for managing their energy usage.
- The meters are a part of the field area network FAN, a communications mesh that transmits information to and from the AMI headend. FAN mesh communications end at an Access Point, which the transition point from FAN to the wide area network WAN and the Company's internal network.
- Once on the Company's internal network, data may move between network segments as allowed by firewalls and other security controls. Ultimately, data is stored on servers that reside in the Company data centers or is securely moved to secure locations in the cloud.

- Company employs layers of security controls to protect the confidentiality, integrity, and availability of data throughout this journey.

We discuss these infrastructure components below.

1. *At the Meter*

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

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

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

detect and respond to any anomalous activity. Additional monitoring of the headend system will trigger alerts for investigation.

2. *On the FAN*

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

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

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

3. *Company Systems and the Internal Network*

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

Data from the intelligent electric distribution network passes through multiple defense-in-depth controls on its way back to the systems in the corporate data centers. Communications will pass through multiple firewalls to ensure that only authorized devices are communicating on authorized ports/protocols. Once the data has been

delivered to the systems responsible for consuming this information, only authorized processes will have the ability to act upon this information.

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

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

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

4. In the Cloud

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

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

VII. INFORMATION ACCESS PLANS AND POLICIES

This section summarizes our information access, privacy, and governance framework. We discuss the ways that we intend to share information from our grid modernization investments with customers earlier in this Chapter.

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

A. Culture

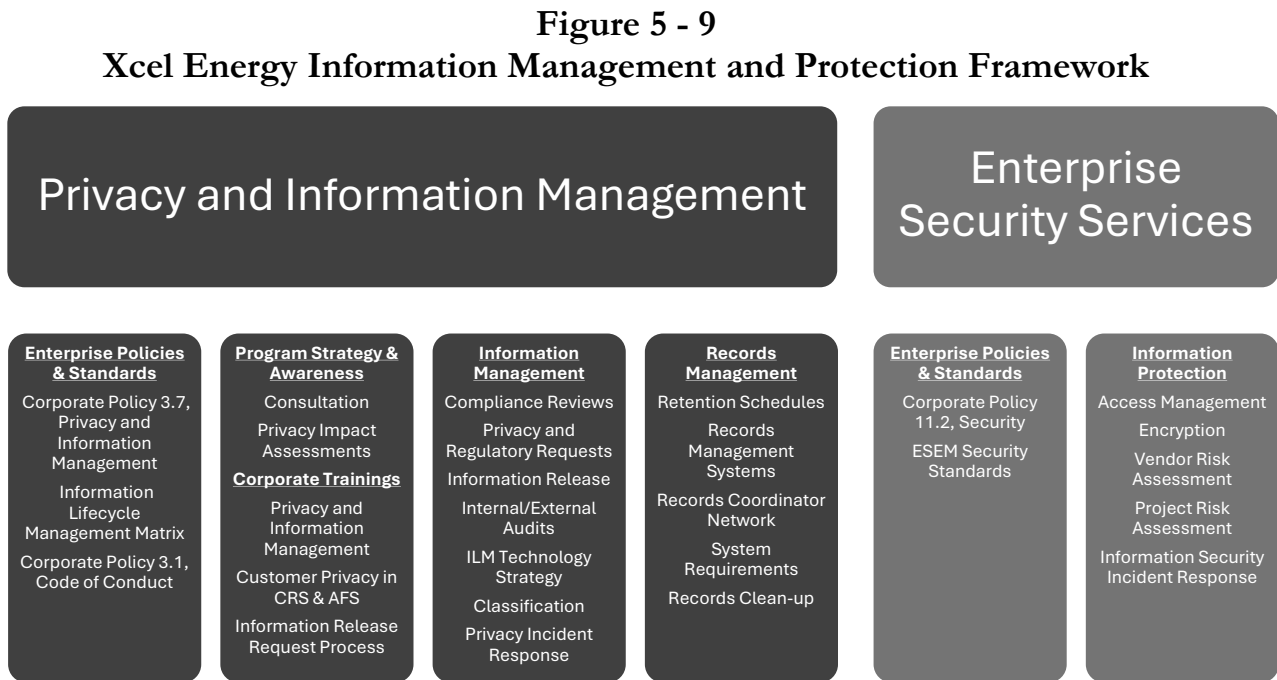
The Company's information is managed as an asset of the business. We leverage information to drive more understanding within the business about how it can be employed to improve operational performance, evaluate industry options, and help customers make better decisions. We have robust privacy and security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

As part of the Company's ongoing efforts to ensure that employees fully understand their responsibilities in safeguarding our information assets, all are required to complete the Privacy and Information Management training on an annual basis.

B. Information Management Framework

The Company's General Counsel function oversees and provides leadership of the Privacy and Information Management policies, standards, procedures, and processes. This includes strategic oversight of the creation, collection, use, retention, and disposal of all company information in all formats. The Enterprise Security System (ESS) function oversees the security requirements and protection of the Company's information assets. Compliance is a corporate and individual responsibility and is monitored and evaluated through the corporate governance framework. The

Company’s information management and protection framework is shown in Figure 5 - 9 below.



C. Information Management and Protection

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

1. Creation and Collection

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

Records are any documentary material, regardless of format, that have been finalized and/or identified on a retention schedule. Non-records are any documentary material, regardless of format, that has not been identified as a record on retention schedule.

Non-records include copies of records and are to be destroyed as soon as their intended purpose has been accomplished.

All Company information, whether it is a record or non-record, is classified into one of four information classifications based on its value or potential risk:

Confidential Restricted Information (CRI). CRI includes information where unauthorized disclosure (inside or outside the Company), alteration, or destruction has the potential for significant harm to the Company, its employees, customers, or shareholders e.g., damage to reputation; damage to the bulk electric system; legal, regulatory, or other sanctions). Information in this classification requires the strongest level of protection. Distribution of CRI must be limited to those with a business need to know, and distribution to any third party must be approved through the information release process. CRI includes personal information such as: Social Security Number; driver's license, state, tribal, student, passport, military, or other government-issued identification numbers; account numbers (bank, credit/debit card) in combination with any security code providing access to the account, any information received directly from a financial institution/bank/mutual fund; biometric identifiers (including fingerprints, voice print, retina or iris image); first name (or first initial) and first and last name; last name (in combination with any one of the following): date of birth, mother's maiden name, digitized or other electronic signature, or DNA profile.

Confidential Information (CI). CI includes information where unauthorized disclosure (inside or outside the Company), alteration, or destruction has the potential for harm to the Company, its employees, and customers (e.g., damage to reputation; material productivity loss; impede the organization's operations to the bulk electric system; legal, regulatory, or other sanctions). Information in this classification requires protection and may only be distributed to those with a business need to know, and distribution to any third party must be approved through the information release process. CI includes customer personal information, such as: customer first and last name, personal postal/email address (geo-location), personal phone numbers, account/debtor number, My Account username and password, energy usage/current charges, billing records, finances, employment history, compensation information (salary, incentive, pension), performance ratings, disciplinary records and grievance files, and health information (disability status or work-related injury).

Internal Information (II). Internal information includes information where unauthorized disclosure (inside or outside the Company), alteration, or destruction is unlikely to cause harm to the Company, its employees, and customers. Information in this classification may not be shared outside the Company without prior approval from

the information owner. It includes employee first/last name, employee and vendor work contact information (phone/fax number, location/postal address, email address, phone numbers), employer assigned identification number, and aggregated customer energy usage data (CEUD).

Unsecured Information (UI). Information that may or must be available to the public and includes the Company's website, and the following documents once published and made available to the general public: Securities and Exchange Commission and Federal Energy Regulatory Commission filings, brochures, advertisements, press releases, annual reports, billboard advertising, formal outage communications, and current billing rates. In terms of customer information, once aggregated CEUD is authorized, it becomes unsecured information (for example, the Community Energy Reports on [xcelenergy.com](https://www.xcelenergy.com)).

2. Use

Our Privacy Notice outlines the ways that we may use the information we obtain about our customers, as follows:¹⁰

- Contact information (such as name, postal address, email address, and phone number) to (provide service, establish and maintain account, run our business, communicate and provide customer support.
- Sensitive Personal Information (such as date of birth, Social Security Number, driver's license number, or government ID number) to set up new service, confirm identify, protect against fraud and collect on past-due debts.
- Demographic information (such as home ownership status and estimated household income) to enroll in energy assistance programs.
- Details about your home (such as dwelling age, size and type, details about appliances and other energy-related equipment used in the home) to gauge interest in energy efficiency programs and market those programs and services.
- Program participation information (such as our renewable energy, energy efficiency, electric vehicle, or energy conservation programs) to facilitate participation in programs.
- Payment history and details (such as payment amounts and dates, financial account number, routing number, and billing address) to process payments for services.

¹⁰ The most up to date Xcel Energy Privacy Notice is available at <https://mn.my.xcelenergy.com/s/privacy>.

- Username or ID and password to provide access to and maintain the security of My Account.
- Wi-Fi network name and password to communicate detailed energy usage data.
- Energy usage data specific to your account.
- Information from credit reporting agencies to market our programs and services and to perform analytics.
- Web browsing details to evaluate and enhance usage of our website.
- Other information that may be provided to operate, evaluate, and improve our business and the products and services we offer such as developing new and analyzing exiting products and services, optimizing customer experience, managing our energy distribution system, reduce costs and improve service accuracy and reliability, manage risk exposure, perform accounting, auditing, and other internal functions).

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

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

3. Release

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

We also release customer information to our contracted agents, when it is necessary for our agent to perform the service(s) specified in an Agreement.¹¹ Contracted agents for normal goods and services go through a security vendor risk assessment (SVRA) screening process intended to provide transparency into security-related risk(s) that could potentially be introduced to the Company as a direct result of utilizing a third-party vendor's product, service, application, etc. All new or amended vendor arrangements are subject to the SVRA process before a contract is signed. We prohibit these service providers from using or disclosing the information we provide them, except as necessary to perform specific services on our behalf or to comply with legal requirements.

For information about the Company's policies, practices, and protocols regarding the release of customer information to customers or third parties upon request the request of a customer, please see our most recent Annual Report.¹²

4. *Disposition*

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

VIII. EXISTING AND POTENTIAL NEW GRID MODERNIZATION PILOTS

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

IDP Requirement No. 3.D.2.l requires the Company to provide:

[the] ...status of any existing pilots or potential for new opportunities for grid modernization pilots.

A. Load Flexibility and Electric Vehicle Pilots

The Company filed a Load Flexibility proposal on February 1, 2021,¹³ and received approval of three pilots on March 15, 2022, including EV Optimize Your Charge

¹¹ Contracted Agents are entities with whom we have a contractual relationship to support our provision of regulated utility service, or that directly provide regulated utility service to our customers on our behalf.

¹² Xcel Energy Compliance Filing – Annual Report on Privacy Policies and Open Data Access Standards, Docket Nos. E,G999/CI-12-1344 and E,G999/M-19-505 (February 28, 2025).

¹³ Docket No. E002/M-21-101.

(Commercial and Residential), Peak Flex Credit, and Thermal Energy Storage. Additionally, there were two demonstrations allowed as part of the proposal including Excess Supply Partners and School Bus Vehicle to Grid (V2G). Cost recovery of these expenses was approved by the Commission's July 17, 2023 Order in Docket No. E002/GR-21-630. The pilot programs launched in late 2022 and are summarized below, along with the demonstration projects. In addition, we discuss our Public Fast Charging Network previously approved by the Commission.

1. EV Optimization Pilot

The EV Optimization Pilot was launched in December 2022 under the name Optimize Your Charge. The intent of the pilot was to manage potential grid impacts by incentivizing customers to charge their EVs during off-peak hours.

As a part of the pilot, customers had a choice in selecting between two charging schedules that are outside of the Company's peak hours. Participants had to conduct at least 25 percent of their charging within the schedule to receive the annual \$50 bill credit incentive. About 94 percent of connected customers were charging 25 percent or more of the time within the off-peak charging schedule they selected. As of May 31, 2025, there were almost 970 residential customers participating in the pilot, with an additional 911 residential customers who had taken some initial action to participate but were not yet fully connected. In addition, there were 11 participating commercial customers.¹⁴

In February 2025, the Company filed a Supplement requesting an extension for the pilot until a successor active managed electric vehicle (EV) charge program can be proposed as part of the 2025 Transportation Electrification Plan (TEP), which will be filed later in 2025. In May 2025, this request was approved.¹⁵

Given that the EV Optimization Pilot is ending, and a permanent active managed charging program is being proposed, we will not include discussions of the EV Optimization Pilot in future IDPs.

¹⁴ Data from our 2025 EV Annual Report submitted in Docket No. E002/M-15-111.

¹⁵ Order, In the Matter of the Petition for Approval of Load Flexibility Pilot Programs and Financial Incentive Mechanism, May 6, 2025, Docket No. E002/M-21-101.

2. *Dynamic Thermal Storage Pilot*

The Dynamic Thermal Storage Pilot, which had been renamed Commercial Thermal Storage, was intended to study incentives provided to commercial customers for the installation and operation of thermal storage solutions, as well as ongoing credits for the associated daily load shifting.

In February 2025, the Company filed a Supplement requesting to close the Commercial Thermal Storage Pilot and cancel the associated tariff pages. There had been no participation in the program since it was launched in 2022. In May 2025, this request was approved.¹⁶ Given that the Dynamic Thermal Storage Pilot has ended, we will not include discussions of the Dynamic Thermal Storage Pilot in future IDPs.

3. *Peak Flex Credit Rider Pilot*

This pilot, launched in November 2022, was designed to explore whether the structure of existing interruptible rates – particularly their requirements and penalties – posed a barrier to broader customer participation. The hypothesis was that more flexible options would increase interest in demand response programs.

The program included two tranches, one for direct participation and another for participation through third-party aggregators; neither tranche garnered significant interest. While pilot participants expressed interest in a program offering shorter contract terms, the additional flexibility provided through options for control hours, seasonality, or notification response time did not generate significant interest. Most participants selected configurations that closely aligned with those already available in the Company's existing demand response programs.

As a result, in August 2025, the Company filed a Supplement proposing to enhance and refine the current demand response programs as opposed to maintaining a separate Peak Flex Credit program.¹⁷ Additionally, the Company requested the pilot be closed to new participants as of September 12, 2025, the planned end date for the pilot. However, enrolled participants can remain on the rate, if they so choose, until updates to the commercial demand response portfolio is launched.

¹⁶ <https://www.edockets.state.mn.us/documents/%7B00784D95-0000-C612-97FA-CAE23B191DA3%7D/download?contentSequence=0&rowIndex=4>

¹⁷ Docket No. E002/M-21-101.

Given that the Peak Flex Credit Rider Pilot has ended, we will not include discussions of the Peak Flex Credit Rider Pilot in future IDPs.

4. *School Bus V2G Demonstration*

The goal of a School Bus Demonstration is to study the value of V2G applications for the distribution grid. Initially approved within the Load Flexibility docket, the Commission subsequently ordered the Company to modify the demonstration plan with an additional proposal.¹⁸ In May 2024, the Commission approved the Company's proposed school bus demonstration project as a part of our 2023 TEP filing.¹⁹

In this year's TEP, the Company is proposing a Commercial EV Infrastructure Rebate and Advisory Program which if approved would support school bus electrification rebates for school bus DCFC equipment and a higher rebate offering for bi-directional charging. Under the school bus demonstration project in conjunction with the Commercial EV Infrastructure Rebate and Advisory Program, the Company will seek to study and address barriers to school bus electrification, school bus bi-directional connection to the grid, and to better understand the costs and benefits of electric school buses as grid resources by providing financial and advisory support for EV Supply Infrastructure (EVSI) equipment, bi-directional capable EV Supply Equipment (EVSE), and related distribution interconnection infrastructure to interested school bus operators.

5. *Public Fast Charging Network Program*

As discussed in the TEP section of this IDP, the Company has installed six public fast charging stations in rural locations with the intention of filling gaps in the public fast charging network not traditionally served by the private market. These sites are currently in rigorous live testing to ensure suitable uptime. The sites are valuable resources for data regarding utilization in these areas and the operational costs and challenges associated with public DCFC operations. Site location information can be found in the TEP.

¹⁸ See Order Accepting 2021 Transportation Electrification Plans and Adopting Additional Information Requirements (May 17, 2022), Docket No. E999/CI-17-879, Order Point No. 3.

¹⁹ See Order Approving Xcel Energy's 2023 Transportation Electrification Plan with Modifications (May 9, 2024), Docket No. E002/M-23-452

B. Colorado Renewable Battery Connect and Minnesota Battery Connect Products

In 2023, Public Service launched its Renewable Battery Connect (RBC) program in Colorado as part of its 2022–2025 Renewable Energy Plan, following the successful completion of an 18-month Residential Battery Demand Response Pilot (marketed as “Battery Connect”) in 2021. The RBC program is a Virtual Power Plant (VPP) offering that builds upon key learnings from the pilot, including how to leverage customer-owned batteries to support grid stability with use cases for reducing peak demand, a 24-hour schedule, and reducing grid ramp-up.

The RBC program introduced several enhancements over the pilot. It offers an upfront incentive of \$350 per kilowatt of the battery’s maximum continuous discharge rating, with a cap of \$5,000 per customer. The program expanded eligibility to include both residential and small business customers. To qualify as a renewable energy resource, participating batteries must be 100 percent charged by an on-site solar system. Customers also receive a \$100 annual participation payment for a five-year term, and those in Income-Qualified or Disproportionately Impacted (IQ/DI) communities are eligible for higher incentives. As of late 2025, nearly 2,500 batteries have been enrolled in the program, representing 25 MW of nameplate capacity, with an additional 15 MW in development. RBC has proven to be highly popular with customers and was the first customer-facing program integrated with the Company’s Aggregator DERMS platform in August 2025. The Company is currently evaluating a transition to a pay-for-performance incentive structure to further optimize program design and refined use cases to support grid constraints.

Building on the success of RBC, the Company will launch its Minnesota Battery Connect program in Q1 2026, as proposed and approved as a modification to the 2024–2026 Energy Conservation and Optimization (ECO) Triennial.²⁰ This program complements the Energy Storage Incentive Program established under Minn. Stat. § 216C.379, which provides a one-time grant of up to \$5,000 for solar PV systems paired with batteries up to 50 kWh. The Minnesota Battery Connect program will adopt key design principles from RBC while tailoring its structure to Minnesota’s regulatory and market context. It will support both new and existing battery

²⁰ Decision, “In the Matter of Xcel Energy’s 2024–2026 ECO Plan: Program Modification Request for Inclusion of Peak Day Partners and Battery Connect Programs”, MN Department of Commerce, July 31, 2024.

installations and allow customers without on-premise solar to participate. The battery grant program is expected to encourage enrollment in the demand response offering.

To support program development and regulatory oversight, the Company will conduct a Measurement & Verification (M&V) study in collaboration with an external partner. This evaluation will generate Minnesota-specific data to assess program impacts and inform future ECO filings.

C. Rate Pilots

The Company piloted a General Service Time of Use rate that encouraged C&I customers with demand equal to or greater than 50 kW over the preceding 12 months to shift load from on- to off- peak times. The pilot included two rate designs.

- The TOU rate featured two time-varying rate components – an energy rate component and a demand charge component. Each component had charges varying based on three time periods
- The Critical Peak Partner (CPP) rate featured volumetric pricing that combined energy and demand charges into one per kWh charge, which varied by time of day using the same time periods as the TOU Rate. CPP also featured a component that allowed the Company to call events for up to 75 hours per year with a much higher per kWh charge during the events.

In June 2024, the Company filed a Petition requesting a modification to the recruitment plan for the pilot to attract more participants. In Reply Comments in October 2024, the Company acknowledged that the revised efforts may not garner the needed participation and stated we were not opposed to setting the pilot aside and instead focus on a plan to transition to a default general service TOU. In April 2025, the Commission suspended the C&I pilot due to lack of participation and ordered the Company to file a partial transition plan based on our 2024 Resource Plan by March 31, 2026.²¹

The Company has concluded TOU pilots for residential and C&I customers. The new residential TOU rate was approved in May 2025²² and will be launched in 2026.

²¹ ORDER REQUIRING PILOT PROGRAM SUSPENSION (April 7, 2025), Docket No. E002/M-20-86.

²² ORDER APPROVING REVISED OPTIN PROPOSAL AND SETTING REPORTING REQUIREMENTS (May 15, 2025), Docket No. E002/M-23-524.

D. Resilient Minneapolis Project

The Resilient Minneapolis Project (RMP) is a pilot project that will deploy battery energy storage systems and microgrid controls at three community locations – Sabathani Community Center, the Minneapolis American Indian Center (MAIC), and a cluster of Minneapolis Public Schools District buildings in North Minneapolis – to create community resiliency hubs. The RMP microgrids will build resilience for vulnerable communities by supporting the hosts’ ability to deliver critical services – shelter, cooling/heating, food provision, communications, refrigeration of medicines, power for an emergency operations center, etc. – in the event of a grid outage affecting those neighborhoods. The Commission first certified RMP in its 2021 IDP Order and approved the revised RMP proposal in its September 4, 2024 Order.²³ RMP seeks to enhance grid resilience and community resilience while advancing the grid modernization objectives of Minn. Stat. § 216B.2425.²⁴

RMP implementation has moved forward smoothly in 2025, including:

- Executing microgrid agreements with Sabathani and MAIC and a subrecipient agreement with Renewable Energy Partners under the Company’s Grid Resilience & Innovation Partnerships (GRIP) award from the U.S. Department of Energy.
- Hiring of an engineering, procurement, and construction (EPC) contractor.
- Completion of detailed engineering designs for the microgrids.
- Progress on federal and city permitting.
- Negotiation of easements with the host sites.

At Sabathani and MAIC, construction is slated to begin in spring 2026. The Company’s partner for the North Minneapolis microgrid, Renewable Energy Partners, has likewise moved forward on hiring of contractors, engineering designs, permitting, and completing interconnection applications for solar.

²³ ORDER ACCEPTING 2021 INTEGRATED DISTRIBUTION SYSTEM PLAN AND CERTIFYING THE RESILIENT MINNEAPOLIS PROJECT (July 26, 2022), ORDER APPROVING XCEL ENERGY’S REVISED RESILIENT MINNEAPOLIS PROJECT (September 4, 2024), Docket No. E002/M-21-694.

²⁴ Minn. Stat. § 216B.2425, Subd. 2(e): “...a utility operating under a multiyear rate plan approved by the commission under section 216B.16, subdivision 19, shall identify in its report investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.”

Implementation of the GRIP award has been more uneven. Unlike other Infrastructure Investment and Jobs Act (IIJA) awards, the Company's GRIP award has never appeared to be under threat of outright cancellation; that said, award implementation has been challenged or significantly delayed at times due to lack of communication from the Department of Energy.

Additional information on the progress of RMP is included in our 2024 RMP Annual Report, filed in Docket No. E002/M-21-694, and in the upcoming December 1, 2025 Annual Report in that same docket.

E. Future Non-Wires Alternative Pilot

As discussed in *Chapter 8: Non-Wires Alternatives Analysis*, our non-wires alternatives (NWA) analysis this year shows five technically feasible projects, however none of them are cost beneficial in all deployment scenarios. Despite this, the Company remains committed to exploring the potential of NWAs and intends to issue a Request for Proposals (RFP) to gauge market interest and identify innovative solutions for two of the projects studied. This proactive approach reflects our dedication to advancing NWA opportunities and fostering collaboration with developers.

CHAPTER 6: DISTRIBUTION FINANCIAL FRAMEWORK AND ACTION PLANS

This Chapter outlines the Company's strategic financial framework and five-year action plan for distribution system investments. These investments are central to the company's long-term vision of building a resilient, modern, and customer-focused grid. The plan is designed to achieve three key goals: delivering excellent service, leading Minnesota's clean energy transition, and keeping customer bills affordable.

The chapter begins with an overview of the budget development process, including a dynamic five-year forecast that guides operations and capital planning. It then highlights investment priorities across four areas: preparing for future system demands, supporting electrification and DER integration, enhancing reliability and resilience, and modernizing grid infrastructure.

Detailed budget categories, historical and projected spending, and regulatory compliance are presented to provide transparency and accountability. Special focus is given to electric vehicle programs and beneficial electrification, reflecting Xcel Energy's commitment to enabling a cleaner energy future. This chapter reflects the information for Distribution budget only. Additional information specific to EV programs is provided in the Transportation Electrification Plan. *Chapter 5: Grid Modernization* provides further information on project-specific costs.

The chapter also includes a five-year action plan that addresses load growth assumptions, investment drivers, cost recovery mechanisms, and customer impacts. A ten-year outlook follows, emphasizing the need for adaptive planning tools and enhanced system capabilities to meet evolving energy needs and policy goals.

We also address new requirements from Docket Nos. E,G999/CI-22-624 and E002/GR-21-630.

I. BUDGET DEVELOPMENT FRAMEWORK FOR DISTRIBUTION SYSTEM INVESTMENTS

The Company's electric and gas utilities are long-term, capital-intensive businesses. To support strategic planning and deliver excellent service, we prepare a five-year financial forecast annually. This forecast anticipates the financial needs of our operating utility companies, including NSPM, and informs the development of realistic, supportable financial plans across the organization. It provides essential

insights for strategic and financial decision-making, helping us lead the clean energy transition while maintaining reliability and affordability. Key components include five-year budgets for operations and maintenance (O&M) and capital expenditures for each of the Company's utility subsidiaries.

Budgeting Process Overview. The five-year forecast includes both O&M and Capital Expenditure budgets. While the processes for developing these budgets are similar, capital projects over \$15 million require additional steps and internal approvals. Projects exceeding \$50 million must go through further internal approval layers beyond those required at the \$15 million threshold. Once finalized, both O&M and capital budgets are subject to monthly variance reviews and comprehensive quarterly evaluations to ensure alignment with financial and operational goals.

Distribution Budget Strategy. Historically, Distribution budgets have focused on immediate reliability needs—such as maintaining feeders, substations, transformers, and service lines, and responding to weather events or government mandates. Today, our strategy has evolved to also support:

- Preparing for future system demands
- Leading the clean energy transition
- Delivering excellent service by enhancing reliability and resilience
- Modernizing customer interactions with the grid

Each year, the first year of the five-year budget is “locked in,” while years two through five are revisited reflect evolving priorities and new information. As we get closer to when spending will occur, our forecasts become more refined, based on more current and relevant data. This iterative approach ensures our investments remain aligned with our strategic goals: delivering excellent service, leading the clean energy transition, and keeping customer bills affordable—while adapting to changing conditions and emerging needs.

In the following sections, we outline what our distribution budget categories include, followed by a presentation of our historical and projected budgets.

A. Distribution Budget Categories

On June 3, 2025, the Minnesota Public Utilities Commission issued a Notice of Approval of Updated Filing Requirements in Docket Nos. E002/CI-18-251, E002/M-23-452, and E002/M-25-142. This Notice approved amended IDP filing requirements pursuant to Order Points 7 and 8 of the Commission's September 16,

2024 Order in Docket No. E002/M-23-452, effective with the Company’s IDP filed on October 31, 2025. Order Point 7 delegated authority to the Commission’s Executive Secretary to work with utilities and stakeholders to modify IDP budget categories to support cross-utility and historical-to-forecasted comparisons, and to approve any resulting stakeholder agreement via notice.

Through a Commission Staff-led workgroup process, stakeholders reached consensus on revised filing requirements that allow the Company to present a high-level summary of historical (past five years) and projected (next five years) distribution system spending using the standardized IDP budget categories, while retaining the use of internal capital budget categories for most other financial information. The Company provides a description of each internal capital budget category below in Table 6-1, and the following cross-reference table to show how the internal capital budget categories align with the IDP categories.

Table 6-1
Financial Categories Cross-Reference

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

* The internal capital budget category of “Wildfire Mitigation” was previously included under the IDP category of “Other” in our 2024 Annual Update. This year, we have reclassified Wildfire Mitigation costs under the IDP category of “Age-Related Replacements and Asset Renewal.”

** The internal capital budget category of “New Business” includes transformer purchases in the Capital Budget Categories while transformer purchases are captured under the IDP category of “Other.”

Our capital projects fall into eight internal capital budget categories, depending on the primary purpose of the project. We outline the contents of our budget categories below:

1. *Asset Health and Reliability*

This category includes projects focused on replacing infrastructure that has high failure rates, which can reduce service reliability and increase O&M costs. When underperforming assets are identified, we budget for projects that will improve their performance. Typical projects include the replacement of underground cables, wood poles, overhead lines, substation equipment, transformers, and switchgear that have reached the end of their useful life. This category also covers replacements necessitated by storm damage or public interference.

This category also includes programs focused on improving the reliability and quality of the electric distribution system. It covers initiatives such as cable replacement, targeted undergrounding, porcelain component upgrades, and broader system enhancements. These efforts are designed to reduce outages, improve voltage stability, and strengthen overall grid resilience.

2. *Capacity*

This category includes capital investments designed to expand or upgrade the distribution system to support load growth from both existing and new customers. It also supports continued service when parts of the distribution system are offline. Projects typically include installing new or upgraded substation transformers and distribution feeders. These capacity-related projects often span multiple years and are driven by increasing load demand. This category also encompasses programs such as grid reinforcement, and feeder load monitoring.

3. *New Business*

This category includes overhead and underground extensions and services required to connect new customers to the distribution system. Capital projects typically involve installing or expanding feeders, primary and secondary extensions, and service laterals that deliver electricity from existing infrastructure to new homes or businesses. It also covers routine purchases of electric meters and transformers to support ongoing

customer growth and system needs. It does not include metering costs related to our AMI plans, which are tracked separately.

This category also includes distribution costs related to interconnecting community solar gardens and extending service for auxiliary electric needs. These costs are billed to the developer in stages throughout the development and construction of the solar garden. Once payment is received and the work is completed, credit is applied to this category.

4. *Advanced Grid Intelligence and Security (AGIS)*

Historically, grid modernization investments were included under the Asset Health budget category. Starting in 2019, we established a separate category to account for major planned investments in systems such as Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI), Field Area Network (FAN), and Fault Location, Isolation, and Service Restoration (FLISR).

These investments aim to:

- Improve power reliability
- Reduce outage durations
- Support integration of Distributed Energy Resources (DER)
- Enable customers to monitor and manage their energy usage

Any future major grid modernization initiatives will also be included in this category. Once these projects transition from initial deployment to ongoing operations, their costs will shift to other relevant budget categories. For example, after the initial rollout of AMI meters, ongoing expenses will be captured under the Metering category.

Project-specific budget forecasts are provided in *Chapter 5: Grid Modernization*.

5. *Mandates*

This category includes projects where existing utility infrastructure must be relocated from public rights-of-way to comply with government directives, typically to accommodate public works initiatives such as road widening or realignment. The volume of these projects generally depends on the availability of municipal and state funding infrastructure improvements. These mandated relocation projects often result in upgraded distribution infrastructure.

6. *Wildfire Mitigation*

This category includes the Company's investments related to mitigating the risk of wildfires, including investments in operational mitigations, overhead assessments and associated mitigations, and small conductor and pole replacements, all targeted to reduce wildfire ignition risk in the wildfire risk areas of the Company's Minnesota service territory. In addition to reducing ignition risk, a portion of these investments, such as small conductor and pole replacements, address some of the oldest assets on our system, serving to preserve the integrity and functionality of the system components now and into the future.

7. *Fleet, Tools, and Communications*

This category includes tools, communication equipment, and various items that do not fit under the other budget categories. Communication-related investments may support specific programs or projects such as:

- Feeder Load Monitoring
- Network Monitoring
- Fiber Buildout
- Cybersecurity
- Locating services
- Ongoing costs following initial deployment of assets like the Field Area Network (FAN), implemented as part of our grid modernization efforts

These items are essential for maintaining and enhancing system functionality but are not easily categorized under other categories.

8. *Electric Vehicle Programs*

This category includes the capital costs associated with EV pilots and programs that were previously approved by the Commission – the Residential EV Charging Tariff, Residential EV Accelerate at Home, Fleet Charging Pilot, Public Charging Infrastructure Pilot, Residential Subscription Service Pilot, and Multi-Dwelling Unit Charging Pilot.¹ As a part of the Minnesota Transportation Electrification Plan (TEP) being filed concurrently with this IDP, the Company is making several proposals, including an expansion of the existing Residential EV Subscription Service Pilot, a

¹ See Docket No. E002/M-17-817; Docket No. E002/M-18-643; Docket No. E002/M-19-186; Docket No. E002/M-19-559.

new electric school bus pilot, and rebates for home wiring for vehicle charging. In addition, we are requesting additional funding to continue our fleet and public charging programs and our EV advisory services.

This category includes capital costs for EV pilots and programs previously approved by the Commission, such as:

- Residential EV Charging Tariff
- Residential EV Accelerate at Home
- Fleet Charging Pilot
- Public Charging Infrastructure Pilot
- Multi-Dwelling Unit Charging Pilot

As part of the TEP, filed concurrently with this Integrated Distribution Plan (IDP), the Company is proposing several new initiatives. These include:

- Commercial EV Infrastructure and Equipment Rebate and Advisory Program
- Residential Advisory Services and Guided Charging Installation Program
- Charging Perks (Active Managed Charging Program)

Further details on our EV plans and investments are provided in the Transportation Electrification Plan.

B. Historic and Budgeted Information (Capital Budget)

This section provides our historic and projected distribution spending for five-years into the past and future, as well as a high-level description of changes in these spending levels and all non-Xcel investments in distribution system upgrades.

IDP Requirement No. 3.A.26² requires the following:

A high-level look at historical distribution system spending for the past 5-years and projected distribution system spending for 5-years into the future in each category listed below:

- a. Age-Related Replacements and Asset Renewal*
- b. System Expansion or Upgrades for Capacity*
- c. System Expansion or Upgrades for Reliability and Power Quality*
- d. New Customer Projects and New Revenue*
- e. Grid Modernization and Pilot Projects*
- f. Projects related to local (or other) government-requirements*

² This IDP Requirement also provides that the Company may include in the IDP any 2018 or earlier data in the following rate case categories: (a) Asset Health; (b) New Business; (c) Capacity; (d) Fleet, Tools, and Equipment; and (e) Grid Modernization.

g. Metering

h. Other

i. Electric Vehicle Programs

~~1) Capital Costs~~

~~2) O&M Costs~~

~~3) Marketing & Communications~~

~~4) Other (provide explanation of what is in "other")~~

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

IDP Requirement No. 3.A.27 requires the following:

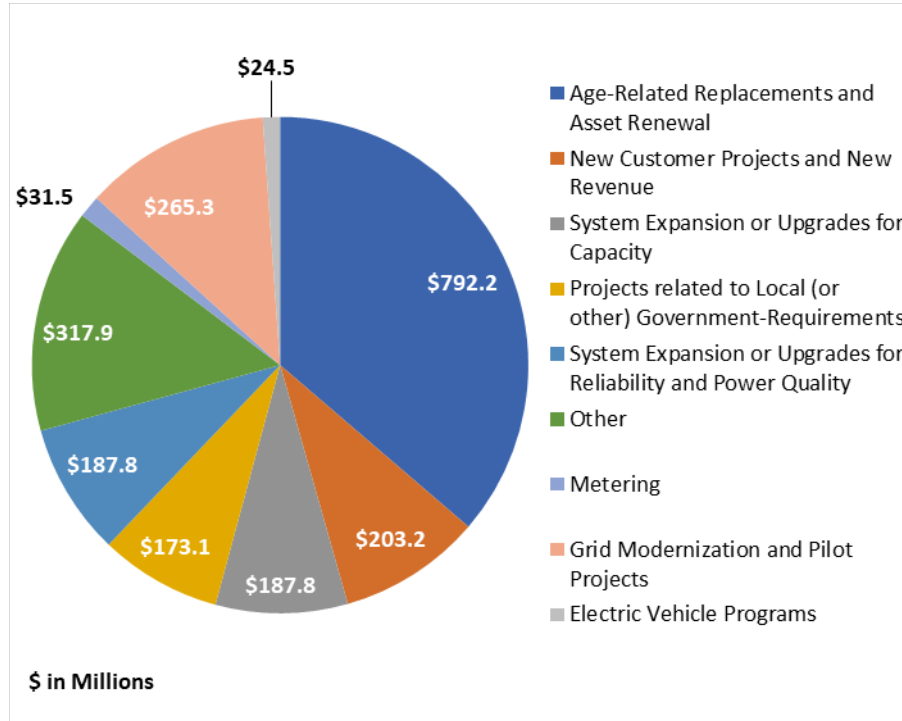
Historical distribution system spending for the past 5-years and projected distribution system spending for 5-years into the future broken down by Xcel's internal distribution budget categories, itemizing any non-traditional distribution projects.

IDP Requirement No. 3.A.28 requires the following:

All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g. CSG, customer-sited, PPA and other) and location (i.e. feeder or substation).

Figure 6-1 below provides a summary of historical actual capital expenditures in the IDP categories.

Figure 6 - 1
Actual Historical Distribution Capital Profile by IDP Category
State of Minnesota – Electric 2020-2024 (excludes CIAC and Solar)



Note: Non-investment items (Contributions In Aid of Construction (CIAC), which partially offset total project costs and 3rd party reimbursements for system upgrades due to interconnections and Solar, which is 100% reimbursable by the developers).

Figure 6-2 below provides a similar summary of historical actual capital expenditures in the Company's internal capital budget categories.

Figure 6 - 2
Actual Historical Distribution Capital Profile by Capital Budget Category
State of Minnesota – Electric 2020-2024 (excludes CIAC and Solar)

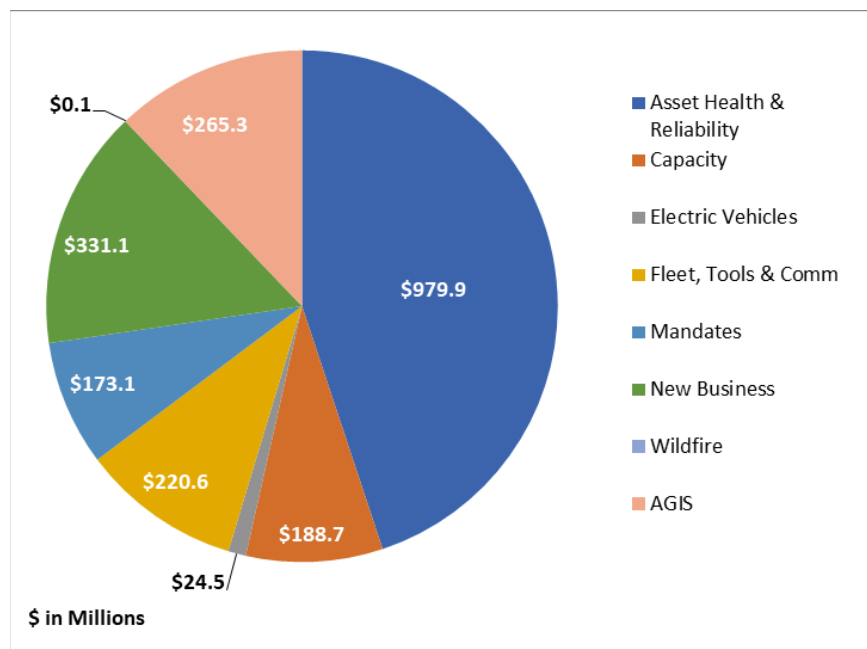
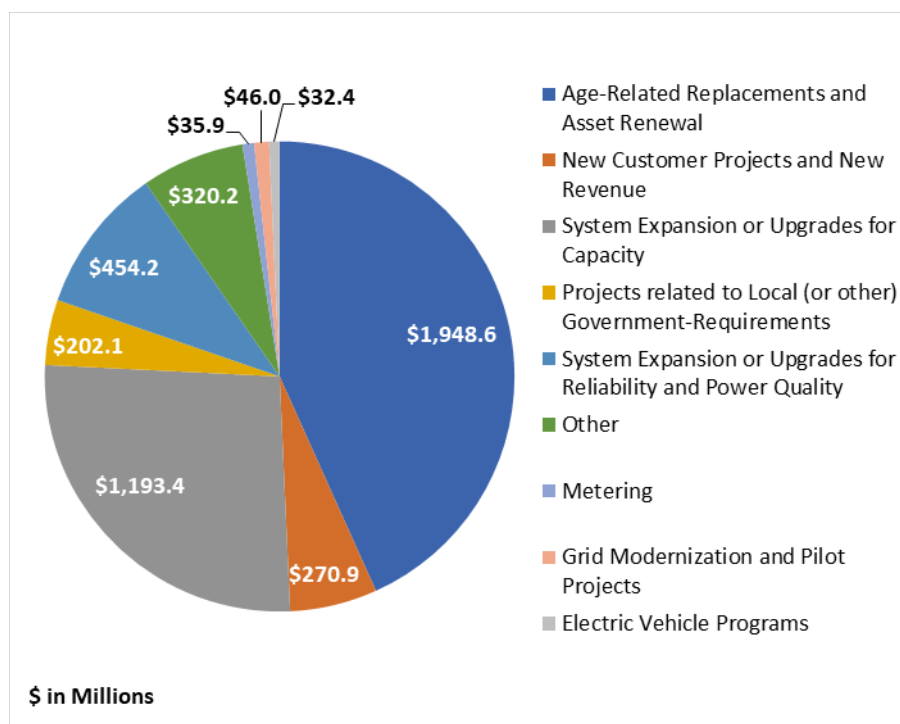


Figure 6-3 below provides an overview of our 5-year capital budget in the IDP categories. We clarify that we do not have any specific non-traditional distribution projects in our five-year budget as we interpret “non-traditional distribution projects” in the context of the IDP Requirements to mean non-wires alternatives projects. However, for projects in the Grid Modernization and Pilot Projects category that could be considered “non-traditional;” see Chapter 5 for an itemization of those projects.

We also have not had any non-Xcel investments in distribution system upgrades (as defined in IDP Requirement No. 3.A.28) from 2020-2024.

Figure 6 - 3
Budgeted Distribution Capital Profile by IDP Category
State of Minnesota – Electric 2026-2030 (excludes CIAC and Solar)



Note: Excludes Non-investment items (Contributions In Aid of Construction (CIAC), which partially offset total project costs and 3rd party reimbursements for system upgrades due to interconnections and Solar, which is 100% reimbursable by the developers).

Figure 6-4 below provides an overview of our 5-year capital budget in the Company's internal capital budget categories.

Figure 6 - 4
Budgeted Distribution Capital Profile by Capital Budget Category
State of Minnesota – Electric 2026-2030 (excludes CIAC and Solar)

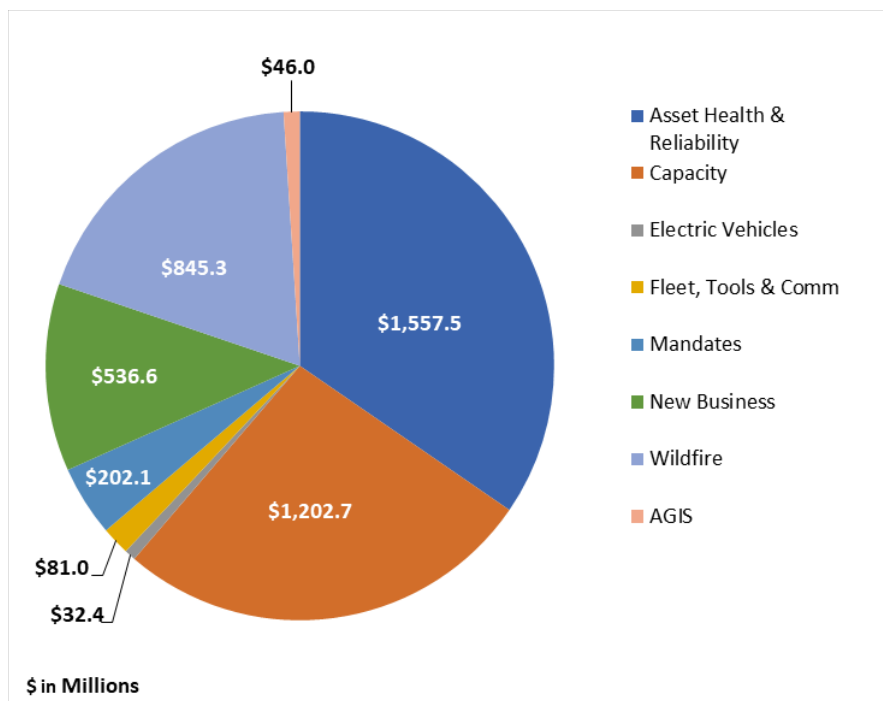


Table 6-2 below provides our annual distribution capital expenditures budget for years 2025-2030 in the IDP categories.

Table 6 - 2
Distribution Capital Expenditures Budget by IDP Category –
State of Minnesota – Electric 2025-2030 (Millions)

IDP Category	Bridge Year	Budget					Budget Avg
	2025	2026	2027	2028	2029	2030	2026-2030
Age-Related Replacements and Asset Renewal	\$392.9	\$488.5	\$474.3	\$360.1	\$338.5	\$287.3	\$389.7
New Customer Projects and New Revenue	\$57.4	\$61.0	\$49.3	\$54.4	\$52.3	\$53.9	\$54.2
System Expansion or Upgrades for Capacity	\$84.7	\$230.6	\$234.8	\$187.0	\$292.9	\$248.1	\$238.7
Projects related to Local (or other) Government-Requirements	\$42.4	\$48.2	\$38.8	\$40.5	\$40.8	\$33.8	\$40.4
System Expansion or Upgrades for Reliability and Power Quality	\$45.5	\$50.7	\$67.3	\$106.3	\$113.1	\$116.8	\$90.8
Other	\$126.7	\$58.8	\$60.0	\$70.6	\$67.6	\$63.3	\$64.0
Metering	\$10.2	\$7.3	\$7.2	\$7.0	\$7.0	\$7.3	\$7.2
Grid Modernization and Pilot Projects	\$29.2	\$16.4	\$29.6	\$0.0	\$0.0	\$0.0	\$9.2
Non-Investment	(\$3.6)	(\$4.0)	(\$4.0)	(\$4.0)	(\$4.0)	(\$4.0)	(\$4.0)
Electric Vehicle Programs	\$4.3	\$18.4	\$2.7	\$3.2	\$3.7	\$4.3	\$6.5
TOTAL	\$789.6	\$976.0	\$960.0	\$825.1	\$911.9	\$810.6	\$896.7

Table 6-3 below provides our annual distribution capital expenditures budget for years 2025-2030 in the Company’s internal capital budget categories.

Table 6 - 3
Distribution Capital Expenditures Budget by Capital Budget Category –
State of Minnesota – Electric 2025-2030 (Millions)

Capital Budget Category	Bridge Year	Budget					Budget Avg
	2025	2026	2027	2028	2029	2030	2026-2030
Asset Health & Reliability	\$353.7	\$295.3	\$327.1	\$328.5	\$327.0	\$279.6	\$311.5
Capacity	\$78.7	\$239.5	\$234.8	\$187.2	\$293.1	\$248.1	\$240.5
Electric Vehicles	\$4.3	\$18.4	\$2.7	\$3.2	\$3.7	\$4.3	\$6.5
Fleet, Tools & Comm	\$23.4	\$17.8	\$16.7	\$19.0	\$15.8	\$11.7	\$16.2
Mandates	\$42.4	\$48.2	\$38.8	\$40.5	\$40.8	\$33.8	\$40.4
New Business	\$176.3	\$100.4	\$99.8	\$112.9	\$110.9	\$112.7	\$107.3
Wildfire	\$85.4	\$244.0	\$214.5	\$137.9	\$124.5	\$124.5	\$169.1
AGIS	\$29.2	\$16.4	\$29.6	\$0.0	\$0.0	\$0.0	\$9.2
Non-Investment	(\$3.6)	(\$4.0)	(\$4.0)	(\$4.0)	(\$4.0)	(\$4.0)	(\$4.0)
TOTAL	\$789.6	\$976.0	\$960.0	\$825.1	\$911.9	\$810.6	\$896.7

In Table 6-3 above, AGIS includes the Distribution component of grid modernization projects such as AMI, FAN, ADMS, FLISR, etc. Similarly, the Electric Vehicles category includes the Distribution component of EV program investments.

In Tables 6-2 and 6-3 above, Non-Investment includes Contributions In Aid of Construction (CIAC), which partially offset total project costs and third-party reimbursements for system upgrades due to interconnections and solar, which are 100 percent reimbursable by the developers; annual totals will vary based on payment and project timing.

C. Cable Replacement Capital Spend

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

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

Cable replacements are included in the “System Expansion or Upgrades for Reliability and Power Quality” IDP budget category and the “Asset Health and Reliability” internal capital budget category.

Underground cable failures are a leading cause of outages for customers served by underground infrastructure, accounting for approximately 65% of customer minutes out (CMO) from 2020 to 2024. The Company’s cable replacement program focuses on:

- Responding to outages caused by cable failures
- Replacing cables that are damaged beyond repair
- Replacing cables that have failed more than once within a two-year period to prevent future outages

Table 6-4 provides actual capital spending on reactive and proactive cable replacements from January 1, 2024, through June 30, 2025:

Table 6-4
Cable Replacement Capital Spend
January 1, 2024 through June 30, 2025

	Actual Capital Spend (Millions)	Actual Capital as a %
Reactive	\$31.8	52.3%
Proactive	\$29.0	47.7%
Total	\$60.8	100.0%

Table 6-5 presents projected spending for the five-year budget period 2026-2030. These projections are based on historical actuals and may change due to variability in cable failure rates, which can fluctuate seasonally and year to year.

The cable replacement program addresses both reactive and proactive replacements, with a primary focus on responding to reactive failures. If reactive failures are lower than expected in a given year, the Company shifts its focus to proactively replacing cables with a history of poor reliability. This was the case in the January 2024 to June 2025 period shown in Table 6-4 which coincided with the lowest rate of tap cable failures in over 10 years. The projected portions of reactive vs proactive are based on longer term historical averages.

Because reactive replacements are difficult to predict annually, combining both proactive and reactive replacements into a single budget category allows for greater flexibility. Separating the budgets would require frequent reallocation of funds,

depending on actual failure rates. The current unified budgeting approach is a more efficient and practical way to manage the program.

Table 6-5
Cable Replacement Capital Budget Forecast (Millions)
2026-2030

	2026	2027	2028	2029	2030	2026-2030
MN tap level cable replacement Budget	\$31.7	\$32.3	\$34.0	\$35.0	\$36.1	\$169.1
MN feeder level cable replacement Budget	\$8.2	\$7.1	\$7.3	\$7.5	\$7.8	\$37.9
Total cable replacement budget	\$39.9	\$39.4	\$41.3	\$42.5	\$43.9	\$207.0
	2026	2027	2028	2029	2030	2026-2030
Forecasted reactive cable Replacements	\$24.0	\$23.7	\$24.8	\$17.0	\$26.3	\$124.2
Forecasted proactive cable Replacements	\$16.0	\$15.8	\$16.5	\$25.5	\$17.6	\$82.8
Total forecasted cable replacements	\$39.9	\$39.4	\$41.3	\$42.5	\$43.9	\$207.0

D. Maximizing Inflation Reduction Act (IRA) Benefits

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

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

In *Chapter 1: System Planning*, we discuss how the IRA has impacted overall distribution planning assumptions.

Regarding capturing and maximizing benefits of the IRA, with respect to the standard distribution system investments included in our five-year budget forecast, none of these projects are eligible for IRA tax credits, which are focused on renewable and carbon-free energy investment and production.

The IRA includes provisions related to transportation electrification. Those provisions include federal tax credits for consumers for the purchase of new (IRC §30D) and used (IRC §25E) electric vehicles of up to \$7,500 and \$4,000 respectively. Commercial clean vehicle purchases are also eligible for tax credits of up to \$40,000 depending on the vehicle weight under IRC 45W. A tax credit under the Federal Alternative Fuel Vehicle Refueling Property Credit (IRC §30C) remains and can provide a 30 percent tax credit per station up to \$100,000 for businesses and up to \$1,000 in other cases. The eligibility and applicability provisions of the IRA are specific, and the Company is claiming these credits, to the extent possible. However, the One Big Beautiful Bill Act that was passed on July 4, 2025, accelerated the termination date for IRC §30D, §25E and §45W, and they are no longer available for purchases after September 30, 2025. In general, the Company will evaluate Federal funding and tax credits opportunities where we are eligible and where we have an applicable scope of work or a project. For example, our proposed Capacity*Connect program would deploy 50-200 MW of distribution-connected battery energy storage systems, which we anticipate would be eligible for at least 30 percent Investment Tax Credit.

While not related to the IRA, we further note that we have been seeking other federal funding opportunities to complement our distribution system investments and keep bills low for customers. We signed an award agreement for NSPM to receive up to \$25 million in funding from the U.S. Department of Energy's (DOE's) Grid Resilience and Innovation Partnership (GRIP) program, funded through the Bipartisan Infrastructure Law. Projects include undergrounding of high-risk distribution circuits, wildfire modeling software, and community resilience microgrid project implementation. We will keep the Commission and parties updated as we continue to make progress on the GRIP award.

E. Planned Distribution Capital Projects

IDP Requirement No. 3.A.29 requires that we provide:

Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should align with Xcel's internal distribution budget categories.

We have included this information in Attachments H and I of this filing. Additionally, Attachment L provides the financial data from this appendix in a live Excel format.

Key investments in the five-year distribution budget include:

- Age-related replacements and asset renewal including reactive and potential proactive system upgrades.
- System expansion or upgrades for capacity
- Wildfire Risk Mitigation, which focuses on reducing the risk of wildfires associated with electric utility infrastructure while improving system resiliency, reliability, and public safety.

However, recent inflation, potential tariffs, and supply chain challenges may reduce the volume of investments that can be completed within current budget levels. As a result, additional budget increases may be necessary to fully implement the five-year investment plans and to meet state policy objectives. For example, the table below is the average manufacturer invoice pricing for distribution load serving transformers used in Minnesota.

Table 6-6
Average Manufacture Invoice Pricing- Distribution Load Serving Transformers

Distribution Load Serving Transformer Average Cost	
2020	\$2,730
2021	\$2,388
2022	\$3,397
2023	\$6,368
2024	\$9,185
2025 Forecast	\$9,323

Finally, although only required for capital under IDP Requirement No. 3.A.29, we provide a similar trend view of our O&M costs over time as *Attachment J* to this IDP.

F. O&M Financial Information

The Distribution O&M budget covers labor costs for maintaining, inspecting, installing, and constructing distribution assets such as poles, wires, transformers, and underground facilities. It also includes labor for vegetation management and damage prevention, as well as materials and minor tools needed to operate and maintain the electric distribution system and fleet (vehicles, trucks, trailers, etc.). Specifically, the fleet-related O&M costs reflect expenditures required to maintain the existing fleet, including annual fuel costs and a proportional allocation of fleet support based on

O&M usage versus capital projects.

Our O&M budgeting process begins with a review of recent historical spending across Distribution activities. We adjust for known changes in labor rates and inflation and normalize for one-time or non-recurring events (e.g., major storms or unique maintenance projects). This baseline is then refined by evaluating anticipated work volumes for both capital and O&M programs, ensuring adjustments are made for measurable changes expected in the upcoming budget year. For example, in programs like cable fault repairs and vegetation management, we assess expected units or line-miles and adjust O&M funding accordingly.

We also incorporate expected efficiency gains from ongoing operational improvements and technology adoption. These anticipated productivity enhancements are already reflected in our O&M forecasts.

Because actual conditions vary year to year, we typically update our O&M forecasts throughout the year. Severe weather is one of the biggest drivers of variability, with restoration costs fluctuating significantly. Additionally, the Distribution unit may be asked to adjust O&M spending mid-year to support broader company needs. When this happens, we strive to reallocate funds within the existing budget, but may exceed it if necessary to maintain safe, reliable service.

Annual O&M expenses are heavily influenced by the frequency and severity of storms across our service area. The unpredictable nature of these events makes budgeting challenging. Table 6-7 below illustrates the variability in storm-related O&M spending—beyond base labor and transportation—from 2020 to 2024.

Table 6-7
2020-2024 Annual NSPM O&M Storm Restoration Expenses
(Millions)

2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	5-Year Average
\$3.70	\$7.10	\$7.50	\$9.00	\$16.80	\$8.82

As shown in the table, O&M expenses for storm restoration rose significantly from 2021 through 2024 compared to 2020 and earlier years, driven by both an increase in storm frequency and the severity of certain events. In 2025, we are forecasting storm-related O&M costs of \$19.4 million, about \$10.6 million higher than the five-year

average.

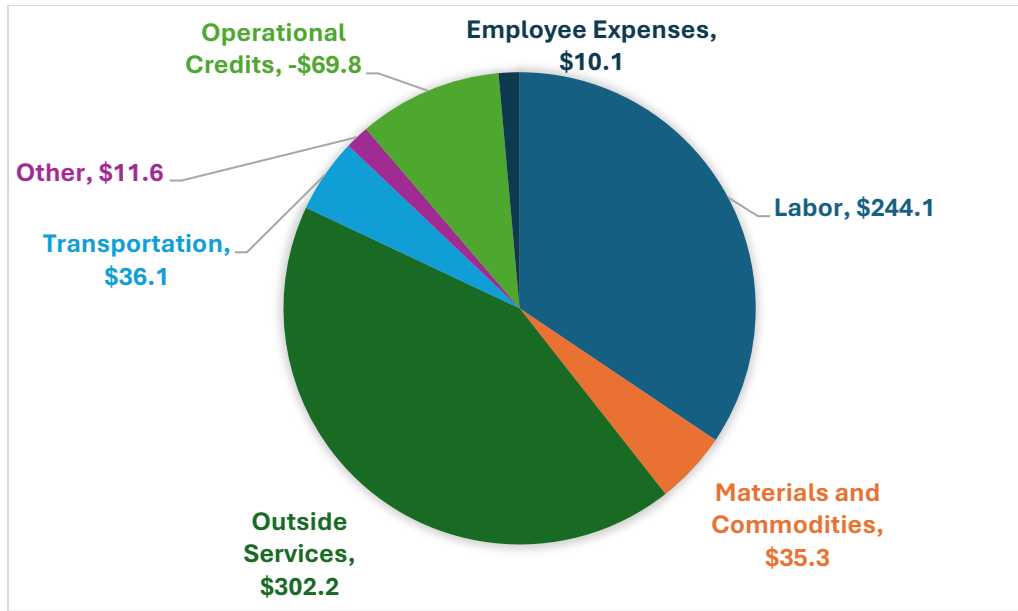
Throughout the year, we closely monitor actual O&M spending against the budget and assess any significant variances as they arise. When budget pressures emerge, we explore mitigation strategies, including reallocating funds from lower-priority or discretionary areas. These reallocations are considered only if the funding need can be reasonably managed within the overall budget. If pressures—such as those caused by major storms—exceed what can be covered through reallocation, we may revise our year-end forecast to reflect spending above the original O&M budget. Any significant budget deviations must be formally reviewed and approved by the Company's Finance Council.

G. O&M Budget

The O&M budget includes labor costs for maintaining, inspecting, installing, and constructing distribution infrastructure such as poles, wires, transformers, and underground electric facilities. It also covers contractor-provided labor for vegetation management and damage prevention. Additionally, the budget accounts for fleet expenses (vehicles, trucks, trailers) and miscellaneous materials and tools needed to operate and maintain the electric distribution system. We generally track Distribution O&M expenditures in seven categories: (1) Labor, (2) Materials and Commodities, (3) Outside Services, (4) Transportation, (5) Other, (6) Operational Credits, and (7) Employee Expenses.

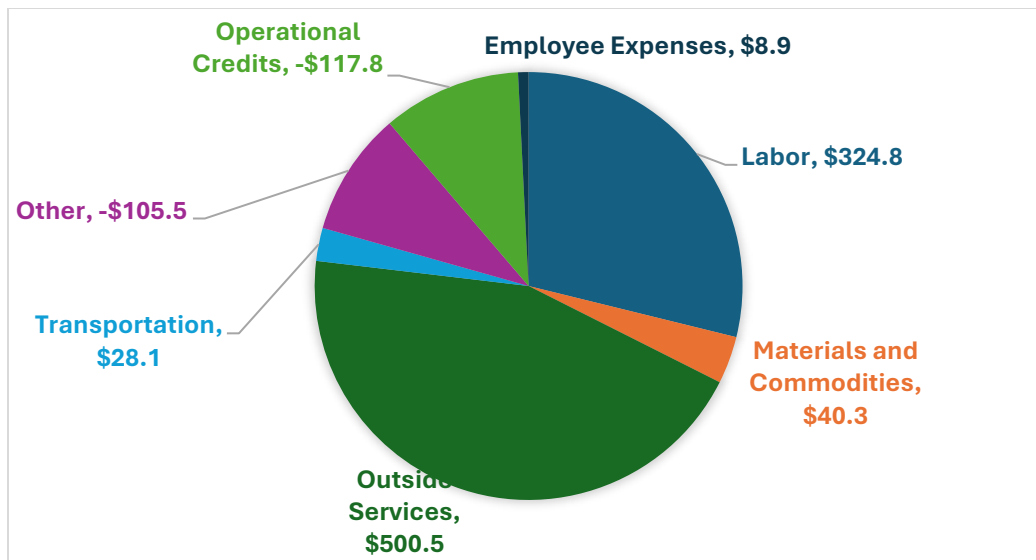
Figures 6-5 and 6-6 below provide a summary of historical actual and budgeted O&M costs in the most descriptive way that we were able to portray them given the reasons we have discussed.

Figure 6-5
Actual Historical Distribution O&M Costs by Cost Element – NSPM Electric 2020-2024 (Millions)



See the Transportation Electrification Plan for O&M expenditures associated with electric vehicle program. The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are \$33.0M and \$11.54M, respectively; Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Figure 6-6
Budgeted Distribution O&M Costs by Cost Element – NSPM Electric 2026-2030 (Millions)



See the Transportation Electrification Plan for O&M budgets specific to electric vehicle programs; there is no EV program-specific O&M budget within Distribution. See Chapter 5 for a project-specific view of grid modernization O&M. The average Contract Outside Vendor annual expense related to Vegetation Management and Damage Prevention are \$41.7M and \$19.6M, respectively; Misc. Other: Includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Table 6-8 below provides a snapshot of our NSPM Operating Company O&M Distribution budget.

Table 6-8
Distribution O&M Expenditures Budget –
NSPM Electric 2025 – 2030 (Millions)

Expenditure Category	Bridge	Budget					Budget Avg
	2025	2026	2027	2028	2029	2030	2026-2030
Labor	\$57.0	\$60.9	\$59.3	\$62.9	\$66.1	\$69.5	\$63.7
Cont. Outside Vendor/Contract Labor	\$29.4	\$35.7	\$35.6	\$35.1	\$38.7	\$42.4	\$37.5
Vegetation Management	\$27.0	\$33.1	\$40.4	\$41.8	\$45.9	\$47.4	\$41.7
Damage Prevention Locates	\$15.7	\$18.8	\$19.2	\$19.6	\$20.0	\$20.4	\$19.6
Grid Modernization Projects	\$0.4	\$0.2	\$1.4	\$1.4	\$2.2	\$2.8	\$1.6
Other (Materials, Transp, First Set Credits)	(\$4.8)	(\$15.7)	(\$25.6)	(\$29.6)	(\$33.0)	(\$37.6)	(\$28.3)
TOTAL	\$124.7	\$133.0	\$130.3	\$131.2	\$139.9	\$144.9	\$135.8

See Transportation Electrification Plan for O&M budgets specific to electric vehicle programs; there is no EV program-specific O&M budget within Distribution. See Chapter 5 for a project-specific view of grid modernization O&M. Other includes Materials, Transportation, Employee Expenses, bad debt, First Set Credits, use costs, office supplies, janitorial, dues, donations, permits, etc.

As compared to our 2025 forecast, our next five-year forecasted O&M budget increases by approximately \$4 million annually from 2026 through 2030. Two primary areas drive the increase. First, we expect an average annual increase of \$4 million in Vegetation Management due to the new contract rates which take effect beginning in 2026 and 2029 with primary providers. Second, we expect an average annual increase of \$2.6 million in Contract Labor in conjunction with increased capital spend and wildfire prevention. These increases are offset by an average increase in First Set Credits (Other) of \$6.6 million in conjunction with increased capital spend (increase in credit results in a decrease).

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

II. COST BENEFIT ANALYSIS

This section means to address the Commission’s September 24, 2024 Order, Order Points No. 11 and 12.

Order Point No. 11 states that:

In its next IDP, Xcel shall include a discussion of the results of stakeholder conversations about ways to conduct program-level cost-benefit analyses for relevant discretionary distribution expenditures.

Order Point No. 12 states that:

As part of the stakeholder effort on cost-benefit analyses, Xcel shall explain how it would define “discretionary” spending in this context and to explain its cost-benefit methodology, including specifically its identification of benefits.

This section provides an overview of the cost-benefit analysis conducted for two discretionary program-level investments. It outlines the financial and operational impacts of each project type, evaluates their alignment with strategic objectives, and assesses their potential to enhance system reliability, customer value, and long-term grid performance. At the CBA Workshops, the Company provided its definition of discretionary in this context as “optional investments by which not executing and spending the funds does not imminently endanger employees or the public from a safety or reliability incident on the system.”

The Cost Benefit Analysis for the Distribution System Programmatic spend is an evaluation that compares the total spend of the programs within the last 5 years (2020-2024) with the anticipated benefits of proactively investing in the distribution system. The two discretionary programs that were evaluated are the End of Life Replacement (ELR) –Breakers (Attachment M **TRADE SECRET IN ENTIRETY**) and the Grid Reinforcement (Attachment N **TRADE SECRET IN ENTIRETY**) programs.

The five-year historical costs associated with the ELR – Breakers and Grid Reinforcement were collected and modeled through a revenue requirement model using the Minnesota weighted average cost of capital over an estimated 50-year life. We then determined the Net Present Value of the annual revenue requirement as the cost comparison in the Cost Benefit Analysis.

For the ELR – Breakers Program, the benefits were focused on overload outages, emergent work vs. proactive work, and equipment outages. This program aims to replace aging equipment that can cause overload-related outages and equipment-related outages that require emergent remediation.

- Overload Outages (Customer Minutes Out) - The analysis looked at the age of the components and estimated the amount of customer minutes out (CMO)

resulting from an overload-related outage if the Company had forgone the capital investment. We identified the locations of the capital spend within the program. We then pulled in five-year historical outage data by location within our Minnesota distribution system. From there, we estimated the amount of overload CMOs and the customer impact cost for the next five years if the Company had forgone investment based upon the age of the components and the historical outage rates for overloads within Minnesota. The customer impact cost was established using the Interruption Cost Estimator (ICE) Calculator 2.0. The total customer impact cost of the overload CMOs were then compared to the capital investment.

- Proactive vs. Emergent Capital Work – The analysis looked at the five-year historical spend of the program and isolated the labor components of the programmatic spend. We then applied a 1.5x escalator to the labor expenses as an estimate for potentially emergent work if NSPM had forgone proactive capital investment. This cost escalator value was determined as a high-level estimate for the cost increase in emergent work due to labor rate changes for emergent work. This is due to the requirement for immediate remediation for customer outages that require potentially higher rates of labor and costs.
- Equipment Outages (Customer Minutes Out) - The analysis took two methods into consideration to estimate equipment-related outages at the associated locations of the programmatic capital investment. First, we looked at the age of the components and estimated the amount of equipment-related CMOs if the Company had forgone the capital investment. We identified the locations of the capital spend within the program. We then pulled in five-year historical equipment outage data by location within our Minnesota distribution system. From there, we estimated the amount of equipment-related CMOs and the customer impact cost for the next five years if the Company had forgone investment based upon the age of the components and the historical outage rates for substation equipment outages within Minnesota. The total customer impact cost of the estimated substation CMOs were then compared to the capital investment. This initial methodology was then compared to the second method used to determine estimated equipment outages. We pulled five-year historical equipment outage data to determine the percentage of substation-related outages as part of the total outages for each location within the Company's Minnesota distribution system. Quartiles were created based upon the level of substation outages as part of total outages with an associated outage growth rate for each percentile. The locations where ELR – Breaker work was

done were then categorized by percentile to determine the estimated substation outage rate for the next five years if the capital investment had been forgone. These estimated CMOs were then averaged, and we applied a customer impact cost for the state of Minnesota to determine the dollar value of the estimated outages saved.

For the Grid Reinforcement Program, the benefits were focused on overload-related outages and emergent work vs. proactive work. This program looks to replace equipment that has high overload rates that can cause overload-related outages that require emergent remediation.

- Overload Outages (Customer Minutes Out) - The analysis looked at the age of the components and estimated the amount of overload-related CMOs if the Company had forgone the capital investment. We identified the locations of the capital spend within the program. We then pulled in five-year historical outage data by location within our Minnesota distribution system. From there, we estimated the amount of overload-related CMOs and the customer impact cost for the next five years if the Company had forgone investment based upon the age of the components and the historical outage rates for overloads within Minnesota. The total customer impact cost of the overload CMOs were then compared to the capital investment.
- Proactive vs. Emergent Capital Work – The analysis looked at the five-year historical spend of the program and isolated the labor components of the programmatic spend. We then applied a 1.5x cost escalator to the labor expenses as an estimate for potentially emergent work if NSPM had forgone proactive capital investment. This cost escalator value was determined as a high-level estimate for the cost increase in emergent work due to labor rate changes for emergent work. This is due to the requirement for immediate remediation for customer outages that require potentially higher rates of labor and costs.

III. NEAR TERM ACTION PLAN

This section outlines our five-year action plan for distribution system investments, as part of a longer-term strategy, as required by filing Requirement No. 3.D.2:

Xcel shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER and electrification futures analysis, hosting

capacity analysis, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:

- a. Overview of investment plan: scope, timing, and cost recovery mechanism*
- b. Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.*
- c. Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.*
- d. System interoperability and communications strategy*
- e. Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, etc.)*
- f. Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)*
- g. Customer anticipated benefit and cost*
- h. Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)*
- i. Plans to manage rate or bill impacts, if any*
- j. Impacts to net present value of system costs (in NPV \$/MWh or \$/kW)*
- k. For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel shall provide all information used to support its analysis.*
- l. Status of any existing pilots or potential for new opportunities for grid modernization pilots.*
- m. The results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology.*
- n. Information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for feeders and substation transformers that have a risk score or planned investment in the budget in future IDPs.*
- o. Long-range distribution studies conducted since the last IDP.*

The plan reflects internal business priorities and incorporates insights from our DER and electrification futures analysis, hosting capacity analysis, and non-wires alternatives analysis. Rather than summarizing each sub-requirement listed in 3.D.2 here, we provide a detailed response in the Compliance Matrix (*Attachment B*). Below, we highlight key themes and near-term priorities.

Over the next five years, our focus is on delivering excellent service while laying the groundwork to lead the clean energy transition. Foundational investments include Advanced Metering Infrastructure (AMI), Field Area Network (FAN), Advanced Distribution Management System (ADMS), and Fault Location Isolation and Service Restoration (FLISR)—all discussed in this and prior IDPs.

We also outline how we are preparing the system to meet future demands, support increased electrification, and integrate distributed energy resources (DERs). These efforts are essential to maintaining affordability and resilience while enabling a cleaner, more flexible energy system. Near-term actions include improving DER integration and planning for the long-term impacts and benefits of higher DER penetration, as detailed in *Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity*.

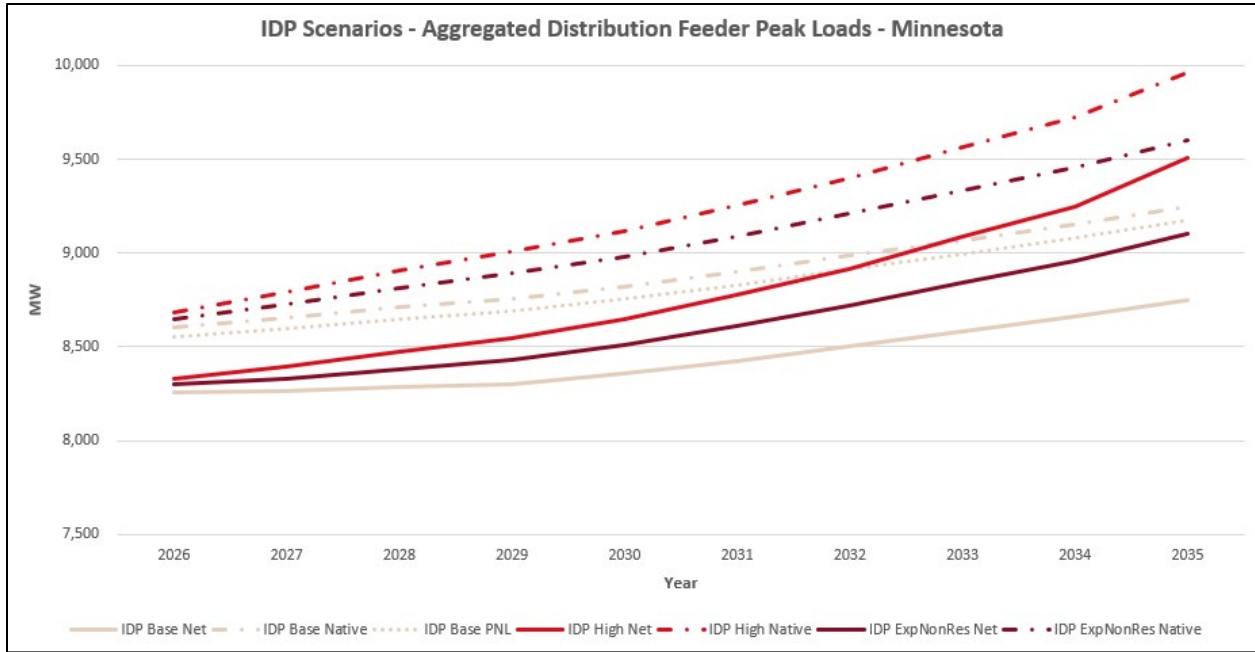
The next sections summarize near-term actions by topic and addresses any remaining elements of filing Requirement No. 3.D.2 not covered elsewhere in the IDP.

A. Load Growth Assumptions

As required by IDP Requirement No. 3.D.2, the five-year action plan must include a detailed discussion of underlying assumptions, including load growth, and the associated costs of planned distribution system investments.

Figure 6-7 below presents the load growth assumptions from our 2025 system planning analysis, as described in *Chapter 1: System Planning*.

Figure 6-7
Distribution System Planning Load Growth Assumptions
NSPM Electric Jurisdiction (2025 Planning Analysis)



Additional load growth assumptions for specific regions within NSPM’s Minnesota service area are provided in *Attachment M*. For details on capital projects included in the current five-year budget cycle, organized by our internal capital budget categories, please refer to *Attachment H*.

B. Grid Modernization Plan

See *Chapter 5: Grid Modernization* and related appendices and attachments as referenced for discussion regarding our grid modernization and related customer, data, and cost recovery plans.

1. Current Initiatives Underway

Table 6-9 summarizes the implementation timeline for our current grid modernization initiatives. We also outline the cost recovery mechanisms supporting these investments.

Table 6-9
Grid Modernization Implementation Timeline

Program	Implementation Timeline
ADMS	Implementation is now complete. Our ADMS was deployed in the first two Minnesota control centers in April 2021 and deployed in the final Minnesota distribution control center in September 2021.
AMI	Meter deployment began in 2022, with substantial completion in 2025 and a relatively small number of installations to be completed in 2026.
FAN	The initial network and security design was completed in 2020. The first FAN device was installed and programmed in May 2021 and the installation and programming of additional FAN devices will continue through 2025, with Network Optimization in 2026. FAN deployment is nearly complete, and we are making progress upgrading the backhaul technology to private LTE.
FLISR	Installation of automated field devices (reclosers and switches) and substation upgrades began in 2021 on select feeders and will continue to be expanded to other feeders through 2027. The FLISR functionality within ADMS is enabled on select feeders and will be continued to be expanded to other feeders through 2027.

Note: The Time of Use (TOU) rate pilot and LoadSEER are not reflected in the table above because the projects are complete. See Chapter 5 for further details on those two projects.

Cost Recovery Mechanisms. We are currently recovering costs for these investments through:

- **Transmission Cost Recovery (TCR) Rider:**
ADMS costs were first included in the TCR in 2018 (Docket No. E002/M-17-797). In 2021, revenue requirements for AMI, FAN, LoadSEER, and the TOU Rate Pilot were added (Docket No. E002/M-21-814). Our 2026 TCR Petition, filed on October 9, 2025, includes updated revenue requirements and adjustment factors for these initiatives.
- **Base Rates:**
The Commission approved recovery of 2022–2024 FLISR program costs in our most recent rate case (Docket No. E002/GR-21-630).

Managing Rate and Bill Impacts. Minimizing customer bill impacts is a strategic priority. Our building-block approach to grid modernization helps manage costs over time. These investments also enable new tools and programs that empower customers to better manage their energy use and potentially reduce bills. Additionally, operational efficiencies gained through modernization are expected to lower the cost of service

compared to a business-as-usual scenario.

The 2026 TCR Petition includes actual and forecasted revenue requirements and adjustment factors through 2026. The proposed adjustments reflect a net reduction in ADMS, AMI and FAN expenditures of approximately \$29.8 million compared to our last TCR Rider filing in Docket No. E002/M-24-371.

2. *Near-Term Grid Modernization Initiatives*

We are seeking certification of a mobile battery in this IDP. Please see *Attachment F* for further details on our request.

While we have not yet incorporated additional grid modernization investments into a formal timeline or budget, *Chapter 5* outlines grid investment technologies.

C. Impacts to Net Present Value of System Costs

IDP Requirement No. 3.D.2.j requires the Company to provide:

...Impacts to net present value of system costs (in NPV \$/RR/MWh or MW)

See *Attachment G: Distribution Function NPV 2025*.

D. Demand Side Management

The five-year action plan for Demand Side Management (DSM), which includes energy efficiency, demand response, and efficient fuel switching, will be shaped primarily by the Minnesota Energy Conservation and Optimization (ECO) Triennial filings and approved Integrated Resource Plans (IRP).

We submitted our 2024–2026 ECO Triennial Plan to the Department of Commerce on June 29, 2023.³ This plan builds on our strong track record in energy efficiency and demand response, while also launching a new era of utility-led programs under the ECO Act of 2021. The plan introduced expanded offerings that reflect evolving customer needs and policy goals. Our next ECO Triennial Plan for 2027-2029 will be filed by June 1, 2026.

³ Docket No. E,G002/CIP-23-92.

The initiatives in the Triennial Plan are expected to continue to deliver performance and reinforce our commitment to delivering excellent service, supporting customer affordability, and advancing Minnesota’s clean energy transition.

1. *Energy Efficiency*

In our 2024–2026 ECO Triennial Plan, the Company proposed exceeding the energy savings targets established in Minn. Stat. §216B.241. Specifically, we aimed to achieve over 1.75 percent annual savings as a percentage of retail sales. These targets align with our DSM commitments in our approved IRP.

Notably, we have several innovative programs and changes within our ECO portfolio. Our residential portfolio leverages educational opportunities to help customers lower their energy bills as reflected in our Home Energy Insights program. In addition, we have increased electric and natural gas incentives for envelope measures as these items have a significant impact on the energy efficiency of homes. For businesses we continue to provide holistic opportunities for lowering energy use and meeting sustainability needs.

In addition, the portfolio has a significant increase in energy efficiency opportunities for our income-qualified customers, increasing our budgets dedicated to this segment to over \$15M and focusing further efforts on workforce development.

2. *Efficient Fuel Switching*

The 2024–2026 ECO Triennial Plan is the first to include Efficient Fuel Switching (EFS) under the ECO Act, enabling the Company to offer incentives to customers who switch from one fuel type to another for the same end use. The primary focus of EFS is encouraging customers to transition from natural gas to electricity.

As Minnesota’s only investor-owned combination electric and natural gas utility, the Company is uniquely positioned to support EFS. We view these measures as a key strategy for achieving our emission-reduction goals across both electric and natural gas operations. However, many EFS technologies are still emerging, and their long-term impacts on both systems remain uncertain.

In the 2024 inaugural year of EFS within the DSM portfolio, and the program delivered a strong performance. The Company achieved 227 percent of its participation target with spending on EFS reaching 178 percent above plan,

generating a portfolio that exceeded expectations. The Company expects these trends to continue into 2025 and beyond.

3. *Demand Response*

The ECO Act has further expanded opportunities to incorporate Demand Response (DR) strategies focused on load shifting, enhancing our ability to manage peak demand and support grid flexibility.

Our 2024–2026 ECO Triennial Plan included behavioral DR and direct load control for residential customers. In addition, we created space in our business programs to work with customers to review load shifting as part of our holistic programming.⁴

E. Electric Vehicle Programs and Grid Integration

The Company is making significant investments in electric vehicle (EV) programs to support the growing adoption of electrified transportation and to manage the impact of EV charging on the distribution system. As EV adoption accelerates in Minnesota, the demand from EV charging will continue to rise. To address this, we offer a range of residential and commercial charging options designed to shift usage to off-peak hours—when system demand is lower and renewable generation is typically higher.

Residential programs include EV Accelerate at Home and Optimize Your Charge, all of which incentivize overnight charging. For commercial customers, offerings include Optimize Your Charge, a Fleet EV Service Pilot, Multi-Dwelling Unit (MDU) pilot, and a Public Charging Infrastructure Pilot.

In addition, the Company has proposed two new programs in our Transportation Electrification Plan (TEP). The first is a new actively-managed charging program, called Charging Perks, which will provide incentives to participating customers to allow the Company to directly manage customer charging schedules to shift consumption away from system peaks. We are proposing to replace Optimize Your Charge with Charging Perks.

The second program proposal included in our 2025 TEP is the Commercial Infrastructure and Equipment Rebate program. This rebate program is intended to be

⁴ Decision, In the Matter of Xcel Energy's 2024-2026 ECO Plan: Program Modification Request for Inclusion of Peak Day Partners and Battery Connect Programs, July 31, 2024.

a replacement for our Fleet, Public Charging, and MDU pilots. Under this program, the Company will offer advisory and financial support to overcome barriers to EV installation and make solutions to customer charging needs attainable. Financial support will be provided for customers to purchase and install electric vehicle supply infrastructure and equipment for EV charging needs.

IV. LONG-TERM ACTION PLAN AND CUSTOMER IMPACTS

In this section, we address the long-term planning requirements of the IDP, focusing on the trajectory of our near-term investments and providing a long-term load forecast.

IDP Requirement No. 3.D.3 requires the following:

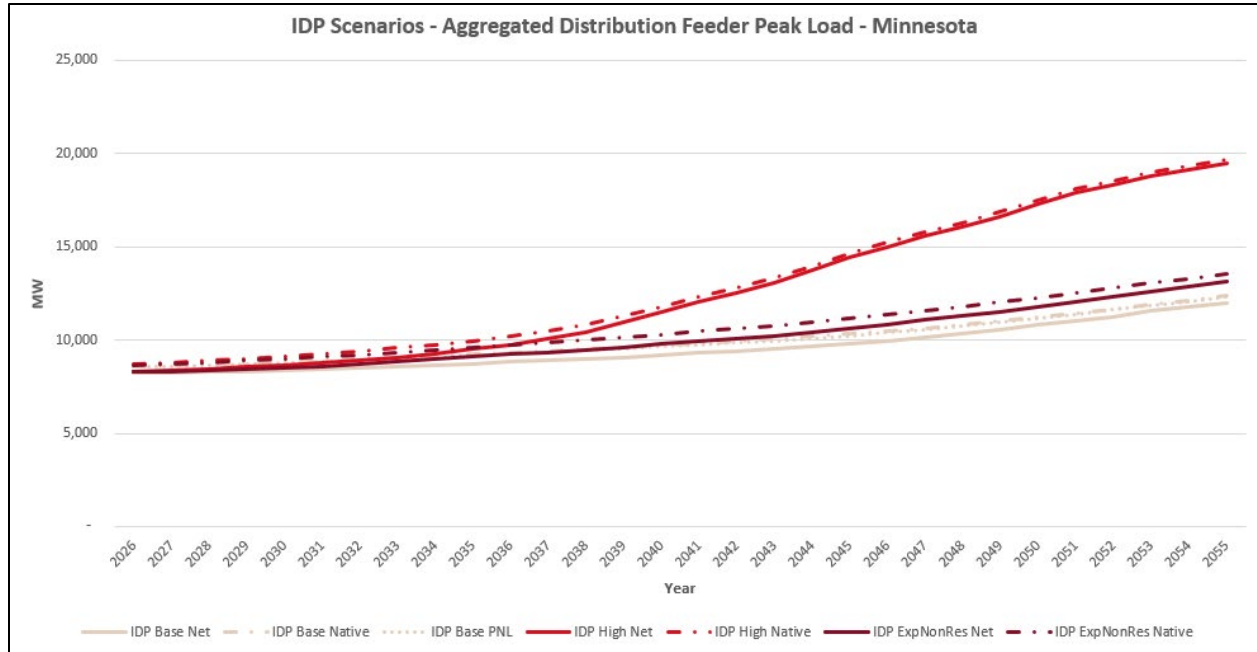
In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term plan discussion should address the long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER and electrification into future planning processes based on the DER and electrification futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.

Our long-term plan builds on the foundation established by our five-year investments, with a focus on adapting the distribution system to support continued load growth, increased electrification, and greater integration of DERs. We also identify areas where planning tools and processes must evolve to meet future system needs and policy goals.

A. Long-Term Load Growth Assumptions

To support long-term planning, we provide a 30-year forecast of aggregated feeder peak load in Figure 6-8 below. This forecast reflects the need for the expansion of distribution system capacity over the next three decades to accommodate growing demand and increased distributed generation and electrification. Additional detail on this forecast is available in *Chapter 1: System Planning*.

Figure 6-8
30-Year Distribution Peak Demand Forecast
 (Total Non-Coincident Peak Demand – Aggregated Feeder Peak Load)



These forecast scenarios incorporate projections for Beneficial Electrification (BE) technology adoption based on NSP's 2024-2026 ECO Plan. Post-2026 electrification represents a continuation of incentives and deployment under that program. This program targeted adoption of Residential and Business Air Source Heat Pumps (ASHP), Cold Climate ASHP, Ground Source Heat Pumps, Water Heating, and Other measures. Under the current base case outlook, the Company's MN territory adds approximately 100,000 kWh of BE load by 2030, 300,000 kWh by 2035, 1,120,000 kWh by 2045, and 2,460,000 kWh by 2055.

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

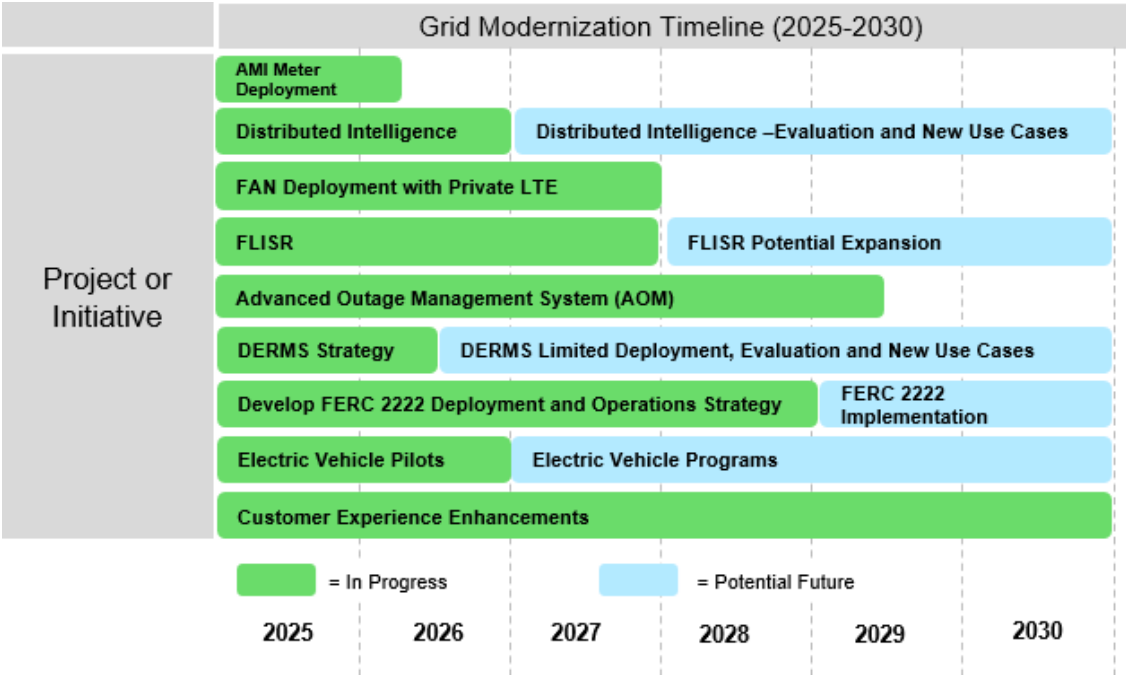
Maintaining a healthy distribution system is essential to delivering reliable electric service today and preparing for the demands of tomorrow. Our long-term strategy includes not only maintaining core infrastructure—such as poles and wires—but also investing in capabilities that support electrification, enable the clean energy transition, enhance resilience, and modernize customer interactions with the grid.

As shown in Figure -6-8, anticipated load growth reflects a fundamental shift from historical planning norms. Previously, load growth was gradual and localized, often

tied to large construction projects with long lead times. Today, we face rapid, system-wide growth driven by electrification and increased adoption of distributed energy resources (DERs). This shift requires proactive planning and expanded resources—both digital and human—to ensure we can continue delivering excellent service while adapting to evolving system needs.

To support this transition, we provide a five-year view of planned and potential grid modernization investments in Figure 6-9. These investments build on earlier modernization efforts and are designed to deliver increasing value to customers over time.

Figure 6-9
Illustrative Long-Term Grid Modernization Plan



Our overall grid modernization strategy that includes our Grid Modernization initiative (also known as Advanced Grid Intelligence and Security, or AGIS), which is a distinct, long-term strategic plan to transform our electric distribution system to update foundational system technologies and capabilities. We are modernizing our grid planning and operations each day as we strive for continuous improvement and to deliver excellent service; the Grid Modernization initiative includes important building blocks that enable us to plan, build, and operate a modernized, hardened, and expanded electric delivery system. In addition, we have continued to develop plans for new technologies on our grid modernization roadmap. We now have plans in

place to implement the AOM project, a limited deployment of Grid DERMS, and continue building on DI capabilities.

We are also actively assessing the timing, people, process, and technology requirements for supporting these new requirements to ensure our approach remains aligned with best practices and overall value to the company.

Beyond grid modernization, system resilience will be critical to maintaining reliability. We regularly assess the health of key infrastructure—such as poles and underground cables—using asset health analyses to guide reinvestment. These efforts help us meet today’s reliability needs while laying the foundation for tomorrow’s grid. At the same time, we continue to strengthen physical and cybersecurity protections across the system.

Looking ahead, we expect technology advancements, policy priorities, and customer expectations to shape our strategy over the next decade. The continued adoption of DERs, aggregated markets, electric vehicles, and other beneficial electrification technologies will require changes in how we plan, operate, and staff our grid. Ensuring our teams have the right skills and tools will be essential to navigating this transformation.

With the strategies outlined in this IDP, we are taking a thoughtful, forward-looking approach to ensure our distribution system remains reliable, resilient, and ready to support Minnesota’s clean energy future.

CHAPTER 7: DISTRIBUTED ENERGY RESOURCES, SYSTEM INTERCONNECTION, AND HOSTING CAPACITY

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

I. PLANNING LANDSCAPE FOR DER

As DER adoption accelerates, we are committed to leading the clean energy transition while continuing to deliver safe, reliable, resilient, and affordable service to our customers. This requires ongoing evolution of our interconnection processes to keep pace with growing demand and system complexity.

Currently, DER interconnections are studied semi-sequentially, with early projects/clusters on a feeder often benefiting from greater hosting capacity. As more DERs connect, available capacity declines, and feeders eventually reach physical limits—thermal, voltage, or otherwise—potentially requiring significant infrastructure upgrades to support additional DER safely.

To address these challenges and enable higher DER penetration, the industry is exploring new technologies and processes, including more active management of interconnections. We are in the early stages of evaluating the tools, systems, and timing needed to support this shift. This includes planning and analysis tools, as well as future systems like Distributed Energy Resource Management System (DERMS), which are discussed throughout this chapter and the broader IDP. We are also closely monitoring industry developments to ensure our approach remains aligned with best practices.

As shown in *Chapter 1: System Planning*, we anticipate substantial DER growth through 2050. Meeting this demand requires a forward-looking vision that spans planning, operations, technology—and coordinates efforts across the distribution and transmission systems. As part of our commitment to delivering excellent service and leading the clean energy transition, we are preparing for the convergence of grid operating technologies to support increased DER and renewable generation,

enhanced security and resilience, and communications for operators and customers.

II. DER STRATEGY ROADMAP

This section outlines our conceptual roadmap for DER strategy, designed to support our role in leading the clean energy transition while continuing to deliver excellent service. The roadmap is organized into these key focus areas:

- Flexible Interconnections
- DERMS, Non-Wires Alternatives (NWA), and Market Participation
- Hosting Capacity
- Data and Automation
- Equity Considerations in Planning

Each category includes a conceptual timeline with key activities through 2030. We note that timelines are illustrative and subject to change. They are intended to show the general sequence, timing, and interdependencies of activities—not fixed start or end dates. Implementation will require additional dedicated resources, including planning and engineering staff.

A. Interconnection Overview

We strive to enhance the efficiency of Distributed Energy Resource (DER) interconnection processes and to identify more cost-effective and flexible alternatives to traditional methods, potentially allowing more DER to connect in certain areas. This approach supports our broader commitment to the clean energy transition while maintaining excellent service for our customers.

Over the past few years, the Company has deployed lean business techniques to improve the process. The Company has a better understanding of the processing time needed in each step of the process, which helps ensure we have the proper amount of resources to support the volumes we are experiencing at any given times. The Company has Daily Operating Review meetings where we discuss application volumes and address trends like increases or decreases in volume. The Company has several touchpoints with developers including several regularly scheduled office hours addressing various topics throughout year and quarterly stakeholder meetings where various program and interconnection developments and topics are discussed.

We also actively participate in the Distributed Generation Working Group (DGWG) that is addressing evaluation of new interconnection options such as limited-export

and non-export configurations. Discussions for these technical topics are ongoing and facilitated by Commission Staff.

B. Flexible Interconnection

We respond to Order Point Nos. 19 and 20 from the Commission’s September 16, 2024 Order in this section.

Order Point 19 requires the following:

Xcel shall demonstrate the Company’s ability to integrate DERs with the tools available to it today and in the near term, including specifically through:

- a) Implementing static Flexible Interconnection prior to implementing full, dynamic Flexible Interconnection; and*
- b) Pursuing a staged approach to Flexible Interconnection, DERMS, and Dynamic Hosting Capacity implementation.*

Order Point 20 requires the following:

Xcel shall be transparent about the conditions under which the Company will use Flexible Interconnection, particularly with impacted DER owner/operators.

Below, Sections 1-3 respond to Order Point 19 and Section 4 responds to Order Point 20.

1. Static Flexible Interconnection Feasibility and Limitations

While static Flexible Interconnection (FI) is technically feasible today, it presents significant limitations that make it a less desirable approach compared to dynamic FI. To implement static FI, detailed system studies specific to the interconnection must be conducted to define flexible operating limits, estimate potential curtailment, and develop a fixed annual operating schedule. This schedule must be conservatively designed, since it needs to allow margins for all types of conditions and cannot benefit from more dynamic forecasting. As a result, this strategy may lead to increased curtailment for the DER owner and reduced utilization of the utility system. Developers would need to accept reduced revenue due to curtailment, which could be more frequent and severe under static FI than dynamic FI.

Further, at the time of our 2023 IDP, we lacked a clear timeline for DERMS implementation. With limited initial deployment now expected in 2026, pursuing static

FI options would be sub-optimal. Given these limitations and the progress made since the 2023 IDP, the Company recommends prioritizing dynamic FI, as outlined below.

2. *Recommendation to Prioritize Dynamic Flexible Interconnection*

The Company strongly recommends prioritizing dynamic FI, enabled by a DERMS, as it aligns more closely with real-time operating conditions. This approach allows for more efficient use of system assets while maximizing revenue opportunities for DER owners. When available, a DERMS can automatically generate dynamic schedules based on near-term grid conditions, offering more precise curtailment and additional value to DER developers.

Importantly, dynamic FI has similar processes to static FI. Both approaches require the same foundational components:

1. Interconnection studies tailored to flexible interconnection requirements, and
2. Communication equipment installed at the DER site to enable data exchange with the Company's central distribution operations.

We are targeting to deploy FI for DER sites 1 MW and larger. We are developing all the technical specifications, processes and other new practices needed for DERMS and a limited rollout is planned for 2026. This timeline supports near-term implementation of dynamic FI and avoids the inefficiencies associated with static scheduling.

3. *Pursuing a Staged Approach to FI, DERMS, and Dynamic Hosting Capacity Implementation*

The foundation for dynamic Flexible Interconnection is a DERMS, which the Company is actively developing. DERMS will enable curtailment more closely aligned with real-time conditions.

Stage 1: Limited DERMS Deployment

We are on track to begin limited DERMS deployment in Q3 2026, focusing the first tranche on between five and ten feeders, selected by the Company based on their potential for use case implementation, including FI. At this stage, the Company recommends implementing dynamic schedules for FI through Grid DERMS. This investment reflects our leadership in the clean energy transition and our commitment

to providing customers with reliable, forward-looking solutions.

Stage 2: Next Phase of Dynamic Flexible Interconnection & Hosting Capacity Integration (Post-DERMS Deployment)

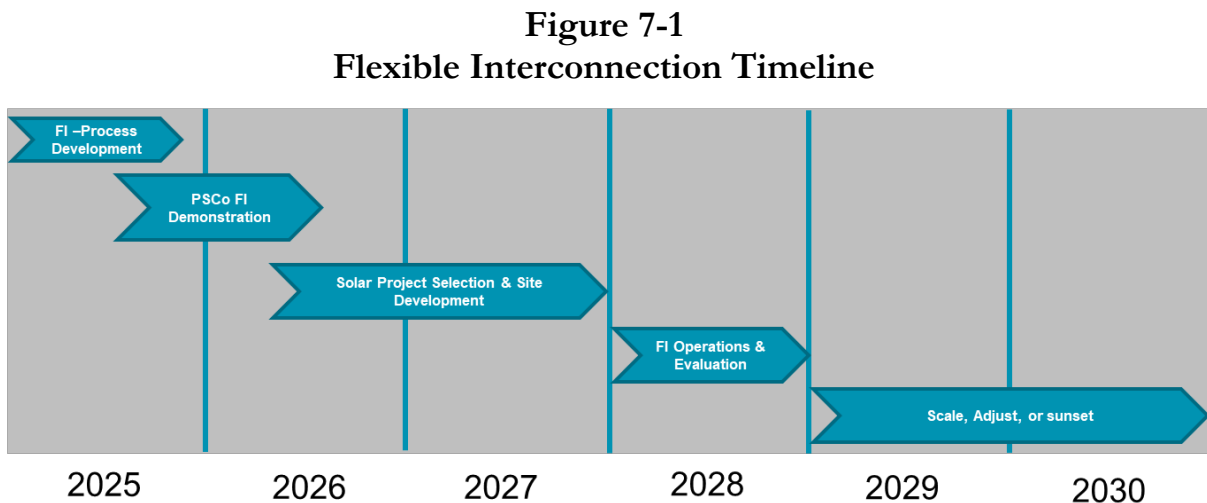
Once DERMS is operational, the next phase of deployment will focus on the operation and validation of FI. Once FI has been successfully implemented and its performance verified, the Company may consider expanding beyond the initially targeted areas as new opportunities emerge.

In parallel, we are enhancing our Hosting Capacity tools. We have improved service by shifting from quarterly toward monthly updates of our hosting capacity map, providing developers with more timely insights.

To fully support developer decision-making and uphold our service standards, we realize that developers need more information on curtailment impacts to estimate long-term financial implications. We are currently evaluating what analysis we can perform to provide further information with the goal of enabling informed investment decisions when the possibility of curtailment exists as a part of FI.

4. *Flexible Interconnection Timeline*

Figure 7-1 below shows our timeline for flexible interconnection:



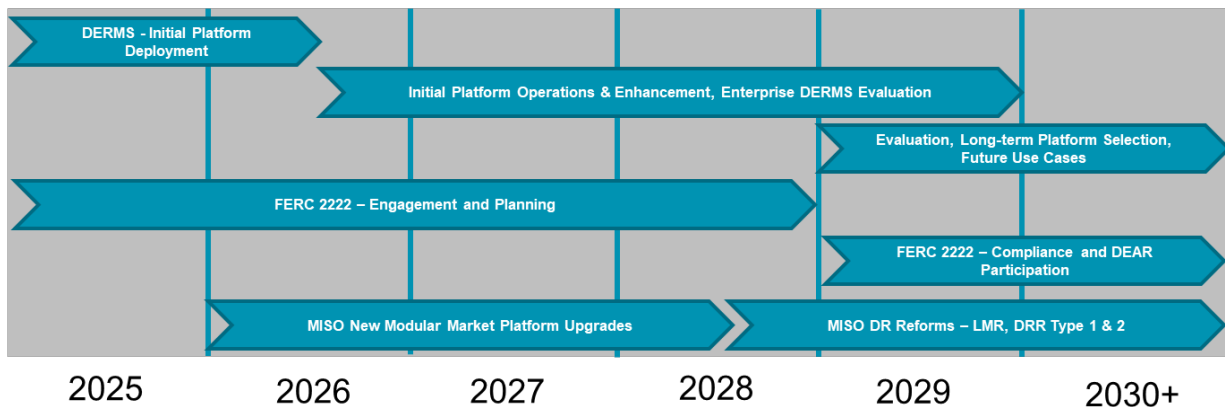
5. *Conditions Under Which Flexible Interconnection Will Be Used*

Order Point No. 20 requires the Company to be transparent about the conditions under which it will implement FI, particularly with affected DER owners and operators.

The Company is committed to maintaining transparency regarding the conditions under which FI will be utilized, particularly with DER owners and operators who may be impacted. As part of this effort, we would utilize an analysis of flexible interconnection during the interconnection review process. This would help customers or developers understand conditions will drive curtailment. This information is intended to support customers in making informed financial decisions about their interconnection options. FI is intended to be one option available for DER owners and operators to avoid the need for distribution upgrades caused by DER interconnections.

C. DERMS, NWA, and Market Participation

**Figure 7 - 2
DERMS, NWA, and Market Participation Roadmap**



A core function of DERMS is enhanced visibility and active management of DERs connected to the distribution system. The Company is excited to roll out its limited deployment of DERMS in 2026. Acquiring and implementing DERMS is a journey and given the level of complexity, it takes time to gain technical and operational experience, refine processes, and work through adjustments and enhancements. As the company gains experience with its initial use cases, we expect to refine FI strategies and inform the more sophisticated strategies and requirements needed for

NWA and DER market participation. While DERMS is not required to enable individual NWA projects or pilots, it will be critical for scaling and coordinating flexible load and generation strategies across the grid. This capability will help us manage DER more efficiently supporting grid reliability. We provide more information on our plan to issue a Request for Proposals for two NWA projects in *Chapter 8: Non-Wires Alternatives*.

DERMS will also play a key role in supporting Federal Energy Regulatory Commission (FERC) Order 2222, which enables DERs to participate in wholesale markets. Requirements for FERC 2222 compliance are still evolving, and we will assess these as part of our DERMS requirements (including new process, existing process modifications, and resource requirements) and technology evaluation. Additional discussion of FERC Order 2222 and DERMS is provided in Section VII, and *Chapter 11: DERMS*, respectively

D. Hosting Capacity

Hosting Capacity Analysis (HCA) is a foundational element of the interconnection process by providing quick indicative metrics at the beginning of the detailed interconnection process. As DER adoption accelerates, HCA can play a role in enabling informed decision-making and reducing uncertainty for DER developers and our customers.

Since the last IDP, we've made meaningful progress in advancing HCA through the implementation of monthly HCA updates. To deliver monthly updates, we completed foundational process improvements and automation that have made HCA more scalable, consistent, and timely. To further enhance transparency and usability, we plan to incorporate transmission study indicators to offer more transparency into the challenges potential interconnection applicants might encounter.

Recognizing the volume and complexity of HCA data, we are also developing an automated quality assessment (QA) framework to ensure data integrity and reliability. Manual QA methods are increasingly impractical at scale, so automation will be key to validating results efficiently. A draft data validation plan is planned to be filed in early 2026 and we are planning stakeholder engagement to help shape its final form. These efforts are designed to improve developer confidence and reduce uncertainty in siting decisions.

With monthly HCA updates nearing full implementation – supported by ongoing monthly analysis and near-complete map update automation– the next phase of development will focus on incorporating transmission study indicators and establishing a robust QA framework. Following those efforts, we plan to conduct a comprehensive assessment of our systems, processes, and personnel to evaluate readiness for future HCA enhancements such as incorporating smart inverter functionality and Time-Series Hosting Capacity (TSHC) in the HCA to reflect current technologies and support flexible interconnection. Following this assessment, further development will be guided by stakeholder input that will help to determine desired improvements and future development.

E. Data and Automation

Data and Automation will be key to delivering next-generation DER interconnection programs, DERMS, and advanced planning capabilities.

Our overall approach to Data and Automation involves several priorities:

- **Comprehensive Data Expansion, Validation, and Integration** – As data availability grows, validation and integration will be key to supporting granular, data-backed analysis.
- **Process Automation** – Concentrating on automation that will increase our ability to deliver on growing customer and stakeholder priorities without increasing costs for customers.
- **Granular, Data-Backed Analysis** – enhance our ability to perform detailed, data-based analysis for better understanding the system, its risks and more aptly scoping and designing solutions to meet future needs.
- **Stakeholder Alignment** – Ensuring that data tools and outputs are transparent, actionable, and aligned with stakeholder expectations and regulatory requirements.

By considering and executing on these priorities, we believe we will build the foundation for a data and automation driven DER strategy that supports advanced interconnections, enhances system reliability, and enables greater DER integration and maximizes the benefits of DER across our distribution system. Building on past and ongoing efforts, we hope to expand data availability and uptake, implement strategies to process, store, and make data accessible, and develop tools to clean, structure, and analyze that data more effectively. At the same time, we seek to increase transparency for stakeholders and use automation to scale these advancements efficiently –

delivering greater value through smarter, more responsive DER planning and integration.

Comprehensive Data Expansion, Validation, and Integration

We continue to expand the breadth and depth of system data by continuing to deploy Advanced Metering Infrastructure (AMI) and Distributed Intelligence (DI), improving sources of network information such as Geospatial Information System (GIS), and increasing Supervisory Control and Data Acquisition (SCADA) capabilities through our Feeder Load Monitoring efforts. To ensure this data is reliable and usable, we are investigating and developing validation tools that utilize cutting edge methods to flag data and fill in gaps. For example, Electric Distribution Data Inspection and Estimation (EDDIE) flags erroneous data by looking for bad data readings, loss of signal, and other issues, and allows an experienced engineer to train a machine learning model by selecting reasonable historical data for that feeder. This training set is then combined with local weather information (where reasonable) to predict feeder performance and fill in gaps where data acquisition fails. Another tool, Gridsight, leverages large AMI datasets to aggregate customer loading data to estimate secondary loading and flag potential issues. We are also building out platforms like Databricks and Power BI to support more scalable data analysis and visualization. As these tools mature, we will increasingly utilize them in our planning and DER Integration workflows to support more consistent, structured, and actionable data, laying the groundwork for more advanced analytics and system insights.

Process Automation

To meet increasing customer and stakeholder expectations without driving up costs, we are investigating automation across key planning and interconnection workflows. This includes automating the generation of forecast models for planning, streamlining model creation and data gathering for interconnection screening and studying processes, and improving the cadence and efficiency of HCA updates. As we continue to refine our systems, we will explore additional opportunities to automate repetitive or resource-intensive tasks—freeing up staff capacity for higher-value analysis and enabling more consistent decision-making.

Granular, Data-Backed Analysis

We are enhancing our ability to perform detailed, data-backed analysis to better understand system behavior and risks under a range of conditions. Tools like CYME and its associated Gateway could enable us to conduct more advanced DER studies or scenario-based DER analysis at the feeder level, providing a more precise view of system constraints and opportunities. We are also exploring the use of Databricks for

delivering more streamlined integration of DER and planning tools and evaluating how AMI data can support more nuanced system operations screening and forecasting, especially for DER. These capabilities will allow us to more effectively scope and design solutions that are tailored to the unique characteristics of each part of the distribution system, while ensuring safe interconnection and maximizing benefits of DER. Additionally, more granular data-backed analysis will be essential when developing advanced flexible interconnections and developing DERMS.

Stakeholder Alignment

Through these many developments, it will be important to be mindful of the impacts and potential benefits such that any efforts are carefully and deliberately targeted to deliver our best for our customers and stakeholders. Whether that be through providing additional analysis or metrics to inform decision making or expanding the realm of possibilities for developing solutions to safely and affordably meet customer needs.

F. Equity Considerations in Planning

We provide annual updates to our Service Quality Interactive Map, which includes electric reliability and demographic data for the communities we serve. Recent updates include several added layers and information at the request of stakeholders and the Commission. In our Service Reliability and Service Quality filing (April 1, 2024), we included the results from an external study conducted by TRC. The study found that outage data generally does not indicate more frequent or longer outages in neighborhoods with higher percentages of people of color (POC), except in areas with both high POC populations and older housing stock. In our April 1, 2025 filing, we expanded this analysis and found that major events—such as the August 14, 2020 storm—were the primary drivers of CELI-12 outages in the studied census block groups (CBGs). In the three years following these events, the affected CBGs experienced CELI-12 rates significantly below the statewide average. This underscores a limitation of the three-year rolling average used in the TRC study, as small geographic areas can be disproportionately impacted by localized extreme events. Given the uncertainty around the return period of such storms and the short timeframe of available data, we did not identify persistent equity disparities.

To further evaluate potential disparities, the Company is initiating a third-party study as directed in Docket No. E-002/M-24-27 Commission Order Point No. 46¹. This independent evaluation will assess our practices and policies related to capital investment planning, outage restoration, and disconnections, with a focus on identifying any racial disparities. The study will include stakeholder engagement throughout its design and implementation, and if completed in time, we intend to summarize the findings and include the evaluator's report in our April 2026 Electric Service Quality filing.

These efforts support our commitment to equitable clean energy access while maintaining reliable service and keeping customer costs low.

III. PROCESSING AND TOOLS

A. Hosting Capacity

IDP Requirement No. 3.B.1 requires the following:

Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER and electrification (in particular PV and electric storage systems), how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources, and any other method in which Xcel anticipates customer benefit stemming from the annual HCA.

At the Company, delivering excellent service means providing customers and stakeholders with the tools and insights they need to make informed energy decisions. Hosting capacity is a key part of that commitment. Since 2016, in compliance with Minn. Stat. § 216B.2425 and Commission orders, we have submitted annual Hosting Capacity Program Reports—most recently on October 31, 2025. These reports offer node-level data to help guide DER siting and highlight areas with available capacity. HCA details are discussed in this report. The addition of the node level data provides more locational information for HCA users. A node is the general term used to describe a point where hosting capacity analysis is performed. This may be a span of conductor, a transformer, or other relevant equipment. A given feeder consists of many nodes, so the analysis is granular and specific. Necessary distribution upgrades

¹ In accordance with Order Point No. 46 in Order Accepting Reports and Setting Additional Requirements, Minnesota Public Utilities Commission, Docket No. E-002/M-24-27, issued January 13, 2025, In the Matter of Xcel Energy's 2023 Annual Safety, Reliability and Service Quality Report.

are identified during the interconnection study process, generally during the system impact studies and facility upgrade phases. Upgrades are specific to the DER projects being proposed.

To support a narrative discussion of how Hosting Capacity Analysis (HCA) advances customer-sited DER and electrification provided by HCA, we focus on the metrics provided and how they can be used to determine interconnection points that may present challenges or require upgrades. These tools/metrics include a heat map to indicate capacity between 0 and 10 MW, Voltage regulation constraints, thermal constraints, protective constraints, feeder topology, installed/queued DG (feeder and transformer), and data cutoff date. Below are descriptions of possible challenges that could (and often will) develop when interconnecting at a node beyond the limit of a given constraint:

Voltage Regulation Constraints: Standard mitigations are used when effective. These consist of using inverter functionality, phase balancing/swapping, adjusting or implementing control of capacitor banks, and/or reconductoring.

Thermal Constraints: Standard mitigations are used when effective. These consist of using inverter functionality, phase balancing/swapping, adjusting or implementing control of capacitor banks, and/or reconductoring.

Protective Constraints: Standard mitigations are used when effective. These consist of reprogramming existing relays and/or reclosers, replacing fuses with upgraded fuses or reclosers, relocating protective devices, and/or proposing the elimination of a level of protection between the Point of Interconnection (POI) and the substation.

Technical Planning Standard: Standard mitigations are used when effective. These consist of using inverter functionality, phase balancing/swapping, adjusting or implementing control of capacitor banks, and/or reconductoring. Given that the TPS establishes the highest penetration of DER allowed on the distribution system, mitigating this constraint often involves replacing or installing new equipment in the substation, which can be prohibitively expensive for many projects.

These standard mitigations are generally of low impact to the operation of the network and are for that reason first to be considered. When these mitigations fail to fully address the constraint, additional solutions need to be considered.

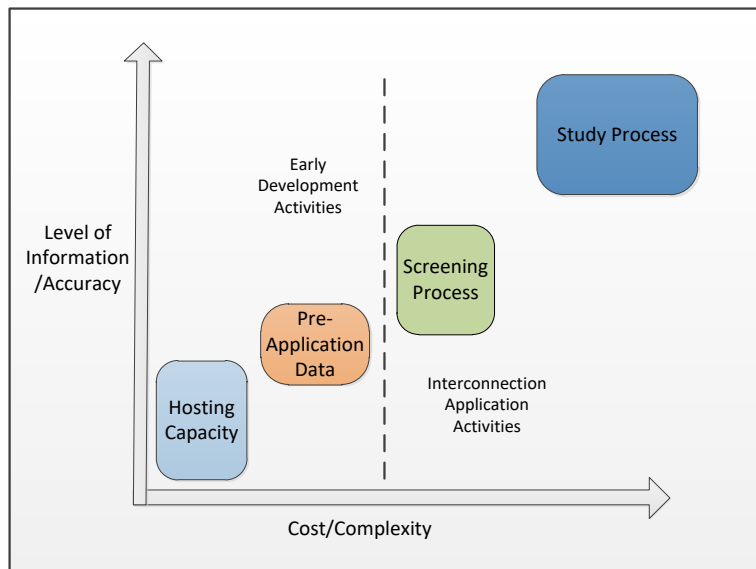
B. Interconnection Process

This section outlines our interconnection process and addresses IDP Requirement No. 3.B.2 regarding data sources and methodology used in the MN DIP initial review screens.

We publish a monthly Hosting Capacity Analysis (HCA) on our website as one tool to help developers identify suitable sites and assess potential constraints. We also provide a monthly Public DER Queue, as required by MN DIP, showing active projects by feeder. For community solar gardens (CSGs), it provides an indication of whether upgrades are needed. Together, the HCA and Public Queue offer insight into interconnection feasibility across our service area.

Figure 7-3 illustrates how the different components of the interconnection process interact, and their relative levels of cost, complexity, and information accuracy. After an application is submitted, engineers conduct screenings and studies to ensure safe and reliable interconnection. Pre-application data and hosting capacity help developers target viable locations before applying.

Figure 7-3
Interconnection Processes



IDP Requirement No. 3.B.2 requires the following:

Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process.

MN DIP Initial Review Screens use simplified analysis and readily available data to determine if a project can proceed without further study. Each application is evaluated against feeder and substation data (e.g., DML, thermal capacity, aggregate DER) to assess potential voltage, thermal, or protection impacts.

If a screen fails, further analysis is conducted. For example, one screen checks that aggregate DER does not exceed 15 percent of peak annual load on a line segment—an indicator of possible reverse power flow and voltage issues. Failed screens move to the Supplemental Review Process.

We use a spreadsheet tool to implement these screens, drawing data from several systems:

- GIS: Verifies service area and site-specific details.
- Salesforce: Tracks active/in-queue DER and links to GIS for feeder data.
- SCADA & LoadSEER: Provide peak load data.
- Outage Management System (OMS) or spreadsheet tools: Estimate fault current.
- Feeder maps/GIS: Identify voltage regulators.

C. Company Costs and Customer Charges Associated with DER Generation Installations

The information we provide below fulfills the following IDP requirements:

IDP Requirement No. 3.A.15 requires the following:

Total costs spent on DER generation installation in the prior year. These costs should be broken down by category in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc.).

IDP Requirement No. 3.A.16 requires the following:

Total charges to customers/ member installers for DER generation installations, in the prior year. These charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.).

IDP Requirement No. 3.A.27 requires the following:

All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g., CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation).

We calculate DER-related costs on a per-project basis and charge customers after interconnection. For large projects like Community Solar Gardens (CSGs), costs may span multiple years. If billing is delayed, those costs are not reflected until invoiced.

Since June 17, 2019, we've followed the MN DIP (Docket No. E999/CI-16-521), which requires tracking DER installation costs. We began collecting this data in 2019. For CSGs (Docket No. E002/M-13-867), we report substation and distribution costs based on billed amounts. In 2024, CSGs were billed \$1.7 million for substation upgrades and \$4 million for distribution upgrades, totaling \$4.7 million.²

For onsite solar projects over 20 kW, which typically proceed directly to a Facilities Study under MN DIP 3.2.2.2 and 3.4.5.2, detailed engineering costs are not provided. In 2024, 24 such projects averaged \$11,734 in upgrade costs.³

We also charge engineering study fees per MN DIP requirements. In 2024, total fees were \$4.6 million, broken down as follows:

- Engineering Process: \$ 2,065,792
- Facility Study: \$ 476,000
- System Impact Study: \$ 1,874,000
- Supplemental Review: \$ 93,600
- Pre-Application: \$ 151,500

Note: Costs reported under 3.A.15 reflect only Xcel Energy expenses. Customer-provided installation costs are reported annually in the “xx-10” docket filed each March 1.⁴

Administrative fees are collected for CSGs and the Ombudsperson. In 2024, we collected \$235,813 dollars for Low-to-Moderate Income CSG projects and \$118,300 for the Commission's Ombudsperson. In addition, we also collect fees for our Cost Share Program (\$554,250 in 2024).

We provide further details regarding our other programs and the compliance filings completed yearly below.

² 2024 Annual Report, Docket No. E999/CI-16-521, March 3, 2024.

³ Id.

⁴ See, for example, Docket No. E999/PR-23-10, available at this link:

<https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={A0E0B487-0000-C917-9986-F4D6E808C8DD}&documentTitle=20234-195095-02>.

1. *Solar*Rewards Community – Dockets No. E002/M-13-867 & No. E002/CI-23-335*

Annual Report filed by April 1 every year (2024 Annual Report filed on April 1, 2025) for our Legacy program only (Docket No. E002/M-13-867).

Deposits: In 2024, we received \$0 for new projects into our deposit accounts for the Legacy program, including any deposit that the Company was holding that the Garden Operator moved to escrow.⁵ Deposits are refunded with interest back to the Garden Operator upon a fully executed interconnection application or if the application is withdrawn.

Application/Administrative Fees: The Company collected \$235,813 in application fees for Low-to-Moderate Income projects.

Participation Fees: Annual participation fees were \$650,000.

Metering Fees: The Company administers metering charges as defined in our Section 10 Tariff based on the applicant's desire for upfront or ancillary meeting charges.

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

Annual Report filed by June 1 every year (2024 Annual Report filed on June 9, 2025). Engineering Fees are no longer administered for Solar*Rewards projects, applicants pay all applicable fees as defined in the MN DIP.

Metering Fees: The Company administers metering charges as defined in our Section 10 Tariff based on the applicant's desire for upfront or ancillary meeting charges.

IV. CURRENT LEVELS OF DISTRIBUTED RESOURCES

In this section, we present current DER volumes for the DER types specified in the IDP DER definition on our Minnesota distribution system, volumes in the interconnection queue, and discuss geographic dispersion.

A. Current and In-Queue DER Volumes

In Tables 7-1 and 7-2 below, we present the DER volumes on our Minnesota distribution system in compliance with IDP Requirement Nos. 3.A.17, 3.A.18, 3.A.19, 3.A.20, 3.A.23, 3.A.24, and 3.A.25.

⁵ The Legacy program was closed on January 1, 2024.

Table 7-1
Distribution-Connected Distributed Energy Resources –
State of Minnesota
(As of March 2025 – as provided in Docket No. E999/PR-25-10)

	Completed Projects		Queued Projects	
	MW/AC	# of Projects	MW/AC	# of Projects
Small Scale Solar PV				
Rooftop Solar	264	16,475	1,262	4,926
RDF Projects	35	25	1	1
Wind	22	79	3	7
Storage/Batteries ⁶	5	430	13	175
	Completed Projects		Queued Projects	
	MW/AC	# of Projects	MW/AC	# of Projects
Large Scale Solar PV				
Community Solar	936	998	254	263
Grid Scale (Aurora)	100	16	0	0

Table 7-2
Minnesota Distributed Energy Resources –
Demand Side Management and EVs

	Completed Projects		Queued Projects	
	Gen. MW	# of Projects	Gen. MW	# of Projects
Energy Efficiency*	2,966	N/A	N/A	N/A
Demand Response	972	441,800	N/A	N/A
Electric Vehicles	N/A	65,689 ⁷	N/A	N/A

*Cumulative since 2005.

For reference, below are the IDP Requirements fulfilled in Tables 7-1 and 7-2 above:

IDP Requirement No. 3.A.17 requires the following:

⁶ All current battery projects within our DER process are associated with other generation projects, such as solar. As such the application does not capture gen. MW as it is accounted for in other categories.

⁷ We do not have information that ties our customer accounts to EV users outside of our customer programs. We estimate that there are 65,689 EVs on the road in our service territory. *See* IDP Requirement No. 3.A.21 below for the sources of this range.

Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/ storage, storage, etc.).

The Company provides total DER interconnection as part of our Distribution Interconnection filing on March 1 of each year. For 2024, these details were provided in Docket No. E999/PR-25-10. Additionally, the Company provides several other tracking sources for this information in other annual reports such as the Solar*Rewards Community Annual Report (Docket No. E002/M-13-867) and Solar*Rewards Annual Report (Docket No. E002/M-13-1015), and Solar Energy Standard Annual Report (most recently in Docket No. E999/PR-23-12). We note that each of these reporting dockets have different reporting requirements and timing and therefore may differ slightly. Additionally, the Company provides quarterly reports regarding interconnection under the MN DIP in Docket No. E999/CI-16-521.

For purposes of this IDP requirement, we provide the information in Tables 7-1 and 7-2 above.

IDP Requirement No. 3.A.18 requires the following:

Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/ storage, storage, etc.).

The Company provides total DER interconnection as part of our Distribution Interconnection filing on March 1 of each year. For 2024, these details were provided in Docket No. E999/PR-25-10. Additionally, the Company provides several other tracking sources for this information in other annual reports such as the Solar*Rewards Community Annual Report (Docket No. E002/M-13-867), Solar*Rewards Annual Report (Docket No. E002/M-13-1015), Solar Energy Standard Compliance (Docket No. E999/PR-23-12), and the Quarterly Compliance Reporting under MN DIP (Docket No. E999/CI-16-521) to name a few.

For purposes of this IDP requirement, we provide the information in Tables 7-1 and 7-2.

IDP Requirement No. 3.A.19 requires the following:

Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/ storage, storage, etc.).

The Company reports the number of installed and pending DER generation systems annually in our March 1 Distribution Interconnection filing and quarterly in Docket No. E999/CI-16-521. For 2025, using end-of-year 2024 data, this information was filed in Docket No. E999/PR-25-10. However, we are currently unable to report distribution system locations for energy efficiency and demand response (DR) programs due to the nature of our DSM offerings. For example, we do not track individual residential purchases of high-efficiency lighting. Additionally, our DSM program systems are separate from those used for distribution system planning and operations. As we continue evaluating enhanced planning and operational tools, we expect to better understand the capabilities available and whether DSM data can be tracked by distribution system location for future reporting.

IDP Requirement No. 3.A.20 requires the following:

Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.).

See Tables 7-1 and 7-2 above.

IDP Requirement No. 3.A.23 requires the following:

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

See Table 7-1 above. We also provide information on the number of installed and pending DER generation and storage systems as part of our Distribution Interconnection filing on March 1 of each year as well as in our Quarterly Compliance Filings in Docket No. E999/CI-16-521. In 2025, with data as of end-of-year 2024, this information was provided in Docket No. E999/PR-25-10.

IDP Requirement No. 3.A.24 requires the following:

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

In 2024, the Company's EE programs saved 516,355 MWh including a demand reduction of 294,347 kW.⁸ Table 7-2 above provides the cumulative savings since 2005. In addition, we note an overlap between the Energy Efficiency and Demand Response lines. Minn. Statute § 216B.241 defines energy efficiency as a reduction in energy for which certain demand response products qualify; therefore, we have included the total cumulative savings for our portfolio in Table 7-2.

⁸ See 2024 Status Report and Associated Compliance Filings, Docket No. E,G002/CIP-20-473, March 31, 2024.

IDP Requirement No. 3.A.25 requires the following:

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

In 2024, the Company's controllable demand in Minnesota was 972 MW which is 11 percent of the system load. See Table 7-2 above.

B. Electric Vehicles and Charging Stations in Service Area

IDP Requirement No. 3.A.21 requires the following:

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

Customers are not required to inform the Company when they purchase an EV, however we are able to estimate the amount of EVs in our service territory through vehicle registration data purchased by the Company. We currently estimate that are 65,689 EVs across all classes in our service territory as of July 2025. Table 7-3 below shows the number of EVs broken down by vehicle type. This is an increase from 34,532 in our 2023 TEP filing, a growth rate of 91 percent.

Table 7-3
Registered EVs in Service Territory by Vehicle Type

Vehicle-type	Estimated Number
Light-duty	65,504
Medium-duty	160
Heavy-duty	25
Total	65,689

Battery electric vehicles (BEVs) now make up most of the light-duty EVs in our service territory, accounting for approximately 46,460 of all vehicles. The remaining portion (19,044) are plug-in hybrid electric vehicles (PHEVs). The Tesla Model Y is the most common EV in operation in the Company's service territory, followed by the Tesla Model 3 and Nissan Leaf.

IDP Requirement No. 3.A.22 requires the following:

Total number and capacity of public access electric vehicle charging stations, broken out by:

a. Number and capacity of known public access Level 2 Charging Stations

b. Number and capacity of Level 2 Charging Stations enrolled in a utility EV program broken out by program

- c. Number and capacity of known public access direct current fast charging (DCFC) stations*
- d. Number and capacity of DCFC installed through a utility EV program, broken out by program*
- e. All other known EV charging stations (by type, ex DCFC, Level 2)*

According to DOE’s Alternative Fuels Data Center, there are approximately 1,105 public EV charging station locations in Minnesota, with 2,800 charging ports.⁹ We estimate that there are 659 Level 2 charging stations in our service territory, representing about 1,584 charging ports. We also estimate that there are about 57 DCFC stations in our service territory, representing 490. Table 7-4 below provides a breakdown of publicly accessible charging stations by type and respective enrollment in a utility program.

Table 7-4
Publicly Accessible Charging Stations

	L2 Charging Ports¹⁰	L2 Ports in a Utility Program¹¹	DCFC Ports¹²	DCFC Ports in a Utility Program¹³
Number of Ports	1,584	372	490	174
Capacity (MW)	NA	4.2	NA	7.0

C. Current DER Deployment – Type, Size, and Geography

IDP Requirement No. 3.A.31 requires the following:

Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.).

The DER deployment in our Minnesota system by type and size is set out above. We provide associated geographic dispersion information and the number of installed and pending DER generation systems as part of our Distribution Interconnection filing on March 1 of each year and as well as in our Quarterly Compliance Filings in Docket No. E999/CI-16-521. In 2025, with data as of end-of-year 2024, this information was provided in Docket No. E002/PR-25-10. We also publish a Public DER Queue, which can be used to track DER installations and applications by feeder, DER type,

⁹ See public online portal at <https://afdc.energy.gov/stations/states> (Accessed September 11, 2025).

¹⁰ Data as of August 26, 2023.

¹¹ Participation data as of 2023 Annual EV Reporting.

¹² Data as of August 26, 2023.

¹³ Participation data as of 2023 Annual EV Reporting.

system size and status. This information is published monthly in the Interconnection Developer Resources portion of our website at <https://mn.my.xcelenergy.com/s/renewable/developers/interconnection>.

IDP Requirement No. 3.A.32 requires the following:

Information on areas of existing or forecasted high DER and/or electrification penetration. Include definition and rationale for what the Company considers “high” DER and electrification penetration.

The Company has made significant improvements in the forecasting process using LoadSEER in the past two years. As described in Chapter 1, we have been working collaboratively with Integral Analytics, the LoadSEER vendor, to introduce speculative adoption points into the LoadSEER model to tune the Spatial Allocation. These points represent specific locations on the distribution system where there is a higher likelihood of adoption of the specific technology or load type being studied. For example, speculative points can be added where undeveloped land of a specific minimum acreage is located within our service territory to represent areas that could be targeted by developers to install CSGs or other front of the meter solar. We then applied this methodology to the state-wide DER adoption forecast scenarios in LoadSEER for the purposes of creating location-specific load forecast scenarios. The results of the solar portions of those location-specific allocations show the geographic areas of the distribution system that are expected to have higher and lower levels of solar adoption. See *Chapter 1: System Planning* for further detail.

In terms of defining “high” DER penetration, we note that this is somewhat of a general term that will likely vary across utilities and the industry and may also depend on the particular issue or scenario being discussed. We believe one way to define high DER penetration is when the connected DER output exceeds feeder load, resulting in reverse power flow. Feeders that exceed the DML and result in reverse power flow are listed in the Public DER Queue. When backward flow occurs, mitigations become necessary.¹⁴ Under this definition, the amount of DER considered to be “high penetration” would vary from feeder to feeder by, among other things, the type of DER, and how it operates, the feeder design and configuration, and the feeder voltage and other attributes.

Another way to define high DER penetration would be setting the high threshold where existing capacity on a particular feeder can no longer be transferred to an

¹⁴ Mitigations may be required for other conditions below this level, such as potential voltage issues or line capacity.

adjacent feeder during abnormal conditions due to the high level of DER. Yet another way to define high DER penetration would be to specify the high level at the planning limits for a feeder or substation – i.e., the TPS, defined as 80 percent of device continuous rating plus the DML.

IDP Requirement No. 3.A.34 requires the following:

Information on distribution upgrades made to accommodate electrification, when known, including whether it was reactive to new load or based on a short-term forecast.

One project to note is a large reactive distribution upgrade is underway to support the electrification of a major customer's heat source. The upgrade project consists of significant investments with over \$30 million budgeted in the next four years to extend a feeder and install a new substation. There will also be transmission costs associated with this project.

IDP Requirement No. 3.A.35 requires the following:

Number of fuel-switching rebated granted through Xcel Energy's Conservation Optimization (ECO) plan in the prior year, broken out by technology type (air/ground source heat pump, water heater, cooking, other industrial process heat, electric vehicles, etc.)

The Company has a variety of measures related to Fuel Switching in its ECO Portfolio that first became available in 2024. Since only the 2024 program year has been completed at the time of filing the Company presents summarized results from Appendix D of the Company's Status Report filed on April 1, 2025 in Docket No. E,G002/CIP-23-92.

Table 7-5
EFS Measures Implemented in 2024

EFS Measure	Count
Panel Upgrade	1
Push Lawn Mower	736
Riding Lawn Mower	27
Commercial Lawn Mower	1202
GSHP	14
Ducted ASHP	906
Ducted Cold Climate ASHP	2026

Ductless Cold Climate ASHP	1402
Ductless ASHP	572
HPWH	57
HPWH + Communications Port	6
Snowblower	85
String Trimmer	12
Edger	8
Cultivator	1
Chainsaw	4
Leafblower	32

IDP Requirement No. 3.A.36 requires the following:

Number of electric space or water heating devices enrolled in a time-of-use rate or demand response program, broken out by program type.

The Company is currently unaware of any customers with electric space heating who are enrolled in a time-of-use (TOU) rate. Customers with electric space heating were restricted from participating in our Residential TOU Rate Pilot which we operated from 2020 to 2022. The time-varying electric space heating option will be launched with the overall residential TOU rate in 2026.

The Company currently has 5,236 electric water heaters enrolled in our Saver's Switch program which is a demand response program. Outside of the customers with electric water heaters participating in our programs such as energy efficiency rebates or Saver's Switch, the Company is unable to identify which customers have electric water heaters and therefore cannot quantify the number of customers with electric water heaters on TOU rates.

V. DER INTEGRATION CONSIDERATIONS

IDP Requirement No.3.C.3 requires the following:

Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER and electrification integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER and electrification adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER and electrification at the listed penetration levels.

A. DER Treatment in the Distribution Planning Load Forecast

With the implementation of LoadSEER, we can now simulate how corporate load and DER forecasts may affect future distribution system loading. This helps us assess system behavior with and without DER impacts. However, LoadSEER has limitations—it does not identify voltage constraints or confirm whether DER can be hosted at specific locations. That level of analysis still requires detailed modeling using a distribution modeling tool like CYME. Additionally, forecasts will never be 100 percent accurate due to the dynamic nature of development. Customer plans change, companies may shift direction, and broader economic conditions can influence adoption patterns – making it essential that our planning and integration methods remain flexible, safe, and responsible considering a dynamic environment.

Our planning is primarily based on native loading (i.e., load without DER generation). Understanding both native and net loading supports a more robust, probabilistic approach to planning, helping us anticipate a range of load conditions and inform risk analysis and project development. This approach underpins our Planned Net Loading (PNL) methodology, discussed further in *Chapter 1*. Planned Net Loading is used in the N-0 risk analysis.

While LoadSEER helps integrate DER forecasts into planning, DER impacts are highly location-specific. Factors such as feeder distance, conductor size, existing DER levels, and project size all influence hosting capacity. Because we cannot predict exact DER placement, forecasts rely on land availability and adoption likelihood. LoadSEER provides directional insights, but detailed interconnection studies are still required to determine actual feasibility.

B. Processes and Tools

Modernizing distribution infrastructure, adopting new planning approaches, and investing in foundational and advanced technologies are essential to managing increasingly complex systems and enabling higher DER penetration. Achieving this requires integrated solutions across multiple IT platforms. Enhanced monitoring and analytics will improve visibility into DER impacts, while increased control and automation will help manage a more dynamic grid. These improvements support the integration of more renewable energy beyond current thresholds. Industry-wide learning continues, with best practices and technologies shared across utilities.

Several tools described below are part of our grid modernization initiative, which was launched with DER integration as a key driver.

Interconnection Review. Each DER project is reviewed for grid impact, especially during minimum load periods. As DER levels rise, reviews become more complex and process improvements are needed. Our current spreadsheet-based review tool has been enhanced with basic automation to pull data from customer applications, streamlining reviews for certain interconnection types. This has reduced review timelines and freed up resources for further improvements. However, more advanced automation and tools will be needed for significant future gains. Access to on-demand and interval voltage data from AMI will support voltage analysis, and initial steps are being made to refine this. In the future, service voltage data from AMI—combined with primary voltage, load, and generation data from ADMS or other tools—could help estimate secondary system impedance and improve DER screening and GIS data validation.

Hosting Capacity Analysis. HCA serves as an early indicator of available capacity on the distribution system, helping customers and developers assess whether to pursue interconnection at a given location. We continue to enhance the HCA, With the full list of improvements available in our 2025 Hosting Capacity Program Report. These updates will provide more current data and improve HCA’s usefulness in the interconnection process.

Planning Tools. As discussed in this IDP, our advanced planning tool LoadSEER enables more robust scenario analysis of DER penetration. LoadSEER integrates baseline DER adoption forecasts with hourly load forecasts, using best-fit analysis to estimate DER impacts at the feeder level. It also supports scenario modeling over time, offering insights into varying adoption patterns. The DER scenarios used in this IDP are detailed in *Chapter 1*. By providing hourly-level forecasts that include DER impacts, LoadSEER equips distribution planning with the data needed for thermal risk analysis and capital budgeting. While LoadSEER’s probabilistic approach cannot replace the deterministic interconnection review process—required to identify cost-causing impacts—it complements HCA by helping identify where DER hosting is constrained and estimating the cost to relieve those constraints. Further detail on cost estimation is provided in *Chapter 10: Distribution System Upgrades*.

Monitoring and Control. The Company is implementing a DERMS system to provide more monitoring and control capabilities for DER. The Company is excited to start

using this application, build processes and start making step changes to support safe, reliable integration of customer DERs by starting to demonstrate real-time monitoring and control. The implementation of FERC Order 2222 further highlights the need for DERMS and secure communication with DERs participating in wholesale markets. Improved asset data, a key benefit of ADMS, also enhances interconnection modeling and planning accuracy.

We continue deploying SCADA to substations not yet equipped, as outlined in *Chapter 4: Distribution System Statistics*. Initial Distributed Intelligence features like Locational Awareness and EV Detection provide deeper insights into secondary systems and EV operations. We plan to expand these capabilities and believe our meter technology is well-positioned to support future DER integration through Wi-Fi and 2030.5 protocols.

C. System Impacts that May Arise from Increased DER Adoption

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

1. Potential System Benefits

Potential benefits of DER include:

- *Reduction of Peak Power Requirements.* Demand response has long helped reduce peak demand and remains a valuable DER. Battery storage can be dispatched during peak periods, and while EVs may eventually offer dispatchable storage, it's critical to manage charging to avoid increasing system or distribution peaks.
- *Emergency Power Sources.* Standby generators typically serve individual customers and offer limited system benefits. However, technologies like battery storage are expanding backup power options, especially for residential customers. When paired with PV, storage systems can supply power during outages.
- *Manage local capacity constraints.* PV may offset early peak demand but, if unmanaged, can create new constraints during low-load periods due to high solar output. Energy storage helps by shifting generation to improve system utilization. Each feeder is unique, and we evaluate DER benefits through our NWA analysis. We also assess DER's role in reducing overload risks during peak conditions using our PNL methodology, described in Chapter 1.
- *Reduction of system power.* Customer-sited PV offsets the overall system power requirements and provide an emissions free power source

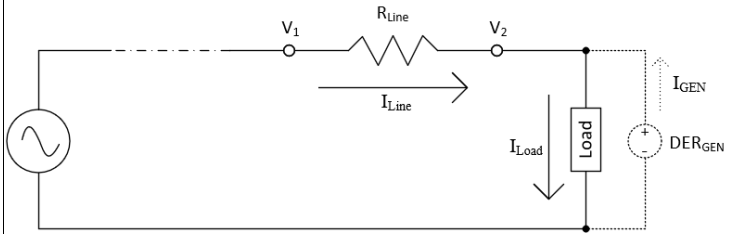
- *Source of renewable energy.* Any interconnected PV or wind generation adds to the percent of delivered energy that comes from carbon-free or renewable energy resources.

We will continue evaluating these benefits through our NWA analysis and work to incorporate DER impacts into distribution planning. As DER costs decline and software platforms mature, we expect opportunities in this area to expand.

2. *Potential Negative Impacts of DER*

Table 7-6 summarizes potential negative impacts of higher DG penetration. Additional impacts may arise under unique circumstances, and this summary does not include effects on the transmission system.

Table 7 - 1
Potential Distribution System Impacts from Distributed Generation

Distribution Impact	Impact Description	Cause
Over-Voltage	Steady-state voltage exceeds the American National Standards Institute (ANSI) C84.1 Range A for Service Voltage of 60HZ AC systems >100V ¹⁵ . The Range A Maximum Utilization and Service Voltages on a 120V base is 126V (1.05 per unit) and is applicable to sustained voltage levels and not to momentary voltage excursions, such as from motor starting currents. ANSI is the industry standard for utility voltage operating range.	In the line segments where generation exceeds the load and reverse power flow is present, voltage rise will typically occur. At a high level, the voltage change calculation is ($V_2 = V_1 - I \cdot R$). However, the current injected by the DER, in excess of load, travels in the opposite direction and mathematically is represented as a negative number. This makes the equation ($V_2 = V_1 - (-I) \cdot R = V_1 + I \cdot R$). From this equation we can see how the power injected by the DER results in a higher voltage. At a more granular level, the voltage change depends both on the power injected by the DER and the impedance it flows through between the site and the load it serves. This impact is usually largest during seasons and times of low load and peak generation, on conductors with high impedances, and locations with large distances to the substation. 

¹⁵ Electric Power Systems and Equipment – Voltage Ratings (60 Hertz), ANSI C84.1-2011.

Distribution Impact	Impact Description	Cause
Voltage Fluctuation	A change or multiple changes in voltage that result in noticeable change in illumination of lights significant enough to cause a visible irritation. ¹⁶	A change in power flow from individual or aggregate increases or decreases in generation or load, which results in a change in current through line segments and a change in voltage. Such events include switching operations, responses to market services, and automatic control of or protection device operation that cause DER or large loads to cease operation. This impact is usually largest during seasons and times of high load and peak generation, where generation is providing voltage support, or when storage or EV devices transition from full charging to full discharging.
Voltage Regulator Operations	A change or multiple changes in voltage that result in an increased number of operations of a voltage regulator or load tap changer.	Voltage fluctuations from the passage of clouds or fluctuations in wind speed, responses to market services, and automatic control of DER, causing the voltage at a regulating device to be out of band. Multiple voltage fluctuations per day can substantially increase the number of operations increasing both voltage fluctuation seen on the feeder and the wear-and-tear on the regulating device.
Thermal Loading of Utility Equipment	The current (Amps) or power flow (kVA) through a specific conductor or device exceeds its continuous/normal rating which results in a reduction of asset health and potential failure increasing the risk to reliability and public safety.	All equipment connected to the electric power system has a thermal limit. This limit can be provided in a variety of different ways, including ampacity, apparent power capacity in Volt-Amperes (kVA), or degrees C rise above ambient. This limit is impacted by a number of factors including but not limited to the standards, initial design, power quality, altitude, burial depth, expected air flow, cool-down time, and asset health. A violation occurs anytime the power flowing (in either the forward or reverse direction) through the device exceeds its limit. Standard transformer cores are designed with an assumed electromagnetic field (EMF) in one direction, from the high side to the low side. Reversing the EMF direction increases the core losses in the transformer, which leads to additional heating and a reduction in asset health. ¹⁷ Devices most commonly at risk include but are not limited to; conductors, cables, transformers, voltage regulators, fuses, reclosers, switches, and switch cabinets.

¹⁶ IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems, IEEE Std 1453-2015.

¹⁷ Cigre Science & Engineering, ABB, Upadhyay, P., Kern, J., Vadlamani, V. (October 2020). Distributed Energy Resources (DERs): Impact of Reverse Power Flow on Transformers.

Distribution Impact	Impact Description	Cause
Desensitizing Protective Device Relays	The fault current (Amps) contribution from DER reduces the fault current that flows through the upstream protective device. This condition can be enough to result in a failure of one or more protective devices to detect a fault condition, which is a risk to reliability and public safety.	A fault occurs when an energized conductor or device comes into contact with other phases, systems, or ground. DER, including non-exporting generation and storage systems, supply current towards that fault location. Since power travels the path of least resistance, the amount of fault current flowing through the upstream device is reduced. The reduction in fault current depends on the size and location of generators as well as the impedance between each source and the fault location. This impact is usually largest on long feeders with high DER penetration.
Additional Element Fault Current	Increased fault current (Amps) from the DER or upgrades required to accommodate the interconnection of DER exceeds the interrupt capability of the protective device and can result in device failure and increased risk to reliability and public safety.	Common upgrades required to interconnect DER, such as larger conductors/cables and transformers, increase fault current to locations downstream of the upgrades. DER, including non-exporting generation and storage systems, also supply additional current towards the fault location. This risk is most common for hydraulic recloser or trip saver with low interrupt capabilities. Operating these devices to interrupt current above the interrupt rating significantly increases the probability of catastrophic failure and reliability and public safety concerns.
Coordination of Protective Devices	Fault current contributed from the DER impacts the coordination of time overcurrent protective schemes increasing the risk of miss-operation of protective devices which reduces reliability and complicates troubleshooting and patrols to locate the fault.	The fault current provided by DER can increase the fault current through series protective devices. The additional fault current can reduce the Coordination Time Interval (CTI) between devices, increasing the risk of miscoordination and mis-operation of devices.
Reverse Power Flow	Changes in power flow direction through devices that can affect the control, operation, or protective settings resulting in regulator runaway or nuisance tripping.	Without generation, power flow from the source (substation) to the load (feeder), referred to as the “forward” direction. Reverse power flow occurs when generation in a given area exceeds the load downstream. This excess power flows from the generator in the “reverse” direction towards the substation. The reverse power flow can cause voltage regulator controls to runaway and fully boost or fully buck resulting in voltage issues. Protective devices with low trip settings can see reverse current greater than its trip rating causing the device to miss-operate. Network systems that utilize network protectors will trip with any reverse power flow.

Distribution Impact	Impact Description	Cause
Unintentional Islanding	When DER keeps a portion of the utility grid energized after removal of the utility source and is not designed to do so.	If the amount of generation closely matches the amount of load on a portion of the system when it is disconnected and isolated from the utility source (substation/grid), then the system is operating within a non-detection zone (NDZ) such that the anti-islanding functions of the DER may not sense the island ¹⁸ . This risk of unintentional islanding is increased if the island includes grid forming inverters, load following schemes, or a rotating mass, such as a synchronous generator or motor. Because the island is unintentional, it does not have the ability to synch with the bulk electric system (BES). Attempting to reconnect an island that is out of sync with the BES can result in significant utility and customer equipment damage.
Transient Over-Voltage (TOV)	An overvoltage of significant magnitude for relatively short durations, which could result in failure of surge arrestors, transformer bushings, insulators, and/or customer equipment. Magnitudes of TOV can be on the scale of 150 percent to 300 percent of the nominal or regulated voltage. Duration of TOV could be as short as a few cycles to as long as 2 seconds. ¹⁹	The presence of DER specifically increases concerns of Ground fault over-voltage (GFOV) and load rejection over-voltage (LROV). In an effectively grounded system, the neutral reference in a voltage phasor diagram has little to no shift from center when there is a current unbalance, such as during a SLG fault. ²⁰ In a system that is not effectively grounded, the neutral reference shifts away from center when there is a current unbalance. The neutral reference shifts towards the faulted phase and causes the line-to-neutral voltage (VLN) in the un-faulted phases to grow to as large as the line-to-line voltage (VLL). The strongest ground source in the grounded wye distribution system is at the substation transformer. During SLG faults, a protective device trips, removing the substation ground source from the line downstream from the protective device. If the DER is downstream of the isolation point, this creates an island for a short duration before DER detects the island and trips. During this time, the island may no longer be effectively grounded and the SLG fault may cause GFOV. LROV can occur during any island scenario. When the island is disconnected from the grid, the excess generation has no outlet and results in an increase to system voltage directly correlated to the amount of excess generation. While LROV is generally smaller in magnitude than GFOV, it is possible

¹⁸ Electric Power Research Institute, Key, T., Huque, A. (2021). Taxonomy for Inverter Island Detection Methods.

¹⁹ Assumes all DER trip within two seconds in compliance with IEEE 1547. Note: IEEE 1547-2018 Subclause 7.4 requires DER to limit their cumulative duration to voltages exceeding 138 percent to one cycle.

²⁰ Voltage Disturbance (2018). Neutral Inversion and Neutral Displacement. <https://voltage-disturbance.com/power-engineering/neutral-inversion-and-neutral-displacement/>.

Distribution Impact	Impact Description	Cause
		for them to occur at the same time resulting in greater voltages on the system.
Current and Voltage Unbalance	Unbalanced currents means more current is flowing through one phase than the other two. Unbalanced currents due to the installation of single-phase DER causes unbalanced voltages. These system imbalances can cause miss-operation of protective devices, unexpected overloads, excessive heating, and damage to customer 3-phase equipment.	The installation of single-phase DER can cause system imbalances by offsetting load, reducing the current flowing on a single phase, or in extreme cases reversing power flow on a single phase. This most commonly occurs with three-phase customers interconnecting single-phase DER and in rural areas where only one phase is available for interconnection.
Load Masking	Generation from DER reduces the amount of power fed from the substation. This effectively hides a portion of load being served on the feeder from metering equipment and can impact planning or operational functions, such as load transfers, which could result in equipment overloads or voltage issues.	Distributed generation can reduce demand and hide reliability risks on a feeder if the planner or operator does not account for the generation on the feeder. This can lead to switching error where more load or generation is transferred than expected during peak times. This impact or risk is highest on feeders with a high aggregation of small DER, or large DER without real-time telemetry.
Arc Flash Energy	An increase in the incident energy, which could impact the ability to perform hot-line work.	Changes in fault current through protective devices caused by DER may increase available fault current or clearing times for protective devices, which will increase the incident energy of an arc flash.
Harmonics	Distortions in voltage and current waveforms that could cause equipment heating, noise, overloads, or shortened equipment life.	Harmonic current distortions can be injected from the DER by power electronic based switching devices, such as inverters, and can impact the harmonic voltage distortion on the utility system. The type and severity of the harmonic contributions depend on the inverter technology, harmonic filters, and configuration of the interconnection.

Electric Vehicle Impacts. EV charging forecasts continue to show strong growth, as outlined in Chapter 1. Charging primarily affects the grid at the service transformer and feeder levels, where it can increase load and alter load shapes.

EV impacts fall into three main categories:

1. **Residential Charging** – Mostly Level 1 and Level 2 chargers, impacting service transformers. These transformers often serve many homes and may be at risk of overload with widespread Level 2 adoption.
2. **Fleet Charging** – Typically Level 2 and Level 3 chargers, impacting feeders. Fleet sites can exceed 1 MW, with some reaching over 10 MW, especially as heavy-duty EVs and buses are deployed.
3. **Public, Commercial, and Workplace Charging** – Also primarily Level 2 and 3 chargers, affecting feeders. Sites usually range from 450 kW to 1.5 MW, with daytime usage expected to grow as EV adoption increases.

Unmanaged EV charging can raise system load at various times, risking overloads on local equipment. Managed charging programs help mitigate these risks by shifting load away from peak periods. The Company offers a portfolio of Clean Transportation programs targeting Residential, Fleet, and Public charging through EV-specific Time-of-Use (TOU) rates and incentives. In our Residential program, over 90 percent of EV charging occurs during off-peak hours, showing strong customer response to price signals. For more on managed charging, customer programs, and technologies like vehicle-to-grid (V2G), see our Transportation Electrification Plan.

Energy Efficiency and Demand Response. Demand response programs are expected to help reduce NSP system peak loads. However, load reductions from energy efficiency and demand response can also create challenges on feeders with high levels of DG. System Impact Studies for DER interconnections evaluate net power flow—calculated as load (kVA) minus generation (kVA). A positive value indicates forward flow from the substation to customers; a negative value indicates reverse flow from customers back to the source.

These studies assume a certain load level at the time of interconnection. If load decreases after the study—due to energy efficiency or demand response—the resulting increase in reverse power flow could trigger new system impacts (see Table 7-6). To mitigate this, technical planning standards include a safety margin to account for potential load reductions. However, this margin primarily addresses overload risks, not over-voltage. Without additional voltage margin, system upgrades may still be needed. Flexible interconnection practices, discussed below, may help reduce this risk.

Distribution-Sized Energy Storage Systems. Energy storage can enhance grid reliability when deployed for that purpose, but most installations in our Minnesota service territory are currently driven by customer interest in backup power. While adoption

remains relatively low, the cost-effectiveness of front-of-the-meter utility installations depends heavily on system location and operation.

The Company's proposed Capacity*Connect, a Distributed Capacity Procurement (DCP) program, is an effort to begin to better understand this dynamic. Capacity*Connect would deploy Company-owned and -operated battery energy storage systems (BESS) of 1-3 MW each, sited strategically at customer site host locations and connected front-of-the-meter to the Company's distribution system to serve primarily as a bulk system asset. By strategically siting these assets on the distribution system, we seek to realize coincident distribution system benefits even as the BESS are operated for bulk system energy and capacity use cases.²¹

In Colorado, we launched the Renewable Battery Connect program, which incentivizes customers to install eligible batteries charged entirely by renewable energy. In exchange, the Company can dispatch the battery during peak demand periods. (See our November 1, 2023 Petition in Docket No. E002/M-23-459 for details.) Other use cases include charging during periods of high renewable generation and reducing grid usage throughout the day. Future opportunities may also include wholesale market participation through aggregation. In its MN territory the Company has approval from the Department of Commerce to launch a pilot, which will begin Q1 2026. While stacking services can improve cost-effectiveness, it adds complexity and may reduce availability for backup power.

Like PV systems, customer-connected energy storage is reviewed through our interconnection process. Customers determine how their systems operate, which may not align with grid optimization. While most residential installations are for backup, aggregated storage could help address local congestion and potentially defer distribution upgrades through NWA or other programs.

For more on the Renewable Battery Connect program and future energy storage pilots, see *Chapter 5: Grid Modernization*.

²¹ See Docket No. E002/M-25-378. The Company's October 3, 2025 Petition proposes Capacity*Connect Phase 2. Phase 1 was approved as a modification to the Company's Energy Conservation and Optimization (ECO) Triennial Plan (see Assistant Commissioner's Decision Addenda, Docket No. E,G002/CIP-23-92, September 3, 2025).

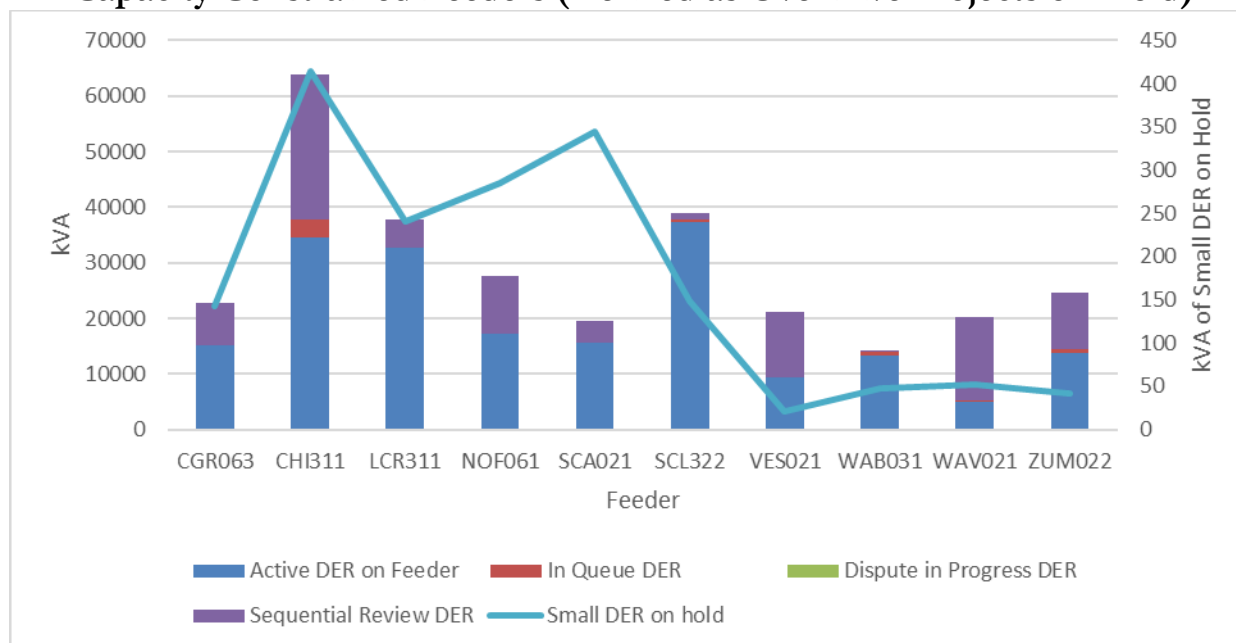
D. Cost-Causation and Barriers to DER Integration

Minnesota’s regulatory framework for DER follows a cost-causation principle, meaning the party causing the need for system upgrades—typically the customer or developer—must pay for them. Under our Section 10 tariff, DER interconnection costs are the responsibility of the installer if upgrades are needed to avoid system impacts. In some cases, these costs lead developers or customers to abandon projects, making upgrade costs a barrier to DER integration. Forecasted upgrade costs and alternative cost allocation strategies are discussed in *Chapter 10: Distribution System Upgrades*.

Another challenge arises when a customer installing a small DER system is required to pay for upgrades—such as a transformer replacement—because they are the last to interconnect, even though earlier customers are contributing to the constraint. Similarly, customers may face high costs for feeder upgrades if larger DER systems (e.g., CSGs) have already consumed available capacity. While the cost-causation model is straightforward and effective when capacity exists, it becomes problematic when capacity is exhausted, as upgrade costs are often too high for individual customers to bear.

Interconnection queue congestion has been a persistent issue since the 2019 IDP filing, especially in areas ideal for siting CSGs. Projects are often delayed due to sequential review processes, lack of available capacity, or disputes affecting other queued projects. A parallel review process was introduced to allow DER projects 40 kW and below to proceed alongside larger projects, provided no material issues exist. However, longer queues can still exist due to larger projects and the level of analysis needed for these project. A summary of DER capacity projects on hold is provided in our October queue report, available on our website.

Figure 7 - 4
Capacity Constrained Feeders (Defined as Over Five Projects on Hold)



If a large customer on a feeder with existing DER were to close or relocate, the resulting drop in demand could trigger reliability concerns, requiring studies and potential upgrades such as reconductoring. These investments take time to plan, permit, and construct.

To address barriers like these, the Company proposed changes in Docket Nos. E999/CI-16-521 and E999/CI-01-1023. The Commission's March 31, 2022 Order included three key updates:

1. Expanded the parallel review process to include projects of all sizes up to the system impact study phase.
2. Authorized mandatory group studies for feeders or substations with three or more applications over 40 kW.
3. Approved a cost-sharing mechanism for DER projects 40 kW and under, funded by a one-time fee from all applicants in that category.

In 2024, the number of capacity-constrained feeders increased by 21. With 53 capacity constrained feeders in January, 2024 to 74 in January 2025. The total number of on-hold projects with queue dates prior to December 31st, 2024 are 298, totaling 420 MW.

Recent state-level queue reform aims to streamline interconnections for smaller DERs. Minnesota Session Laws 2023, Ch. 60, Art. 12, Sec. 75 requires prioritization for projects under 40 kW AC, and funding from the Distributed Energy Resources System Upgrade Program supports the small interconnection cost-sharing program ordered in Docket No. E002/M-18-714.

We remain optimistic about group/cluster studies as a way to reduce queue times and share upgrade costs. Our pilot showed mixed results: while total study duration was longer, per-project study time was shorter, and administrative steps were streamlined. In 2024, only seven cluster studies resulted in a signed interconnection agreement, averaging \$3.32 million in upgrade costs.

One key takeaway: when significant upgrades are required, a minimum number of participants may be needed for cost-sharing to make interconnections viable. As of October 1st, 2025, 10 more cluster studies are planned, including five requiring new feeders or transformers. These will help us evaluate the feasibility of cluster studies for addressing thermal limitations and high interconnection costs.

We note that in 2024, the Minnesota Legislature adopted a DER cost-sharing framework that allows pro rata sharing of distribution upgrade costs among DER participants. This framework is outlined in Laws of Minnesota 2024, Chapter 126, Article 6, Section 53, with further details available in Docket No. E002/CI-24-288. Standards to implement this framework are currently under development in that docket. The implementation of this framework will establish an alternative cost allocation method for DER-driven upgrades in Minnesota.

Additionally, the Proactive Distribution Grid Upgrades framework, approved by the Commission in Docket No. E002/CI-24-318, establishes a process for the Company to invest proactively in the distribution system to create hosting capacity for DER and load before that capacity is needed. After an upgrade is complete, interconnecting customers may access the newly created capacity by paying a pro rata fee assessed on a per-kW basis. The Company filed its first Proactive Upgrade Proposal in conjunction with this IDP.

Longer term, we are monitoring developments in flexible interconnection strategies, discussed further in Section II.B above.

E. Types of System Upgrades that may be Needed to Support Higher DER Penetration

While the process improvements discussed above will help support increased DER adoption, the Company, developers, and the Commission continue to explore ways to integrate more DER efficiently.

In the long term, we are evaluating flexible interconnection capabilities as discussed in Section II above. These approaches could allow more DER to connect without requiring system upgrades, though they may limit DER output during times of grid constraint.. Our next steps and long-term vision for flexible interconnections are outlined in Section

We also expect FERC Order 2222 to drive significant changes to our interconnection process later this decade, including new requirements for aggregated DER registration and enhanced monitoring and control. (See Section VII for more detail.)

As discussed throughout this IDP, grid modernization investments will improve real-time system visibility, helping us better understand how PV affects operations and refine planning assumptions. Adjustments to smart inverter settings may also support integration.

Table 7-7 summarizes traditional mitigation strategies used to address common system impacts from DER. In some cases, multiple upgrades may be needed to accommodate additional DER.

Table 7 - 2
Potential Mitigations for Common Impacts

Category	Impacts	Mitigation
Voltage	Overvoltage	Adjust DER power factor setting, reconductor
	Voltage Fluctuation	Adjust DER power factor setting, reconductor
	Voltage Regulator Operations	Adjust DER power factor setting, reconductor
Loading	Thermal Limits	Reconductor, replace equipment
	Load Masking	Real-Time generation output communicated over SCADA
Unbalance	Current and Voltage Unbalance	Swap phases on single phase taps, conversion from single phase tap to a three phase tap

Protection	Additional Element Fault Current	Replace protective equipment
	Protective Device Reduction of Reach	Adjust relay settings, replace relays, move or replace protective equipment
	Coordination of Protective Devices	Adjust relay settings, replace relays, move or replace protective equipment
	Reverse Power Flow	Update controls on regulation devices, install Power Control System on DER to control power output/export
	TOV	Provide a ground reference, implement fast tripping on DER, installation of Direct Transfer Trip (DTT)
	Unintentional Islanding	Implementation of Voltage Supervisory Reclosing (VSR), installation of DTT, delay reclosing ²²

VI. ADVANCED INVERTER AND IEEE 1547 CONSIDERATIONS AND IMPLICATIONS

In this section, we begin with general discussion on inverter advancements and then address IDP Requirements Nos. 3.A.7 and 3.A.33:

IDP Requirement No. 3.A.7

Discussion of and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities and constraints related to interoperability and advanced inverter functionality).

IDP Requirement No. 3.A.33

Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.

Finally, we share our perspective on how IEEE Std. 1547-2018—and its amendment, IEEE 1547a-2020—impacts interconnection standards and processes.

A. Inverter Advancements

Advancements in inverter technology offer valuable tools to reduce system impacts from PV and other inverter-based DER. The industry standard governing DER

²² Delaying reclosing impacts reliability and reduces the customer experience. It does not eliminate the risk, only reduces the risk.

interconnection—IEEE 1547, revised in 2018²³ and amended in 2020²⁴ (IEEE 1547a-2020)—sets requirements for performance, operation, testing, and interoperability. Key updates include support for smart inverter capabilities such as ride-through during abnormal conditions, voltage regulation, and control of real/reactive power. These features are increasingly important as DER penetration grows, and interoperability is a core consideration in our grid modernization efforts.

Smart inverters compliant with IEEE 1547 are being used for installation today. Inverters with this qualification are capable of performing defined grid supportive functions beneficial to both Area EPS operators and DER installers. The installation of this equipment should be dependent on certification under the most recent version of UL1741. The programming and operation of smart inverter functions should be defined by OEM recommendations along with the company's requirements as determined by the Technical Services Manual and the project specific study.

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

IDP Requirement No. 3.A.7 requires the following:

Discussion of and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g., opportunities and constraints related to interoperability and advanced inverter functionality).

IEEE 1547-2018 (amended by 1547a-2020) focuses on interconnection and interoperability requirements for DER. It introduces advanced inverter functions—such as ride-through, voltage regulation, and reactive power control—that can help mitigate DER impacts. As we transition to the CYME planning tool, we will look at modeling the smart inverter settings in a more standardized fashion due to the increased capabilities this tool provides.

The IEEE-1547 standard's requirement for DER to support reactive power control throughout its lifetime is especially valuable for addressing voltage issues. The Company currently applies a standard approach to set a fixed power factor at 0.9 leading or lagging to help address system impact issues, typically voltage rise. In study

²³ See IEEE Publishes Standard Revision for Interconnection and Interoperability of Distributed Energy Resources (DER) with Associated Electric Power Systems Interfaces, Piscataway, NJ (April 2018). http://standards.ieee.org/news/2018/ieee_1547-2018_standard_revision.html

²⁴ See IEEE Publishes Standard Revision for Interconnection and Interoperability of Distributed Energy Resources (DER) with Associated Electric Power Systems Interfaces, Piscataway, NJ (April 2020) <https://standards.ieee.org/ieee/1547a/7696/>.

cases where this is insufficient to address issues from interconnection, the intervention is expanded to the application of Volt-VAR or Volt-Watt functionality. The inverter functions are set based on typical curves and guidelines from IEEE 1547-2018 references.

IEEE 1547-2018 establishes standardized communication and interoperability requirements for DERs, enabling consistent and scalable integration of third-party generation and storage resources across utility systems.

C. Advanced Inverters Response to Abnormal Grid Conditions

IDP Requirement No. 3.A.33 requires the following:

Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.

Abnormal voltage and frequency issues can arise from both distribution and transmission system conditions. On the distribution side, factors such as high DER penetration, high source impedance, and variable loads can lead to abnormal behavior. While the smart inverters have not shown as much capability in being able to compensate for system level issues, advanced inverters can help address local issues introduced by the DER connecting to the distribution system

On the transmission side, events like generation loss or line faults can cause grid disturbances. A key reason for updating IEEE 1547-2018 (amended by 1547a-2020) was to ensure DER can support the grid during such events. The updated standard now requires ride-through capabilities and offers flexible trip settings to support coordination among transmission and distribution operators.

Forecasting where and when abnormal conditions involves conducting a more detailed engineering study for each project as it goes through the MN DIP interconnection process. Some smart inverter functions can be used to reduce system impacts.

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

As discussed, IEEE 1547-2018, amended by IEEE 1547a-2020, is the current standard for DER interconnection and interoperability. The Company developed a roadmap for adopting the standard, outlining near- and long-term implementation strategies.

The revised standard introduced three key capabilities for DER:

1. Local grid support functions
2. Response to abnormal grid conditions
3. Information exchange for operational purposes

While not all capabilities are expected to be implemented immediately, the standard provides flexibility for grid operators preparing for high DER penetration.

Regarding DER response to abnormal grid conditions, IEEE 1547 assigns a guidance role to both the Authority Governing Interconnection Requirements and the Regional Reliability Coordinator—in Minnesota, these are the Minnesota Commission and MISO, respectively.

VII. CHANGES OCCURRING AT THE FEDERAL AND REGIONAL LEVEL

We would like to express some reservations about the continued requirement to respond to FERC Order 841, which was issued on February 15, 2018—over seven years ago. Its relevance to current distribution planning is increasingly limited considering more recent federal regulations. For instance, our discussions have shifted to include FERC Order 2222, which reflects more current regulatory priorities. Rather than continuing to provide analysis of FERC Order 841, it may be more useful to revise this requirement to include a high-level summary of recent FERC Orders and their potential implications for distribution planning. This approach may better inform stakeholders about emerging trends and evolving regulatory developments.

IDP Requirement No. 3.C.4 requires the following:

Include information on anticipated impacts from FERC Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM-18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations [RTO] and Independent System Operators [ISO]).

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

A. FERC Order Nos. 841 and 2222

FERC Order No. 841, issued in February 2018, directed Regional Transmission Operator (RTOs) and Independent System Operators (ISOs) to revise their tariffs to enable storage resources to participate in Energy, Capacity, and Ancillary markets, regardless of whether they are connected at transmission or distribution voltage. In September 2020, FERC Order No. 2222 expanded this directive to allow distributed energy resource (DER) aggregations to participate in wholesale markets, as outlined in Docket No. RM18-9-000.

The Company has been working with MISO to understand some of the processes associated with FERC Order 841 for distribution-connected storage. In the future, Order 2222 introduces significant complexity for the Company. The order requires coordination across our transmission and distribution systems, regulatory jurisdictions, and market participants. The Company must now address a range of new workstreams to support DER aggregation and wholesale market participation, including:

- Data Access and Privacy
- Operational Coordination
- Metering and Telemetry
- Interconnection
- Aggregation registration and Review
- IT and Technology Requirements.
- Interoperability
- Regulatory Coordination
- Cost and Investment Recovery
- Organizational Change Management

Even at low DER penetration levels, enabling distributed energy resource aggregators (DERAs) to participate in wholesale markets presents challenges that scale with adoption. For example:

- *Distribution System Usage:* Distribution networks were not designed for large-scale energy exports. Interconnection studies may identify significant feeder and substation upgrades, and cost assignment for these upgrades—currently borne by the DER—must be reevaluated. Order 2222 anticipates distribution access charges for DERs transmitting services to the MISO market as a means to make our customers whole.

- *Aggregation Reviews*: Evaluating the impact of DERAs on system reliability requires new analytical tools, new processes, new technology systems and staffing. These reviews are more dynamic than traditional interconnection studies and must account for real-time operational risks.
- *Distribution Operations*: Electric distribution companies (EDCs) must monitor DER market activity and retain the ability to curtail DERs to maintain safe operations. This requires enhanced communications, DER tracking systems, and operational coordination with RTOs/ISOs.
- *Wholesale Market Issues*: Challenges include wholesale metering and telemetry requirements, coordination among RTOs/ISOs, Electric Distribution Companies (EDCs), and aggregators, and the scalability of market software to manage numerous small resources. RTOs/ISOs are addressing these issues through stakeholder processes and tariff revisions, with varying timelines and models across regions.

Given the scope of Relevant Electric Retail Regulatory Authority (RERRA) responsibilities, distribution utilities will need to develop state-jurisdictional tariffs and agreements that define roles and responsibilities for DERs, aggregators, and utilities. RERRAs must also evaluate funding requests for staffing and systems and determine appropriate cost allocation mechanisms.

The Company remains committed to supporting DER aggregations and storage participation in wholesale markets. To address implementation challenges, we continue to participate in collaborative initiatives such as the Distributed Energy Resource Task Force (DERTF) to provide insights and consensus recommendations for Order 2222 implementation.

B. MISO

FERC Order No. 2222 required Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to submit compliance filings by July 19, 2021. MISO requested and received an extension to April 18, 2022, and submitted its initial compliance filing on April 14, 2022. As of January 2025, FERC approved MISO's revised compliance filing, which sets a final implementation date of 2030 with full participation and enrollment of DER Aggregations in MISO markets by June 1, 2029. MISO justified the extended timeline by citing the need for significant upgrades to its market systems, including a new modular market platform, enhancements to locational enrollment systems, and updates to settlement systems. Since then, MISO

has engaged stakeholders through its DERTF to address and shape MISOs implementation strategy.²⁵

C. Potential Impact of FERC Orders

FERC Order 2222 introduces transformative changes to DER participation in wholesale markets, but many implementation details fall under the jurisdiction of Relevant Electric Retail Regulatory Authority (RERRA). Key areas requiring RERRA action include:

- *DER Interconnections:* Existing processes like MN DIP and existing tariffs may need updates to accommodate wholesale participation. The Company is working through requirements and reaching out to MISO and other stakeholders for more information and clarification, but is only in initial stages.
- *DER Aggregation Review:* Distribution utilities must assess whether DER aggregations impact system safety or reliability. While FERC mandates the review, it's scope intersects with RERRA authority. Utilities and RERRAs should collaborate to streamline aggregation review processes and leverage existing interconnection data.
- *Dual Participation:* DERs may participate in both wholesale markets and retail programs, but safeguards are needed to prevent double compensation. RERRAs must determine programs compatibility and ensure transparency in compensation structures.
- *Distribution System Management Tools:* Utilities require advanced tools for real-time monitoring, aggregation reviews, and operational coordination. These tools are still evolving and may require significant investment. RERRAs must establish cost recovery mechanisms that equitably distribute expenses among stakeholders.
- *Aggregator Participation (ARCs):* If the Commission revisits ARC participation (e.g. Docket E999/CI-22-600), coordination with the Organization of MISO States (OMS) is recommended to ensure appropriate oversight processes in place. OMS should also engage with MISO on the effectiveness of its demand response performance measurement and verification.²⁶
- *Customer Protections:* As third-party aggregators gain access to customer data, RERRAs should establish rules for ARC certification, data privacy, and truth-

²⁵ Access the recording of this DERTF meeting at: <https://cdn.misoenergy.org/20210728%20RERRA%20O2222%20Coordination%20Workshop%20Recording578273.mp4>. Last accessed October 19, 2021.

²⁶ The Company also raised this issue in comments filed in the Commission's Docket No. E999/CI-22-600, In the Matter of a Commission Investigation into the Potential Role of Third-Party Aggregation of Retail Customers.

in-advertising. These protections must ensure fair compensation and secure data handling.²⁷

- *Data Security and Privacy*: With increased data exchange between utilities, aggregators, and market operators, robust cybersecurity and privacy frameworks are essential. Utilities must adopt interoperable standards like the Common Information Model (CIM) to support secure and standardized data sharing.

²⁷ Id.

CHAPTER 8: NON-WIRES ALTERNATIVES ANALYSIS

This appendix addresses IDP Requirement Nos. 3.E.1, 3.E.2, and 3.A.5.d, as well as IRP Order Point No. 9.D.¹ These requirements focus on our methodology for Non-Wires Alternatives (NWA) analysis, including project identification, comparison to traditional solutions in terms of viability, cost, and long-term value, and coordination between distribution system planning and the Integrated Resource Plan (IRP).

Our approach reflects the Company's commitment to delivering excellent service, leading the clean energy transition, and keeping bills as low as possible. By applying rigorous, expert-driven analysis, we ensure NWAs are evaluated with the same level of scrutiny as conventional investments—balancing reliability, affordability, and sustainability. This coordination helps us build a smarter, more resilient grid while guiding decisions with deep technical expertise.

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

- 1. Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.*
- 2. Xcel shall provide information on the following:*
 - *Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability)*
 - *A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation)*
 - *Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed*
 - *A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.*

IDP Requirement No. 3.A.5.d requires:

- 5. Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned*

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

modifications or planned changes to the existing process to improve coordination and integration between the two plans, including:

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

IRP Order Point No. 9.D states:

- 9. Xcel shall take steps to better align distribution and resource planning, including:*
- D. Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources to address discrete distribution system costs.*

Regarding IDP Requirement No. 3.A.5.d and IRP Order Point No. 9.D, this Chapter discusses improvements to our NWA analysis overall. See *Chapter 1: System Planning* for more detailed discussion on coordination between the IRP and IDP regarding NWA analysis.

I. INTRODUCTION: NWA ANALYSIS

Our 2025 NWA analysis reviewed 12 projects selected using established NWA criteria. The process largely mirrored our 2024 approach, with one key enhancement: the inclusion of the Planned Net Loading methodology for assessing N-0 risks.

Of the 12 projects analyzed, six were found to be technically feasible, though not cost-beneficial in all cases. We still plan to issue a Request for Proposal (RFP) for one project to gauge developer interest in Non-Wires Alternatives, including our proposed “ARR split” compensation model.

We also revisited six potentially viable projects from the 2024 IDP. The remaining ten projects from last year’s analysis no longer meet NWA criteria, primarily because they’ve moved into years 1–2 of the budget.

The remainder of this chapter provides a detailed overview of our 2025 NWA analysis, including methodology, assumptions, and calculations, as well as our plan to issue an RFP in alignment with the Commission’s Order.

II. 2025 NWA ANALYSIS RESULTS

IDP Requirement No. 3.E.1 requires the following:

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

This section presents the results of our 2025 NWA analysis, which reviewed 12 projects with total costs exceeding \$2 million and meeting the criteria outlined in Sections V through VIII. Table 8-1 summarizes the findings, followed by a detailed discussion of the one project identified as both technically feasible and cost-beneficial.

A. Summary of Analysis Approach

While Sections V and VIII provide a detailed explanation of our methodology, we offer a brief overview here to contextualize the results. As in our 2024 analysis, we examined the peak load curve for each feeder or transformer risk, forecasted through the end of the deferral period (five years after the planned in-service date of the traditional project). We applied targeted demand response (DR) to reduce load, followed by energy storage and/or solar generation to address any remaining deficiency. In some cases, existing solar on specific feeders was also factored into the analysis. Full results, load curves, and assumptions are provided in this section.

Consistent with our 2024 approach, DR was only considered for N-0 risks. This decision reflects the complexity of N-1 analysis—due to multiple feeder configurations and limited access to individual customer load data. By focusing on N-0 risks, we aim to refine our process, assess its value, and determine future steps for broader risk categories.

B. Summary of Results

Table 8-1 summarizes the results of our 2025 NWA analysis. A positive Incremental Net Impact indicates that modeled benefits exceed modeled costs in the stacked values model; the value shown reflects the most cost-effective scenario. A negative value means the modeled costs outweigh the benefits.

Table 8-1
2025 NWA Candidate Projects – Results Summary

Project Title	Technically Feasible	Incremental Net Impact	Traditional Project Cost
Install Stillwater Lake Elmo Area Substation	N	\$-10,676,842	\$ 18,100,000
Install Lindstrom Area Substation	N	\$-479,1050	\$ 13,700,000
Install Baytown BYT Feeders	N	\$-343,540	\$ 3,000,000
Reinforce Credit River CTR TR2	N	\$2,340,4834	\$ 5,200,000
Reinforce Lexington TR1 and TR2	Y	\$3,352,058	\$ 7,400,000
Reinforce Parkers Lake feeders	Y	\$1,876,812	\$ 2,250,000
Reinf. Coon Creek CNC TR1 to 50 MVA	Y	\$2,130,901	\$ 2,500,000
Reinforce Elm Creek TR1 to 50 MVA	Y	\$1,997,692	\$ 2,400,000
Install Osseo OSS TR3	Y	\$4,491,830	\$ 4,600,000

The Incremental Net Impact provides an initial indication of whether a project may be cost-beneficial. However, like any model, it has limitations, which we discuss further below. It is important to note that the project cost estimates are desktop estimates based on historical and currently available costs, and that no field investigations or constructability discussions have been discussed at this stage. Thus, any potential NWA project would require additional analysis to confirm true cost-effectiveness and technical feasibility.

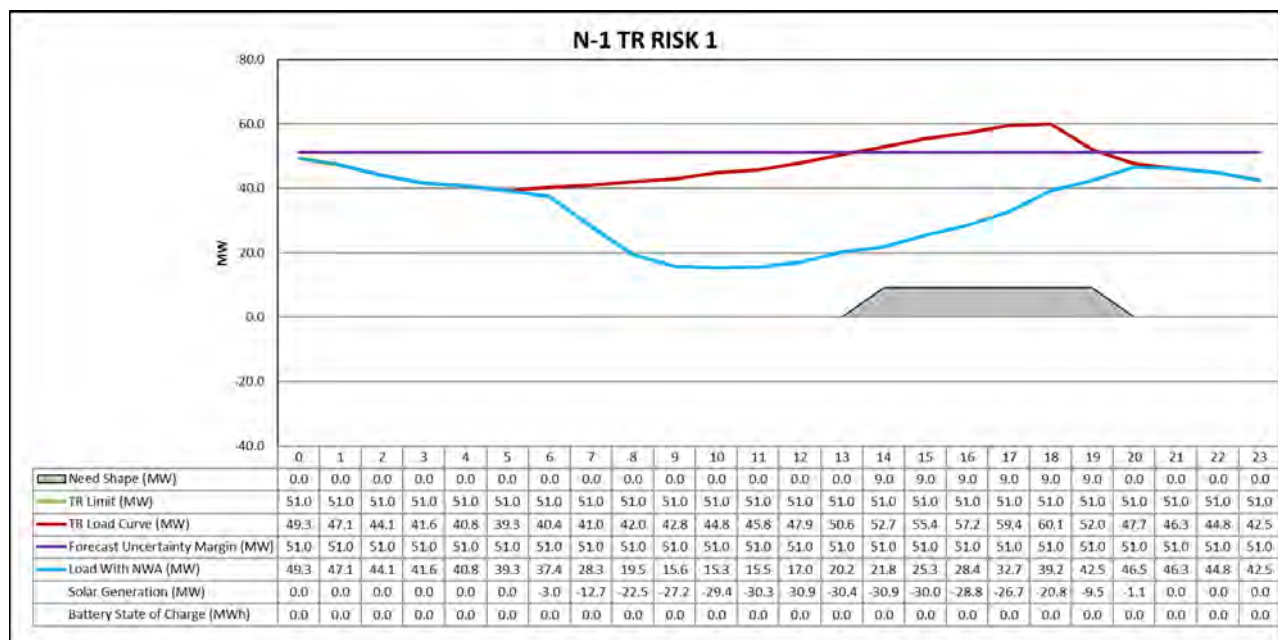
C. Feasible Projects – Reinforce Lexington TR1 and TR2

Below is an overview of reinforcing Transformers 1 & 2 at the Lexington substation.

Capacity risks addressed:	1
Feeder normal overloads:	0
Feeder contingency risks:	0
Transformer normal overloads:	0
Transformer contingencies:	1
Traditional solution:	Upgrade substation transformers TR1 and TR2 to 70MVA
NWA solution:	New solar PV systems at strategic locations to mitigate risks and keep costs at a minimum.

Figure 8-1 illustrates the amount of load at risk if one of the project's associated transformers fails.

Figure 8-1
Transformer N-1 Contingency Load Risk



Existing solar on feeder (MW):	0.0
Available relief from DSM (MWh):	0.0
Technology or Technologies:	Solar and Storage
Incremental Solar Capacity (MW):	47.6
Incremental Storage Capacity (MW/MWh):	0.0/0.0
Risk mitigated:	Transformer N-1

Table 8-2 summarizes the optimal DER solution for each risk addressed by this mitigation option.

Table 8-2
Reinforce Lexington TR1 and TR2 – Summary of DER Solutions

Capacity Risk	Need Shape		Demand Response (MWh)	Optimal DER Solution		
	Overload (MW)	Duration (Hours)		Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)
N-1 TR RISK 1	9.0	5.0	0.0	0.0	47.6	0.0/0.0
Total			0.00	0.0	47.6	0.0/0.0

Table 8-3 summarizes the overall incremental net impact of the optimal NWA solution, including a detailed view of the incremental impact of each cost/benefit category.

Table 8-3
Reinforce Lexington TR1 and TR2 – Costs and Benefits Summary

	Incremental Impact
Energy Generation	\$ 1,977,480.45
Generation Capacity + MISO Reserves	\$ 687,107.25
Transmission Capacity	\$ 32,621.24
Deferral Benefit	\$ 474,945
GHG Emissions + Other Environmental	\$ 2,152,732
Solar Cost	\$ (1,601,849)
Battery Cost	\$ (585,773)
Interconnection Fees	\$ (34,000)
Total Benefit	\$ 5,602,721
Total Cost	\$ (2,250,663)
Net Impact	\$ 3,352,058

Incremental Net Impact		NWA Solution	
		Least Cost-Effective Solution	Optimal Solution
Discount Rate	WACC	-\$477,858.38	\$3,352,058.13
	Societal	-\$837,832.55	\$3,153,769.33

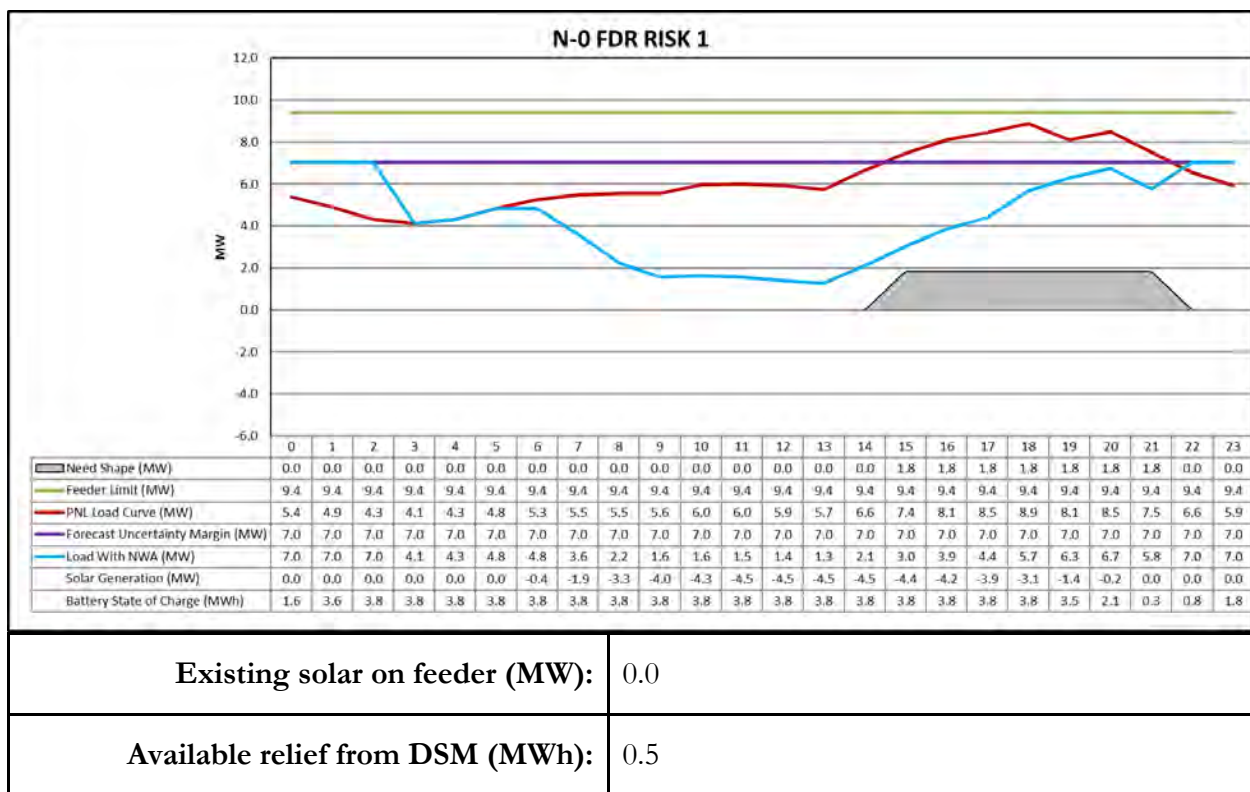
D. Feasible Projects – Reinforce Parkers Lake Feeders

Below is an overview of reinforcing feeder capacity at Parkers Lake.

Capacity risks addressed:	3
Feeder normal overloads:	3
Feeder contingency risks:	0
Transformer normal overloads:	0
Transformer contingencies:	0
Traditional solution:	Upgrade feeder capacity for three Parkers Lake feeders by installing parallel cable in duct and reinforcing feeder reactors inside substation.
NWA solution:	New solar PV systems and battery storage at strategic locations to mitigate risks and keep costs at a minimum.

Figure 8-2 illustrates one of the normal overloads associated with this project.

Figure 8-2
Feeder N-0 Normal Overload Risk



Technology or Technologies:	Solar and Storage
Incremental Solar Capacity (MW):	7.0

Incremental Storage Capacity (MW/MWh):	2.0/8.5
Risk mitigated:	Feeder N-0

Table 8-4 summarizes the optimal DER solution for each risk addressed by this mitigation option.

Table 8-4
Reinforce Parkers Lake Feeders – Summary of DER Solutions

Capacity Risk	Need Shape		Demand Response (MWh)	Optimal DER Solution		
	Overload (MW)	Duration (Hours)		Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)
N-0 FDR RISK 1	1.8	7.0	0.5	0.0	7.0	2.0/8.5
N-0 FDR RISK 2	0.6	6.0	0.08	0.0	7.2	0.0/0.0
N-0 FDR RISK 3	1.0	10.0	0.62	0.0	7.2	1.1/3.8
Total			1.2	0.0	21.4	3.1/12.3

Table 8-5 summarizes the overall incremental net impact of the optimal NWA solution, including a detailed view of the incremental impact of each cost/benefit category.

Table 8-5
Reinforce Parkers Lake Feeders – Costs and Benefits Summary

	Incremental Impact
Energy Generation	\$ 1,132,843
Generation Capacity + MISO Reserves	\$ 273,522
Transmission Capacity	\$ 12,986
Deferral Benefit	\$ 349,009

GHG Emissions + Other Environmental	\$ 1,472,577
Solar Cost	\$ (955,538)
Battery Cost	\$ (306,017)
Interconnection Fees	\$ (102,000)
Total Benefit	\$ 3,240,937
Total Cost	\$ (1,364,125)
Net Impact	\$ 1,876,812

Incremental Net Impact		NWA Solution	
		Least Cost-Effective Solution	Optimal Solution
Discount Rate	WACC	-\$21 -\$212,223.40	\$1,877,102.51\$1,876,811.73
	Societal	-\$167,7 -\$167,738.37	\$1,613,916.68

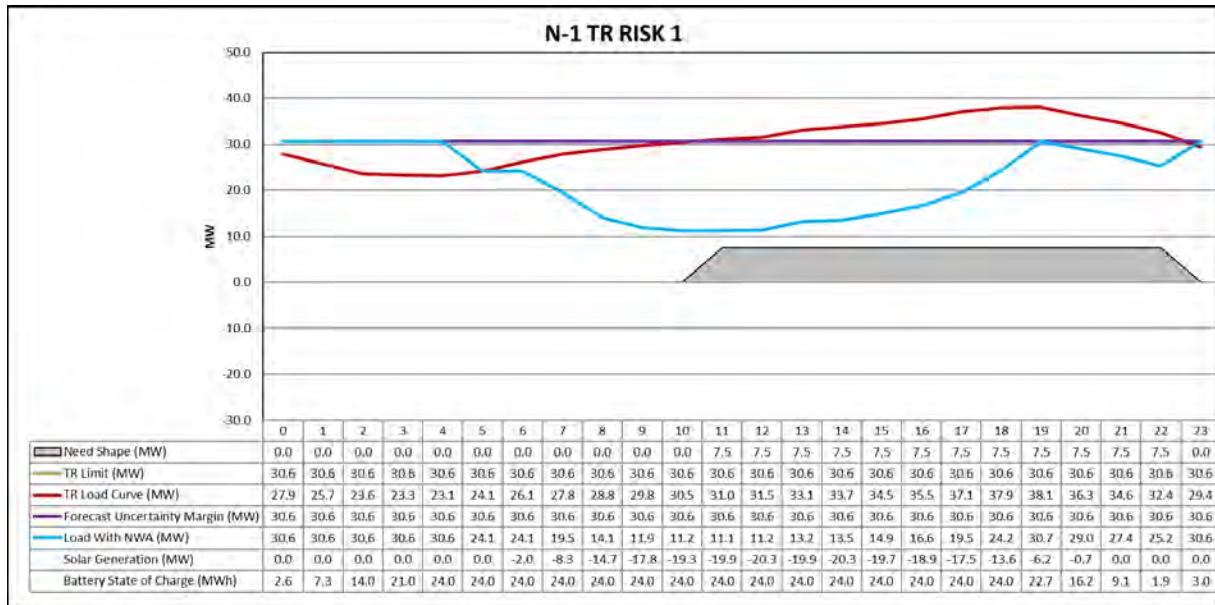
E. Feasible Projects – Reinforce Coon Creek CNC TR1 to 50MVA

Below is an overview of upgrading a transformer at the Coon Creek substation.

Capacity risks addressed:	1
Feeder normal overloads:	0
Feeder contingency risks:	0
Transformer normal overloads:	0
Transformer contingencies:	1
Traditional solution:	Upgrade substation transformer to 50MVA
NWA solution:	New solar PV systems and battery storage at strategic locations to mitigate risks and keep costs at a minimum.

Figure 8-3 illustrates the load at risk in the event of a failure of one of the project's associated transformers.

Figure 8-3
Transformer N-1 Contingency Load Risk



Existing solar on feeder (MW):	0.0
Available relief from DSM (MWh):	0.0
Technology or Technologies:	Solar and Storage
Incremental Solar Capacity (MW):	31.2
Incremental Storage Capacity (MW/MWh):	88.3/249.1
Risk mitigated:	Transformer N-1

Table 8-6 summarizes the optimal DER solution for each risk addressed by this mitigation option.

Table 8-6
Load Transfer CNC Transformer – Summary of DER Solutions

Capacity Risk	Need Shape		Demand Response (MWh)	Optimal DER Solution		
	Overload (MW)	Duration (Hours)		Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)
N-1 TR RISK 1	7.5	12.0	0.0	0.0	31.2	88.3/249.1
Total			0.0	0.0	31.2	88.3/249.1

Table 8-7 summarizes the overall incremental net impact of the optimal NWA solution, including a detailed view of the incremental impact of each cost/benefit category.

Table 8-7
Load Transfer CNC Feeder – Costs and Benefits Summary

Cost/Benefit Category	Incremental Impact
Energy Generation	2,233,771.00
Generation Capacity + MISO Reserves	568,527.50
Transmission Capacity	26,991.52
Deferral Benefit	\$474,945
GHG Emissions + Other Environmental	\$2,302,514
Solar Cost	\$(1,713,302)
Battery Cost	\$(1,728,547)
Interconnection Fees	\$(34,000)
Total Benefit	\$5,606,749
Total Cost	\$(3,475,849)
Net Impact	\$2,130,901

Incremental Net Impact		NWA Solution	
		Least Cost-Effective Solution	Optimal Solution
Discount Rate	WACC	-\$1,194,945.27	\$2,130,900.51

	Societal	-\$1,441,806.25	\$1,933,034.47

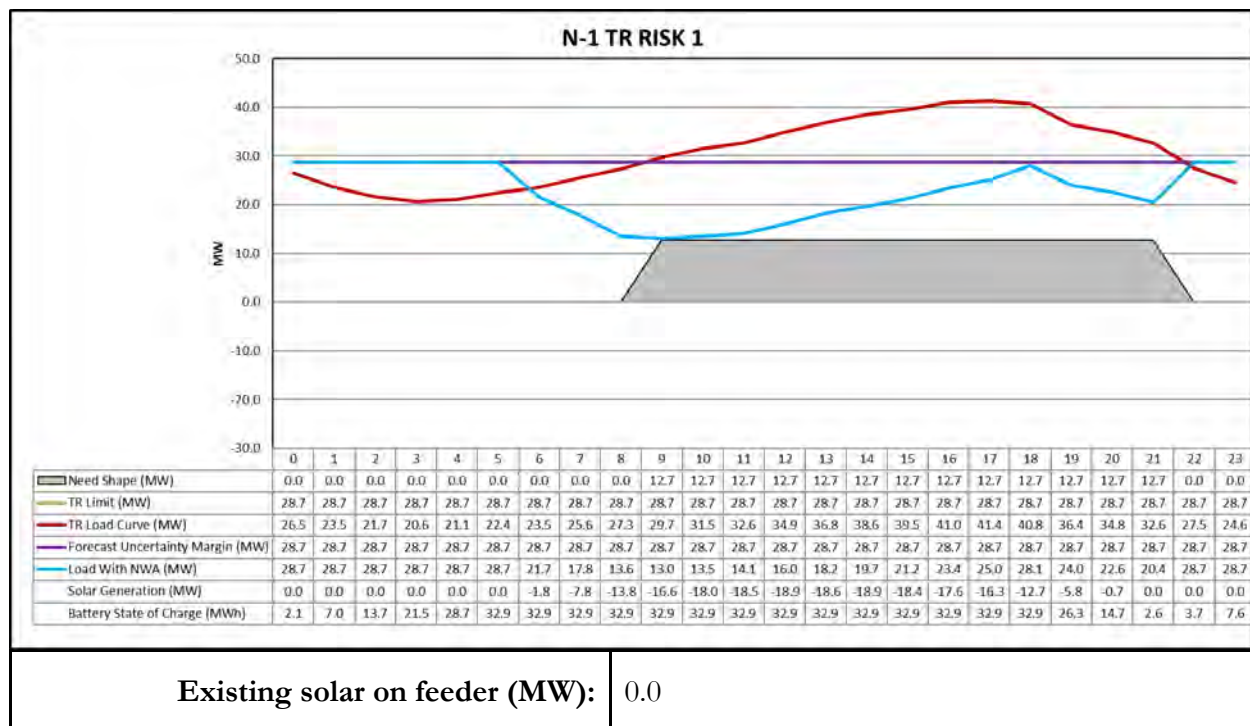
F. Feasible Projects – Reinforce Elm Creek TR1 to 50MVA

Below is an overview of reinforcing a transformer at Elm Creek substation.

Capacity risks addressed:	2
Feeder normal overloads:	0
Feeder contingency risks:	0
Transformer normal overloads:	1
Transformer contingencies:	1
Traditional solution:	Upgrade substation transformer to 50MVA
NWA solution:	New solar PV systems and battery storage at strategic locations to mitigate risks and keep costs at a minimum.

Figure 8-4 illustrates the amount of load at risk if one of the project’s associated transformers fails.

Figure 8-4
Transformer N-1 Contingency Load Risk



Available relief from DSM (MWh):	0.0
Technology or Technologies:	Solar and Storage
Incremental Solar Capacity (MW):	29.1
Incremental Storage Capacity (MW/MWh):	13.8/239.6
Risk mitigated:	Transformer N-1

Table 8-8 summarizes the optimal DER solution for each risk addressed by this mitigation option.

Table 8-8
Load Transfer ECK Transformer – Summary of DER Solutions

Capacity Risk	Need Shape		Demand Response (MWh)	Optimal DER Solution		
	Overload (MW)	Duration (Hours)		Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)
N-1 TR RISK 1	12.7	13.0	0.0	0.0	29.1	13.8/239.6
N-0 TR RISK 1	0.6	3.0	6.67	0.0	22.9	0.0/0.0
Total			0.0	0.0	52.0	13.8/239.6

Table 8-9 summarizes the overall Incremental Net Impact of the optimal NWA solution, along with a detailed breakdown of each cost and benefit category.

Table 8-9
Reinforce Elm Creek TR1 to 50MVA – Costs and Benefits Summary

Cost/Benefit Category	Incremental Impact
Energy Generation	\$ 2,676,768
Generation Capacity + MISO Reserves	\$ 963,640

Transmission Capacity	\$ 45,750
Deferral Benefit	\$ 930,892
GHG Emissions + Other Environmental	\$ 2,655,563
Solar Cost	\$ (1,976,005)
Battery Cost	\$ (3,230,915)
Interconnection Fees	\$ (68,000)
Total Benefit	\$ 7,272,613
Total Cost	\$ (5,274,920)
Net Impact	\$ 1,997,692

Incremental Net Impact		NWA Solution	
		Least Cost-Effective Solution	Optimal Solution
Discount Rate	WACC	-\$2,165,349.40	\$1,997,692.48
	Societal	-\$2,165,349.40	\$930,892.20

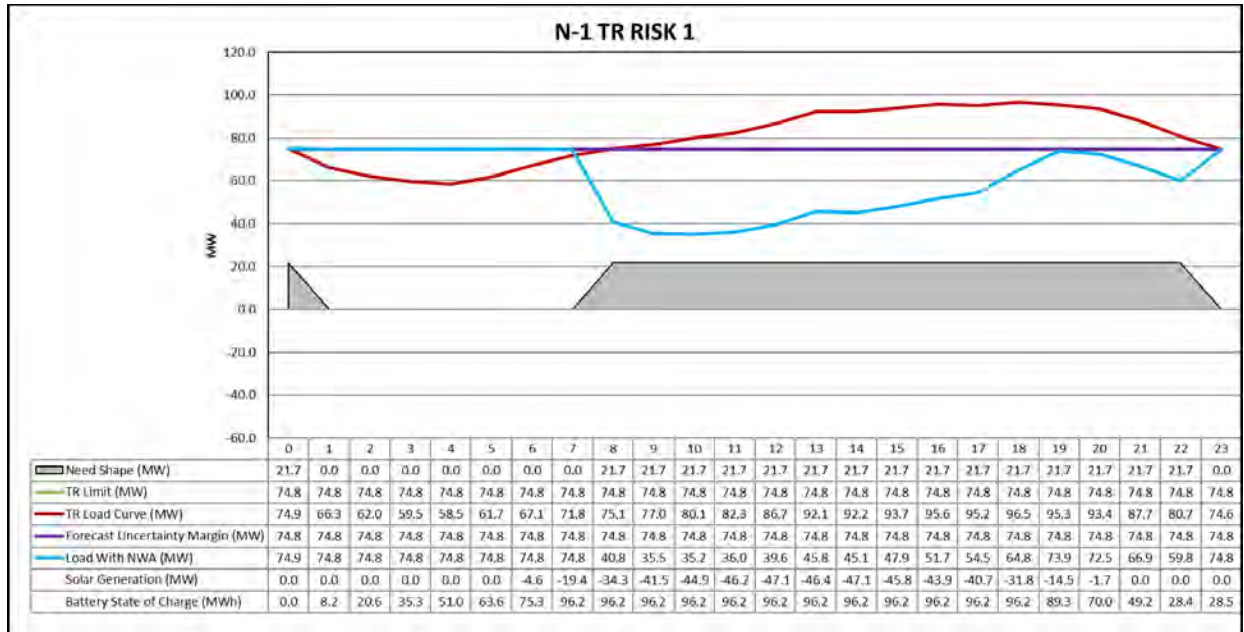
G. Feasible Projects – Install Osseo OSS TR3

Below is an overview of installing a third transformer at Osseo substation.

Capacity risks addressed:	2
Feeder normal overloads:	1
Feeder contingency risks:	0
Transformer normal overloads:	0
Transformer contingencies:	1
Traditional solution:	Install 3 rd transformer at Osseo substation
NWA solution:	New solar PV systems and battery storage at strategic locations to mitigate risks and keep costs at a minimum.

Figure 8-5 illustrates the amount of load at risk if one of the project's associated transformers fails.

Figure 8-5
Transformer N-1 Contingency Load Risk



Existing solar on feeder (MW):	0.0
Available relief from DSM (MWh):	0.0

Technology or Technologies:	Solar and Storage
Incremental Solar Capacity (MW):	72.6
Incremental Storage Capacity (MW/MWh):	23.6/419.8
Risk mitigated:	Transformer N-1

Table 8-10 summarizes the optimal DER solution for each risk addressed by this mitigation option.

Table 8-10
Install Osseo OSS TR3 – Summary of DER Solutions

Capacity Risk	Need Shape		Demand Response (MWh)	Optimal DER Solution		
	Overload (MW)	Duration (Hours)		Existing Solar PV (MW)	Incremental Solar PV (MW)	Battery Storage (MW/MWh)
N-1 TR RISK 1	21.7	15.0	0.0	0.0	72.6	23.6/419.8
N-0 FDR RISK 1	2.6	11.0	2.1	0.0	9.7	2.8/28.2
Total			2.1	0.0	82.3	26.4/448.0

Table 8-11 summarizes the overall Incremental Net Impact of the optimal NWA solution, along with a detailed breakdown of each cost and benefit category.

Table 8-11
Install Osseo OSS TR3 – Costs and Benefits Summary

Cost/Benefit Category	Incremental Impact
Energy Generation	\$7,657,654
Generation Capacity + MISO Reserves	\$1,845,000
Transmission Capacity	\$87,594
Deferral Benefit	\$873,899
GHG Emissions + Other Environmental	\$7,661,476
Solar Cost	\$(5,700,907)
Battery Cost	\$(7,864,885)
Interconnection Fees	\$(68,000)
Total Benefit	\$18,125,622
Total Cost	\$(13,633,792)
Net Impact	\$4,491,830

Incremental Net Impact		NWA Solution	
		Least Cost-Effective Solution	Optimal Solution
Discount Rate	WACC	-\$6,145,347.08	\$4,491,830.19

	Societal	-\$6,420,535.01	\$4,386,849.17

III. PLAN TO ISSUE A REQUEST FOR PROPOSAL

Order Point No. 26 of the Commission’s September 16, 2024 Order states:

Xcel shall conduct a Request for Information (RFI) process to assess the feasibility of its planned Non-Wires Alternatives solicitation, including the proposed “ARR split” compensation, and make a compliance filing reporting on the results of the RFI within 12 months of this order.

Per the Commission's Order, we proceeded with the following proposed timeline after the 2024 NWA analysis:

Step	Target Date
Issue RFI	January 6, 2025
RFI Responses Due	February 6, 2025
RFI Report Submitted to the Commission	April 1, 2025
Start of 2025 NWA Analysis	July 1, 2025

The RFI received one response from the MN Department of Commerce but no responses from the developer community. This RFI sought feedback on:

- The feasibility of future NWA solicitations.
- The feasibility of the proposed “ARR split” compensation for NWA solution providers.
- Examples of successful NWAs, recommendations for improvements, and key insights from experiences with NWAs.

That being said, the Company is committed to pursuing the potential benefits of NWAs. Therefore, we lay out the following plan:

The projects for which we intend to go out to RFP are the **Reinforce Parkers Lake feeders** and **Reinforce Coon Creek CNC TR1 to 50 MVA** projects. We identified these projects as good candidates for our first solicitation because they both reflect the possibility of being cost-beneficial, and also require the smallest amount of incremental DER. These factors make them the most feasible for successfully siting DER and implementing an NWA in developed suburbs.

To better understand how we can enhance our NWA analysis, we are proposing to issue an RFP to gauge market interest in developing these two NWA projects no later than June 1, 2026. Responses to the RFP would then be due 60 days after the issuance

of the RFP, or by July 31, 2026. The Company would then review the bids received and consider selecting a project within 60 days from the response due date, or by September 30, 2026. We would then include a summary of the results of the RFP in our 2026 IDP Annual Update on November 1, 2026. We summarize this timeline in the following table:

Step	Target Date
Issue RFP	No later than June 1, 2026
RFP Responses Due	July 31, 2026
Bid Review and Project Selection	September 30, 2026
RFP Report Submitted to the Commission (Included in 2026 IDP Annual Update Report)	November 1, 2026

IV. NWA ANALYSIS IN THE PLANNING PROCESS

In Section II, we outlined the projects evaluated for potential NWAs. Here, we explain how this year’s NWA analysis fits into our broader system planning process.

A. Overview

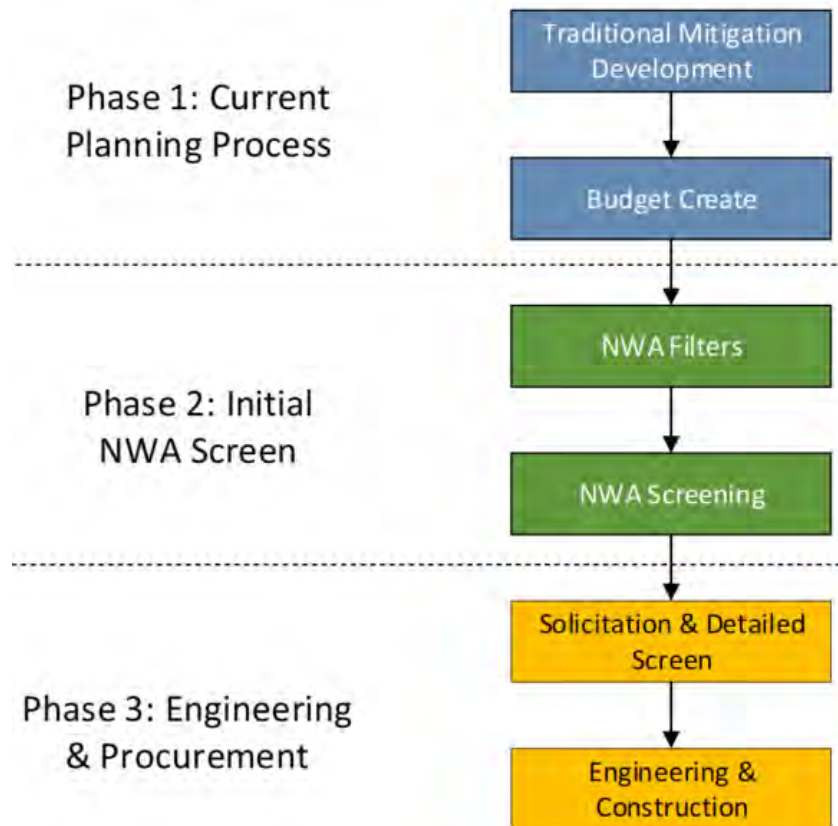
Today, NWA analysis is highly manual and time-intensive—especially as project risks increase. The process involves extracting peak load curves from LoadSEER for feeders and substation transformers, blending them for unique contingency scenarios, and layering in demand response (DR), existing generation, and additional solar as needed. These inputs help determine final energy and demand values used to size appropriate energy storage devices for each identified risk the traditional project aims to mitigate.

As our NWA analysis evolves and we consider future solicitations and requirements, additional staffing may be necessary to sustain and advance this work.

Many capacity projects with budgets over \$2 million involve multiple risks, significantly increasing the complexity of NWA solutions and the resources needed for analysis. In contrast, projects with fewer risks tend to be more localized and easier to evaluate. We also seek opportunities to deploy resources that can mitigate multiple risks by placing them strategically within the system.

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

Figure 8-6
NWA Analysis Process Phases Appended to Existing Planning



We expect future tool enhancements to help streamline the NWA analysis process. While much of the work will remain manual for now, we are actively engaging with industry partners to drive improvements and are evaluating existing tools that could automate complex but repeatable aspects of NWA analysis.

B. Approach

For each project that meets our screening criteria, we analyze the peak load curve for each affected feeder or transformer, forecasting five years beyond the traditional project's in-service date. These forecasts use LoadSEER data, which incorporates both known and probabilistic DER and electrification adoption. This five-year outlook aligns with the assumed deferral window in our analysis.

We then apply targeted demand response (DR) to reduce peak load, followed by energy storage and/or solar generation to address any remaining deficiencies. In some cases, existing solar on specific feeders was also factored into the analysis.

IDP Requirement No. 3.E.2. requires in part that the Company:

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

Per IDP Requirement No. 3.E.1, the Company reviews traditional projects with costs exceeding \$2 million.

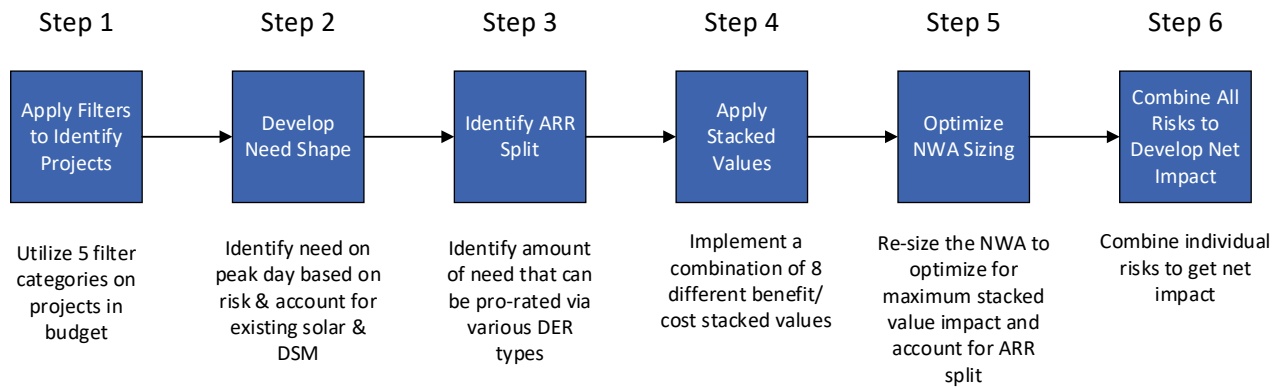
Our current planning process for NWAs follows three phases:

- *Phase 1:* Traditional mitigations are developed and submitted through the budget creation process.
- *Phase 2:* Budgeted projects are evaluated using NWA filters and a screening tool. Projects that pass move to Phase 3.
- *Phase 3:* Engineering and procurement begin. Projects are solicited, and bids undergo detailed screening. If bids are shown to be cost-beneficial, the project proceeds to final engineering, construction, and commissioning.

C. Initial NWA Analysis Steps

In conducting NWA analysis, our primary focus is on the steps outlined in Phase 2 of Figure 8-6, which includes the Initial NWA Screen. This process is further detailed through six key steps, illustrated in Figure 8-7 below:

Figure 8-7
The Six Steps of the Initial NWA Screen



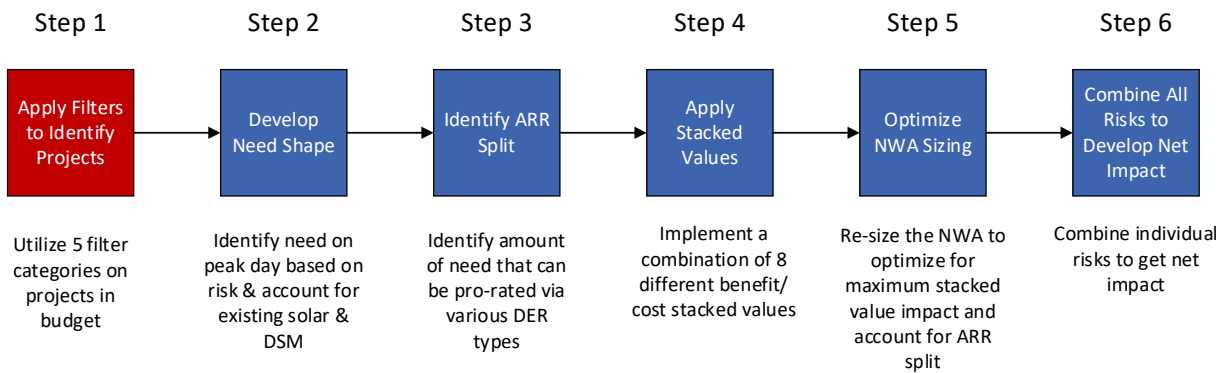
The first step in NWA analysis involves applying filters to identify eligible projects. Once a project list is established, we develop a *need shape*—a load reduction requirement that represents the amount of risk to be mitigated under a potential power purchase agreement (PPA) with an NWA developer. This need shape accounts for the load-reducing effects of existing solar and demand response programs.

Next, we determine the Avoided Revenue Requirement (ARR) split, which estimates the proportion of solar and battery storage needed to meet the need shape. This percentage is later used in Step 5 during optimization and cost analysis.

Following the ARR split, we estimate stacked values—eight key benefit and cost components that can be reasonably assessed during the initial screen. If the project advances past this stage, additional stacked values are considered during detailed engineering based on bid specifics.

We then optimize the mix of technologies to maximize stacked value and align with the ARR split. Finally, the optimal NWA solutions for each risk are aggregated to calculate the total net impact, which indicates whether the project is likely to be cost beneficial.

Here, we discuss Step 1: Apply Filters to Identify Projects. Steps two through six are discussed in Section VII: Risk Type, Size, and Quantity, as those steps can occur only after project types are identified and timelines have been established.



In the initial screen and consistent with our 2024 analysis, we apply a set of filters to traditional projects in the budget to identify which projects are appropriate to consider for NWA analysis. Projects must meet the following criteria to pass these filters and move to NWA analysis:

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

V. PROJECT TYPES

IDP Requirement No. 3.E.2 requires, in part, that the Company provide
...information on ...Project types that would lend themselves to non-traditional solutions (i.e. Load relief or reliability)

This section outlines the three project types considered in our NWA analysis: mandates, asset health and reliability, and capacity. We also explain why capacity projects are generally the most suitable for non-traditional solutions.

A. Mandated Projects

Mandated projects require the Company to relocate infrastructure within public rights-of-way to accommodate public initiatives, such as road widenings or realignments. NWAs are generally not suitable for these projects due to technical constraints. If infrastructure is not replaced, some customers would lose physical connection to the grid and would need to be served through local alternatives like distributed generation.

However, serving customers independently undermines the interconnected nature of the distribution system, which is essential for reliability. Interconnectedness allows for switching customers between feeders during maintenance or outages, providing flexibility and redundancy. Disconnecting customers from the grid compromises these benefits and is not a viable long-term solution.

Additionally, mandated projects are often driven by municipal or state funding timelines and may not appear in the Company's five-year budget, especially beyond one to two years. These projects typically require completion before the public work begins. For example, a municipality may allocate funding two years before construction starts, with design completed in the first year. This leaves the Company less than a year to design, fund, and relocate infrastructure—making it impractical to implement a detailed NWA within such a compressed timeframe.

B. Asset Health and Reliability Projects

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

Keeping customers connected to the grid is the major reason Asset Health and Reliability projects are not suitable for NWAs. If we chose not to replace distribution infrastructure due to aging assets, there is a high level of risk that certain assets would fail, and customers would experience an outage. To avoid or prevent the outage the customers would need to be served via some other local islanded generation. From a reliability perspective, at some point our customers would need to be hooked back up to the distribution grid rather than staying in a permanent microgrid. Because asset health affects every part of the distribution system and is essential to maintaining reliability, an NWA is not workable.

C. Capacity Projects

Capacity projects are well-suited for NWAs because they address load deficiencies that can be deferred or mitigated by strategically placed DER. DER that generates, discharges, or reduces electricity consumption downstream on a feeder can reduce the load flowing through the substation.

Unlike mandated projects, capacity projects are not externally required, so each is prioritized based on a cost-benefit score. For an NWA to be viable, it must be cost-competitive with traditional solutions, aligning with our strategic goal of maintaining affordable bills while balancing system needs.

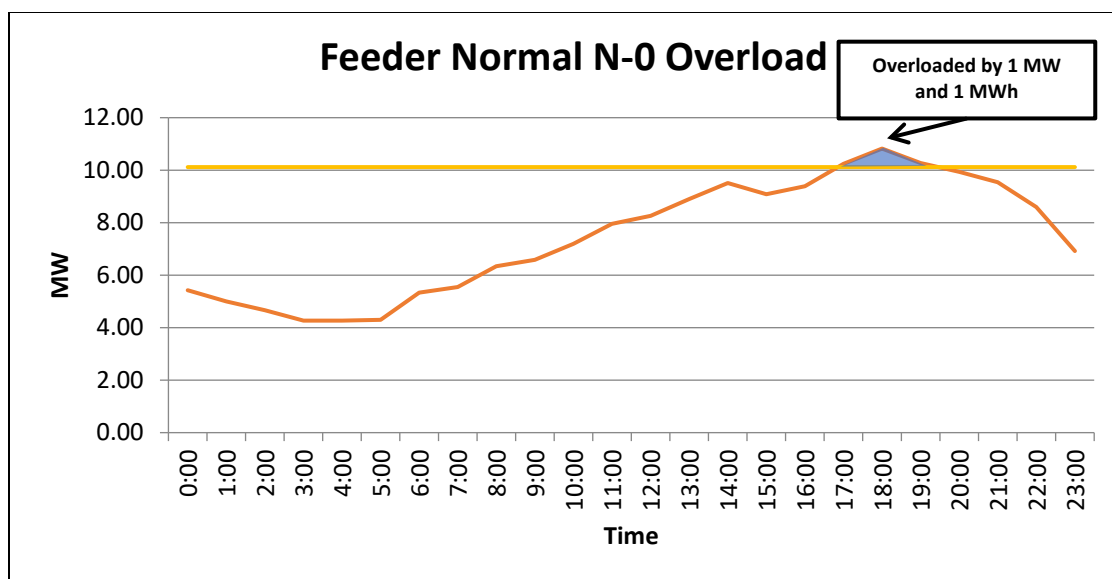
Capacity risks fall into two categories:

- *N-0 (system intact)*: Normal overloads under standard operating conditions.
- *N-1 (first contingency)*: Overloads that occur when a single system element fails.

Planning criteria require mitigation for all N-0 risks exceeding 75 percent loading and all N-1 risks. NWA viability varies between these categories due to the nature of the risks.

N-0 risks typically involve substation transformers or feeders that exceed the 75 percent threshold. Below, we provide an example of an N-0 overload that surpasses the 100 percent feeder limit.

Figure 8-8
Illustrative N-0 Overload

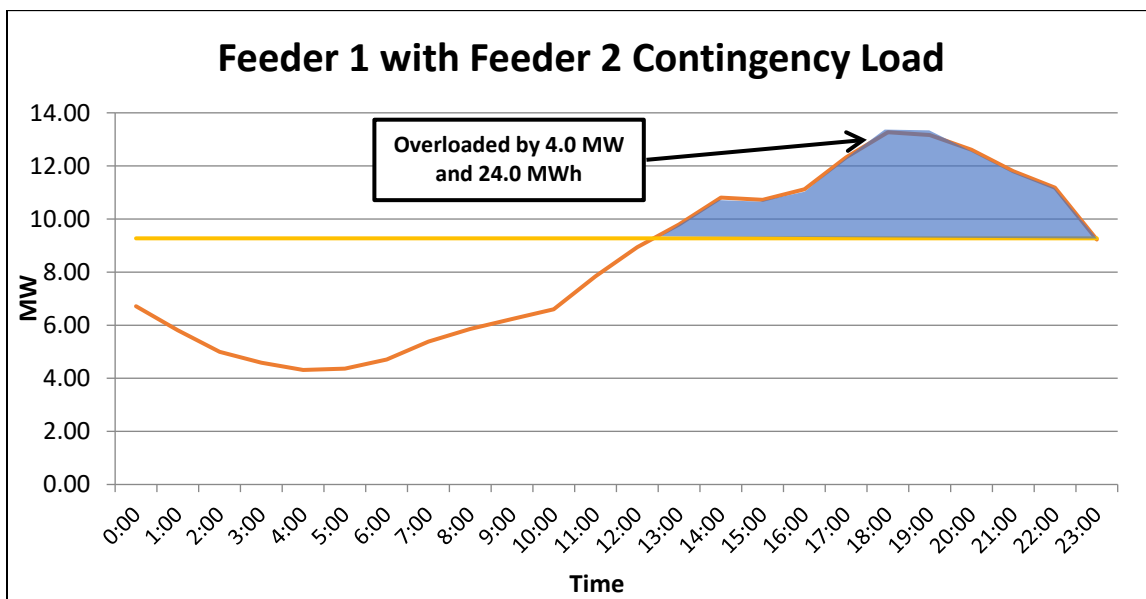


In Figure 8-8, the overload is relatively minor, peaking at 1 MW. Due to its small magnitude, the duration is brief, resulting in approximately 1 MWh of total overload.

N-1 overloads occur when a feeder fails and its load is redistributed to adjacent feeders, potentially causing overloads. These events typically result in greater magnitude and duration than N-0 risks, making them less suitable for NWA solutions.

Figure 8-9 illustrates an N-1 scenario: if Feeder 2 experiences an outage, its load is divided into three sections. The first and third sections can be transferred to adjacent feeders without issue. However, transferring the second section to Feeder 1 causes a 4 MW overload. The resulting peak day load curve for Feeder 1, post-transfer, is shown below.

Figure 8-9 Peak Day Load Curve for Feeder 1 After Transfer of Feeder 2, Section 2 Load



The illustrative N-1 overload in Figure 8-9 shows a typical magnitude for risks requiring mitigation—4.0 MW at risk. However, even this moderate load results in a prolonged overload duration of 10 hours. Compared to the smaller and shorter N-0 overload in Figure 8-8, both the magnitude and duration of the N-1 risk are significantly greater. As a result, N-1 risk-driven projects are generally less viable for NWA solutions.

VI. TIMELINE

IDP Requirement No. 3.E.2 requires in part that the Company:

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

For this analysis, we assume a three-year timeline is generally needed to properly evaluate and implement most NWA solutions. However, due to recent increases in lead times for substation transformers, traditional projects involving these components require a minimum of four years to allow for a full NWA evaluation. These timelines include internal analysis and all steps in the RFP process—issuing, receiving, screening, technical and sourcing reviews, contract negotiations, regulatory approvals, and construction.

If an NWA proves infeasible or no bids are received, this timeline still allows the Company to proceed with the traditional project and meet the original in-service date. This approach aligns with timelines used by other utilities in similar analyses. That said, ongoing supply chain constraints—affecting not only transformers but other key materials—may require future adjustments. We may need to limit NWA consideration to projects with at least five years before the required in-service date.

VII. RISK TYPE, SIZE, QUANTITY

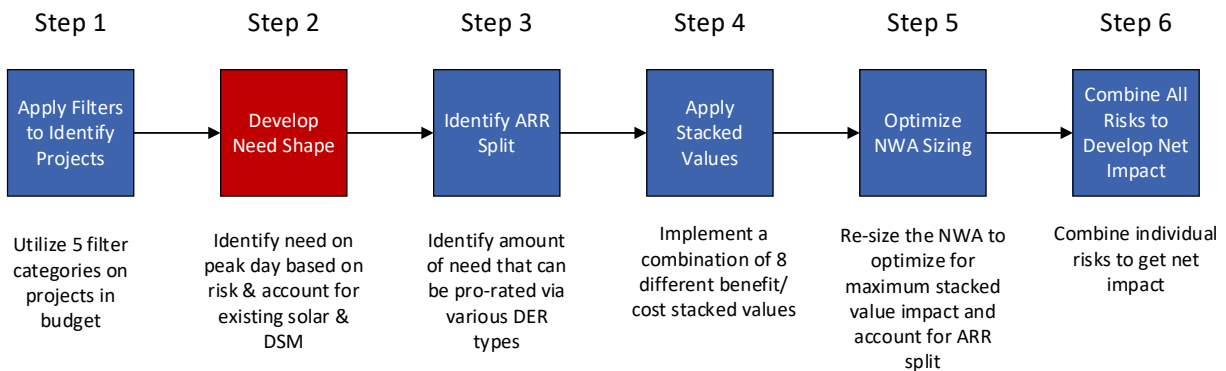
Since we began conducting broad NWA analysis in 2019, we observed that some traditional projects were being included in the analysis that were not actually feasible. These infeasible projects were either mitigating excessive quantities of risks (greater than five risks), mitigating risks that existed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

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

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

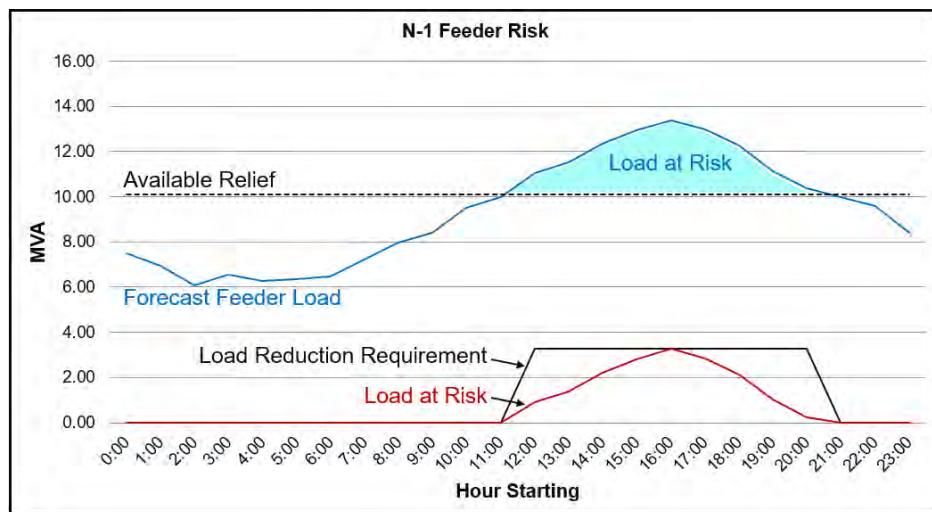
Step 1 is outlined in Section V.B., with the balance of the process outlined below.

Step 2: Develop Need Shape



After a project list has been identified, the initial NWA screening can begin. The first component of this involves developing a need shape. Figure 8-10 below reflects a simplified example of a need shape for a N-0 normal overload.

Figure 8-10
Load Reduction Requirement



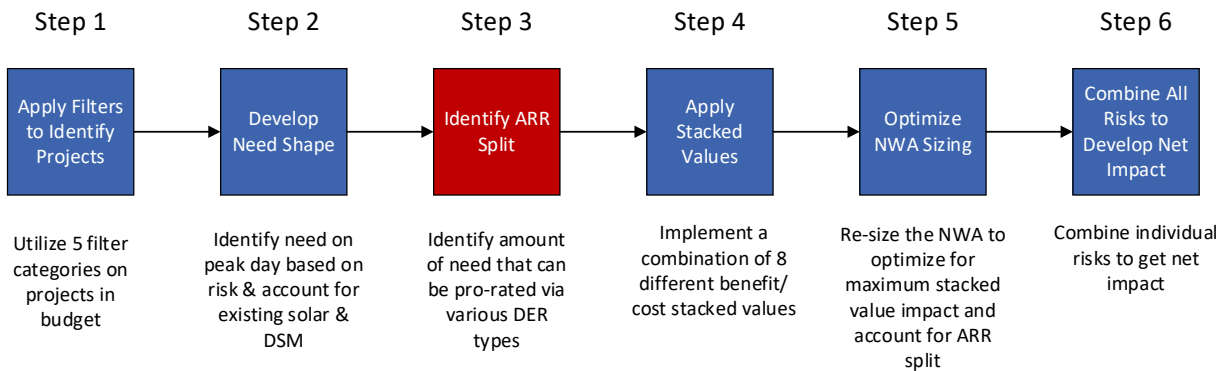
The need shape for NWA risks is described as the required peak contribution for the duration of the risk. This enables the Company to account for uncertainties in the forecasted load shape. This approach to load reduction is consistent with NWA load reduction contract structures seen in the industry. Figure 8-10 illustrates the need shape as the “Load Reduction Requirement” at the bottom.

In the figure above, the forecasted feeder load exceeds the capacity which indicates an overload. The need shape, which is also known as the load reduction requirement, is

sized based on the peak of the load at risk and extends across all hours for which load is at risk. This reflects the general format for how the Company anticipates an NWA project will be structured in the context of a PPA with an NWA developer.

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

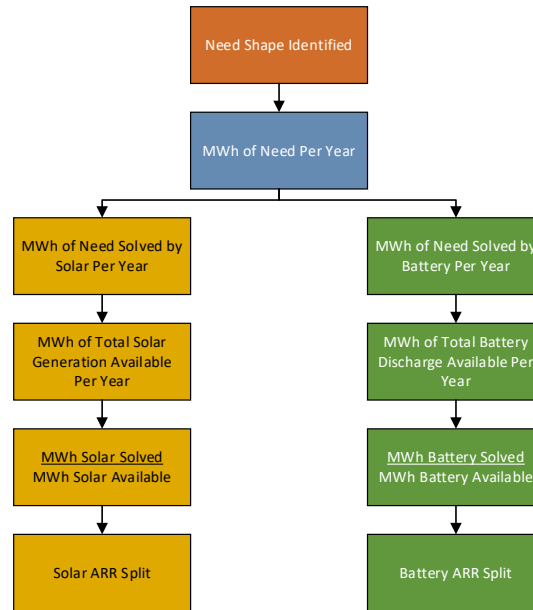
Step 3: Identify ARR Split



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

The ARR split represents the pro-rated NWA costs and stacked values that are proportional to the contribution of the DER to solving the risks. Figure 8-11 below reflects a flow chart of how ARR split is calculated:

Figure 8-11
Flow Chart Depicting ARR Split Calculation



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

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

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

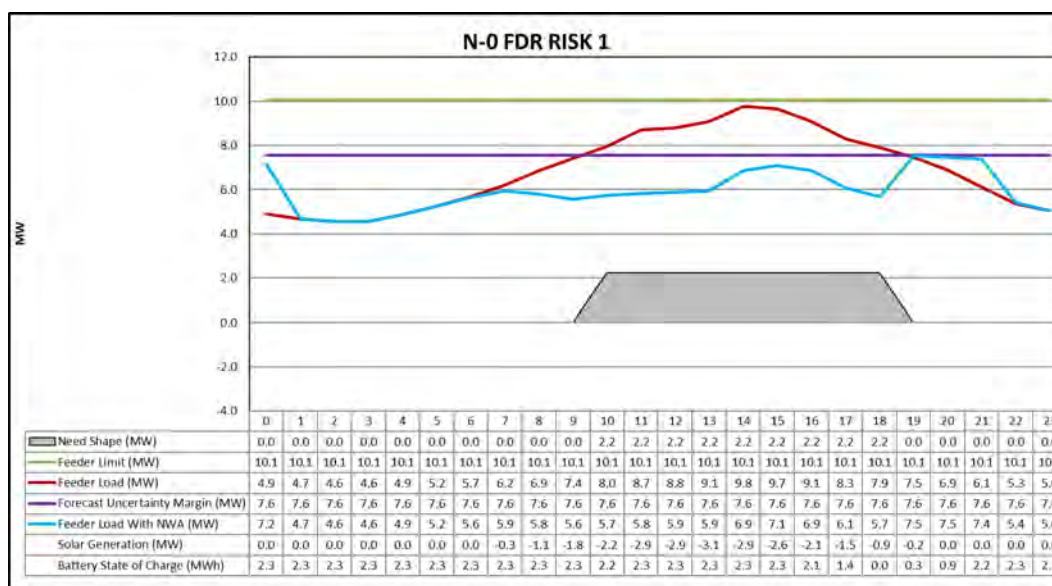
$$ARR\ Split_{Solar} = \frac{MWh\ Solar\ Used\ for\ NWA\ Annually}{MWh\ Solar\ Available\ Annually}$$

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

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

Bringing the need shape and ARR split concepts together, Figure 8-12 below reflects an example of an N-0 risk.

Figure 8-12
Example N-0 Risk



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

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

With the duration of the need shape extending to 6 p.m., the solar generation alone cannot meet the need shape, so battery storage is required to supplement. For battery storage, there needs to be enough hours with available grid capacity to first charge before it can then discharge when solar is not available for each 24-hour load cycle. For the solar ARR split, the amount of total MWh of solar generation available per year from the required solar (estimated using the solar curve) is 15,403 MWh.

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

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

The final ARR splits for the solar and battery storage required for the NWA solution are 26 percent and 24 percent, respectively. The results are summarized in Table 8-12 below.

Table 8-12
ARR Split Example

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

A. ARR Split Impacts

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

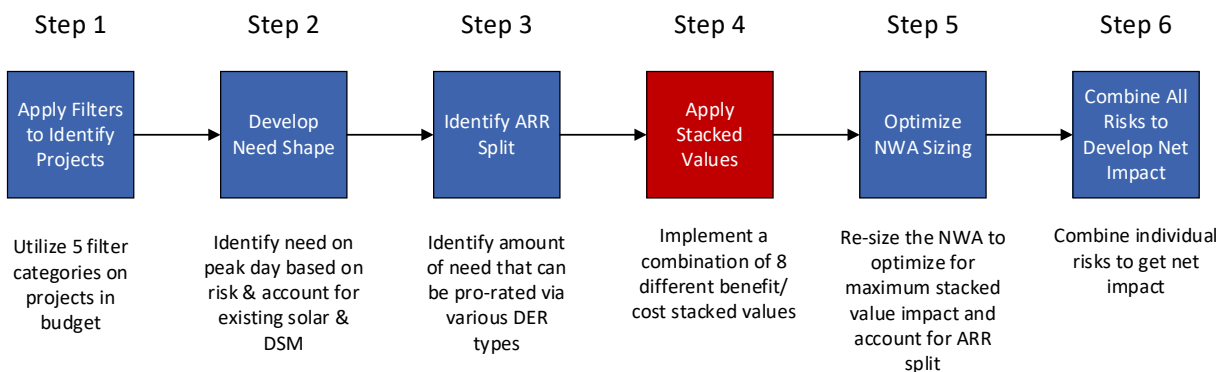
The ARR split concept can be described as prorating NWA costs and stacked values proportional to the fraction of NWA DER output that solves the system risk. For example, consider a 1 MW solar installation that produces 2,000 MWh annually, but only 400 MWh throughout the year are during the needed load reduction period. In

this case, costs and benefits would prorate to 20 percent of the total to reflect the portion of the NWA necessary to solve the risk and defer the traditional solution. Further, the costs of energy storage are additionally prorated based on the percentage of the energy storage system's useful life that is needed for the deferral period. For example, consider a battery storage system that has a useful life of 15 years, of which it will only be needed for the five years of the NWA deferral period. In this case, the cost of the battery storage would prorate to one-third of the total battery storage cost to reflect the portion of the battery's life that is needed for the NWA. This structure reflects NWA approaches at other utilities and allows potential NWA providers (including the Company) to own the DERs and leverage their projects for other needs or uses cases outside of the load reduction period.

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

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

Step 4: Apply Stacked Values



As we have noted, we engaged with stakeholders to explore ways to advance our NWA analysis, including screening criteria, analysis methodology and assumptions,

and evaluation parameters.² We also explored how we might include a broader set of costs and benefits in future NWA analyses, which is sometimes referred to as “stacked values.”

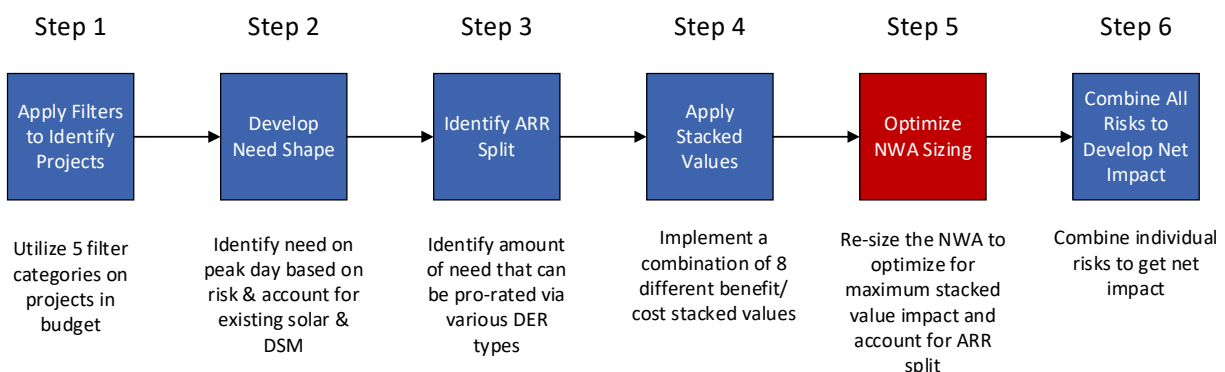
Within the initial cost-benefit screening, we conduct a comprehensive assessment, in which we analyze market inputs and develop stacked values with the resulting data. During Phase 2, the initial NWA screen, a set of discrete stacked values are considered as defined in the National Standards Practice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

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

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

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

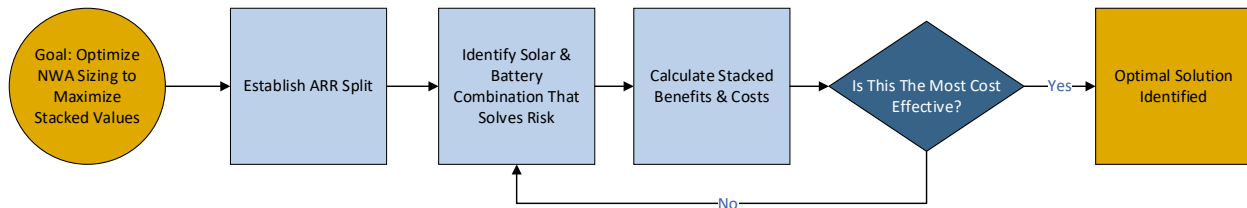
Step 5: Optimize NWA Sizing



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

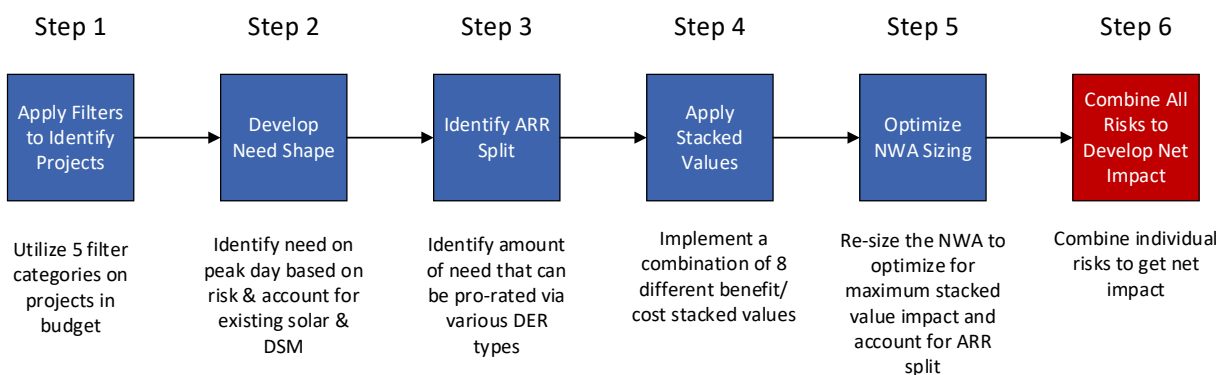
After the stacked values are calculated and applied in the NWA analysis, NWA sizing is optimized to maximize the stacked value impact. Figure 8-13 below reflects a flow chart of the logic behind the optimization algorithm:

Figure 8-13
Simplified Algorithm for Calculating the Most Cost-Effective Combination of NWA Technologies



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

Step 6: Combine All Risks to Develop Net Impact



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

$$\text{Net Impact} = \text{Total Benefit} - \text{Total Cost}$$

With this formula, if the resultant value is positive, then there is more benefit than cost and the project would be considered cost beneficial. If the value is negative, then the costs exceed the benefits and would not be considered cost beneficial. Because this net impact is based on the results of the initial screen, it does not consider all possible costs and benefits associated with the NWA project. Rather, it represents the most impactful costs and benefits that can reasonably be calculated at an early stage of project development. Therefore, a positive or negative net impact does not absolutely determine whether a project would be cost-beneficial but instead, provides an indication of whether a project would be worth investigating further for an NWA in a market solicitation.

In the example shown in Figure 8-14 below, the traditional project has five different risks with different feeder sections contributing to these risks. The optimal NWA solution for each risk is identified and combined to develop a total benefit, total cost, and resulting net impact.

Figure 8-14
Example Project with Optimal NWA Solution and Stacked Values Identified for Each Risk

Capacity Risk		Need Shape		Optimal DER Solution						Stacked Values Cost Split
Anonymized Name	MW Overload	Duration	MWh Overload Annual	DSM	Solar			Battery Total		
				MWh	Existing MW	New MW	Acres	MW	MWh	
N-1 FDR RISK 1, SECTION 1	0.14	2	24	0.0	0.00	11.5	80	0.00	0.00	\$64,233
N-1 FDR RISK 1, SECTION 2	0.16	1	14	0.0	0.00	10.2	71	0.00	0.00	\$17,895
N-1 FDR RISK 4, SECTION 1	2.07	13	2,340	0.0	0.00	11.4	80	2.25	20.32	\$326,696
N-1 FDR RISK 5, SECTION 1	2.73	10	2,373	0.0	0.00	10.2	71	2.96	21.04	\$910,257
N-1 FDR RISK 6, SECTION 1	2.35	8	1,633	0.0	0.00	13.5	94	2.55	15.50	\$775,223
N-1 FDR RISK 7, SECTION 3	0.09	1	8	0.0	0.00	9.0	63	0.00	0.00	\$37,620
TOTAL	61.60	83	62,772	0.00	0.00	65.80	461	7.76	56.85	\$2,131,925

For each risk, the need shape is identified as well as the optimal DER solution, which can comprise demand response, solar, and battery storage. The stacked values cost split represents how much each risk contributes to the total net impact. Adding up each of these stacked value cost splits comprises the cost and benefits summary shown in Figure 8-15. In this case, the total benefit exceeds the total cost, resulting in a positive net impact.

Figure 8-15
Individual Cost and Benefit Calculations for an Example Project, Used to Calculate the Net Impact

Cost and Benefits Summary	
Energy Generation	\$1,544,526
Generation Capacity + MISO Reserves	\$473,600
Transmission Capacity	\$20,332
Deferral Benefit	\$800,717
GHG Emissions + Other Environmental	\$2,112,750
Solar Cost	\$(2,177,637)
Battery Cost	\$(438,363)
Interconnection Fees	\$(204,000)
Total Benefit	\$4,951,924
Total Cost	\$(2,819,999)
Net Impact	\$2,131,925

One key contributor to the cost effectiveness of this project is the impact of the ARR split pro-rating the cost for the DER in the NWA solution. The actual, total cost to install the DER would be considerably higher than reflected in the stacked values – the costs shown in the stacked values represent only the prorated portion of the total DER costs that would be allocated to the NWA and paid for by the Company. As a result of this, the actual capital costs would be higher than is represented in the stacked values, and it is assumed that the owner of the DER asset would be willing to install the DER at their own cost with the Company contributing only the pro-rated amount itemized in the stacked values.

Additionally, the results shown above represent the “optimal” NWA solution as determined in the NWA analysis methodology. The NWA methodology determines the optimal solution by selecting the unique combination of solar and energy storage that mitigates the risks but also maximizes the incremental net impact. However, this optimization naturally leads the model to maximize the amount of solar incorporated in the NWA solution due to the higher rate of benefit accrual for solar compared to energy storage. While the maximum amount of solar that can be accommodated in the solution was constrained by the feeder Technical Planning Standard (TPS), it was not constrained by other factors such as land availability for hosting solar PV.

Therefore, the optimal solution may not be a realistic solution based on what can actually be built; the most realistically buildable solution may be sub-optimal and would yield a lower incremental net impact.

At this point, the initial NWA screen is completed for this project. If the project passes the screen with a positive cost-benefit then Phase 3, the Engineering and Procurement stage, would be the next step for the NWA project.

VIII. 2025 NWA ENHANCEMENTS

In the 2025 NWA analysis, we introduced minor process enhancements, with a focus particularly on N-0 risks. A key improvement was the integration of planned net loading (PNL) into the analysis process for both feeders and substation transformers. These enhancements enable the Company to more accurately account for the dependability of solar photovoltaic (PV). By applying the PNL methodology, which applies an expected dependability factor to each solar PV, the NWA solutions become dependent on the solar operating as anticipated during peak conditions. If the solar is not available during peak conditions or underperforms relative to its assumed dependability, grid reliability could deteriorate, which could potentially result in equipment overloads, failures, and outages. See Chapter 1 for more detail on our PNL methodology.

IX. ASSUMPTIONS AND CALCULATIONS

For all NWA studies, we made reasonable assumptions toward streamlining the process. Our goal in these studies is to reduce overloads down to 75 percent of the capacity rating and contingencies with a 25 percent forecast uncertainty margin down to 100 percent of the capacity rating based on the forecasted loading at the end of the deferral period. While the forecast uncertainty margin provides some flexibility, there is no “spare” capacity in these solutions and any additional load growth not planned for in the load forecast or the forecast uncertainty margin could cause additional risk; it would ultimately require an additional risk analysis, associated mitigation, and potentially another NWA analysis to address this incremental risk. The introduction of the forecast uncertainty margin reduces the risk of needing “spare” capacity during the deferral period, but it is not eliminated.

In this section, we discuss the reasonable assumptions we make in our NWA analysis and provide the calculations we used.

A. Peak Day Conditions

When conducting an NWA analysis, we assumed that peak day conditions contain the highest magnitude of risk. Therefore, rather than doing the analysis for potentially multiple overload events during the year, NWA studies are done utilizing the forecasted peak day for the study deferral year. LoadSEER is used to generate these 24-hour load curves and forecasts for the peak day.

B. Peak Load

Calculating various costs and benefits requires an assessment of how many times per year the NWA will be needed to reduce system demand, but this assumption is difficult to accurately estimate because peak load is typically driven by weather conditions on weekdays during the summer. Therefore, the NWA needs to be able to reduce the effective system loading during any weekday during the summer months (June through September). In the future, as parts of the system electrify, areas could become winter peaking. In these cases, NWA solutions will need to provide relief in the winter months as well, possibly over the nighttime hours.

When approaching feeder and transformer risks, load that was not able to be offset by solar or DR resulted in energy storage solutions. To appropriately account for the various cost and benefits, we considered both the charging and discharging of the battery storage system throughout the peak day.

The solar output curve we used ranges from 56-65 percent of nameplate output from 10:00 a.m. to 4:00 p.m., and to percentages less than that outside of that timeframe. We obtained this solar curve from the NREL PV Watts tool as representative of the average hourly solar output in the summer peaking months of July and August.

The DR curves we applied assumed peak at 6:00 p.m. on associated feeders, with a maximum of four-hour duration. Load reduction curves from DR were applied to risks that had N-0 overloads. Risks containing N-1 contingencies were generally not considered for DR due to the complexity of the N-1 analysis (combinations of feeders resulting in multiple configurations and customer make-ups) and the difficulty in obtaining necessary data, such as individual customer loads.

Energy efficiency is already included in our load forecasts. It is common to both the traditional projects as well as the NWAs and therefore not considered as an NWA component. As noted previously, we explored use of a broader set of values and

revenue streams for future NWA analyses with stakeholders in 2021 and have included those value and revenue streams in this analysis.

C. Impact of the Technical Planning Standard

The analysis methodology calculates the optimal mix of solar PV and energy storage needed to address the remaining risk while maximizing the incremental net impact, which is calculated as the net benefits minus the net costs. However, the maximum quantity of solar PV that can be accommodated in the NWA analysis was constrained by the affected feeder's Technical Planning Standard (TPS). The TPS is defined as 80 percent of the feeder's continuous rating plus the daytime minimum load. This constraint was added to prevent the model from violating the planning limit for maximum distributed generation on the affected feeders. In reality, upgrades could nonetheless be required in order to interconnect the calculated amount of incremental solar on the affected feeders, but these costs were not considered in the NWA analysis. Additionally, there were no constraints applied based on land availability or other factors that could prevent the optimal solution from being realistic. Therefore, the most realistic solution may differ from the optimal solution and would result in a different, lower incremental net impact. To characterize this range of possible solutions, the incremental net impact for both the optimal solution and the least cost-effective solution is provided in the NWA analysis results for each project below.

D. Discount Rates and Cost-Effectiveness Ranges

Order Point No. 3 of the Commission's July 26, 2022 Order in Docket No. E002/M-21-694 requires the Company to use both weighted average cost of capital (WACC) and societal discount rate in its NWA analysis and discuss the results of the two approaches in a future IDP stakeholder meeting. This year, we continued the practice we employed in our most recent NWA analysis in this 2025 IDP. In compliance with the Order, we calculated two Incremental Net Impact values for each project analyzed; one using WACC and one using a societal discount rate.

The approach we have taken in this analysis, while compliant with the Commission's Order, is imperfect and provides limited value in assessing which, if any, projects to move forward to a solicitation phase. For all the projects evaluated in 2025, the incremental net impact of the optimal solution was very similar under both discount rates, differing by less than \$100,000 in many cases.

For each project we analyzed this year, as shown below in Section II, the potential range in NWA net impact is shown in two different ways. First, a range was made from least cost effective to most cost-effective. The most cost-effective solution is optimized to have the greatest net impact possible as calculated from the stacked values. In many cases, this means that the most cost-effective NWA solution has a significant amount of solar. However, the amount of solar in some of these solutions is extremely high and may be infeasible.

For example, in one most cost-effective solution for a project studied in our 2022 baseline compliance filing, just the solar component of the NWA required installing 24 MW of solar in St. Louis Park, which could take 165 acres of land. In this case, the project had a positive incremental net impact, but the project requires a large amount of solar in a densely populated suburb.

On the other side of the range, the least cost-effective solution addresses a situation where the NWA has a much larger battery component, resulting in a lower incremental net benefit. However, this solution may be a more realistic scenario for projects in dense metro areas, where installing very large quantities of solar is not possible, but installing a large battery that takes up less land may be more feasible. However, the least cost-effective solution could have a minimally positive or even negative incremental net impact.

This illustrates not only how big of an impact stacked values have towards projects but also how much solar in particular impacts the modeled cost effectiveness of the project.

The second component of these tables is shown on the rows under the discount rates. Generally speaking, WACC represents the cost for the Company to acquire capital for investments. In the context of an NWA, this is typically used for costs and benefits that are related to utility function, like building assets and the cost of producing energy.

Societal discount rate represents the relative value of costs and benefits from projects that benefit society or the broader public. Thinking about this in terms of NWAs, this is typically used for carbon avoidance and societal benefits from solar.

Keeping these definitions and applications in mind, notice the WACC and societal rows in the Incremental Net Impact Summary tables for each project studied below. Each of these rows represent using only WACC discount rates for all stacked values

and societal discount rates for all stacked values, respectively. As noted above, the different discount rates did not result in demonstrably different results.

E. Forecast Uncertainty Margin

In our 2023 NWA analysis, a new metric titled the forecast uncertainty margin was added to the NWA initial screen. This margin reflects the fact that forecasts are inherently uncertain and cannot be perfectly accurate. It also aligns with our planning standards, which target feeder loading at 75 percent of capacity or less and targets substation transformer loading below 100 percent of capacity. Since NWA solutions are sized based on forecasted peaks, accounting for inaccuracies in potential load growth is critical.

Forecasts can have relatively high accuracy when observed at the system-wide level, but at the granularity of an individual feeder circuit or substation discrete changes, such as one large customer connecting to the grid, can introduce significant variance in the forecast. Even if load growth was anticipated in an area and included in the forecast, if the actual customers that ultimately interconnect in the area happen to have a higher or lower load density than was assumed then the forecast will not have been accurate. If an NWA is sized to precisely meet the need identified in the forecast, then such a forecast variance could cause the NWA to no longer be able to meet the need that actually develops based on how the NWA technology was sized. Therefore, NWAs need to be sized accordingly to account for uncertainty in the forecast.

In the N-0 risk case, the forecast uncertainty margin reflects 75 percent of the feeder limit, which aligns with our planning criteria. In the N-1 risk case, we scale the peak of the N-1 overload load curve up by 25 percent and assess the overload against 100 percent of the feeder limit, which also aligns with our planning criteria.

For both cases, the need shape is developed using the forecast uncertainty margin, resulting in a larger need shape, which is important to ensure the NWA is sized appropriately to be able to maintain reliability under futures with higher loads.

F. Project Feasibility

Our 2024 NWA analysis included a more in-depth scrutiny of project feasibility, and we have continued this in 2025. Specifically, for a project to be feasible, if a battery is required in the NWA solution, the battery must be at a full state of charge by the first

hour of the need shape. This ensures that the battery, which is charged from the grid, can discharge when needed. If the battery does not have a full state of charge by the first hour of the need shape, it cannot discharge enough MW or MWh required to meet the entirety of the need shape. Thus, if a project contained a risk that proved to be infeasible, the project as a whole is rendered infeasible. Project feasibility does not consider constructability components of projects. Construction elements of projects are considered during final engineering and design stages of an NWA and not during the initial screen.

G. Cost and Benefit Assumptions

Regarding cost assumptions, previously we utilized a flat battery storage unit cost based solely on energy capacity (MWh) using existing available industry costs. Since the 2022 NWA analysis, we have been using battery storage costs based on both the energy (MWh) and power (MW) components of battery storage systems. We obtained the formula we used to calculate these costs from the 2023 NREL Annual Technology Baseline (ATB).³ Although the NREL ATB has been updated since 2023, we continued to use the 2023 values so that our assumptions continue to align with our most recent IRP. Table 8-13 below shows the cost and benefit assumptions used in the NWA analysis.

Like battery storage, solar PV costs were obtained from the NREL ATB, which uses estimated PPA costs per MWh of annual production. Both battery storage and solar PV costs were pro-rated in the analysis based on the percentage of the annual production that coincides with the load reduction period. Because the battery storage cost estimates reflect the actual costs to install the battery storage system, these costs were further pro-rated based on the percentage of the battery's useful life that is needed for the NWA deferral period. These pro-rated components of the analysis are described as the ARR Split.

We did not include O&M costs related to maintaining solar or battery storage systems. DSM Program Administration Costs as well as End-of-Life Replacement costs were not included. Additionally, we assumed that land would be available at key locations on feeders/transformers/substations that would enable the NWA solution and did not include any potential land lease or purchase costs in our analysis.

³ Available at <https://atb.nrel.gov/electricity/2023/data>.

Table 8-13
Cost and Benefit Assumptions in NWA Analysis

Assumption	Value	Source/Basis
Economic		
Deferral Period	5 years from project in-service date	Currently expected structure of potential future NWA load reduction contracts
Need Shape - Days Per Week	5 (weekdays)	
Need Shape – Months Per Year	4 (June through September)	
General Cost Escalation Rate (Inflation)	2.00%	2024-2040 IRP, RP-24-67
Discount Rate (Weighted Average Cost of Capital [WACC])	6.39%	2024-2040 IRP, RP-24-67
Societal Discount Rate	3.00%	2024-2026 ECO Triennial Docket (No.E002/CIP-23-92)
Year 1	2028	
Energy Supply		
Year 1 Annual Average On-Peak Marginal Energy Cost	\$37.25/MWh	2024-2040 IRP, RP-24-67
Year 1 Annual Average Off-Peak Marginal Energy Cost	\$29.02/MWh	2024-2040 IRP, RP-24-67
Year 1 Surplus Capacity Credit	\$5.57/kW-month	2024-2026 ECO Triennial Docket (No.E002/CIP-23-92)
Levelized Avoided Emissions Benefit	\$42.2/MWh	2024-2026 ECO Triennial Docket (No.E002/CIP-23-92), Attachment A filed on 1/29/24
MISO Reserve Margin	7.9%	MISO - 2025/2026 Season, Summer
Transmission		
Year 1 Transmission Capacity Credit	\$3,424/MW	2024-2026 ECO Triennial Docket (No.E002/CIP-23-92)
Transmission Capacity Cost Escalation Rate	2.35%	2024-2026 ECO Triennial Docket (No.E002/CIP-23-92)
Transmission System Losses	95.7%	2024-2026 ECO Triennial Docket (No.E002/CIP-23-92)
DER		
Total Battery Cost	Total System Cost (\$) = Battery Storage Capacity	2023 NREL ATB

Assumption	Value	Source/Basis
	(MWh) * Battery Energy Cost (\$/MWh) + Battery Power Capacity (MW) * Battery Power Cost (\$/MW) + Battery Power Constant (\$)	
Battery Energy Cost	\$177,256/MWh	2023 NREL ATB
Battery Power Cost	\$733,827/MW	2023 NREL ATB
Battery Power Constant	\$171,644	2023 NREL ATB
Battery Useful Lifetime	15 years	2023 NREL ATB
Battery Roundtrip Efficiency	85%	2023 NREL ATB
Battery Depth of Cycle	70%	2023 NREL ATB
DER Planning Limit	80% Feeder/TR Capacity + Fixed Daytime Minimum Load – Existing Solar	Technical Planning Standard
Solar PPA Cost	Ranges from \$33.97 - \$37.97/MWh	2023 NREL ATB
Solar Annual Rating	1791 MWh/MW	NREL PVWatts
Average DER Interconnection Study Cost	\$34,000	Sum of Fees for System Impact Study, Facility Study, and Processing Fees
Exclusions		
O&M Costs	Not included in analysis	
DSM Program Administration Costs	Not included in analysis	
Land Costs and Availability	Not included in analysis	
End of Life Replacement Costs	Not included in analysis	

H. Stacked Values Formulas

Calculation – Avoided Energy Generation (Benefit)

$$\begin{aligned} & \text{Avoided Energy Generation } [\$] \\ &= \text{PV Avoided Energy Generation } [\$] \\ &+ \text{Battery Avoided Energy Generation } [\$] \end{aligned}$$

Calculation – PV Avoided Energy Generation (Benefit)

$$\begin{aligned} & \text{PV Avoided Energy Generation } [\$] \\ & \text{Deferral Period} \\ &= \sum_{y=1} \text{PV Annual Output During Load Reduction Period [MWh]} \\ & * \text{Year 1 Annual Average On Peak Marginal Energy Cost } [\$/\text{MWh}] \\ & / \text{Transmission System Losses } [\%] * \left(\frac{1 + \text{Inflation Rate}}{1 + \text{Discount Rate}} \right)^y \end{aligned}$$

Calculation – Battery Avoided Energy Generation (Benefit)

$$\begin{aligned} & \text{Battery Avoided Energy Generation } [\$] \\ & \text{Deferral Period} \\ &= \sum_{y=1} \text{Battery Annual Output During Load Reduction Period [MWh]} \\ & * \left(\text{Year 1 Annual Average On Peak Marginal Energy Cost } [\$/\text{MWh}] \right. \\ & \quad \left. - \frac{\text{Year 1 Annual Average Off Peak Marginal Energy Cost } [\$/\text{MWh}]}{\text{Battery Roundtrip Efficiency } [\%]} \right) \\ & / \text{Transmission System Losses } [\%] * \left(\frac{1 + \text{Inflation Rate}}{1 + \text{Discount Rate}} \right)^y \end{aligned}$$

Calculation – Avoided Generation Capacity and MISO Reserves (Benefit)

$$\begin{aligned}
& \text{Avoided Generation Capacity and MISO Reserves [\$]} \\
& \quad \text{Deferral Period} \\
& = \sum_{y=1}^{\text{Deferral Period}} \text{NWA Demand Rating [MW]} \\
& \quad * \text{Year 1 Surplus Capacity Credit [$/MW]} \\
& \quad / \text{Transmission System Losses [\%]} \\
& \quad * \frac{\text{NWA Annual Output During Load Reduction Period [MWh]}}{\text{NWA Annual Output [MWh]}} \\
& \quad * \left(\frac{1 + \text{Inflation Rate}}{1 + \text{Discount Rate}} \right)^y
\end{aligned}$$

Calculation – Avoided Transmission Capacity (Benefit)

$$\begin{aligned}
& \text{Avoided Transmission Capacity [\$]} \\
& \quad \text{Deferral Period} \\
& = \sum_{y=1}^{\text{Deferral Period}} \text{NWA Demand Rating [MW]} \\
& \quad * \text{Year 1 Transmission Capacity Credit [$/MW]} \\
& \quad / \text{Transmission System Losses [\%]} \\
& \quad * \frac{\text{NWA Output During Load Reduction Period [MWh]}}{\text{NWA Annual Output [MWh]}} \\
& \quad * \left(\frac{1 + \text{Inflation Rate}}{1 + \text{Discount Rate}} \right)^y
\end{aligned}$$

Calculation – Deferral Benefit (Benefit)

$$\begin{aligned}
& \text{Deferral Benefit [\$]} \\
& = \text{Year 1 Traditional Solution Cost [\$]} \\
& \quad * \left(1 - \left(\frac{1 + \text{Inflation Rate}}{1 + \text{Discount Rate}} \right)^{10} \right)
\end{aligned}$$

Calculation – Solar Cost (Cost)

$$\begin{aligned}
& \text{Solar Cost } [\$] \\
& \text{Deferral Period [years]} \\
& = \sum_{y=1} \text{PV Annual Output During Load Reduction Period [MWh]} \\
& * \text{Year 1 PPA Cost } [\$/\text{MWh}] * \left(\frac{1 + \text{Inflation Rate}}{1 + \text{Discount Rate}} \right)^y
\end{aligned}$$

Calculation – Battery Cost (Cost)

$$\begin{aligned}
& \text{Battery Cost } [\$] \\
& = (\text{Battery Storage Capacity [MWh]} * \text{Battery Energy Cost } [\$/\text{MWh}] \\
& + \text{Battery Power Capacity [MW]} * \text{Battery Power Cost } [\$/\text{MWh}] \\
& + \text{Battery Power Constant } [\$]) \\
& * \frac{\text{Battery Annual Output During Load Reduction Period [MWh]}}{\text{Battery Annual Output [MWh]}} \\
& * \frac{\text{Load Deferral Timeframe [years]}}{\text{Battery Useful Lifetime [years]}}
\end{aligned}$$

Calculation – Interconnection Fees (Cost)

$$\begin{aligned}
& \text{Interconnection Fees } [\$] \\
& = \text{Number of Interconnection Points} \\
& * \text{Average Interconnection Study Cost } [\$]
\end{aligned}$$

Calculation – Avoided GHG and Other Avoided Environmental Impacts (Benefit)

$$\begin{aligned}
& \text{Avoided Greenhouse Gas Emissions and Other Avoided Environmental Impacts } [\$] \\
& = \text{PV Annual Output During Load Reduction Period [MWh]} \\
& * \text{Levelized Avoided Emissions Benefit } [\$/\text{MWh}] \\
& * \text{Deferral Period [years]}
\end{aligned}$$

.....

CHAPTER 9: STAKEHOLDER ENGAGEMENT

In this Chapter, we discuss our efforts to engage with stakeholders, the input we have received from stakeholders and how it was incorporated into our 2025 IDP.

I. WORKSHOP SERIES OVERVIEW

Per Commission Orders¹ and updated filing requirements,² the Company was required to conduct stakeholder outreach in conjunction with the development of our 2025 Integrated Distribution Plans.

IDP Filing Requirement No. 2 requires:

Stakeholder Meeting(s): Xcel should hold at least one stakeholder meeting prior to filing the November 1 MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 filing as deemed appropriate by the utility. At a minimum, Xcel should seek to solicit input on the following MN-IDP topics: (1) the load, electrification and DER forecasts, and 5-year distribution system investments, (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission's Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP. Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, a stakeholder meeting may be held in combination with the comment period to solicit input.

Order Point No. 10 requires:

Xcel shall engage in additional stakeholder discussions on approaches to apply cost-benefit analyses, or a similar type of evaluation, strategically to program-level investments for discretionary projects for certification or cost recovery proceedings.

Order Point No. 11 requires:

In its next IDP, Xcel shall engage in additional stakeholder discussions on approaches to apply cost-benefit analyses for relevant discretionary distribution expenditures.

Order Point No. 12 requires:

¹ Docket No. E002/M-23-452 Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements (September 16, 2024) (2023 IDP Order)

² Docket No. E002/M-23-452 Notice of Approval of Updated Filing Requirements (June 3, 2025)

As part of the stakeholder effort on cost-benefit analyses, Xcel shall explain how it would define "discretionary" spending in this context and to explain its cost-benefit methodology, including specifically its identification of benefits.

Order Point No. 17 requires:

Xcel shall work with stakeholders to refine its planned net load methodology. Xcel shall also evaluate alternative approaches to applying the dependability factor, including applying it to hourly photovoltaic generation and to photovoltaic nameplate capacity. Xcel shall engage parties that commented on planned net load in this proceeding as it evaluates seasonal dependability factors and alternative planned net load approaches. Xcel shall include a report describing the results of this evaluation and changes to its proposed planned net load methodology in its next IDP.

Order Point No. 22 requires:

Xcel shall 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. The filing shall be filed in Xcel's 2025 IDP, or at the time of request for certification or cost recovery for any DERMS investments, whichever is sooner.

The Company held a total of eight workshops between April and August 2025 on the following topics:

- Planned Net Loading (PNL),
- Cost Benefit Analysis (CBA),
- Distributed Energy Resource Management Systems (DERMS), and
- Overall IDP preview

We structured the workshop series based upon the amount of material we wanted to share with stakeholders regarding our initial planning concepts, the need for sufficient opportunity to obtain stakeholder feedback, and toward sharing with stakeholders how their input was taken into consideration in the IDP. We were encouraged by Commission Staff to allow for more interaction from stakeholders, similar to the Commission-led Proactive Grid Upgrades Workgroup. Toward this objective, this is the first IDP where we invited registrants to present their perspectives at Workshops. Over 220 external stakeholders participated in the eight workshops, with many of those participating in more than one event. This Chapter includes details about the workshops provided, the input received and how it was considered.

We listened to, and reflected upon, our stakeholders' input and incorporated it into our plans where appropriate and will continue to evaluate where that feedback can be incorporated going forward. This Chapter includes details about the workshops provided, the input received and how it was considered.

Invitations to workshops were filed in Docket Nos. E002/M-23-452 and E002/M-25-242, emailed to those who have requested to be on our "Interested Parties List," and emailed to individuals who indicated specific interest in our CBA, PNL or DERMS workshops. Approximately 450 stakeholders on our Interested Parties List received email invitations for each workshop. Invitations to our DERMS workshops were also mailed to our Distributed Energy Resources distribution list, which is comprised of over 2,700 stakeholders – some who may also be on our Interested Parties List. To enhance future engagement, at every workshop, we referenced the Company's "Interested Parties List" and provided direction on how stakeholders could be added to the list.

Attendance at our workshops ranged from nine to 101 participants. Participants were given ample opportunity to ask questions and provide feedback and input during each workshop. Consistent with the Commission's July 23, 2020 Order in Docket No. E002/M-19-666, workshops were open to any interested person.³ Based on prior feedback collected through a survey of stakeholders indicating that stakeholders preferred to participate in workshops virtually, all of the workshops were offered virtually. We also initially offered an in-person option for the PNL Workshop 2 and CBA Workshop 2, but due to extremely low interest in the in-person option, we ultimately only held those workshops virtually. In an effort to connect directly with stakeholders, we provided an in-person option for the IDP Preview, of which four stakeholders took advantage.

After each workshop, we filed our workshop materials in Docket Nos. E002/M-23-452 and E002/M-25-142. Based on prior feedback from stakeholders, the slide-deck was shared with registrants prior to each workshop so that registrants could prepare for the workshop by previewing the materials.

In sum, over 17 hours of workshops were offered over the course of the eight workshops in an effort to share insights and gather input on our 2025 IDP from our stakeholders.

³ Order Point 5 states, "Xcel must allow any interested person to participate in stakeholder engagement meetings regarding its IDP and HCA."

The following table outlines the relevant 2023 IDP stakeholder related Order Points and the corresponding workshops at which they were addressed.

Table 9-1
2023 IDP Order Points and Stakeholder Outreach Efforts

Order Points (OP)/ IDP Filing Requirement	Addressed in Workshop(s):
OP No. 11: In its next IDP, Xcel shall engage in additional stakeholder discussions on approaches to apply cost-benefit analyses for relevant discretionary distribution expenditures.	CBA Workshop 1: April 17, 2025 CBA Workshop 2: June 3, 2025
OP No. 12: As part of the stakeholder effort on cost-benefit analyses, Xcel shall explain how it would define "discretionary" spending in this context and to explain its cost-benefit methodology, including specifically its identification of benefits.	CBA Workshop 1: April 17, 2025 CBA Workshop 2: June 3, 2025
OP No. 17: Xcel shall work with stakeholders to refine its planned net load methodology. Xcel shall also evaluate alternative approaches to applying the dependability factor, including applying it to hourly photovoltaic generation and to photovoltaic nameplate capacity. Xcel shall engage parties that commented on planned net load in this proceeding as it evaluates seasonal dependability factors and alternative planned net load approaches. Xcel shall include a report describing the results of this evaluation and changes to its proposed planned net load methodology in its next IDP.	PNL Workshop 1: April 17, 2025 PNL Workshop 2: May 8, 2025 PNL Workshop 3: July 9, 2025
OP No. 22: Xcel shall 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. The filing shall be filed in Xcel's 2025 IDP, or at the time of request for certification or cost recovery for any DERMS investments, whichever is sooner.	DERMS Stakeholder Workshop 1: June 16, 2025 DERMS Stakeholder Workshop 2: July 7, 2025
IDP Filing Requirement No. 2: Stakeholder Meeting(s): Xcel should hold at least one stakeholder meeting prior to filing the November 1 MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 filing as deemed appropriate by the	IDP Preview: August 19, 2025

utility. At a minimum, Xcel should seek to solicit input on the following MN-IDP topics: (1) the load, electrification and DER forecasts, and 5-year distribution system investments, (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission’s Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP. Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, a stakeholder meeting may be held in combination with the comment period to solicit input.	

II. WORKSHOP SUMMARIES

In this section, we provide a summary of each stakeholder workshop. For each workshop summary in this section, we provide:

- Workshop logistics
- Stakeholder participation
- An overview of the workshop content and presentations. We note that each workshop presentation was filed in the instant docket.
- A discussion of stakeholder questions and input received and where we have considered or incorporated the input.

A. PNL Workshop 1

Logistics: virtual, held April 17, 2024

Attendance: 20 participants

Meeting Materials: Link to eDockets [20255-218744-01](#)⁴

1. *Summary of Workshop 1*

The objective of this Workshop was to provide an overview of the Company’s current PNL methodology, answer questions about the methodology, and gather input from stakeholders both in general and on specific topics.

We commenced the Workshop by providing an overview of the electric power system

⁴ See Xcel Energy PNL Workshop 1 Materials, Docket Nos. E002/M-23-452 and E002/M-25-142 (May 9, 2025) [20255-218744-01](#)

planning process with a focus on the distribution planning process. We explained that our process starts with load forecast development, followed by risk analysis, the development of mitigation plans and associated budgets, and the finalization of projects details prior to moving to the design and construction phase.

We discussed in detail our N-0 and N-1 risk analysis objectives and processes, as well as our LoadSEER forecasting process and discussed how these processes all work together to evaluate feeder and substation transformer risks for both intact and abnormal system configurations.

We next presented information comparing net loading and native loading methodologies and noted that our PNL approach calculates a new value between net load and native load by incorporating partial DER impacts. We described how this conservative approach helps minimize risk to the distribution system and we walked through examples that demonstrated this.

Next, we discussed our solar dependability factor (DF). We provided data from our distribution system that shows average solar output as a percentage of nameplate capacity across the year at varying times of day. The DF is established to ensure the PNL will always fall between the native and net load and represents the amount of solar generation that can be depended upon to reduce peak load every year. We also explained why the DF cannot be based on solar nameplate and provided examples of feeder overload risk analysis considering feeder contingencies.

We indicated that our initial PNL methodology uses a DF of 15 percent for solar photovoltaics. However, based on input received from stakeholders in response to our 2023 IDP we asked stakeholders a series of questions to help guide changes in our DF and PNL methodology. Those questions, along with stakeholder feedback received are noted in the following section.

2. Facilitated Questions and Answers

Q1. Interactive Polling Question: “Which areas of refinement should be prioritized for the PNL Methodology?”

Of the seven responses received to this question, six indicated that “seasonal or otherwise differentiated dependability factors” should be prioritized. The seventh response indicated that the “dependability factor applied to hourly generation” should be prioritized. The results of this poll drove, in part, our efforts to develop and

incorporate a proposed seasonal dependability factor into our 2025 IDP for implementation in our 2027 IDP.

Q2. Interactive Polling Question: “Are there examples of similar methodologies used in other jurisdictions that should be considered?”

Stakeholders indicated that:

- Interstate Renewable Energy Council (IREC) and NV Energy are developing a methodology based on a Southern California Edison approach.
- San Diego Gas and Electric has a methodology that could be considered.
- Illinois utilities have been ordered to count solar as a capacity resource.
- PJM, Indiana and Michigan have adopted Effective Load Carrying Capability (ELCC) and MISO uses ELCC to accredit wind and solar resources until they have sufficient data to base a determination on otherwise. Southwest Power Pool was also mentioned.

Q3. Interactive Polling Question: “Would any stakeholders be willing to present a specific proposal for refinement of the PNL methodology in the next workshop?”

Three stakeholders volunteered to present at PNL Workshop 2:

- Massoud Amin, representing Renewable Energy Partners (REP)
- Cody Davis, representing Vote Solar and Environmental Law and Policy Center (ELPC), and
- Steve Coleman, representing himself

3. Other Stakeholder Input Received

- A stakeholder noted that it might be useful to know how the native load calculation works separately and that the movement from net to native load is important to consider in the process.
- A stakeholder asked why we were not differentiating between winter and summer dependability in regard to feeder peaks. It was suggested that we use two dependability factors- one for winter and one for summer peaks.

B. PNL Workshop 2

Logistics: virtual, held May 8, 2025

Attendance: 16 participants

Meeting Materials: Link to eDockets [20256-219798-01](#)⁵

1. *Summary of Workshop 2*

The objective of this Workshop was to facilitate a discussion between stakeholders and the Company on PNL concepts; seek feedback and proposals from stakeholders for refining the PNL methodology including applying the dependability factor to hourly PV generation or nameplate capacity; and developing seasonal dependability factors. Stakeholders were offered the option to present on PNL methodologies used in other jurisdictions during the Workshop registration process. Three stakeholders signed up to present:

- Massoud Amin, representing REP
- Cody Davis, representing Vote Solar and ELPC and
- Steve Coleman, representing himself

Cody Davis presented a detailed proposal for a Photovoltaic (PV) Dependability Methodology based on system size – large and small size DER – inclusive of seasonal considerations. Massoud Amin presented a PNL methodology incorporating ELCC. Steve Coleman also presented on incorporation of ELCC for capacity accreditation. We appreciate these stakeholders for their time and effort in compiling these presentations and sharing their thoughts and aspirational visions with us.

2. *Stakeholder Input*

We heard from stakeholders at this workshop that they want us to consider:

- Dependability factor percentages
- Accounting for seasonal differences
- Differentiation by solar type
- Methods for evaluating PNL during the loss of one Community Solar Garden (CSG)
- Use of emergency ratings in distribution planning
- Native load methodology for historic and forecasted peaks

⁵ See Xcel Energy PNL Workshop 2 Materials, Docket Nos. E002/M-23-452 and E002/M-25-142 (June 10, 2025) [20256-219798-01](#)

- Revising the PNL calculation
- Incorporating future PV interconnections

C. PNL Workshop 3

Logistics: virtual, held July 9, 2025

Attendance: 11 participants

Meeting Materials: Link to eDockets [20258-221836-01](#)⁶

1. *Summary of Workshop 3*

The objective of this final PNL Workshop leading up to our 2025 IDP was to share our proposal for refining our PNL methodology based upon input from PNL Workshops 1 and 2.

We provided an overview of takeaways from Workshops 1 and 2, most notably, pointed out stakeholder prioritization for the development of a seasonal or otherwise differentiated DF. In addition, we described other stakeholder input received as noted in the Workshop 2 summary. Based on input received we are proposing in this IDP filing to change our PNL methodology to use season dependability factors – one for summer and one for winter – for use in our 2027 IDP.

We observed notable differences by solar type and acknowledged that developing more granular hourly solar generation profiles by type and geographic area would require further investigation, with potentially limited value. Nonetheless, we indicated that we would consider these refinements in our proposal.

We also indicated that developing a method to evaluate PNL during the loss of a Community Solar Garden (CSG) was a good idea but would need further thought into how it would be integrated with the planning process.

We noted that the suggestion to refine our PNL calculation by incorporating ELCC proposed a novel approach. However, our PNL approach is geared towards individual feeders on the distribution system while the ELCC approach is geared towards the bulk system. We will continue to conduct our analysis in LoadSEER so that our processes are streamlined. We intend to take a careful, thoughtful approach with implementation of our PNL approach and will continue to hone our processes as we

⁶ See Xcel Energy PNL Workshop 3 Materials, Docket Nos. E002/M-23-452 and E002/M-25-142 (August 6) [20258-221836-01](#)

learn more throughout the PNL implementation.

2. *Stakeholder Input*

- We heard from stakeholders that they would like to see this process move faster.
- Stakeholders suggested that we should consider utilizing batteries, CSG's, large EV charging systems and other large loads to help stabilize the grid.

D. CBA Workshop 1

Logistics: virtual, held April 17, 2025

Attendance: 12 participants

Meeting Materials: Link to eDockets [20255-218747-01](#)⁷

1. *Summary of Workshop 1*

The intent of this Workshop was to discuss the definition of “discretionary” in the context of program-level distribution investments, and to gather input on CBA methodologies and mechanics. The Company invited interested parties to participate directly in the workshop by presenting their thoughts on CBA methodologies for program-level distribution investments for discretionary projects. We also indicated that we were seeking input on examples of CBA methodologies used in other jurisdictions, inputs and benefits that should be considered in CBAs for these types of investments, how to quantify system risks, costs, and benefits, and the types of discretionary expenditures or programs to which a CBA might provide helpful insights.

Two stakeholders registered to present at CBA Workshop 1:

- Leo Ndiaye, Department of Commerce (Department) and
- Curt Volkmann, representing Fresh Energy (FE)

The Department presented that CBAs can take into consideration reliability, capital and operating expenditures, CO2 emissions, and other miscellaneous categories.

FE shared details about GridLab's Grid Modernization Playbook, and details about

⁷ See Xcel Energy CBA Workshop 1 Materials, Docket Nos. E002/M-23-452 and E002/M-25-142 (May 9, 2025) [20255-218747-01](#)

cost benefit analyses undertaken by Xcel Energy, Dominion Energy, Ameren, Commonwealth Edison, and DTE. FE recommended that the Company provide increased transparency into net customer benefits of planned investments, enhance the methodology employed for our Advanced Grid Intelligence and Security (AGIS) CBAs where there is flexibility in when, where and how much to spend, identify easily quantifiable benefits and learn from other utilities' methodologies.

The Company provided its definition of discretionary as optional investments by which not executing and spending the funds does not imminently endanger employees or the public from a safety or reliability incident on the system. A discussion ensued articulating the differences between mandatory and discretionary spending with reactive work for asset health, mandates, new extensions for customers, and safety related issues all being considered mandatory projects.

2. Stakeholder Questions and Input

The Company posed a series of interactive polling questions to participants during the workshop. Those questions and responses follow.

Q1. Would you suggest any changes to what we consider discretionary investments?

Stakeholder feedback:

- One participant recommended adding a new discretionary category for “Grid Modernization”.
- There is a blurry line between discretionary and mandatory and investments don’t always fit into a clear bucket.

Q2. Are there any other benefits that we should consider?

Stakeholder feedback:

- Focus on benefits that are easy to quantify and monetize. Safety, resilience and sustainability are very hard to monetize.
- Additional cost and flexible load interconnections such as load interconnections for EV charging.

Q3. Of all the benefits discussed, what benefit should we prioritize?

Stakeholder feedback:

- Two stakeholders indicated that we should prioritize reliability.
- One stakeholder indicated that we should prioritize customer costs.

Q4. Are there any other costs that we should consider in our CBA?

Stakeholder feedback:

- It's important to translate costs into revenue requirements including taxes, financing, etc. to reflect customer impacts.
- There should be a base case and comparison case which evaluates a suite of options to determine which is the best option to be utilized in cost recovery, or at least provide a benefit associated with the spend.

Q5. What costs listed should not be considered in a cost benefit assessment, if any?

Stakeholder feedback:

- Consider the lifespan of the investment.

Q6. Of all the costs discussed, which should we prioritize as part of a cost benefit assessment?

Stakeholder feedback:

- One stakeholder indicated prioritization of utility investments and then avoided future capital investments.
- Another stakeholder indicated prioritization of investments for programs where planned spending is increasing significantly as compared to historical spend.

Q7. Are there any other methodologies that we should consider for discretionary programs?

Stakeholder feedback:

- Performance Incentive Mechanisms and Willingness to Pay.
- Not a different methodology but possibly using a benefit-cost ratio as an outcome of the analysis.
- Provide information in a less formal format if possible.

Q8. What methodology do you recommend using for the cost benefit assessment that best balances efficiency and quality?

Stakeholder feedback:

- Present a base case and comparison case considering capital costs as well as O&M costs.
- Develop a CBA approach for one or more big buckets of spending.

As a result of this workshop and stakeholder recommendations, we convened meetings with four different utilities to discuss their CBA methodologies. We presented summaries of these conversations at CBA Workshop 2. We thank our stakeholders for helping connect us to these utilities to further discuss CBA's.

E. CBA Workshop 2

Logistics: virtual, held June 3, 2025

Attendance: 9 participants

Meeting Materials: Link to eDockets [20256-219797-01](#)⁸

1. Summary of Workshop 2

The objective this Workshop was to share our planned approach for CBAs in our 2025 IDP, considering feedback and input from CBA Workshop 1.

We summarized the stakeholder input we received during Workshop 1:

- Start simple
- Start with quantitative analysis
- Demonstrate investment value and asset impact
- Clearly categorize projects and consider including a grid modernization category
- Reflect full customer impact through revenue requirements

We summarized the benchmarking discussions that we held with other utilities. We stated that we will continue these discussions and will leverage them in future CBAs. What we heard from the other utilities:

⁸ See Xcel Energy CBA Workshop 2 Materials, Docket Nos. E002/M-23-452 and E002/M-25-142 (June 10, 2025) [20256-219797-01](#)

- The utilities indicated that they are also applying CBA's to discretionary projects,
- Several utilities have hired contractors to assist with CBA model development while others have relied on a mix of consultant services and in-house products,
- Two utilities indicated that they started utilization of CBA on small pilots and then expanded to other programs,
- Most included System Average Interruption Duration Index (SAIDI) and other outage statistics in the CBA,
- Utilization of the Lawrence Berkeley National Laboratory Interruption Cost Estimate (ICE) calculator was common amongst all utilities,
- Equity and affordability approaches varied but were not included in CBA first attempts,
- Generally, CBAs were run on projects/programs associated with rider recovery.

We reiterated our definitions of mandatory and discretionary spending and outlined that we would conduct CBAs in our 2025 IDP for the end-of-life replacement of breakers and grid reinforcement programs.

2. Stakeholder Questions and Input

We posed interactive polling questions to workshop participants. Those questions and responses are summarized below.

Q1. Was there anything else discussed at the CBA Workshop 1 that we may have missed (regarding stakeholder input)?

Stakeholder feedback:

- Consider basing the CBA approach on the one used in the Company's AGIS CBA.
- Consider evaluation of run to failure versus replacement
- Consider impacts to low-income customers
- Include Grid Modernization CBA's going forward.

Q2. Does the methodology we've discussed today align with your expectations as a starting point for discretionary CBA?

Stakeholder feedback: none received.

Q3. If our proposed methodology does not meet your expectations, what is missing from our proposal?

Stakeholder feedback: none received.

F. DERMS Workshop 1

Logistics: virtual, held June 16, 2025

Attendance: 101 participants

Meeting Materials: Link to eDockets [20257-221344-01](#)²

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

² 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](#)

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.

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 (DGGW) 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.

G. DERMS Workshop 2

Logistics: virtual, held July 8, 2025

Attendance: 28 participants

Meeting Materials: Link to eDockets [20258-221838-01](#)¹⁰

1. *Summary of Workshop 2*

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.

2. *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.

¹⁰ See Xcel Energy DERMS Workshop 2 Meeting Materials, Docket Nos. E002/M-23-452 and E002/M-25-142 (August 6, 2025) [20258-221838-01](#)

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?”

Stakeholder feedback:

- 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?”

Stakeholder feedback: 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.

H. IDP Preview

Logistics: hybrid (virtual and in-person), held August 19, 2025

Attendance: 23 total participants – 19 virtual and four in-person

Meeting Materials: Link to eDockets [20259-223185-01](#)¹¹

1. Summary of Workshop

The intent of this Workshop was to provide stakeholders a summary of key aspects of our forthcoming 2025 IDP filing, including forecasting, preliminary distribution system budgets, a Non-Wires Alternative (NWA) overview, grid modernization plans, and approaches to DERMS, CBAs, PNL, proactive distribution grid upgrades, targeted undergrounding, wildfire protection, and certification requests.

We commenced the Workshop by providing an overview of the electric power system planning process with a focus on the distribution planning process. We explained that our process starts with load forecast development, followed by risk analysis, the development of mitigation plans and associated budgets, and the finalization of projects details prior to moving to the design and construction phase.

This was followed by a detailed discussion regarding our forecasting processes and the three forecast scenarios developed for our 2025 IDP which are 1) base case, 2) high adoption and 3) expanded non-residential. We walked through details of each of the forecasts that are incorporated into the IDP:

- corporate sales and demand,
- beneficial electrification,

¹¹ See Xcel Energy IDP Preview Workshop Materials, Docket Nos. E002/M-23-452 and E002/M-25-142 (September 19, 2025) [20259-223185-01](#)

- energy efficiency,
- rooftop solar,
- front of the meter solar,
- battery storage, and
- electric vehicles.

Next, we discussed proposed budget investments through 2030 and walked through each of the investment categories:

- asset health and reliability,
- capacity,
- wildfire,
- new business,
- mandates,
- AGIS,
- fleet,
- tool and communications,
- electric vehicles, and
- O&M which includes labor, vegetation management, damage prevention, AGIS and other.

We shared an overview of our NWA process including project identification and noted that PNL is now integrated into that process and that we have a goal of pursuing at least one project through an RFP process¹².

We next provided a detailed overview of our grid transformation journey including AMI and FAN deployment details and benefits.

We ended the workshop discussing new features of our 2025 IDP:

- DERMS,
- PNL,
- CBAs,
- proactive distribution grid upgrades,
- targeted undergrounding plans,

¹² Order Point No. 6 of the Commission's July 23, 2020 Order states: *Xcel must engage stakeholders in further advancing the Company's NWA Analysis, including but not limited to, screening criteria, analysis methodology and assumptions, and NWA evaluation parameters.*

- wildfire protection programs, and
- certification request.

2. *Stakeholder Questions and Input*

Q1. Asked through interactive polling: What ideas/suggestions do you have to encourage bids for our Non-Wires Alternatives projects?

Input received:

- A suggestion was made to work directly with organizations such as MnSEIA and CCSA to help communicate with their members about upcoming RFPs emphasizing collaborative communication.

III. POST IDP WORKSHOP SERIES SURVEY AND RESULTS

After the conclusion of the workshop series, we requested feedback on the workshop series through an online survey. We sent the survey to everyone who participated in one or more of the workshops. The intent of the survey was to obtain feedback on the workshops in order to inform future efforts. The survey included questions pertaining to duration; frequency; location; satisfaction; helpfulness of external stakeholder presentations and the ability to preview the workshop slide deck; and if the level of information shared was appropriate. We also requested feedback on how we could improve stakeholder efforts going forward. We sent the survey to 221 emails requesting survey participation and we received nine responses, for a response rate of approximately four percent. Those that responded provided the following input:

- All but one respondent indicated that the duration of workshops was “just right”. One respondent indicated a preference for shorter workshop durations resulting in more workshops.
- Most found the level of detail presented in the workshops “just right” with two indicating that the information was too simplified.
- All respondents but one found it helpful to receive the slide deck prior to the workshop in order to preview the slides.
- Seven respondents indicated that they felt they had sufficient opportunity to provide input at the workshops. Two felt they did not have sufficient opportunity to provide input and both acknowledged that they did not provide any input.
- Respondents indicated that it was helpful to hear presentations from external stakeholders and the Company’s response to them.

- All but one felt that they had a better understanding of the Company's IDP process as a result of the workshop series.
- Participants generally support the Company's IDP process, especially as it pertains to gathering stakeholder input.
- Seven of the nine indicated satisfaction with the stakeholder process.
- All respondents indicated a preference to attend workshops virtually.
- The location of in-person workshops did not impact their decision to attend in person.
- One respondent suggested it would be helpful to break down discussions between those interested in flexible load from those interested in flexible generation.
- Another voiced frustration with the solar installation approval process from the installer perspective.
- One respondent suggested the Company provide the opportunity to subscribe to certain topics that pertain to the IDP stakeholder process. The Company currently maintains a general Interested Parties Distribution List and informs everyone on that list of all workshop opportunities. The Company prefers to over-broadcast rather than under-broadcast workshop opportunities allowing the stakeholders to choose for themselves if they would like to participate or not.

We appreciate the valuable feedback provided by the survey respondents and will consider the feedback in future workshops.

CHAPTER 10: DISTRIBUTION SYSTEM UPGRADES

Minn. Stat. § 216B.2425 as amended by the Minnesota Session Laws, 2023, Regular Session Chapter 60 (H.F. No. 2310) states:

Subd. 9. Integrated distribution plan; contents.

The public utility that owns a nuclear generating plant must include the following information in the public utility's annual integrated distribution plan filed with the commission, beginning with the plan due November 1, 2023:

- (1) a forecast of distribution system upgrades necessary to accommodate the interconnection of distributed generation resulting from the utility's compliance with sections 216B.1641 and 216B.1691, subdivision 2h, and other customer-sited projects, including energy storage systems;*
- (2) an evaluation of measures that can reduce the need for or cost of distribution system upgrades to enable the interconnection of distributed generation resources, including but not limited to the employment of smart inverters, grid management tools, distributed energy resources management tools, and energy export tariffs; and*
- (3) a discussion of alternative methods to allocate costs of distribution system upgrades among distributed generation owners or developers and ratepayers.*

Additionally, Order Point No. 3.d of the Commission's September 16, 2024 Order says:

In its next IDP, Xcel shall report on its progress to improve forecasting, including:

- d) Utilizing IDP forecast scenarios to perform sensitivities on grid capacity or capital expense plans.*

We address each requirement below.

I. FORECAST OF UPGRADES

The law requires:

- (1) a forecast of distribution system upgrades necessary to accommodate the interconnection of distributed generation resulting from the utility's compliance with sections 216B.1641 and 216B.1691, subdivision 2h, and other customer-sited projects, including energy storage systems;*

Minn. Stat. § 216B.1641 is the Community Solar Garden (CSG) statute, the 2023 update which substantially modified the CSG program.

Minn. Stat. § 216B.1691, subd. 2h, outlines the new Distributed Solar Energy Standard (DSES), which requires three percent of the Company's total retail electric

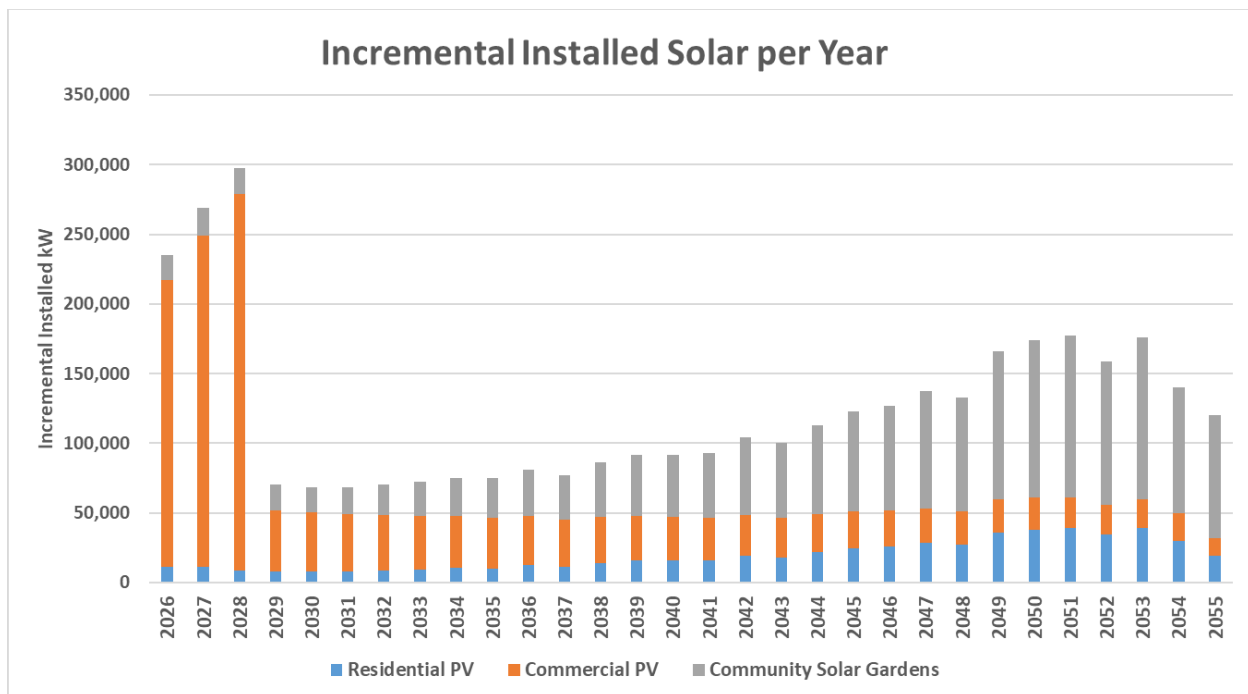
sales in Minnesota to be generated from qualifying solar energy generating systems by the end of 2030. In brief, to count toward the standard, the solar energy generating system must:

- (1) have a capacity of ten megawatts or less;
- (2) be connected to the public utility's distribution system;
- (3) be located in the Minnesota service territory of the public utility; and
- (4) be constructed or procured after August 1, 2023.

A. Analysis Methodology

To develop the required forecast of distribution system upgrades, we used the location-specific LoadSEER forecast data, as discussed in *Chapter 1: System Planning*. Specifically, we used the allocation data from the IDP Base Case scenario of the solar PV adoption forecast. This scenario includes three components: Residential PV, Commercial PV, and Community Solar Gardens (CSGs). Solar projects developed under the Distributed Solar Energy Standard (DSES) are included in the Commercial PV component. The total amount of solar that was allocated to the distribution system over the 30-year-analysis period is shown in Figure 10-1.

Figure 10 - 1
Forecasted Solar Allocated to the Distribution System



The allocation data used in this analysis comes from the Spatial Allocation of the

forecasted solar PV adoption in LoadSEER. This process generates a year-by-year, feeder-level forecast of the nameplate solar PV generation allocated to specific locations on the distribution system.

To estimate total DER on each feeder, we combined this allocated solar forecast with the quantity of existing and queued DER for each feeder. This total nameplate capacity was then compared against two thresholds: the planning limit, known as the Technical Planning Standard (TPS), and the indicative hosting capacity (HC) from the Company's Hosting Capacity Analysis (HCA). If the total DER exceeded either threshold in a given year, the amount of excess kW was recorded.

To estimate upgrade costs, the excess kW was multiplied by the marginal cost of distribution capacity. A two percent annual cost escalation rate was also applied to the marginal cost of distribution capacity to reflect expected increases in costs over the forecasted period.

The marginal cost of distribution capacity used in this study was \$800/kW, consistent with the value used in our most recent Distributed Capacity Procurement (DCP), also known as Capacity*Connect (Docket No. E002/25-378).¹ This cost was derived from two established sources: demand-side management modeling in Minnesota and the Company's Colorado Aggregator Virtual Power Plant settlement agreement. It serves as a general planning benchmark and is not intended to represent the specific cost of every kilowatt of distribution capacity. Actual upgrade costs can vary widely depending on factors such as feeder topology, voltage level, equipment type and site-specific conditions.

While \$800/kW is the marginal capacity cost used for this forecast, it likely underrepresents long-term average costs. As DER penetration increases, many forecasted investments will require increasingly significant infrastructure upgrades—such as substation expansion or new substations—which we are already beginning to see in some cases. These larger investments tend to have a higher cost per kW than the current average cost of upgrades. Additionally, this cost only reflects the distribution portion of costs. Significant DER growth may also create constraints in some parts of the transmission system, which will require separate mitigation efforts.

¹ The distribution marginal capacity cost used in the DCP is an annualized value, calculated by dividing a total cost of \$800/kW over 20 years, resulting in \$40/kW-year. For this analysis, we required the full, non-annualized value to reflect the one-time cost of increasing capacity on the distribution system each year an upgrade is required. Therefore, we used the total \$800/kW figure.

Due to the time and resources required for the analysis, we were unable to identify specific mitigations with associated costs for each feeder with a forecasted violation. However, identifying precise mitigations for each feeder would not necessarily improve the accuracy of the upgrade cost estimates. The location-specific forecast in LoadSEER highlights locations with a higher likelihood of DER adoption, but the actual sites of adoption will ultimately be determined by the DER owners and developers. As such, using the marginal cost of distribution capacity is a reasonable proxy when applied across a large sample of feeders needing mitigation. While this method may not yield accurate cost estimates for individual limit violations, it provides a reasonable approximation of the total distribution cost to mitigate all forecasted violations using average cost assumptions.

The forecast of upgrades was calculated using two different threshold scenarios. The first scenario uses the existing TPS as the DER planning limit for the feeders, and is the only factor considered when determine when upgrades are needed. The TPS is defined as 80 percent of the continuous rating plus the daytime minimum load (DML) and determines the maximum allowable penetration of DER on a feeder or substation transformer before upgrades are required. The second scenario uses the TPS as one factor when determining when upgrades are needed but also further constrains available capacity based on the results from the 2025 HCA The methodology used to develop the HCA results are described in the HCA report to be filed by November 1, 2025.

The goal of including the indicative hosting capacity in a scenario is to capture potential distribution system constraints that may be more restrictive than those identified through the TPS. The HCA evaluates not only the TPS but also additional technical factors—such as voltage rise, thermal limits, protection and coordination—that could trigger the need for upgrades prior to the TPS being reached or exceeded.

However, the HCA has limitations. It does not provide a comprehensive estimate for an entire feeder. Instead, it uses sequential nodal analysis, which calculates the maximum acceptable DER penetration at a given node without increasing DER penetration at other nodes. Currently, there is no widely accepted method for calculating the total hosting capacity of a feeder as doing so presents a computationally complex challenge with limited practical value for interconnection customers.

Therefore, what is used here is the maximum hosting capacity available at any given node on a feeder as a conservative proxy for total feeder capacity. This nodal maximum is presented alongside the TPS to provide a more nuanced picture of

possible upgrade costs. The costs derived from this analysis should be considered as a reasonable upper bound for the potential cost of interconnecting forecasted DER.

B. Summary of Results

The costs calculated using the methodology above consist of two components: existing costs and forecasted costs.

- *Existing costs* refer to the costs required to bring all of the feeders within their planning or hosting capacity (TPS/HC) limits, based on the currently installed and in-queue DER. For example, if a feeder has a TPS/HC limit of 10 MW, with 12 MW of installed and in-queue generation, the existing cost reflects the investment needed to raise the limit to 12 MW. These costs are considered “existing” because they are based on known DER adoption and would be incurred before any additional forecasted DER adoption is added.
- *Forecasted costs* are based on the DER allocations from LoadSEER and assume that the existing constraints have already been mitigated. Over the 30-year forecast period, more feeders are expected to experience capacity constraints. For this reason, using the marginal cost of distribution capacity provides a reasonable estimate of upgrade costs for forecasted constraints.

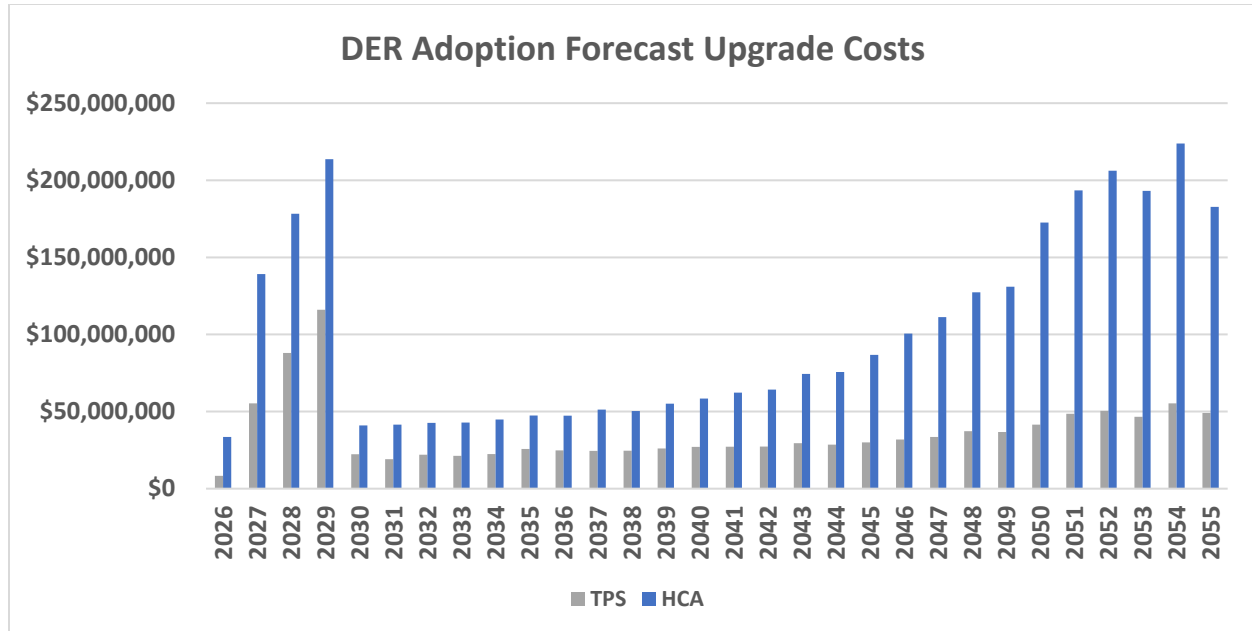
The sum of the existing and forecast costs represents the total costs required over the 30-year forecast period to accommodate the forecasted solar PV adoption. These totals are summarized in Table 10-1 below for each scenario.

Table 10 - 1
Summary of Upgrade Cost Components for Each Cost Scenario (in Millions)

Cost Scenario	Existing Constraint Cost	2026-2055 Forecast Cost	Total 30-Year Cost
HCA	\$833.8	\$3,092.8	\$3,926.6
TPS	\$558.6	\$1,101.0	\$1,659.6

As shown above, the total 30-year cost for either cost scenario is significant, with both exceeding \$1 billion. However, there are important differences in the costs for each scenario. Costs are substantially greater in the HCA scenario compared to the TPS scenario. This is because the HCA analyzes a broader set of constraints—such as voltage and protection limits—in addition to the TPS, making it a more conservative and location-specific estimate. As a result, the HCA scenario provides an upper bound for potential system upgrade costs. The TPS scenario only accounts for the TPS as a threshold for upgrades, offering a lower bound for system upgrade costs.

Figure 10 – 2
Forecast of Upgrade Costs 2026-2055, for TPS and HCA Cost Scenarios



The annual costs shown in Figure 10-2 demonstrate that the difference in costs between the TPS and HCA scenarios grows over the forecast period. After the early 2040s, costs in the HCA scenario become substantially greater than those in the TPS scenario. This reflects the more conservative nature of using hosting capacity results for this analysis. Because feeders only incur upgrade costs once their limits are exceeded—and HCA limits are generally lower than TPS limits—more feeders begin to exceed those thresholds and accumulate costs as DER adoption continues to increase later in the forecast period.

II. MEASURES THAT CAN REDUCE THE NEED FOR OR COST OF DISTRIBUTION UPGRADES

The law requires:

(2) an evaluation of measures that can reduce the need for or cost of distribution system upgrades to enable the interconnection of distributed generation resources, including but not limited to the employment of smart inverters, grid management tools, distributed energy resources management tools, and energy export tariffs;

The Company has been actively studying, evaluating, testing, and piloting emerging technologies to improve DER integration and is encouraged by the potential benefits.

The innovative solutions referenced above include cutting edge technologies that offer opportunities to reduce system impacts and upgrade costs. Examples such as energy storage programs, advanced inverter functions, and Distributed Energy Resources Management System (DERMS) are being implemented today and their roles are discussed in *Chapters 7 and 11*.

Our DER strategy roadmap, discussed in *Chapter 7*, also considers new tools, technologies, and policies. Below, we address the specific measures listed in Minn. Stat. § 216B.2425 subd. 9(2) as part of our ongoing commitment to grid modernization and effective DER integration.

A. Smart Inverters

The Company requires UL 1741 certified Smart Inverters for all large DER applications. During the interconnection review process, the Company determines whether the application will operate at a fixed power factor or utilize one of the variable smart inverter operating curves. Smart inverters can help mitigate voltage impacts and, in cases of high reverse power flow, reduce thermal overloads. These capabilities can lower the need for system upgrades, potentially making interconnection more efficient and cost-effective.

B. Grid Management Tools

We understand this requirement to be seeking information on how an Advanced Distribution Management System (ADMS) could help reduce the need for or costs of system upgrades. ADMS provides real-time visibility into DER impacts, giving Company personnel enhanced information to support engineering judgement and case-by-case evaluations. This allows us to assess whether it is safe for DER to operate in an alternate configuration that would otherwise require disconnection or potentially costly system upgrades to operate.

ADMS also has potential to support hosting capacity through functions like voltage optimization and other automated control capabilities. As we continue to gain experience with these tools and testing new functionalities, we also look forward to the limited deployment of Grid DERMS, which will further enhance grid visibility and control. For more information on our grid modernization efforts, see *Chapter 5*.

We are also leveraging enhancements from AMI, specifically the Grid Visibility Tool, to streamline review of applications in the Engineering Review and Supplemental Review processes. This tool helps reduce the need for certain field verifications and

allows us to confirm equipment operating status.

C. DER Management Tools

A DERMS may enhance the integration and utilization of DER to meet the needs of the grid, customers, the market, and regulatory entities. DERMS enables more dynamic interactions between customers and the distribution grid, supporting greater flexibility and control. As part of our phased approach to deploying Grid DERMS, our next step is to gain more operational experience managing DER before deploying more broadly.

This phased implementation allows the Company to meet policy and regulatory goals while meeting customer and business needs. It also helps us understand the new requirements, resources and processes needed for broader DERMS deployment, allowing us to refine our approach over time.

We anticipate FERC Order 2222 will drive new business requirements, operational dynamics between distribution and transmission, and potential market implications between retail and wholesale markets. DERMS is expected to play a key role in meeting FERC Order 2222.

One potential application of DERMS is enabling flexible interconnection agreements, which could reduce the need for or cost of system upgrades—provided the approach is scalable and performs as expected. However, flexible interconnections are still a relatively new concept and continue to be defined and evaluated. See *Chapter 11* for a more detailed discussion regarding DERMS.

D. Energy Export Tariffs

We understand this requirement to be seeking information on DER compensation methodologies that could reduce the need for distribution system upgrades. Energy export tariffs are part of the Company's Solar*Rewards programs; i.e., those approved programs include compensation for the energy that is exported to the grid. The company does not have any additional plans for implementing new energy export tariffs at this time.

III. ALTERNATIVE COST ALLOCATION METHODS

The law requires:

(3) a discussion of alternative methods to allocate costs of distribution system upgrades among

distributed generation [DG] owners or developers and ratepayers.

A core principle of utility ratemaking is cost causation—costs should be paid by those who cause them. In Minnesota, when distribution system upgrades are needed to interconnect new generation or load, those costs are currently paid by the cost-causer, consistent with this principle.

For the Company’s Community Solar Garden (CSG) program, developers are responsible for the costs of required upgrades. Similarly, in Commission-approved competitive resource acquisition processes—such as those we would use to procure distributed solar projects under the Distributed Solar Energy Standard (DSES)—bidders include known or anticipated interconnection costs in their bid price. The developer pays these costs directly. While all customers benefit from these system resources, the costs are ultimately recovered through rates as part of the contracted price. This approach applies whether a project connects at the transmission or distribution level and encourages developers to choose cost-effective interconnection locations.

As part of our due diligence in recent resource acquisitions, we have evaluated interconnection risks and costs, with overall project pricing being a key factor—since selected project costs are passed on to customers. We expect to use similar evaluation criteria in future RFPs, consistent with Commission-approved processes.

We also note that the Minnesota Legislature has adopted a DER cost-sharing framework that allows pro rata sharing of distribution upgrade costs among DER participants. This framework is outlined in Laws of Minnesota 2024, Chapter 126, Article 6, Section 53, with further details available in Docket No. E002/CI-24-288. Standards to implement this framework are currently under development in that docket. The implementation of this framework will establish an alternative cost allocation method for DER-driven upgrades in Minnesota.

To meet our statutory obligation under Minn. Stat. § 216B.2425, subd. 9(3), we also provide below the alternative cost allocation methods identified and shared in our 2023 IDP.

A. Retroactive Cost Sharing Between DG Facilities

Under this method, triggering projects (i.e., the first interconnection applicant) would be required to pay for the costs of interconnection, but the utility would provide them with “true-up” payments collected from subsequently interconnected facilities taking advantage of the capacity created by the upgrades their facility triggered. At our IDP

stakeholder workshop on June 12, 2023, which was shortly after this and many other new IDP filing requirements were passed, we asked stakeholders if they had ideas for alternative methods to allocate costs of distribution system upgrades. We received one comment suggesting this approach.

This approach would not shift costs to customers; however, it could lead to higher costs or carrying costs for the first DG owner because there would be no guarantee whether or when subsequent projects would seek to interconnect and thus, share in the cost. Administratively, this approach would be burdensome and costly to manage because it would require new application, tracking, and billing functionalities – and the associated human resources – which would further increase costs to all applicants.

B. Prospective, Location-Specific Cost Sharing Between DG Facilities (“Cost Sharing 2.0”)

In this method, also known as “Cost Sharing 2.0,” utilities would determine the costs of making a system upgrade and calculate a per-kW cost for the upgrades, which would be assessed to each DG facility interconnecting to that portion of the system based upon the facility’s nameplate capacity. The portions of the system targeted for upgrades may be identified either by the utility’s analysis of future expansion needs or pending requests for interconnection.

We note that the Commission has approved a form of prospective cost sharing for small solar projects. The program, funded an extra fee assessed to interconnection applications for most solar projects up to 40 kW, provides up to \$15,000 to eligible projects to cover certain interconnection-related costs.²

Additionally, the Proactive Distribution Grid Upgrades framework, approved by the Commission in Docket No. E002/CI-24-318, incorporates elements similar to “Cost Sharing 2.0” by requiring a per-kW fee from both load and generation interconnections in areas of the distribution system where proactive upgrades have been approved.

² Order Approving Implementation of Cost Sharing Plan as Modified (Docket No. E002/M-18-714), December 19, 2022.

C. Costs of Interconnection Paid by the Utility and Recovered from All Customers

This approach would expand the portion of interconnection costs recovered in the utility's rate base to include all upgrades on the utility side of the point of interconnection (i.e., for a small generator interconnecting at the customer meter, all upgrade costs would be rate based). Some argue that broader public policy benefits of DG mean that all customers should bear the cost of interconnection to the point of common coupling.

D. Network Upgrade/System Enhancement Credits

In this approach, when studying a new interconnection, utility customers and facilities in that area would also be analyzed for needed upgrades. If network upgrades are found to be a common benefit for the interconnecting facility and surrounding utility customers and facilities, costs can be shared between surrounding facilities and the interconnecting project. This approach is a hybrid wherein the utility analyzes the potential broader benefits of network upgrades and costs are shared if benefits are identified. This may reduce developers' costs and motivate developers to site projects most efficiently. However, this approach would take time to develop, as would the needed tools and supporting human resources, and customers and developers may not agree on common benefits so that would also need further development and discussions.

IV. FORECAST SENSITIVITIES ANALYSIS

Order Point No. 3.d of the Commission's September 16, 2024 Order says:

In its next IDP, Xcel shall report on its progress to improve forecasting, including:

d) Utilizing IDP forecast scenarios to perform sensitivities on grid capacity or capital expense plans.

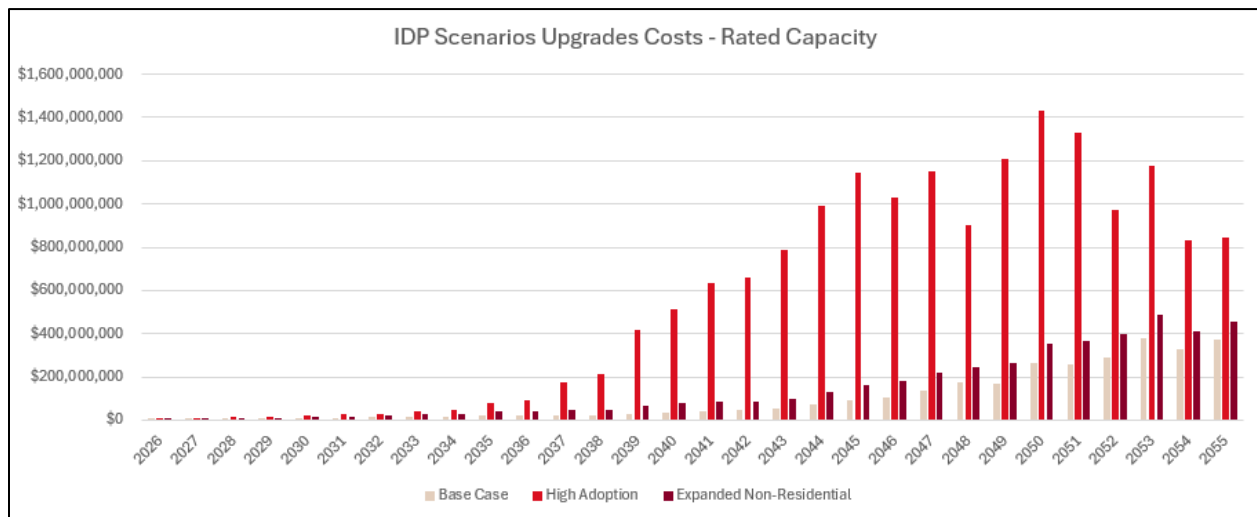
A sensitivities analysis was conducted on the LoadSEER IDP scenario forecast results. For each year, the capacity shortfall at each node was calculated based on how much the forecasted demand exceeds 100 percent of the node's rated capacity, and a marginal cost of \$800/kW was applied to estimate the cost of addressing these shortfalls. The methodology and assumptions used to conduct this analysis mirrors the methodology described in Section I above. However, the analysis was conducted three times—once for each forecast scenario. The incremental annual costs for each forecast scenario are shown in Figure 10-3 below.

In summary, the estimated 30-year cost to resolve N-0 violations to within 100 percent of rated capacity is:

- \$3.0 billion for the Base Case scenario,
- \$16.8 billion for the High Adoption scenario, and
- \$4.4 billion for the Expanded Non-Residential Scenario.

These figures represent the cost of distribution upgrades required to serve load that exceeds the rated capacity of each feeder. It is important to note that further costs would be required to upgrade the system to be within the planning limits for load described in *Chapter 1*.

Figure 10-3
Incremental Results for Potential Capacity Costs Related to Scenarios



CHAPTER 11: DISTRIBUTED ENERGY RESOURCE MANAGEMENT

In this chapter, we provide our initial DERMS roadmap and other DERMS-related information specified in Order Point No. 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.” We previously submitted this roadmap and supporting information in our Capacity*Connect (C*C) filing,² where we sought approval for a limited deployment of a GRID DERMS necessary to implement C*C.³

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

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

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

² Docket No. E002/M-25-378.

³ The 2023 IDP Order also required the Company conduct robust stakeholder outreach to inform stakeholders about DERMS. See Order Point No. 22. Information about our stakeholder workshops, previously submitted with our C*C filing, is also provided in Chapter 9 of this IDP.

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).⁴ 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.

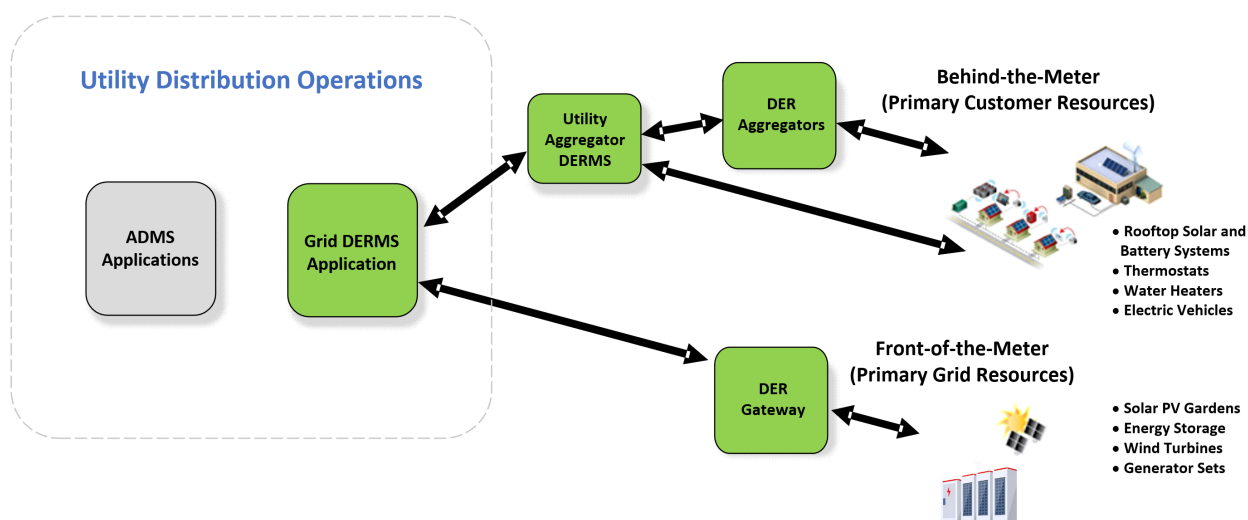
Aggregator DERMS: Primarily behind-the-meter resources, such as solar arrays and demand response assets. It also could facilitate control of these resources in coordination with the market and Distributed Energy Resource Aggregators (DERA). It is important to note that unlike Grid DERMS, Aggregator DERMS 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 we view the journey towards enterprise DERMS as a process that will need to integrate technology, people, and processes.

⁴ EPRI, *Aggregator DERMS-Use Cases and Requirements: Reference Language for Implementation and Integration of a DER Aggregation Type/Grid-Service Providing DERMS* (2024).

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 11-1
High-Level Enterprise DERMS Architecture – Illustrative Example

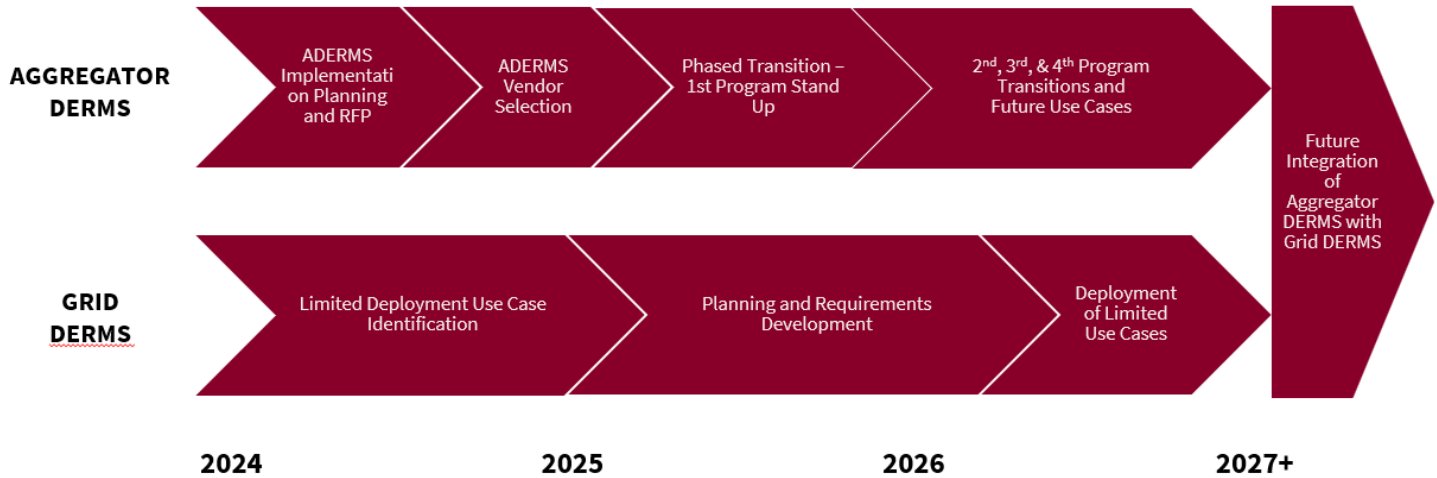


B. DERMS Roadmap and Implementation Timeline

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 11-2 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 11-2
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.

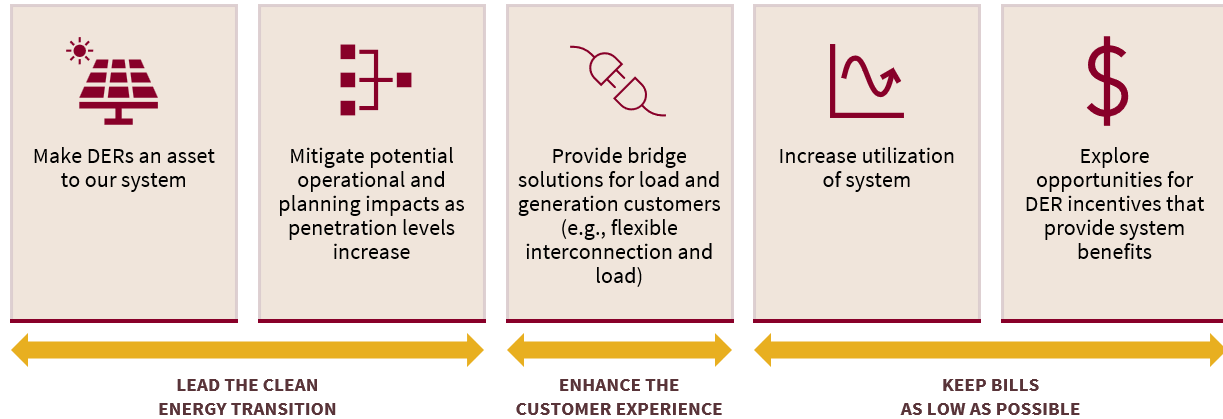
The Company views Enterprise DERMS and the business and customer processes that it can help enable, as a critical part of our strategy for planning and operating the grid – particularly during this period of rapid change and demand growth in the industry. Specifically, Enterprise DERMS can support several 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 11-3 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 11-3
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.

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 Capacity*Connect (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 the Company 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 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.

4. Comparison of Approaches

A table summarizing the potential deployment options that were explored by the Company is presented below. As explained above, 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 11-1
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. 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. Cons: - Future integration risk – eventually we will need to integrate Aggregator DERMS with Grid DERMS.	- 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. - Enhanced vendor accountability – a single vendor would be responsible for integration between Aggregator DERMS and Grid DERMS. - Potential integration and maintenance efficiencies. - 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.	- 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). - Implementation speed. - Challenging to 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).

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 No. 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.

A. Grid DERMS Use Cases

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

1. *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 timelines typically required under traditional interconnection agreements. Beneficiaries include DER developers, customers seeking faster interconnection, and grid operators managing system constraints.

2. *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.

3. *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 No. 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 No. 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?

A. 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.

B. 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 No. 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.⁵ This strategy allows the Company to:

- Optimize existing capacity and assets without compromising reliability for firm customers.
- Avoid or reduce costly interconnection-related upgrades⁶

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:

⁵ Curtailment or energization limits are dispatched based on day-ahead forecasted grid conditions.

⁶ 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.

- 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?

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:

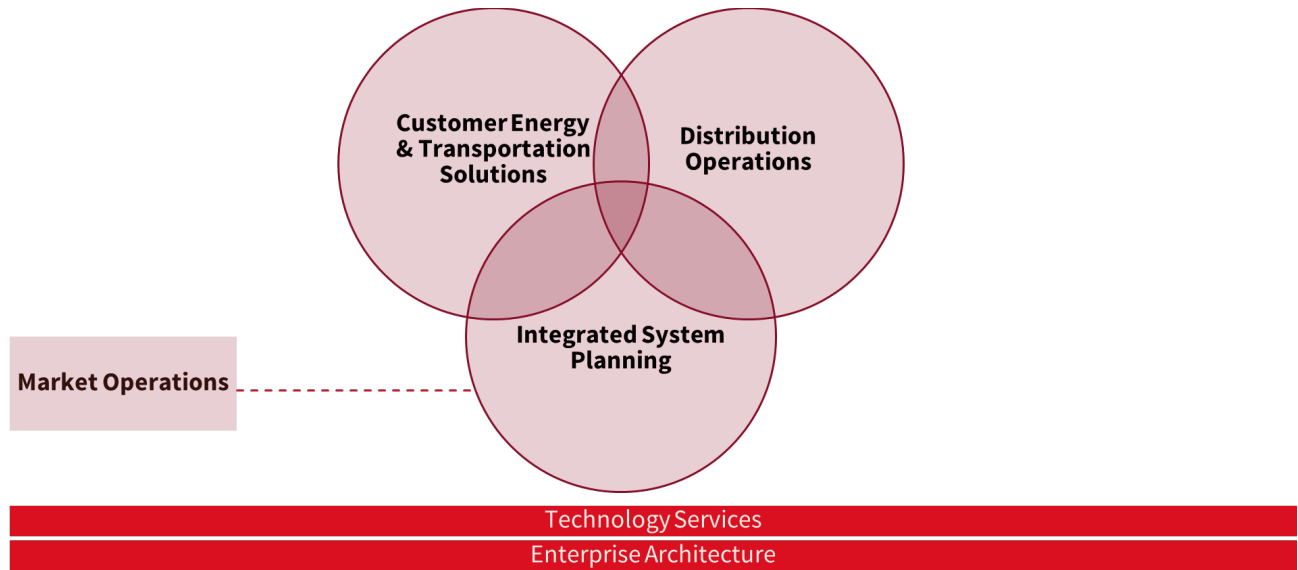
- Software design and architecture
- Development of detailed process, functional and technical requirements
- Software licensing fees
- System testing and validation
- Integration with existing grid systems and platforms

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 11-4
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 No. 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.⁷ 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 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.

⁷ 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.”).

IDP Piece	Title	Non-Public Designation
Attachment D	Distribution Risk Scoring Methodology	Attachment D Parts II and III contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Part III contains information Xcel Energy maintains as trade secret data as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use. Part III is marked as “Not-Public” in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material: 1. Nature of the Material: Calculations of expected Customer Minutes Out given electric distribution asset load and failure rate data 2. Authors: Electric Systems Performance and the Risk Analytics Department 3. Importance: Key values to determine the potential reliability of certain projects 4. Date the Information was Prepared: October 2025
Attachment E	Risk Scored Project Details	Attachment E contains two shaded and marked columns that contain (1) forecasted peak demand and (2) peak capacity by feeder and/or substation that Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Additionally, these fields for certain feeders contain information that if made public would be counter to our requirement to protect the anonymity of our customers’ energy usage information unless we have the customers’ consent to disclose it (Commission Order dated January 19, 2017 in Docket No. E,G999/CI-12-1344).
Attachment M	ELR- Cost Benefit Analysis	Attachment M is marked “Not-Public” in its entirety as it comprises information the Company considers to be economic data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential economic data that derives 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. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data. 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. 1. Nature of the Material: Cost Benefit Analysis Model developed by the Company 2. Author(s): Jessica Terry 3. Importance: Contains not-public, proprietary information. 4. Date the Information was Prepared: October 2025.
Attachment N	Grid Reinforcement- Cost Benefit Analysis	Attachment N is marked “Not-Public” in its entirety as it comprises information the Company considers to be economic data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential economic data that derives 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. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data. 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. 1. Nature of the Material: Cost Benefit Analysis Model developed by the Company 2. Author(s): Jessica Terry 3. Importance: Contains not-public, proprietary information. 4. Date the Information was Prepared: October 2025.

Statute	Requirement
Minn. Stat. § 216B.2425, subd. 2(e).	In addition to providing the information required under this subdivision, a utility operating under a multiyear rate plan approved by the commission under section 216B.16, subdivision 19, shall identify in its report investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.
Minn. Stat. § 216B.2425, subd. 3.	Subd. 3. Commission approval. By June 1 of each even-numbered year, the commission shall adopt a state transmission project list and shall certify, certify as modified, or deny certification of the transmission and distribution projects proposed under subdivision 2. The commission may only certify a project that is a high-voltage transmission line as defined in section 216B.2421, subdivision 2, that the commission finds is: (1) necessary to maintain or enhance the reliability of electric service to Minnesota consumers; (2) needed, applying the criteria in section 216B.243, subdivision 3; and (3) in the public interest, taking into account electric energy system needs and economic, environmental, and social interests affected by the project.
Minn. Stat. § 216B.2425, subd. 9.	The public utility that owns a nuclear generating plant must include the following information in the public utility's annual integrated distribution plan filed with the commission, beginning with the plan due November 1, 2023: 1) a forecast of distribution system upgrades necessary to accommodate the interconnection of distributed generation resulting from the utility's compliance with sections 216B.1641 and 216B.1691, subdivision 2h, and other customer-sited projects including energy storage systems; 2) an evaluation of measures that can reduce the need for or cost of distribution system upgrades to enable the interconnection of distributed generation resources, including but not limited to the employment of smart inverters, grid management tools, distributed energy resources management tools, and energy export tariffs; and 3) a discussion of alternative methods to allocate costs of distribution system upgrades among distributed generation owners or developers and ratepayers.

Section	Heading	MPUC IDP Requirement (Notice of Updated Filing Requirements in Docket No. E002/M-23-452, based on Docket No. E002/CI-18-251)	Location
	Planning Objectives	The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to: 1. Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state’s energy policies; 2. Enable greater customer engagement, empowerment, and options for energy services; 3. Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies; and, 4. Ensure optimized utilization of electricity grid assets and resources to minimize total system costs. 5. Provide the Commission with the information necessary to understand Xcel’s short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.	Attachment C: Correlation of IDP Content to Commission's IDP Planning Objective
		Commission review of ~~annual~~ distribution system plans ~~are~~ is¹ not meant to preclude flexibility for Xcel to respond to dynamic changes and on-going necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments. ¹ <i>In the Matter of Xcel Energy’s Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request, Docket No. E-002/M-19-666, Order Accepting Integrated Distribution Plan and Modifying Filing Requirements (Nov. 2, 2020), Ordering Para. 4.</i>	N/A
		For filing requirements which Xcel claims is not yet practicable or is currently cost-prohibitive to provide, Xcel shall indicate for each requirement: 1. Why the Company has claimed the information is not yet practicable or is currently cost-prohibitive; 2. How the information could be obtained, at what estimated cost, and timeframe; 3. What the benefits or limitations of filing the data in future reports as related to achieving the planning objectives; 4. If the information cannot be provided in future reports, what information in the alternative could be provided and how it would achieve the planning objectives.	Attachment C: Correlation of IDP Content to Commission's IDP Planning Objective
		Xcel shall discuss in future filings how the IDP meets the Commission’s Planning Objectives, including: 1. An analysis of how the information presented in the IDP related to each Planning Objective, 2. The location in the IDP, 3. Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and 4. Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel’s ability to meet the Planning Objectives² ² <i>In the Matter of Xcel Energy’s 2018 Integrated Distribution Plan, Docket No. E-002/CI-18-251, Order Accepting Report, and Amending Requirements (July 16, 2019), Ordering Para. 5.</i>	Attachment C: Correlation of IDP Content to Commission's IDP Planning Objective
1	Filing Date	Filing Date: Require Xcel to file annually with the Commission beginning on November 1, 2018, and biennially starting Nov 1, 2021³ an Integrated Distribution Plan (MN-IDP or IDP) for the 10-year period following the submittal. Xcel must continue to file an annual update of baseline financial data and non-wires alternatives analysis.⁴ The Commission will either accept or reject a distribution system plan by June 1 (to the extent practicable) of the following year based upon the plan content and conformance with the filing requirements and Planning Objectives listed above. The plan will be reviewed and may be combined with the Biennial Distribution System Plan required by Minn. Stat. 216B.2425 and associated certification requests, as authorized in that docket (E002/M-17-776). ³ <i>In the Matter of Xcel Energy’s Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request, Docket No. E-002/M-19-666, Order Accepting Integrated Distribution Plan, Modifying Reporting Requirements, and Certifying Certain Grid Modernization Projects (July 23, 2020), Ordering Para. 2.</i> ⁴ <i>July 23, 2020, Order (19-666) Ordering Para. 3</i>	This biennial IDP is being submitted on October 31, 2025 in compliance with this requirement.

Section	Heading	MPUC IDP Requirement (Notice of Updated Filing Requirements in Docket No. E002/M-23-452, based on Docket No. E002/CI-18-251)	Location
2	Stakeholder Meetings	Stakeholder Meeting(s): Xcel should hold at least one stakeholder meeting prior to filing the November 1 MN-IDP to obtain input from the public. The stakeholder meeting should occur in a manner timely enough to ensure input can be incorporated into the November 1 filing as deemed appropriate by the utility. At a minimum, Xcel should seek to solicit input on the following MN-IDP topics: (1) the load, electrification, and DER forecasts, and 5-year distribution system investments, (2) proposed 5-year distribution system investments, (3) anticipated capabilities of system investments and customer benefits derived from proposed actions in the next 5-years; including, consistency with the Commission’s Planning Objectives (see above), and (4) any other relevant areas proposed in the MN-IDP. Following the November 1 filing, the Commission will issue a notice of comment period. If deemed appropriate by staff, a stakeholder meeting may be held in combination with the comment period to solicit input.	Chapter 9: Stakeholder Engagement
3	Filing Requirements	Definitions: The following definitions are adopted for the purposes of these requirements. a. Distributed Energy Resources (DER): “supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or utility side of the electric meter.”⁵ This definition for this filing may include, but is not limited to: distributed generation, energy storage, electrified end uses that can be used as a resource, demand side management, and energy efficiency.⁶ b. Electrification: the conversion of an energy-consuming device, system, or sector from non-electric sources of energy to electricity. This includes but is not limited to transportation electrification, cooking appliances, space heating and cooling, water heating, and industrial processes. c. Energy Efficiency: measures or programs that target consumer behavior, equipment, processes, or devices and are designed to reduce the consumption of electricity on either an absolute or per unit of production basis. ⁵ See Minnesota Staff Grid Modernization Report, March 2016. ⁶ See report on IDP prepared for the Commission by consultants ICF International, in In the Matter of the Commission Investigation into Grid Modernization, Docket No. E-999/CI-15-556, Notice of Integrated Distribution Planning Report and Stakeholder Workshop (September 13, 2016), eDockets ID: 20169-124836-01.	Chapter 1: System Planning
3.A.1	Baseline Distribution System and Financial Data System Data	Modeling software currently used and planned software deployments	Chapter 1: System Planning
3.A.2	Baseline Distribution System and Financial Data System Data	Percentage of substations and feeders with monitoring and control capabilities, planned additions	Chapter 4: Distribution System Statistics
3.A.3	Baseline Distribution System and Financial Data System Data	A summary of existing system visibility and measurement (feeder-level and time interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)	Chapter 4: Distribution System Statistics
3.A.4	Baseline Distribution System and Financial Data System Data	Number of customer meters with AMI/smart meters and those without, planned AMI-investments, and overview of functionality available	Chapter 4: Distribution System Statistics
3.A.5	Baseline Distribution System and Financial Data System Data	Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans, including a. Setting the forecasts for distributed energy resources and electrification consistently in its resource plan and its IDP b. Conducting advanced forecasting to better project the levels of distributed energy resource and electrification deployment at a feeder level, using Xcel's advanced planning tool. c. Proactively planning investments in hosting capacity and other necessary system capacity to allow distributed generation, electrification, and electric vehicle additions consistent with the forecast for distributed energy resources and electrification. d. Improving non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources e. Planning for aggregated distributed energy resources to provide system value including energy/capacity during peak hours⁷ ⁷ July 26, 2022, Order (21-694) Ordering Para. 4	Chapter 1: System Planning Chapter 8: Non-Wires Alternatives Analysis
3.A.6	Baseline Distribution System and Financial Data System Data	Discussion of how DERs and electrification is considered in load forecasting [and thus system planning] and any expected changes in load forecasting methodology	Chapter 1: System Planning

Section	Heading	MPUC IDP Requirement (Notice of Updated Filing Requirements in Docket No. E002/M-23-452, based on Docket No. E002/CI-18-251)	Location
3.A.7	Baseline Distribution System and Financial Data System Data	Discussion if and how IEEE Std. 1547-2018 ⁸ impacts distribution system planning considerations (e.g., opportunities & constraints related to interoperability and advanced inverter functionality). [IEEE Standard 1547-2018, published April 6, 2018]. ⁸ IEEE Standard 1547-2018 published April 6, 2018.	Chapter 7: Distributed Energy, Resources, System Interconnection, and Hosting Capacity
3.A.8	Baseline Distribution System and Financial Data System Data	Estimated distribution system annual loss percentage for the prior year	Chapter 4: Distribution System Statistics
3.A.9	~~Baseline Distribution System and Financial Data System Data~~	~~For the portions of the system with SCADA capabilities, the maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system~~	No longer applies. Order Point 6 in the Commission's September 16, 2024 Order omits this requirement.
3.A.10	Baseline Distribution System and Financial Data System Data	Total distribution substation capacity in kVA	Chapter 4: Distribution System Statistics
3.A.11	Baseline Distribution System and Financial Data System Data	Total distribution transformer capacity in kVA	Chapter 4: Distribution System Statistics
3.A.12	Baseline Distribution System and Financial Data System Data	Total miles of overhead distribution wire	Chapter 4: Distribution System Statistics
3.A.13	Baseline Distribution System and Financial Data System Data	Total miles of underground distribution wire	Chapter 4: Distribution System Statistics
3.A.14	Baseline Distribution System and Financial Data System Data	Total number of distribution premises	Chapter 4: Distribution System Statistics
3.A.15	Baseline Distribution System and Financial Data System Data	Total costs spent on DER generation installation in the prior year. These costs should be broken down by category in which they were incurred (including application review, responding to inquiries, metering, testing, make ready, etc).	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.16	Baseline Distribution System and Financial Data System Data	Total charges to customers/member installers for DER generation installations, in the prior year. These charges should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.17	Baseline Distribution System and Financial Data System Data	Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.18	Baseline Distribution System and Financial Data System Data	Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.19	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.20	Baseline Distribution System and Financial Data System Data	Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity

Section	Heading	MPUC IDP Requirement (Notice of Updated Filing Requirements in Docket No. E002/M-23-452, based on Docket No. E002/CI-18-251)	Location
3.A.21	Baseline Distribution System and Financial Data System Data	Total number of electric vehicles in service territory, by type where possible (e.g. light duty, transit, medium duty, heavy duty) ⁹ ⁹ In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Docket No. E-999/CI-17-879, Order Accepting Filings and Establishing Requirements for Additional Filings (December 12, 2019), Ordering Para. 8.a.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.22	Baseline Distribution System and Financial Data System Data	Total number and capacity of public access electric vehicle charging stations, broken out by: a. Number and capacity of known public access Level 2 Charging Stations ¹⁰ b. Number and capacity of Level 2 Charging Stations enrolled in a utility program, broken out by program ¹¹ c. Number and capacity of known public access direct current fast charging (DCFC) stations ¹² d. Number and capacity of DCFC installed through a utility EV program, broken out by program ¹³ e. All other known EV charging stations (by type, ex DCFC, Level 2) ¹⁰ December 12, 2019 Order (17-879), Ordering Para. 8.e ¹¹ December 12, 2019 Order (17-879), Ordering Para. 8.e ¹² December 12, 2019 Order (17-879), Ordering Para. 8.f ¹³ December 12, 2019 Order (17-879), Ordering Para. 8.f	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.23	Baseline Distribution System and Financial Data System Data	Number of units and MW/MWh ratings of battery storage	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.24	Baseline Distribution System and Financial Data System Data	MWh saving and peak demand reductions from EE program spending in previous year	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.25	Baseline Distribution System and Financial Data System Data	Amount of controllable demand (in both MW and as a percentage of system peak)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.26	Baseline Distribution System and Financial Data System Data	A high-level look at historical distribution system spending for the past 5-years and projected distribution system spending for 5-years into the future, in each category listed below: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other i. Electric Vehicle Programs ¹⁴ ¹⁴ In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Docket No. E-999/CI-17-879, Order Accepting 2020 Transportation Electrification Plans, Adopting Additional Informational Requirements, and Establishing Biennial Filing Requirement (April 16, 2021), Ordering Para. 3.a.	Chapter 6: Distribution Financial Framework and Action Plans
3.A.27	Baseline Distribution System and Financial Data System Data	Historical distribution system spending for the past 5-years and projected distribution system spending for 5-years into the future broken down by Xcel's internal distribution budget categories, itemizing any non-traditional distribution projects.	Chapter 6: Distribution Financial Framework and Action Plans

Section	Heading	MPUC IDP Requirement (Notice of Updated Filing Requirements in Docket No. E002/M-23-452, based on Docket No. E002/CI-18-251)	Location
3.A.28	Baseline Distribution System and Financial Data System Data	All non-Xcel investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g., CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation.)	Chapter 6: Distribution Financial Framework and Action Plans
3.A.29	Baseline Distribution System and Financial Data System Data	~~Projected distribution system spending for 5 years into the future for the categories listed above, itemizing any non-traditional distribution projects~~	Removed from Filing Requirements per Notice of Updated Filing Requirements (6/3/25)
3.A.29	Baseline Distribution System and Financial Data System Data	Planned distribution capital projects, including drivers for the project, timeline for improvement, summary of anticipated changes in historic spending. Driver categories should align with Xcel's internal distribution budget categories.	Chapter 6: Distribution Financial Framework and Action Plans Attachment H: Capital Project List by IDP Category Attachment I: Capital Profile Trend
3.A.30	Baseline Distribution System and Financial Data System Data	Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement	Chapter 1: System Planning Chapter 8: Non-Wires Alternatives Analysis
3.A.31	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.32	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas of existing or forecasted high DER and/or electrification penetration. Include definition and rationale for what the Company considers “high” DER and electrification penetration.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.33	Baseline Distribution System and Financial Data DER Deployment	DER Deployment: Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.34	Baseline Distribution System and Financial Data DER Deployment	Information on distribution upgrades made to accommodate electrification, when known, including whether it was reactive to new load or based on a short-term forecast.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.35	Baseline Distribution System and Financial Data DER Deployment	Number of fuel-switching rebated granted through Xcel Energy's Conservation Optimization (ECO) plan in the prior year, broken out by technology type (air/ground source heat pump, water heater, cooking, other industrial process heat, electric vehicles, etc.)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.A.36	Baseline Distribution System and Financial Data DER Deployment	Number of electric space or water heating devices enrolled in a time-of-use rate or demand response program, broken out by program type.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity

Section	Heading	MPUC IDP Requirement (Notice of Updated Filing Requirements in Docket No. E002/M-23-452, based on Docket No. E002/CI-18-251)	Location
3.A.37	Electric Vehicles	Electric Vehicles: A summary table with the following information for each EV rate offering or program during the reporting period: a) Number of customers and/or vehicles enrolled at the end of the reporting period b) Total energy consumed (MWh) during each EV tariff charging period c) Peak demand (MW) and the date and time at which occurred ¹⁶ ¹⁶ December 12, 2019 Order (17-879), Ordering Para. 8b, 8c, and 8d	Transportation Electrification Plan
3.A.38	Electric Vehicles	Electric Vehicles: Any system upgrades performed to accommodate EV charging, total costs paid by utility and by customer, and average cost per upgrade. Cost should be reported separately for the following customer groups: Residential, Government Fleet, Private Fleet, and Public Charging, Other (specify) ¹⁷ ¹⁷ December 12, 2019 Order (17-879), Ordering Para. 8g; April 16, 2021 Order (17-879), Ordering Para. 3.b	Transportation Electrification Plan
3.B.1	Hosting Capacity and Interconnection Requirements	Provide a narrative discussion on how the hosting capacity analysis filed annually on November 1 currently advances customer-sited DER (in particular PV and electric storage systems) and electrification, how the Company anticipates the hosting capacity analysis (HCA) identifying interconnection points on the distribution system and necessary distribution upgrades to support the continued development of distributed generation resources ¹⁸ , and any other method in which Xcel anticipates customer benefit stemming from the annual HCA. ¹⁸ Minn. Stat. 216B.2425, Subd. 8	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.B.2	Hosting Capacity and Interconnection Requirements	Describe the data sources and methodology used to complete the initial review screens outlined in the Minnesota DER Interconnection Process. ¹⁹ ¹⁹ In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611, Docket No. E-999/CI-16-521, Order Establishing Updated Interconnection Process and Standard Interconnection Agreement (August 13, 2018), establishing Minnesota's Distributed Energy Resources Interconnection Process (MN DIP) 3.2, "Initial Review."	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.C.1	Distributed Energy Resource and Electrification Scenario Analysis	In order to understand the potential impacts of faster-than-anticipated DER and electrification adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER and electrification deployment on Xcel's system. Scenarios should reflect a reasonable mix of individual DER and electrification adoption and aggregated or bundled DER/electrification service types, dispersed geographically across the Xcel distribution system in the locations Xcel would reasonably anticipate seeing DER and electrification growth take place first, and how the [utility] would anticipate the combined impacts of simultaneous DER and electrification growth. Xcel must provide detail on how, in aggregate, the energy and climate goals of the Minnesota communities it serves, along with customer preference trends, are reflected. In particular, distribution generation planning should include consideration of local community generation goals and beneficial electrification. ²⁰ For electric vehicle forecasts scenarios, Xcel shall provide base-case, medium, and high adoption, capacity, and energy forecasts by sector (light duty, medium duty, and heavy duty). ²¹ ²⁰ July 23, 2020 Order (19-666), Ordering Para. 4 ²¹ December 12, 2019 Order (17-879), Ordering Para. 8h and 8i	Chapter 1: System Planning Attachment K
3.C.2	Distributed Energy Resource and Electrification Scenario Analysis	Include information on methodologies used to develop the low, medium, and high scenarios, including the DER and electrification adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER and electrification load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.	Chapter 1: System Planning
3.C.3	Distributed Energy Resource and Electrification Scenario Analysis	Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER and electrification integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER and electrification adoption, potential barriers to DER and electrification integration, and the types of system upgrades that may be necessary to accommodate the DER and electrification at the listed penetration levels.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
3.C.4	Distributed Energy Resource Scenario Analysis	Include information on anticipated impacts from FERC Order 841 ²² (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM-18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators) ²² Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 162 FERC ¶61,127 (February 28, 2018)	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity

Section	Heading	MPUC IDP Requirement (Notice of Updated Filing Requirements in Docket No. E002/M-23-452, based on Docket No. E002/CI-18-251)	Location
3.D.1	Long-Term Distribution System Modernization and Infrastructure Investment Plan	<i>[Merged into 3.D.2 per July 16, 2019 Order, Order Point 4] 18-251</i>	N/A
3.D.2	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Xcel shall provide a 5-year Action Plan as part of a 10-year long term plan ²³ for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER and electrification future analysis, hosting capacity analysis ²⁴ , and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (expanding on topics and categories listed above). 23 Modified by July 16, 2019, Order (18-251), Ordering Para. 4 24 Modified by July 16, 2019, Order (18-251), Ordering Para. 4	Chapter 5: Grid Modernization Chapter 6: Distribution Financial Framework and Action Plans
		Xcel should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum:	See 3.D.2 Subparts below.
3.D.2.a	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Overview of investment plan: scope, timing, and cost recovery mechanism	Chapter 5: Grid Modernization
3.D.2.b	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise. ²⁵ ²⁵ See https://gridarchitecture.pnnl.gov/	Chapter 5: Grid Modernization
3.D.2.c	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.	N/A - no investment proposal
3.D.2.d	Long-Term Distribution System Modernization and Infrastructure Investment Plan	System interoperability and communications strategy	Chapter 5: Grid Modernization
3.D.2.e	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Costs and plans associated with obtaining system data (EE load shapes, PV output profiles with and without battery storage, capacity impacts of DR combined with EE, EV charging profiles, load profiles of electrification, etc.)	Chapter 1: System Planning
3.D.2.f	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)	Chapter 5: Grid Modernization

Section	Heading	MPUC IDP Requirement (Notice of Updated Filing Requirements in Docket No. E002/M-23-452, based on Docket No. E002/CI-18-251)	Location
3.D.2.g	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Customer anticipated benefit and cost	Attachment D: Distribution Risk Scoring Methodology Attachment E: Risk Scored Project Details Attachment F: Certification Request Attachment G: Distribution Function NPV
3.D.2.h	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)	Chapter 5: Grid Modernization
3.D.2.i	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Plans to manage rate or bill impacts, if any	Chapter 6: Distribution Financial Framework and Action Plans
3.D.2.j	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Impacts to net present value of system costs (in NPV RR/MWh or MW)	Chapter 6: Distribution Financial Framework and Action Plans Attachment G: Distribution Function NPV
3.D.2.k	Long-Term Distribution System Modernization and Infrastructure Investment Plan	For each grid modernization project in its 5-year Action Plan, Xcel should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Xcel shall provide all information used to support its analysis. ²⁶ ²⁶ July 16, 2019, Order (18-251), Ordering Para. 3	Cost and Benefit Information for a Mobile Battery Certification Request are included in Attachment F.
3.D.2.l	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Status of any existing pilots or potential for new opportunities for grid mod pilots.	Chapter 5: Grid Modernization
3.D.2.m	Long-Term Distribution System Modernization and Infrastructure Investment Plan	The results of its annual distribution investment risk-ranking and a description of the risk-ranking methodology. ²⁷ ²⁷ July 16, 2019, Order (18-251), Ordering Para. 9	Chapter 1: System Planning Attachment D: Distribution Risk Scoring Methodology
3.D.2.n	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Information on forecasted net demand, capacity, forecasted percent load, risk score, planned investment spending, and investment summary information for feeders and substation transformers that have a risk score or planned investment in the budget cycle in future IDPs ²⁸ ²⁸ July 16, 2019, Order (18-251), Ordering Para. 10	Chapter 1: System Planning Attachment E: Risk Scored Project Details
3.D.2.o	Long-Term Distribution System Modernization and Infrastructure Investment Plan	Long-range distribution studies conducted since the last IDP ²⁹ ²⁹ July 16, 2019, Order (18-251), Ordering Para. 11	N/A; addressed in Chapter 1: System Planning

Section	Heading	MPUC IDP Requirement (Notice of Updated Filing Requirements in Docket No. E002/M-23-452, based on Docket No. E002/CI-18-251)	Location
3.D.3	Long-Term Distribution System Modernization and Infrastructure Investment Plan	In addition to the 5-year Action Plan, Xcel shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER and electrification into future planning processes based on the DER and electrification futures analysis, and any other types of changes that may need to take place in the tools and processes Xcel is currently using.	Chapter 6: Distribution Financial Framework and Action Plans
3.E.1	Non-Wires (Non- Traditional) Alternatives Analysis	Xcel shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent 5 years that are anticipated to have a total cost of greater than \$2 million. For any forthcoming project or project in the filing year, which cost \$2 million or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.	Chapter 8: Non-Wires Alternatives Analysis
3.E.2	Non-Wires (Non- Traditional) Alternatives Analysis	Xcel shall provide information on the following: a. Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability) b. A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation) c. Cost threshold of any project type that would need to be met to have a non-traditional solution reviewed d. A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.	Chapter 8: Non-Wires Alternatives Analysis
3.F.1	Transportation Electrification Plan	Xcel shall provide a summary of the utility's ongoing transportation electrification efforts, including existing programs and projects in development over at least the next 2 years. ³⁰ ³⁰ December 12, 2019 Order (17-879), Ordering Para. 8j	Transportation Electrification Plan
3.F.2	Transportation Electrification Plan	Xcel shall provide a discussion of how it plans to facilitate: ³¹ a. availability and awareness of public charging infrastructure, including an assessment of the private sector fast charging marketplace for the utility's service territory b. availability of residential charging options for both single family and multiple unit dwellings c. programs or tariffs in development to address flexible load or reduce metering and data costs; and d. fleet electrification. ³¹ December 12, 2019 Order (17-879), Ordering Para. 8k	Transportation Electrification Plan
3.F.3	Transportation Electrification Plan	Xcel shall provide a discussion of how it plans to optimize EV benefits, including a discussion of how to align charging with periods of lower customer demand and higher renewable energy production and by improving grid management and overall system utilization/efficiency. ³² ³² December 12, 2019 Order (17-879), Ordering Para. 8m	Transportation Electrification Plan
3.F.4	Transportation Electrification Plan	Xcel shall include a discussion of how it plans to encourage more customers with electric vehicles to participate in managed charging. ³³ ³³ In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Docket No. E-999/CI-17-879, Order Accepting 2021 Transportation Electrification Plans and Adopting Additional Informational Requirements (May 17, 2022), Ordering Para. 4.	Transportation Electrification Plan
3.F.5	Transportation Electrification Plan	Xcel shall provide a discussion that addresses divestment issues and identifies possible divestment strategies for its DCFC Network approved in Docket 20-745 at the conclusion of the pilot program. ³⁴ ³⁴ In the Matter of Xcel Energy's Petition for Approval of Electric Vehicle Programs as part of its COVID-19 Pandemic Economic Recovery Investments, Docket No. E-002/M-20-745, Order Approving Public Charging Station Proposal (April 27, 2022), Ordering Para. 8.	Transportation Electrification Plan
3.F.6	Transportation Electrification Plan	Xcel shall provide evaluations of non-pilot EV programs that examine the cost-effectiveness of the programs as currently designed and potential changes that could improve their cost-effectiveness. ³⁵ ³⁵ In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure, Docket No. E-999/CI-17-879, Order Accepting 2020 Transportation Electrification Plans, Adopting Additional Informational Requirements, and Establishing Biennial Filing Requirement (Apr 16, 2021), Ordering Para. 3.c.	Transportation Electrification Plan
3.F.7	Transportation Electrification Plan	Xcel shall provide a summary of customer EV education initiatives. The Company does not need to provide specific examples of outreach materials. ³⁶ ³⁶ December 12, 2019 Order (17-879), Ordering Para. 8l	Transportation Electrification Plan
3.F.8	Transportation Electrification Plan	Xcel shall provide summaries of any proposals or pilots, including links to full reports, submitted to other regulatory agencies or jurisdictions (for example, proposals submitted under Conservation Improvement Programs or pilots run in other states). ³⁷ ³⁷ December 12, 2019 Order (17-879), Ordering Para. 8n	Transportation Electrification Plan
3.F.9	Transportation Electrification Plan	Xcel shall provide citations with links to the most recent reports for any ongoing EV pilots or programs. ³⁸ ³⁸ December 12, 2019 Order (17-879), Ordering Para. 8o	Transportation Electrification Plan

Section	Heading	MPUC IDP Requirement (Notice of Updated Filing Requirements in Docket No. E002/M-23-452, based on Docket No. E002/CI-18-251)	Location
3.F.10	Transportation Electrification Plan	Xcel shall provide historical spending for the past 5-years on all transportation electrification initiatives broken down across sections of its budget: Budget Category (ex. Distribution, IT, Transmission, etc.), Capital, O&M, Marketing & Communications, Other (provide explanation of what is in "other")	Transportation Electrification Plan
3.F.11	Transportation Electrification Plan	Xcel shall provide future spending for the next 5-years on all transportation electrification initiatives broken down across sections of its budget: Budget Category (ex. Distribution, IT, Transmission, etc.), Capital, O&M, Marketing & Communications, Other (provide explanation of what is in "other")	Transportation Electrification Plan

Order Point	MPUC IDP Requirement (8/7/18 Order in Docket Nos. E002/M-17-775 & E002/M-17-776)	Location
11	Xcel may file a Grid Modernization Report and certification request on November 1, 2018 in combination with an Integrated Distribution Plan in Docket No. E-002/CI-18-251. The filing should include for any certification request(s) at a minimum: (1) details on why the project is necessary for grid modernization; (2) how it is in the public interest; (3) how it is consistent with the Commission's Guiding Principles for Grid Modernization (Docket 15-556); (4) the intended objectives for the project; (5) a description of the available alternatives to meet the intended objectives; (6) a cost benefit analysis of the project; (7) and potential interrelation with other initiatives, projects, and Xcel's long-term grid modernization plans.	Attachment F: Certification Request
Order Pt.	MPUC IDP Requirement (7/16/19 Order in Docket No. E002/CI-18-251)	Location
6	Xcel shall provide additional information on the Incremental Customer Investment Initiative and the System Expansion or Upgrade for Reliability and Power Quality increases beginning in 2021.	Not applicable for 2025 IDP. See Company's October 30, 2020 filing in Docket No. E002/M-19-666 at Page 6. Item will be removed in next IDP.
7	Xcel shall make the development of enhanced load and DER forecasting capabilities, as well as, tracking and updating of actual feeder daytime minimum loads, a priority in 2019 and include a detailed description of its progress in the Company's 2019 IDP.	Not applicable for 2025 IDP. No longer relevant - provided in Docket No. E002/M-19-666. Item will be removed in next IDP.
8	Xcel shall provide all information, analysis, and assumptions used to support the cost/benefit ratio for AMI, FAN and FLISR; and IVVO and CVR cost-benefit analysis as part of its 2019 IDP filing or other future filings.	Not applicable for 2025 IDP. No longer relevant - provided in Docket No. E002/M-19-666. Item will be removed in next IDP.
Order Pt.	MPUC IDP Requirement (7/23/20 Order in Docket No. E002/M-19-666)	Location
5	Xcel must allow any interested person to participate in stakeholder engagement meetings regarding its IDP and HCA.	Chapter 9: Stakeholder Engagement
6	Xcel must engage stakeholders in further advancing the Company's NWA Analysis, including, but not limited to, screening criteria, analysis methodology and assumptions, and NWA evaluation parameters.	Chapter 9: Stakeholder Engagement
9	The Commission requests that the Department file a report by November 1, 2020, including recommendations on specific metrics, detailed methods for evaluating performance, and consumer protections or other conditions, including cost caps, that should be applied to the certified projects. The report should be informed by a stakeholder process and will be made part of the record for any future cost recovery proceedings. <u>Xcel must participate in the stakeholder process, which must be open to all interested parties, and fully cooperate with the Department.</u>	Not applicable for 2025 IDP. Confirmed - Xcel Energy participated in all workshops for Docket No. E002/DI-20-627 (10/23/2020; 11/20/2020). Item will be removed in next IDP.

12	Xcel must produce a draft rate design “roadmap” with input from stakeholders and file it with the Commission by October 1, 2020. The Commission delegates authority to the Executive Secretary to set schedules and gather information on, or refer to the appropriate docket(s), the following: a. A summary of the Company’s current advanced rate designs and demand management programs, advanced rate designs in development, and relevant industry best practices. b. A timeline for proposing advanced rates and/or demand management programs for all customer classes. c. A discussion on what should be discussed in petitions for rate design changes, including: i. Whether program design strategies will be needed to support low income customer participation in these offerings, ii. Application to distributed energy resources and beneficial electrification, iii. Implementation plans, including education and outreach to customers, and iv. Evaluation plans.	Not applicable for 2025 IDP. Filed 10/1/2020 in Docket No. E002/M-19-666. Item will be removed in next IDP.
13	60 days prior to a petition to seek rider recovery for AGIS costs, Xcel Energy shall file preferred procedural paths forward with one option being a contested case. The Commission will make a procedural and scoping decision prior to the consideration of a rider recovery determination. The Executive Secretary is authorized to establish a comment and reply schedule prior to the procedural and scoping hearing.	Not applicable to 2025 IDP. Filed 8/28/2020 in Docket No. E002/M-19-666. Item will be removed in next IDP.
Order Pt.	MPUC IDP Requirement (11/2/20 Order in Docket No. E002/M-19-666)	Location
4	Xcel Energy, Minnesota Power, Otter Tail Power, and Dakota Electric Association’s IDP filing requirements in the second paragraph under Planning Objectives are corrected as shown: Commission review of ~~annual~~ distribution system plans are is not meant to preclude flexibility for [UTILITY] to respond to dynamic changes and on-going necessary system improvements to the distribution system; nor is it a prudency determination of any proposed system modifications or investments.	See IDP Planning Objectives for Xcel Energy with the 12/8/22 Order.
Order Pt.	MPUC IDP Requirement (7/26/22 Order in Docket No. E002/M-21-694)	Location
2	Xcel shall file its smart inverter roadmap and related consultant reports in this docket by November 1, 2022	Submitted in Annual Update, Attachment E, submitted 11/1/2022 in Docket No. E002/M-21-694. Item will be removed in next IDP.
3	Xcel shall use both the WACC and societal discount rate in its NWA analysis and discuss the results of the two approaches in a future IDP stakeholder meeting.	Chapter 8: Non-Wires Alternatives Analysis

5	Within 90 days, Xcel shall make a compliance filing that outlines key difference between its Colorado and Minnesota distribution system planning processes, including but not limited to a discussion of the following: a. Orders, rules, and statutes pertaining to distribution system planning b. How Xcel Energy conducts DER and load forecasting, including the Company's implementation of LoadSEER c. How Xcel Energy conducts its NWA analysis d. How Xcel Energy conducts its Hosting Capacity analysis	Compliance filing submitted 10/24/2022 in Docket No. E002/M-21-694. Item will be removed in next IDP.
6	Xcel shall hold a series of stakeholder meetings to collaborate with interested parties, obtain input, and generate new ideas around a shared vision of the distribution grid of the future. This stakeholder series is intended to provide transparency into the Company's distribution planning process and explore how Minnesota's public policy goals will be realized on the distribution system and impact the Company's future plans. This stakeholder series should be timed such that stakeholder input can be incorporated into the Company's next IDP filing and next IRP filing and include at least four meetings. The topics will include, but not be limited to the following: a. Integrated Distribution Planning 101 b. Identify the public policy goals that are changing the expectations of the distribution grid and how each public policy is expected to be realized on the grid in the near- and long-term. c. How energy efficiency, demand response, and other DER might impact Xcel's planning processes d. How Xcel should consider and incorporate local clean energy goals in its planning processes e. What investments are necessary to achieve the distribution grid of the future, and the criteria Xcel should use to plan and prioritize those investments	Compliance filing submitted 8/1/23 in Docket No. E002/M-21-694. Item will be removed in next IDP.

6 (Continued)	f. Prioritizing the use of "net load" in its load forecasts and system planning, including developing a methodology for incorporating the load reducing impact of distributed generation into its load forecasts and system planning processes g. Develop a methodology for valuing the load-modifying impacts of demand response in load forecasts and present a load forecast that includes demand response contributions h. Identify appropriate transportation, building, and industrial end use electrification scenarios for inclusion in the 2023 IDP load forecasts i. How Xcel anticipates proactively planning for grid investments to allow distributed generation and EV additions consistent with the DER forecast j. Estimate the potential synergies between interconnection upgrades sand planned distribution capital investments, and discuss the anticipated overlap between planned investments and capacity constrained locations on Xcel's distribution system. Xcel shall make a compliance filing with the summary of the stakeholder process and a list of next steps by August 1, 2023. Xcel shall include a summary of the stakeholder series in its next IDP and relevant summary in its next IRP, including how it considered and incorporated stakeholder input.	Compliance filing submitted 8/1/23 in Docket No. E002/M-21-694. Item will be removed in next IDP. Chapter 1: System Planning- Order Point .f
7	The Commission certifies the Resilient Minneapolis Project and limits cost recover to a cost cap of \$9 million unless Xcel can show by clear and convincing evidence that the costs were reasonable, prudent, and beyond the Company's control. Xcel shall file reports annually on December 1st through 2026. The first report is due on December 1, 2022 and must contain the following information: a. Define and quantify the emergency service capabilities and capacity in more detail and in more concrete terms than Xcel has hitherto provided in its proposal and via discovery responses. b. Report on the status of the emergency service capacity to ensure that the benefits are or can be realized, and to develop a process and a plan for demonstrating that the benefits can be realized. c. Define a process for identifying and addressing the potential situation in which either or both of the following conditions arise: the project fails to deliver all, or a large portion of Xcel's claimed quantified benefits and/or the claimed unquantified benefits cannot or are unlikely to materialize	Filed 12/1/22 in Docket No. E002/M-21-694. Item will be removed in next IDP.

8	Xcel shall consult with stakeholders, including RMP site partners, on the development of a set of evaluation metrics that allow comparison to other resilience offerings. This set of evaluation metrics shall be included in Xcel's December 1 annual reports. Xcel shall provide the following information and data to the greatest extent practicable. Where the Company is not able to do so, it shall explain why. Where applicable, Xcel must include data in spreadsheet (.xlsx) format. In consultation with stakeholders Xcel shall consider the following reporting elements when developing evaluation metrics:	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. Item will be removed in next IDP.
8.a	Xcel shall include optional feedback from site hosts and community partners, using a form Xcel distributes on an annual (or more frequent) basis, which invites partners to discuss their experience participating in the project, its impact on the organization or community, or other information partners wish to share with the Commission.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. Item will be removed in next IDP.
8.b	Xcel shall file a spreadsheet reporting, for each RMP site, the number of union labor jobs or contracts and the number of contracts awarded to women- and minority-owned businesses.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. Item will be removed in next IDP.
8.c	Xcel shall file a spreadsheet reporting, for each RMP site, the number of workers trained in the operation of energy systems and the number of energy-related jobs created	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. Item will be removed in next IDP.
8.d	Xcel shall record in a spreadsheet any instances of natural events or Company-orchestrated simulations in which RMP systems switch to "islanded mode" and how the system performs	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. Item will be removed in next IDP.
8.e	Xcel shall track in a spreadsheet or in narrative form how RMP sites' rooftop solar, BESS, and microgrid are dispatched and optimized daily to mitigate system peaks, manage and shape demand, and integrate more solar generation.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. Item will be removed in next IDP.
8.f	Xcel shall report in a spreadsheet, for any of the RMP site, when a generator is used, for how long, and the generator power capacity and fuel source.	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. Item will be removed in next IDP.
8.g	Xcel shall quantify in a spreadsheet the number and type of HVAC upgrades, building envelope upgrades, energy efficiency measures, and/or demand response program undertaken at any of the RMP sites, shared at the discretion of RMP site hosts and partners	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. Item will be removed in next IDP.
8.h	Xcel shall develop metrics related to resiliency benefits and energy equity and data collection on those topics	See 12/1/22 RMP Annual Report in Docket No. E002/M-21-694. Item will be removed in next IDP.
9	Xcel shall file a letter in this docket to notify the Commission and stakeholders if the Company encounters any significant procurement challenges related to RMP, including delays, low bid numbers, or unexpected costs	See April 19 and June 9, 2023 filings in Docket No. E002/M-21-694. Item will be removed in next IDP.

10	Xcel shall include a discussion of the RMP in comparison to battery and microgrid programs/projects in Xcel's service territories in other states, lessons learned from these programs as they move through construction and into operation, and specific details how these lessons are informing RMP project decisions, reducing costs, and/or improving efficacy a. Xcel shall include this information in Xcel's 2023 IDP filing b. Xcel shall include this information in each of Xcel's annual reports filed in Docket No. E-002/M-21-694	See <i>Appendix B3</i> in 2023 IDP (Docket No. 23-452). No longer relevant for 2025 IDP. Item will be removed in next IDP.
11	Xcel shall report on the Resilient Minneapolis Project in its quarterly reports in Docket No. E,G-999/M-20-492	See Docket No. E,G999/M-20-492. Item will be removed in next IDP.
Order Pt.	MPUC IDP Requirement (12/8/22 Order in Docket No. E002/M-21-694)	Location
3	Allows utilities to file EV data in future IDP Plans that align with the data filed in their Annual Program Electric Vehicle reports (due June 1 of each year)	Transportation Electrification Plan
Order Pt.	MPUC IRP Requirement (4/15/22 Order in Docket No. E002/RP-19-368)	Location
9	Xcel shall takes steps to better align distribution and resouce planning, including: A. Set the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan. B. Conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level, using Xcel's advanced planning tool. C. Proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources. D. Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources to address discrete distribution system costs. E. Plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.	See corresponding IDP Requirement 3.A.5. Chapter 1: System Planning Chapter 8: Non-Wires Alternatives Analysis
Page #	Docket No. 16-521, Staff Briefing Papers for the May 20, 2021 Commission Meeting	Location
22	Already, the Commission has seen crossover with the DGWG and IDPs, hosting capacity analysis, grid modernization investments, and more. As mentioned, the rate-regulated utilities will discuss anticipated impacts of the FERC Orders in their IDPs to be filed November 1, 2021. Staff anticipates more robust discussion of these issues in the 2021 IDPs.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
Order Pt.	MN Electric Rate Case Requirements (Order 7/23/23 in Docket No. 21-630)	Location

27.b	Xcel must report, beginning in its next IDP due November 1, 2023, on the FLISR budget approved in the present rate case along with a summary of FLISR's reliability results in its Integrated Distribution System Plan.	Chapter 5: Grid Modernization
29	In its next Integrated Distribution Plan, Xcel must propose and discuss ways for the IDP Process to inform financial and cost recovery issues in rate cases, including but not limited to: a. The feasibility of conducting cost-benefit analyses for discretionary portions of the distribution budget; b. The decisions needed in the IDP to provide guidance to Xcel to ensure distribution spending that may be approved in forthcoming rate cases is in alignment with policy goals established through the IDP	See <i>Executive Summary</i> of 2023 IDP (Docket No. 23-452). Not applicable for 2025. Item will be removed in next IDP.
31	Xcel must track its planned and actual spending on reactive and proactive cable replacements and include the information as part of its IDP budget filing.	Chapter 6: Distribution Financial Framework and Action Plans
33	The Commission rejects Xcel's proposal for the Distributed Intelligence program without the prejudice and direct Xcel to refile its proposal in its next IDP consistent with the Company's Colorado settlement	Not applicable for 2025 IDP. See 2023 IDP, Appendix J: Distributed Intelligence in Docket No. E002/M-23-452. Item will be removed in next IDP.
36	Xcel must file an assessment and explanation in the next IDP of whether (Integrated Volt-Var Optimization) IVVO is in the public interest.	See Appendix B1 in 2023 IDP and compliance filing filed in Docket No. E002/M-23-452 on 3/14/25. Not applicable for 2025 IDP. Item will be removed in next IDP.
128	The Commission adopts the Department's recommended grid modernization filing requirements	Chapter 5: Grid Modernization Chapter 6: Distribution Financial Framework and Action Plans
133	Xcel shall, in its next Integrated Distribution plan ("IDP), quantify the incremental hosting capacity and beneficial electrification that will be accommodated by its planned distribution system investments	See Appendix C in 2023 IDP. Not applicable for 2025 IDP. Item will be removed in next IDP.
Order Pt.	TCR (Order 6/28/23 in Docket No. 21-814)	Location
17	Xcel shall provide a comprehensive framework in its November 1, 2023, Integrated Distribution Plan for assessing: a. HAN, AMI, and AMI-DI specifications and related customer data access policies. b. Bring-your-own device HAN requirements and terms c. Potential terms and conditions for third-party data access to AMI, AMI-DI or HAN. d. Methods to provide customers equal access to the level of data available to the utility. e. A summary of industry customer data access standards	Not applicable for 2025 IDP. Item will be removed in next IDP.
Order Pt.	IRA (Order 9/12/23 in Docket No. CI-22-624)	Location

1	The utilities shall maximize the benefits of the Inflation Reduction Act in [...] integrated distribution plans [...]. In such filings, utilities shall discuss how [...] the Act has impacted planning assumptions including (but not limited to) [...] the adoption rates of electric vehicles, distributed energy resources, and other electrification measures.	Chapter 6: Distribution Financial Information and Action Plans
Order Pt.	MPUC IDP Requirement (5/9/24 Order in Docket No. E002/M-23-452)	Location
21	Xcel must include the following components in its next transportation electrification plan: a. a proposal to actively manage electric vehicle charging; b. a proposal for a successor to the current Multi-Dwelling Unit (MDU) Pilot program; c. a discussion of potential modifications to the A15 and A14 rates to shift the demand charge limiter for electric vehicle charging stations; d. a discussion of how streetside charging near high concentrations of multi-dwelling units and/or renters fits within Xcel's programming; e. a discussion of how heavy-duty electric vehicle offerings fit within Xcel's programming; f. a robust discussion of equity, including an analysis of how Xcel's EV programs are serving those disproportionately impacted by transportation pollution, as well as renters, multifamily housing residents, communities of color, low-to-moderate income customers, and rural communities; and what gaps may remain; g. a discussion of how Xcel is coordinating between electric vehicle, energy efficiency, and building electrification planning, including, for example, ECO programs; h. a discussion of how Xcel is supporting adoption of electric school buses, beyond its Electric School Bus V2G Demonstration, including if EVSE rebates were offered under ECO; how Xcel is mitigating and streamlining interconnection; and how Xcel is promoting or educating school bus operators and/or school districts on the availability of electric school bus funding; and i. a discussion of an optional add-on subscription tier in the EV Subscription Service program for drivers wanting to charge more than 1,000 kWh off-peak.	Transportation Electrification Plan
Order Pt.	MPUC IDP Requirement (9/16/24 Order in Docket No. E002/M-23-452)	Location
2	Xcel shall report all DERs and DER forecasts in MWac in future IDPs.	Chapter 1: System Planning

3	In its next IDP, Xcel shall report on its progress to improve forecasting, including: a) Refining its residential beneficial electrification forecasts to include low, medium, and high adoption scenarios. b) Presenting an initial C&I beneficial electrification forecast, or if the Company is unable to complete one by that time, the Company shall explain why not and include a detailed explanation of how it is thinking about this forecast, information challenges it raises, and approaches Xcel is considering. c) Evaluating the accuracy of LoadSEER forecasts. d) Utilizing IDP forecast scenarios to perform sensitivities on grid capacity or capital expense plans.	Chapter 1: System Planning Chapter 10- Distribution System Upgrades
4	In future IDPs, Xcel shall provide standalone forecasts for demand response, load flexibility, and energy efficiency.	Chapter 1: System Planning
5	Xcel shall provide a comparison of the forecast provided in the IDP to actuals in its next IDP.	Chapter 1: System Planning
6	The Commission modifies Xcel's IDP reporting requirements to discontinue requirement 3.A.9.	N/A
7	The Commission delegates authority to the Executive Secretary to work with Xcel and stakeholders on ways to modify the IDP budget categories to allow for comparisons between utilities and comparison of historic to forecasted data. The Commission delegates authority to the Executive Secretary to approve via notice a stakeholder agreement on amended reporting requirements if one is reached.	See Notice of Updated Filing Requirements filed on 6/3/25 in Docket No. E002/M-23-452
8	The Commission delegates authority to the Executive Secretary to work with Xcel, the Department, and stakeholders to modify the IDP reporting requirements to include discussions of the impacts of electrification where appropriate and consider alternative dockets and the timeliness for a beneficial electrification plan and whether the filing requirements should be part of future IDPs. The Commission delegates authority to the Executive Secretary to approve via notice a stakeholder agreement on amended reporting requirements if one is reached.	See Notice of Updated Filing Requirements filed on 6/3/25 in Docket No. E002/M-23-452
9	Xcel shall provide a discussion of how it tracks, protects, and considers the restoration of vulnerable populations and critical customer load, such as hospitals and first responder sites, during extended outage events in its next IDP.	Chapter 3: Distribution Operations
10	Xcel shall engage in additional stakeholder discussions on approaches to apply cost- benefit analyses, or a similar type of evaluation, strategically to program-level investments for discretionary projects for certification or cost recovery proceedings.	Chapter 9: Stakeholder Engagement
11	In its next IDP, Xcel shall include a discussion of the results of stakeholder conversations about ways to conduct program-level cost-benefit analyses for relevant discretionary distribution expenditures.	Chapter 9: Stakeholder Engagement
12	As part of the stakeholder effort on cost-benefit analyses, Xcel shall explain how it would define "discretionary" spending in this context and to explain its cost-benefit methodology, including specifically its identification of benefits.	Chapter 6: Distribution Financial Information and Action Plans Chapter 9: Stakeholder Engagement

13	The Commission delegates authority to the Executive Secretary to work with Xcel and stakeholders to develop a proposal for what distribution data is reported in the IDP and what data continues to be reported in other dockets. The goal of the process is to develop a comprehensive list of existing distribution data reporting requirements and to identify which, if any, pieces of information are missing and should be included in future IDPs. At minimum, the proposal should address the following types of data: a) Reliability data such as SAIDI, SAIFI, CAIDI, CEMI, and CELI. b) Distribution spending by IDP budget categories. c) Whether there is available hosting capacity for generation or load at the primary system level. d) Demographic data including race and income. e) Installed DERs, ECO rebates, DR customers enrolled in programs. f) Data reported at a feeder and/or census block group level.	Distribution Data workgroup kicked off and on-going.
14	The Commission delegates authority to the Executive Secretary to establish a stakeholder process to develop a framework on cost allocation and proactive upgrades for Xcel. The stakeholder workgroup may also include Dakota Electric Association, Minnesota Power, and Otter Tail Power if they wish to participate. The Commission sets the following guidelines for the process: a) The goal of the workgroup is to develop a framework for proactive upgrades and cost allocation for Commission consideration and possible adoption. b) The process does not need to reach consensus but should aim to clearly identify areas of agreement and disagreement to facilitate a Commission decision. c) The Commission establishes a goal of completing the stakeholder process by July 1, 2025. At the conclusion of the process there will be a notice and comment period on any framework followed by a Commission decision. d) The framework should address, at minimum, the following topics: i) How to allocate the costs of proactive upgrades. ii) How to ensure any proactive upgrades are distributed in an equitable manner throughout a utility's service territory. iii) If costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for certain customer classes. iv) How a proactive upgrade program would integrate with a utility's planned distribution investment programs. v) How a utility's other capacity programs and changes to distribution standards impact available hosting capacity. vi) How to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption. vii) Whether there should be changes to any of a utility's service policy provisions such as Contributions In Aid of Construction (CIAC).	Proactive Grid Upgrades Proposal
15	The Commission delegates authority to the Executive Secretary to approve via notice the tariff changes outlined in Xcel's letter dated June 12, 2024, if no objections are filed within 30 days of this order.	N/A

16	Xcel shall track and report on the amount of each CIAC waiver granted to residential customers and the revenues foregone as a result of the waiver and file the data in its Annual EV Reports due June 1 annually. Xcel shall report the aggregate number and dollar amount of waivers starting with its 2025 IDP.	Transportation Electrification Plan
17	Xcel shall work with stakeholders to refine its planned net load methodology. Xcel shall also evaluate alternative approaches to applying the dependability factor, including applying it to hourly photovoltaic generation and to photovoltaic nameplate capacity. Xcel shall engage parties that commented on planned net load in this proceeding as it evaluates seasonal dependability factors and alternative planned net load approaches. Xcel shall include a report describing the results of this evaluation and changes to its proposed planned net load methodology in its next IDP.	Chapter 1: System Planning Chapter 9: Stakeholder Engagement
18	Xcel shall implement the 15 percent DFPV in the next planning cycle for N-0 risk analysis in the next IDP.	Chapter 1: System Planning
19	Xcel shall demonstrate the Company's ability to integrate DERs with the tools available to it today and in the near term, including specifically through: a)Implementing static Flexible Interconnection prior to implementing full, dynamic Flexible Interconnection; and b)Pursuing a staged approach to Flexible Interconnection, DERMS, and Dynamic Hosting Capacity implementation.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
20	Xcel shall be transparent about the conditions under which the Company will use Flexible Interconnection, particularly with impacted DER owner/operators.	Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity
21	The Commission directs the Distributed Generation Workgroup to take up the topic of Flexible Interconnection to work through questions related to Static Flexible Interconnection as well as Dynamic Flexible Interconnection which is enabled by DERMS.	N/A
22	Xcel shall 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. The filing shall be filed in Xcel's 2025 IDP, or at the time of request for certification or cost recovery for any DERMS investments, whichever is sooner.	Chapter 11: DERMS

23	Xcel shall file a detailed roadmap for DERMS deployment that addresses the questions provided below. Xcel must adequately address these questions before any DERMS investments will be approved. The roadmap and answered questions shall be filed in Xcel's 2025 IDP, or at the time of request for certification or cost recovery for any DERMS investments, whichever is sooner. Questions to address: a) What are the alternatives to DERMS? b) What are the specific use cases for which DERMS will be utilized and who are the intended beneficiaries? c) Will participation in DER Management be voluntary or required? Will requirements vary based on resource size, resource type, program participation, market participation, or other factors? Will it be available for load interconnections (e.g., EV charging hubs) or interconnections utilizing limited import/export control systems? d) How will communications be established between Xcel's DERMS and customer DER? Who will bear the ongoing cost for any necessary communications infrastructure? e) 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? f) How will prospective applicants 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? g) What are the expected deployment and integrations costs for DERMS? What is the expected ongoing licensing, operating, and infrastructure costs to execute and maintain DERMS functionality? From whom will these costs be recovered? h) How are equity and energy justice principles being incorporated within the use cases, process design, and cost allocation?	Chapter 11: DERMS
24	The Commission delegates authority to the Executive Secretary to open a new docket for Xcel Energy for the purposes of reviewing and approving Distributed Intelligence (DI) program terms and conditions. Xcel shall submit any requests to implement customer facing DI-enabled programs prior to rollout for Commission approval. This includes proposals the Company may make as part of its ECO portfolio. Proposals must include tariff pages with terms and conditions and be consistent with the terms of the February 18, 2022 Colorado Settlement in Proceeding No. 21A-0279E as outlined in the Commission's July 17, 2023 Order in E002/GR-21-630 and any other applicable Minnesota standards on data privacy. This is not a cost recovery docket and approval made in the docket have no bearing on prudence for future cost recovery proceedings.	Not applicable for 2025 IDP.
25	Xcel shall re-evaluate IVVO for its Minnesota service area (applying the new Minnesota Test for cost-effectiveness and updated assumptions informed by PSCo's experience with IVVO). As part of this analysis, Xcel shall identify feeders where IVVO is most cost-effective, discuss the potential for targeted deployment to these areas and/or in under-resourced communities, and report on its updated evaluation within six months of this order.	See compliance filing made on 3/14/25 in Docket No. E002/M-23-452.
26	Xcel shall conduct a Request for Information (RFI) process to assess the feasibility of its planned Non-Wires Alternatives solicitation, including the proposed "ARR split" compensation, and make a compliance filing reporting on the results of the RFI within 12 months of this order.	Chapter 8: Non-Wires Alternatives Analysis

27	The Commission delegates authority to the Executive Secretary to conduct stakeholder meetings to discuss developments, identify areas of agreement and disagreement, and discuss next steps for the informal process led by Xcel and the Commission outlined in the above ordering paragraphs 7, 8, 10, 13, 17, and 22, with the goal of having the discussion with enough time for incorporation into the next IDP filing due by November 1, 2025.	N/A

Correlation of IDP Content to Commission's IDP Planning Objectives

The Commission's Integrated Distribution Planning Requirements for Xcel Energy state:

Xcel shall discuss in future filings how the IDP meets the Commission's Planning Objectives, including:

- 1. An analysis of how the information presented in the IDP related to each Planning Objective,*
- 2. The location in the IDP,*
- 3. Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives, and*
- 4. Suggestions as to any refinements to the IDP filing requirements that would enhance Xcel's ability to meet the Planning Objectives.*

For filing requirements which Xcel claims is not yet practicable or is currently cost-prohibitive to provide, Xcel shall indicate for each requirement:

- 1. Why the Company has claimed the information is not yet practicable or is currently cost-prohibitive;*
- 2. How the information could be obtained, at what cost, and time frame;*
- 3. What the benefits or limitations of filing the data in future reports as related to achieving the planning objectives;*
- 4. If the information cannot be provided in future reports, what information in the alternative could be provided and how it would achieve the planning objectives.*

The Commission's Planning Objectives state:

The Commission is facilitating comprehensive, coordinated, transparent, integrated distribution plans to:

- 1. Maintain and enhance the safety, security, reliability, and resilience of the electricity grid at fair and reasonable costs, consistent with the state's energy policies;*
- 2. Enable greater customer engagement, empowerment, and options for energy services;*
- 3. Move toward the creation of efficient, cost-effective, accessible grid platforms for new products and services, with opportunities for adoption of new distributed technologies;*
- 4. Ensure optimized use of electricity grid assets and resources to minimize total system costs; and*
- 5. Provide the Commission with the information necessary to understand Xcel's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.*

We have followed the format the Department used in their February 22, 2019 Comments in Docket No. E002/CI-18-251 (as well as our 2019 and 2021 IDP filings) in complying with the Commission's requirement.

A. Planning Objective #1

The first planning objective of the IDP is:

Maintain and enhance the safety, security, reliability, and resilience of the electricity grid at fair and reasonable costs, consistent with the state's energy policies.

We provide a high-level analysis of the location of these topics in the IDP in Table 1 below. Below are the topics found in our 2025 IDP and their respective locations.

Table 1
Location of Topics of the First Planning Objective in the IDP

Topic	IDP Location – Significant Discussion	IDP Location – Additional or Related Discussion
Safety	Chapter 3 – Distribution Operations Chapter 7 – Distributed Energy Resources, System Interconnection, and Hosting Capacity	Integrated Distribution Plan Chapter 2 – Customer, Operational, and Planning Data Management, Security, and Information Access Plans and Policies
Security	Chapter 5- Grid Modernization	Integrated Distribution Plan Chapter 1 – System Planning Chapter 6 – Distribution Financial Information and Action Plans Chapter 7 – Distributed Energy Resources, System Interconnection, and Hosting Capacity
Reliability	Integrated Distribution Plan Chapter 1 – System Planning Chapter 2 – Standards, Asset Health, and Reliability Management Chapter 5 – Grid Modernization Chapter 6 – Distribution Financial Information and Action Plans Chapter 7 – Distributed Energy Resources, System Interconnection, and Hosting Capacity	Chapter 3 – Distribution Operations Chapter 8– Non-Wires Alternatives Analysis

Topic	IDP Location – Significant Discussion	IDP Location – Additional or Related Discussion
Resilience	Integrated Distribution Plan Chapter 2 – Standards, Health, and Reliability Management Chapter 6 – Distribution Financial Information and Action Plans	Chapter 5 – Grid Modernization
Fair and Reasonable Costs	Integrated Distribution Plan Chapter 8 – Non-Wires Alternatives Analysis Chapter 10 – Distribution System Upgrades	Chapter 1 – System Planning Chapter 6 – Distribution Financial Information and Action Plans
Consistent with State Energy Policies	Integrated Distribution Plan Chapter 1 – System Planning Chapter 5 – Grid Modernization Chapter 7 – Distributed Energy Resources, System Interconnection, and Hosting Capacity Chapter 8 – Non-Wires Alternatives Analysis Chapter 10 – Distribution System Upgrades	Chapter 2 – Standards, Asset Health, and Reliability Management Chapter 6 – Distribution Financial Information and Action Plans Chapter 9 – Stakeholder Engagement

As suggested by the table above, the topics of the first planning objective are central to the planning and operation of the distribution grid, and the Company has addressed each of the topics broadly and substantively.

B. Planning Objective #2

The second planning objective of the IDP is to enable greater customer engagement, empowerment, and options for energy services.

In support of this planning objective, we discuss our customer strategy in *Chapter 5: Grid Modernization*. There are also related discussions in *Chapter 5* when discussing our plans for Advanced Metering Infrastructure (AMI), Field Area Network (FAN), Fault Location, Isolation, and Service Restoration (FLISR), and Advanced Distribution Management System (ADMS), each of which are technological innovations that are geared toward fulfilling the second planning objective.

Extensive discussions in *Chapter 7: Distributed Energy Resources, System Interconnection, and Hosting Capacity*, as well as again in *Chapter 5* regarding grid modernization pilots also support the Commission’s second planning objective.

We note that this list is not exhaustive of the items discussed in the IDP that relate to the second planning objective. However, this does represent that we provided extensive information and discussion of items related to the second planning objective.

C. Planning Objective #3

The third planning objective of the IDP is designed to move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies.

Much of the information and discussion provided in the IDP related to the second planning objective are also applicable to the third planning objective. Specific to the adoption of new distributed technologies, we provide extensive discussion of our DER roadmap in *Chapter 11: DERMS*. Our discussion of our grid modernization investments – AMI, FAN, FLISR, and ADMS – provides information and discussion relevant to the third planning objective. These are discussed throughout the filing but particularly in *Chapter 5: Grid Modernization*.

Grid-facing platforms and tools also relate to the third planning objective, such as LoadSEER, Distributed Energy Resources Management System (DERMS), and Distributed Intelligence (DI) are discussed throughout the IDP, most notably in *Chapter 1: System Planning*, *Chapter 5: Grid Modernization*, *Chapter 7: Distributed Energy Resources*, *System Interconnection*, and *Hosting Capacity*, and *Chapter 11: DERMS*.

Chapter 5: Grid Modernization also relates to the third planning objective. Specifically, we provide information on load flexibility and EV pilots and demonstration projects, as well as a residential battery demand response pilot, rate pilots, and potential new pilots. Each of these pilots supports the third planning objective as they provide potential new platforms for new products, new services, and opportunities for adoption of new distributed technologies.

We note that this list is not exhaustive of the items discussed in the IDP that relate to the third planning objective. However, this does represent that we provided extensive information and discussion of items related to the third planning objective.

D. Planning Objective #4

The fourth planning objective of the IDP is designed to ensure optimized utilization of electricity grid assets and resources to minimize total system costs.

In the IDP, we discuss our efforts toward integrated planning in Chapter 1 (System Planning), which supports the fourth planning objective.

In the context of the Company's planning efforts related to distributed energy resources (DER), we also provide *Chapter 7: Distributed Energy Resources, System Interconnections, and Hosting Capacity*, as well as *Chapter 10: Distribution System Upgrades*.

The investments that we are currently making in asset health and reliability management, discussed in *Chapter 2*, and grid modernization, such as ADMS, AMI, FAN, and FLISR help to lay the foundation for continued resiliency and reliability, and will allow us to respond to increased DER penetration. These are discussed throughout the filing but particularly in *Chapter 5*.

Again, we note that this list is not exhaustive of the items discussed in the IDP that relate to the fourth planning objective. However, this does represent that we provided extensive information and discussion of items related to the fourth planning objective.

E. Planning Objective #5

Finally, and as noted above, the fifth planning objective of the IDP is to provide the Commission with the information necessary to understand the Company's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of customer cost and value.

The IDP provides a comprehensive discussion about our short-term and long-term distribution system plans and investments, as well as how we plan the system and develop budgets, within *Chapter 1: System Planning*, *Chapter 2 Standards, Health, and Reliability Management*, *Chapter 5: Grid Modernization*, and *Chapter 6: Distribution Financial Information*.

First, we note that we already conduct a robust CBA/risk analysis for capacity projects, as discussed in *Ch1: System Planning* and *Attachment D: Risk Scoring Methodology*. This risk scoring methodology helps prioritize capacity projects based on the reliability and financial benefits of the projects compared to the costs. While we have called it a risk analysis, it is a CBA.

With regard to the costs and benefits of specific investments, we discuss our robust CBA/risk analysis for capacity projects, as discussed in *Ch. 1: System Planning* and *Attachment D*. In addition, we provide *Ch. 8: Non-Wires Alternatives Analysis*, which provides the analyses we performed to evaluate non-traditional distribution system solutions to our traditional distribution solutions.

With regard to customer value, in *Ch. 5: Grid Modernization*, we discuss the overall customer strategy and benefits of our grid modernization strategy. We also provide the impacts to net present value of system cost in *Attachment G (Distribution Function NPV)*.

We note that this list is not exhaustive of the items discussed in the IDP that relate to the fifth planning objective. However, this does represent that we provided extensive information and discussion of items related to the fifth planning objective.

F. IDP Filing Requirement Refinements

We also express some reservations about the continued requirement to respond to FERC Order 841, issued in 2018, given its limited relevance to current distribution planning. Instead of continuing detailed analysis of FERC Order 841, it may be more useful to revise IDP Requirement 3.C.4 to include a high-level summary of recent FERC Orders and their implications, which could better inform stakeholders about emerging trends and evolving regulatory priorities.

I. RISK SCORING METHODOLOGY

As part of our risk analysis and mitigation processes, discussed as part of our annual System Planning process, Xcel Energy personnel enter projects throughout the year in the Risk Register/Workbook. Along with the description of the project, the originator must identify the primary business value driving the investment and may also enter the benefit and any associated service quality metric impacts (i.e., customer minutes out, which impacts System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Customer Average Interruption Duration Index (CAIDI), etc.). After Distribution Operations and Risk Analytics review the projects to ensure the data is accurate, Business Area Finance sets-up all appropriate accounting structures.

Projects run through the risk model for scoring. This process involves various steps:

- A project's raw financial benefit is calculated based on a project's gross cash flow (generally, incremental revenue plus realized salvage value less incremental recurring costs, non-recurring costs (e.g., taxes), and capital expenditures) and avoided costs.
- A project's raw reliability benefit is calculated based on overload customer minutes out (considering mega volt-amperes (MVA) beyond threshold, customers per MVA, capacity, demand growth, and annual hours at risk). It is also based on contingency customer minutes out (considering peak load less available relief MVA, customers per MVA, time to restore, peak day hours out, annual hours at risk, and yearly failure rate of equipment at risk), and the number of customer complaints to the public utilities commission.
- The raw reliability benefit is converted into the same metric as the raw financial benefit using a conversion factor (e.g., \$3.11/customer minute out) based on an algorithm.
- Jurisdictional factors (including discount rates, income tax rates, property tax rates, inflation rates, historical Commission complaints, historical Quality of Service plan (QSP) SAIDI data, and historical transformer failure data) are applied to the financial benefit and reliability benefit.
- A benefit : cost ratio (also known as a Risk Score) based on the jurisdictional financial and reliability benefits and annualized costs of each project is calculated.

From these calculations the projects get prioritized – and based on the capital budget, the projects that will be funded in the current 5-year budget are selected.

Part II reflects all Distribution projects budgeted in the latest/most current

available budget (July 2023) at the time of our IDP filing. Budgets are formally updated annually and rebalanced on an ongoing basis. Project scopes and/or timelines are subject to change at any time based on (but not limited to) engineering studies, area considerations, design estimates, permitting feasibility, capital target changes, and emergent circumstances.

Capacity is the only IDP category for which Risk Scores are applicable because it is the only category where we can objectively quantify the annual risk. Capacity projects are driven by feeder and transformer risks that can be quantified in terms of increased reliability. We use the risk score to help prioritize capacity projects; however, as discussed in the system planning Appendix, the risk score is not the only factor used to determine budget priority. For other budget categories that may not be driven by reliability, and for which the risks may not be objectively quantifiable, we prioritize projects based on other factors:

- *Mandates.* Government- or customer-driven work that is covered by our tariffs or involves relocating our facilities in public rights of way when in conflict with road projects, for example. This work category is not negotiable and has established timelines/due dates – and a portion may additionally be emergent in the current year, potentially requiring us to reprioritize/rebalance our budgets.
- *New Business.* Customer-driven work under our tariffs, including customer requests for changes or applications for new service. Like Mandates, this work category is not negotiable, has established timelines/due dates, and a portion may additionally be emergent in the current budget year.
- *Asset Health.* Programs or projects driven by engineering analyses to address aging infrastructure and improve system resilience. Our budget benefit/cost model does not effectively capture the long-term value that a programmatic approach to asset health provides.
- *Blankets.* Blankets fund high volume, low dollar, current year, reactive work and can contain hundreds of smaller projects and therefore does not lend itself to risk-ranking.
- *Programs.* Also see Asset Health above. Programs are funded based on identified needs or risks outside of the budget risk scoring model. Programmatic work for the current year is typically defined in-year based on equipment failures that are occurring, or after the previous year's reliability results are available and analyzed. For example, our cable replacement program is based on in-year cable failures and customer impacts, and is driven by engineering and reliability needs, not a budgeting risk model. As noted in Asset Health, our budget benefit/cost model does not effectively capture the long-term value that a programmatic engineering approach to cable failures provides.

Parts II and III contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service.

Part III contains information Xcel Energy maintains as trade secret data as defined by Minn. Stat. § 13.37, subd. 1(b). This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

PROTECTED DATA SHADED

II. CAPACITY RANKINGS

Mitigation No.	Mitigation Title	Jurisdiction	Lifespan of Project	Total Annualized Costs (\$M's)	Reliability Benefit - CMO (Electric)	Financial Benefit	Reliability Benefit (\$M's)	Financial Benefit (\$M's)	Total Weighted Benefit (\$M's)	Project Score
				[PROTECTED DATA BEGINS...						
E141.019925	SUBS Reinforce Gopher TR1	NSPM - ED	40							2.30
E141.019929	Install Midtown MDT Feeder	NSPM - ED	40							1.55
E141.019956	Reinforce Terminal TER073	NSPM - ED	40							0.23
E141.019958	Reinforce Moore Lake MOL071	NSPM - ED	40							1.29
E141.020729	Reinforce Saint Louis Park SLP092	NSPM - ED	40							0.02
E141.021648	Reinforce Elliot Park ELP081	NSPM - ED	40							1.15
E141.021663	Extend Southtown Feeder SOU069	NSPM - ED	40							0.68
E141.022785	Reinforce Elliot Park Feeder ELP084	NSPM - ED	40							692.43
E141.022787	Reinforce SLP85 Feeder	NSPM - ED	40							0.02
E141.024063	Install Midtown MDT072 Feeder	NSPM - ED	40							73.26
E141.024064	Extend Elliot Park Feeder ELP082	NSPM - ED	40							1.02
E141.024065	Reinforce Medicine Lake MEL073	NSPM - ED	40							231.66
E141.024066	Reinforce Medicine Lake MEL089	NSPM - ED	38							0.77
E141.024067	Install New Midtown MDT064	NSPM - ED	40							35.15
E141.024119	Reinforce Elliot Park ELP071 Feeder	NSPM - ED	35							169.20

E141.025583	Reinforce Southtown Feeder SOU075	NSPM - ED	40								7.37
E141.025584	Reinforce WRR Feeder WRR064	NSPM - ED	40								104.29
E141.025596	Reinforce Moore Lake Feeder MOL066	NSPM - ED	40								11.06
E141.025671	Install Downtown Minneapolis Sub	NSPM - ED	90								11.00
E141.026014	Install Lake Harriet Area Substation	NSPM - ED	35								1.53
E141.026460	New Main Street Sub	NSPM - ED	90								0.00
E142.010995	Install Watertown TR2 14MVA	NSPM - ED	40								0.02
E142.011721	Install Orono ORO TR2 & Feeder	NSPM - ED	40								0.07
E142.013437	Install Excelsior EXC TR2	NSPM - ED	40								0.02
E142.024045	Install Dahlgren DHL062 Feeder	NSPM - ED	35								11.22
E142.025707	Extend MND061	NSPM - ED	35								23.44
E143.017702	Install Viking VKG Feeder	NSPM - ED	40								0.65
E143.017703	Blue Lake reinforce banks to 50MVA and add feeder	NSPM - ED	40								0.05
E143.019054	Reinforce Edina EDA062	NSPM - ED	40								1.63
E143.022265	Install Hyland Lake HYL TR01	NSPM - ED	40								11.31
E143.022793	Reinforce Wilson WIL072	NSPM - ED	40								42.46
E143.022794	Install Wilson Feeder WIL064	NSPM - ED	40								4.37
E143.022795	Extend Hyland Lake HYL074	NSPM - ED	40								20.17
E143.024049	Extend East Bloomington EBL066	NSPM - ED	40								0.76
E143.024051	Reinforce East Bloomington EBL062	NSPM - ED	40								618.57
E143.024054	Install South Airport Substation	NSPM - ED	38								0.03
E143.025546	Install Hyland Lake HYL067	NSPM - ED	40								20.08
E143.025592	Load Transfer BLL071 to BLL064	NSPM - ED	40								9,961,223.97
E143.025599	Extend Nine Mile Creek NMC061	NSPM - ED	35								0.28
E143.025609	Reinforce Wilson Feeders	NSPM - ED	40								17.14
E143.025610	Extend Edina EDA064	NSPM - ED	40								54.89

[illegible]

E144.025375	Reinforce Sibley Park SIP Feeders	NSPM - ED	40								0.03
E144.025384	Reinforce Eastwood ESW Feeders	NSPM - ED	40								1.89
E144.025395	Reinforce Credit River CTR TR2	NSPM - ED	40								0.49
E144.025396	Convert Minnesota Lake MNL 4 kV	NSPM - ED	40								0.94
E144.025406	Install Northfield Area Substation	NSPM - ED	40								0.98
E144.025520	Install Medford Junction MDF TR2	NSPM - ED	40								0.72
E144.025522	Install Zumbro Falls Area Substation	NSPM - ED	40								1.96
E144.025523	Install Wells Creek WEL TR2	NSPM - ED	40								0.30
E144.025524	Install Swan Lake SWN TR2	NSPM - ED	40								0.18
E144.025532	Install New Rapidian Area Substation	NSPM - ED	40								0.56
E146.024017	Install Averill AVR TR02	NSPM - ED	40								0.04
E147.011060	Install Meadow Lake Area Sub	NSPM - ED	40								0.33
E147.011656	Reinf. Coon Creek CNC TR1 to 50 MVA	NSPM - ED	40								0.02
E147.012459	Install 2-50 MVA at Brooklyn Park	NSPM - ED	40								0.02
E147.013373	Reinforce Basset Creek BCR TR1	NSPM - ED	40								0.14
E147.013374	Reinforce Elm Creek TR1 to 50 MVA	NSPM - ED	40								0.15
E147.013379	Install West Coon Rapids WCR TR	NSPM - ED	40								0.04
E147.014487	Upgrade TWL061 feeder capacity	NSPM - ED	40								19.87
E147.015683	Install Osseo OSS TR3	NSPM - ED	40								0.52
E147.016682	Reinforce TWL079 and TWL081	NSPM - ED	40								35.07
E147.022783	Reinforce All Osseo OSS Feeders	NSPM - ED	40								4.29
E147.024026	Reinforce Twin Lakes Multiple Feeders	NSPM - ED	40								2.91

E147.024028	Reinforce Parkers Lake PKL085	NSPM - ED	40								18.48
E147.024033	Reinforce Parkers Lake PKL065	NSPM - ED	40								11.78
E147.024193	Reinforce Twin Lakes TWL078	NSPM - ED	40								6.21
E147.024221	Reinforce Brooklyn Park BRP072	NSPM - ED	40								58.12
E147.024224	Install New Elm Creek Area Substation	NSPM - ED	40								28.93
E147.024227	Load Trnsfr CRL033 CRL027 CRL031	NSPM - ED	40								31.12
E147.025578	Install Greenfield GFD TR2	NSPM - ED	50								0.01
E147.025785	Install New North Brooklyn Park Substation	NSPM - ED	40								4.38
E147.026950	Reinforce Parkers Lake feeders	NSPM - ED	40								0.54
E150.013326	Install West Hastings WEH TR2	NSPM - ED	40								0.67
E150.020609	Extend Woodbury WDY321 for WDY312	NSPM - ED	40								50.24
E150.021670	Install Cottage Grove CGR TR03	NSPM - ED	40								72.03
E150.021672	Install Chemolite CHE TR03	NSPM - ED	40								36.06
E150.022038	Install Stockyards STY TR03	NSPM - ED	40								188.42
E150.022705	Reinforce West Hastings WEH TR1	NSPM - ED	40								0.76
E150.022709	Install Williams Brothers TR4	NSPM - ED	35								3.48
E150.022735	Install Lone Oak LOK Feeder	NSPM - ED	35								0.04
E150.022858	Install Inver Hills IVH TRs	NSPM - ED	40								0.02
E150.023935	Install Feeder Tie RMT321-RMT312	NSPM - ED	35								10.67
E150.023945	Reinforce Lone Oak LOK082 & LOK093	NSPM - ED	35								0.02
E150.023953	Reinforce Rogers Lake RLK073	NSPM - ED	40								3.49
E150.023955	Reinforce Rogers Lake RLK Feeders	NSPM - ED	40								14.66
E150.023962	Reinforce Hastings HAS022	NSPM - ED	35								729.94
E150.024167	Install Lone Oak LOK TR3	NSPM - ED	38								0.02

E150.025518	Extemd Vermilion Feeder VMR062	NSPM - ED	40							0.22
E150.025772	Reinforce Cottage Grove TR1 and TR2	NSPM - ED	35							5.15
E151.000726	Install Prior PRR TR2	NSPM - ED	40							6.71
E151.012409	Install Western WES TR3 & Feeders	NSPM - ED	40							0.02
E151.023984	Reinforce Dayton's Bluff DBL067	NSPM - ED	40							0.02
E151.023987	Reinforce Merriam Park MPK072	NSPM - ED	40							0.02
E151.023988	Reinforce Merriam Park MPK081	NSPM - ED	40							0.02
E151.023992	Reinforce Merriam Park feeders	NSPM - ED	40							0.02
E151.024013	Reinforce Merriam Park MPK085	NSPM - ED	35							0.02
E151.024018	Reinforce Upper Levee UPP081	NSPM - ED	35							0.02
E151.024029	Reinforce Western WES061 and WES075	NSPM - ED	35							10.83
E151.024039	Reinforce WES065 and WES076	NSPM - ED	40							0.56
E151.024040	Reinforce Western WES062 Feeder	NSPM - ED	40							0.02
E151.024041	Reinforce Western WES074 Feeder	NSPM - ED	35							0.65
E151.027215	N-0 Upper Levee UPP082 78% OL	NSPM - ED	35							0.03
E152.024015	Install Tracy Area Substation	NSPM - ED	90							0.00
E154.010157	Install Two Transformers Albany ALB	NSPM - ED	40							0.04
E154.013603	Convert Bird Island BIS 4kV	NSPM - ED	40							4.26
E154.022738	Install Dayton Area Sub	NSPM - ED	40							2,415.56
E154.022742	Reinforce Meire Grove TR1	NSPM - ED	40							0.10
E154.022828	Install Blue Heron TR2	NSPM - ED	40							0.04
E154.024027	Install New Avon-St Joseph Area Substation	NSPM - ED	40							7.34
E154.025412	Reinforce Granite City GRC Feeders	NSPM - ED	40							38.18
E154.025422	Reinforce St Cloud SCL311	NSPM - ED	40							4,651.98

E154.025423	Install Stewart STW TR2	NSPM - ED	40								0.33
E154.025426	Install Danube DAN TR2	NSPM - ED	40								1.02
E154.025431	Reinforce Linn Street LNS Feeders	NSPM - ED	40								1.54
E154.025434	Install Atwater ATW TR2	NSPM - ED	38								0.03
E154.025435	Install Lowry LOW TR2	NSPM - ED	40								0.03
E154.025436	Install New Clara City Area 23.9 kV Substation	NSPM - ED	40								0.02
E154.025440	Install Cokato-Howard Lake Area Substation	NSPM - ED	40								0.02
E154.025448	Install Montrose MTR TR2	NSPM - ED	40								0.32
E154.025451	Install Douglas County DGC TR4	NSPM - ED	40								0.03
E154.025452	Install Brooten Area Substation	NSPM - ED	38								0.03
E154.025453	Install Maple Lake MAP TR2	NSPM - ED	40								0.02
E154.025454	Install MNV211-YLM211 Feeder Tie	NSPM - ED	40								0.03
E154.025460	Install Wobegon Trail WOB TR2	NSPM - ED	40								0.03
E154.025461	Install New Paynesville Transmission PAT Feeder	NSPM - ED	40								6.78
E154.025462	Install Dassel Area Substation	NSPM - ED	40								0.02
E154.025496	Rebuild Sedan SED Substation	NSPM - ED	40								0.04
E154.025498	Convert Watkins WKN 4 kV Substation	NSPM - ED	40								2.11
E154.025547	Install Renville RNV TR2	NSPM - ED	40								0.02
E154.025548	Install Kimball KIM TR2	NSPM - ED	40								0.02
E154.025558	Install Lake Lillian LIL TR2	NSPM - ED	40								0.02
E154.025561	Reinforce Maynard MYN021	NSPM - ED	40								0.02
E154.025571	Install Villard Area Substation	NSPM - ED	40								0.02
E154.026926	Install St Cloud Area Substation	NSPM - ED	40								66.71
E154.026928	Install Sartell Area Substation	NSPM - ED	40								57.50
E156.007927	Install Goose Lake GLK TR3	NSPM - ED	40								0.19
E156.007927	Install Goose Lake GLK TR3	NSPM - ED	40								0.19
E156.010177	Install Kohlman Lake KOL Feeder	NSPM - ED	40								1.59

E156.011061	Install Wyoming WYO Feeder	NSPM - ED	40									0.60
E156.011749	Reinforce LEX ties	NSPM - ED	40									0.14
E156.011752	Install Lindstrom LIN Feeder	NSPM - ED	40									0.04
E156.011764	Reinforce Tanners Lake TLK Sub Equip	NSPM - ED	40									0.10
E156.011874	Install Birch Area Sub	NSPM - ED	40									0.02
E156.013545	Expand AHI substation	NSPM - ED	40									2.74
E156.015811	Reinforce Oakdale OAD073 & OAD075	NSPM - ED	40									0.08
E156.020602	Reinforce Ramsey Feeders RAM063 RAM071	NSPM - ED	40									0.04
E156.025438	Reinforce Oak Park OPK067 OPK073	NSPM - ED	40									416.77
E156.025589	Install Baytown BYT Feeders	NSPM - ED	50									6.80
E156.025590	Reinforce Kohlman Lake KOL	NSPM - ED	50									0.60
E156.025591	Reinforce Lexington LEX062	NSPM - ED	35									0.02
E156.025593	Reinforce Oakdale OAD Feeders	NSPM - ED	35									2.96
E156.026934	Reinforce Ramsey RAM072 RAM077	NSPM - ED	40									12.04
E156.026935	Reinforce Wyoming WYO022 WYO031	NSPM - ED	40									7.03
E156.026945	Install Stillwater Lake Elmo Area Substation	NSPM - ED	40									74.99
E156.026953	Reinforce Lexington TR1 and TR2	NSPM - ED	40									0.06
E156.026954	Reinforce Lexington LEX062 LEX071	NSPM - ED	40									743.46
E156.026957	Install Lindstrom Area Substation	NSPM - ED	40									5.73
E156.026996	Install Oakdale OAD066	NSPM - ED	40									31.67
E156.026997	Install Oakdale OAD076	NSPM - ED	40									0.85
E156.026998	Reinforce Oakdale OAD073 OAD075	NSPM - ED	40									253.95
E156.027000	Reinforce Tanners Lake TLK061	NSPM - ED	40									375.03
E156.027003	Load Transfer Tanners Lake TLK077 to TLK067	NSPM - ED	40									162.11
											...PROTECTED DATA ENDS]	

III. Mitigation Calculation Examples

A. Contingency (N-1) Inputs

[PROTECTED DATA BEGINS...

[illegible]

...PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS...

[illegible]

...PROTECTED DATA ENDS]

B. Overload (N-0) Inputs

[PROTECTED DATA BEGINS...

1	2	3	4	5	6	7	8	9	10	11	12	13
14	15	16	17	18	19	20	21	22	23	24	25	26
27	28	29	30	31	32	33	34	35	36	37	38	39
40	41	42	43	44	45	46	47	48	49	50	51	52
53	54	55	56	57	58	59	60	61	62	63	64	65
66	67	68	69	70	71	72	73	74	75	76	77	78
79	80	81	82	83	84	85	86	87	88	89	90	91
92	93	94	95	96	97	98	99	100	101	102	103	104

...PROTECTED DATA ENDS]

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Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2026 Forecasted Demand kVA	2026 Forecasted Capacity kVA	2026 Forecasted Percent Loading	Planned Spending in 5 Year Budget
				[PROTECTED DATA BEGINS...					
E141.019925	SUBS Reinforce Gopher TR1	2019.0541	1		2.30			52%	\$ 300,000
E141.019929	Install Midtown MDT Feeder	2017.0541	1		1.55			108%	\$ 3,300,000
E141.019956	Reinforce Terminal TER073	2020.0340	1		0.23			45%	\$ 1,100,000
E141.019958	Reinforce Moore Lake MOL071	2020.0351	1		1.29			76%	\$ 550,000
E141.020729	Reinforce Saint Louis Park SLP092	2020.0300	1		0.02			74%	\$ 4,050,000
E141.021648	Reinforce Elliot Park ELP081	2020.0239	1		1.15			116%	\$ 400,000
E141.021663	Extend Southtown Feeder SOU069	2020.0309	1		0.68			42%	\$ 350,000
E141.022785	Reinforce Elliot Park Feeder ELP084	2022.0427	0		692.43			116%	\$ 500,000
E141.022787	Reinforce SLP85 Feeder	2020.0305	1		0.02			84%	\$ 2,710,000
E141.024063	Install Midtown MDT072 Feeder	2023.0817	0		73.26			102%	\$ 1,500,000
E141.024064	Extend Elliot Park Feeder ELP082	2020.0238	1		1.02			80%	\$ 310,000
E141.024065	Reinforce Medicine Lake MEL073	2020.0558	0		231.66			112%	\$ 1,000,000
E141.024066	Reinforce Medicine Lake MEL089	2016.0513	0		0.77			96%	\$ 2,160,000
E141.024067	Install New Midtown MDT064	2021.0451	0		35.15			110%	\$ 4,950,000
E141.024119	Reinforce Elliot Park ELP071 Feeder	2023.0822	0		169.20			103%	\$ 530,000
E141.025583	Reinforce Southtown Feeder SOU075	2023.0427	0		7.37			92%	\$ 3,600,000
E141.025584	Reinforce WRR Feeder WRR064	2020.0334	0		104.29			104%	\$ 1,400,000
E141.025596	Reinforce Moore Lake Feeder MOL066	2023.0329	0		11.06			94%	\$ 3,000,000
E141.025671	Install Downtown Minneapolis Sub	2023.0282	0		11.00			97%	\$ 1,000,000
E141.026014	Install Lake Harriet Area Substation	2012.0216	0		1.53			93%	\$ 3,000,000
E141.026460	New Main Street Sub	2024.2044	0		0.00			42%	\$ 5,000,000
E142.010995	Install Watertown TR2 14MVA	2005.0542	1		0.02			56%	\$ 1,580,000
E142.011721	Install Orono ORO TR2 & Feeder	2005.0539	1		0.07			65%	\$ 700,000
E142.013437	Install Excelsior EXC TR2	2005.0538	1		0.02			64%	\$ 400,000

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E142.024045	Install Dahlgren DHL062 Feeder	2014.0473	1		11.22			58%	\$ 500,000
E142.025707	Extend MND061	2023.0325	0		23.44			94%	\$ 1,950,000
E143.017702	Install Viking VKG Feeder	2016.0418	1		0.65			48%	\$ 3,850,000
E143.017703	Blue Lake reinforce banks to 50MVA and add feeder	2017.0447	1		0.05			55%	\$ 874,000
E143.019054	Reinforce Edina EDA062	2016.0386	1		1.63			67%	\$ 500,000
E143.022265	Install Hyland Lake HYL TR01	2020.0166	1		11.31			62%	\$ 3,800,000
E143.022793	Reinforce Wilson WIL072	2017.0454	1		42.46			62%	\$ 400,000
E143.022794	Install Wilson Feeder WIL064	2016.0402	1		4.37			74%	\$ 1,245,000
E143.022795	Extend Hyland Lake HYL074	2016.0389	1		20.17			94%	\$ 600,000
E143.024049	Extend East Bloomington EBL066	2018.0905	1		0.76			79%	\$ 550,000
E143.024051	Reinforce East Bloomington EBL062	2023.0264	0		618.57			123%	\$ 700,000
E143.024054	Install South Airport Substation	2023.0861	1		0.03			57%	\$ 20,000,000
E143.025546	Install Hyland Lake HYL067	2023.0139	0		20.08			86%	\$ 1,640,000
E143.025592	Load Transfer BLL071 to BLL064	2024.0778	0		9961223.97			86%	\$ 40,000
E143.025599	Extend Nine Mile Creek NMC061	2018.0918	1		0.28			92%	\$ 1,380,000
E143.025609	Reinforce Wilson Feeders	2023.0498	0		17.14			102%	\$ 5,920,000
E143.025610	Extend Edina EDA064	2016.0369	0		54.89			96%	\$ 1,160,000
E143.025703	Reinforce WSG Feeders	2023.0522	0		181.29			111%	\$ 460,000
E144.000791	Install La Crescent Area Sub	2004.1112	1		0.14			72%	\$ 600,000
E144.000793	Install Zumbrota ZUM TR	2004.1114	1		28.36			109%	\$ 5,600,000
E144.002712	Install Goodview GVW Feeder	2004.0808	1		3.30			104%	\$ 1,200,000
E144.008708	Reinforce Cannon Falls CAF TR1	2005.0386	1		2.73			106%	\$ 3,591,025
E144.010884	Install Belle Plaine Area Sub	2004.1288	1		9.12			100%	\$ 400,000
E144.010889	New Pine Island Area Sub	2007.0715	1		0.03			114%	\$ 385,000
E144.010920	Reinforce Burnside BUR TR2	2006.0285	1		4.88			29%	\$ 4,400,000
E144.012525	Install New Dodge Center Area Sub	2011.0101	1		0.02			66%	\$ 450,000
E144.013446	Reinforce Waseca WAS TR2	2014.0160	1		0.10			71%	\$ 2,600,000
E144.013520	Install New Winona Area Sub	2014.0082	1		0.26			67%	\$ 2,000,000
E144.013622	Convert Lafayette LAF 4kV	2013.0846	0		0.24			111%	\$ 400,000
E144.015692	Install East Mankato Area Substation	2016.0175	1		0.06			51%	\$ 3,230,000
E144.018971	Reinforce Veseli VES TR1	2013.1536	0		9583.23			109%	\$ 50,000

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E144.020614	Reinforce Faribault FAB TR2	2005.0479	1		0.02			121%	\$ 600,000
E144.024031	Convert Gaylord GAY 4kV	2005.0480	1		0.02			71%	\$ 400,000
E144.024034	Reinforce Waterville TR3	2013.1500	1		0.04			103%	\$ 550,000
E144.024037	Install West Byron WEB TR2	2013.0155	0		113.99			124%	\$ 2,100,000
E144.024038	Reinf West Faribault WEF TR7	2023.0481	0		0.03			60%	\$ 7,766,543
E144.025161	Reinforce Fair Park FAP TR2	2023.1875	1		0.06			63%	\$ 2,971,960
E144.025325	Install Altura ALT TR2	2013.0156	1		0.19			74%	\$ 200,000
E144.025326	Install Frontenac FRO TR2	2005.0570	1		1.09			64%	\$ 200,000
E144.025335	Reinforce Eagle Lake EGL Feeders	2005.0452	1		0.09			75%	\$ 400,000
E144.025336	Install Gibbon GIB TR2	2007.0590	1		0.13			69%	\$ 200,000
E144.025338	Green Isle FRI 4 kV Conversion	2005.0482	1		0.05			64%	\$ 300,000
E144.025351	Install Henderson HEN TR2	2006.0133	1		0.25			78%	\$ 200,000
E144.025352	Install New Lake City Area Substation	2009.0882	1		0.02			76%	\$ 300,000
E144.025354	New Mazeppa Area Substation	2005.0573	1		0.02			45%	\$ 5,100,000
E144.025365	Reinforce Red Wing REW Feeders	2024.0797	0		10.00			97%	\$ 1,700,000
E144.025374	Castle Rock CSR 4 kV Conversion	2005.0387	1		0.59			45%	\$ 300,000
E144.025375	Reinforce Sibley Park SIP Feeders	2018.0091	1		0.03			73%	\$ 400,000
E144.025384	Reinforce Eastwood ESW Feeders	2023.0284	0		1.89			82%	\$ 2,500,000
E144.025395	Reinforce Credit River CTR TR2	2012.0198	1		0.49			74%	\$ 100,000
E144.025396	Convert Minnesota Lake MNL 4 kV	2005.0488	1		0.94			77%	\$ 300,000
E144.025406	Install Northfield Area Substation	2013.1547	1		0.98			72%	\$ 2,200,000
E144.025520	Install Medford Junction MDF TR2	2006.0135	1		0.72			49%	\$ 3,600,000
E144.025522	Install Zumbro Falls Area Substation	2005.0564	1		1.96			78%	\$ 1,000,000
E144.025523	Install Wells Creek WEL TR2	2005.0571	1		0.30			51%	\$ 1,000,000
E144.025524	Install Swan Lake SWN TR2	2007.0721	1		0.18			47%	\$ 100,000
E144.025532	Install New Rapidian Area Substation	2007.0718	1		0.56			15%	\$ 4,710,368

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E146.024017	Install Averill AVR TR02	2020.0144	1		0.04			55%	\$ 2,400,000
E147.011060	Install Meadow Lake Area Sub	2011.0145	0		0.33			84%	\$ 20,000,000
E147.011656	Reinf. Coon Creek CNC TR1 to 50 MVA	2011.0067	1		0.02			38%	\$ 2,500,000
E147.012459	Install 2-50 MVA at Brooklyn Park	2012.0513	1		0.02			57%	\$ 4,900,000
E147.013373	Reinforce Basset Creek BCR TR1	2013.0595	1		0.14			43%	\$ 2,400,000
E147.013374	Reinforce Elm Creek TR1 to 50 MVA	2012.0530	1		0.15			27%	\$ 2,400,000
E147.013379	Install West Coon Rapids WCR TR	2013.0532	1		0.04			75%	\$ 300,000
E147.014487	Upgrade TWL061 feeder capacity	2014.0485	1		19.87			98%	\$ 250,000
E147.015683	Install Osseo OSS TR3	2012.0543	1		0.52			59%	\$ 400,000
E147.016682	Reinforce TWL079 and TWL081	2016.0529	1		35.07			68%	\$ 1,000,000
E147.022783	Reinforce All Osseo OSS Feeders	2012.0534	1		4.29			94%	\$ 9,000,000
E147.024026	Reinforce Twin Lakes Multiple Feeders	2023.0453	0		2.91			94%	\$ 12,850,000
E147.024028	Reinforce Parkers Lake PKL085	2022.0485	0		18.48			104%	\$ 85,000
E147.024033	Reinforce Parkers Lake PKL065	2023.0374	0		11.78			95%	\$ 3,700,000
E147.024193	Reinforce Twin Lakes TWL078	2023.0456	0		6.21			92%	\$ 3,500,000
E147.024221	Reinforce Brooklyn Park BRP072	2023.0224	0		58.12			92%	\$ 500,000
E147.024224	Install New Elm Creek Area Substation	2023.1135	0		28.93			75%	\$ 10,000,000
E147.024227	Load Trnsfr CRL033 CRL027 CRL031	2023.0252	0		31.12			81%	\$ 300,000
E147.025578	Install Greenfield GFD TR2	2005.0505	1		0.01			68%	\$ 30,000
E147.025785	Install New North Brooklyn Park Substation	2023.1131	0		4.38			69%	\$ 700,000
E147.026950	Reinforce Parkers Lake feeders	2025.1107	0		0.54			80%	\$ 2,000,000
E150.013326	Install West Hastings WEH TR2	2008.2304	1		0.67			45%	\$ 2,029,000

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E150.020609	Extend Woodbury WDY321 for WDY312	2021.0130	1		50.24			101%	\$ 584,000
E150.021670	Install Cottage Grove CGR TR03	2021.0365	1		72.03			75%	\$ 2,213,000
E150.021672	Install Chemolite CHE TR03	2021.0094	1		36.06			76%	\$ 14,700,000
E150.022038	Install Stockyards STY TR03	2021.0857	0		188.42			122%	\$ 2,000,000
E150.022705	Reinforce West Hastings WEH TR1	2021.0132	1		0.76			45%	\$ 2,029,000
E150.022709	Install Williams Brothers TR4	2021.0127	1		3.48			40%	\$ 56,000
E150.022735	Install Lone Oak LOK Feeder	2021.0108	1		0.04			108%	\$ 1,300,000
E150.022858	Install Inver Hills IVH TRs	2022.0812	1		0.02			69%	\$ 15,833,918
E150.023935	Install Feeder Tie RMT321-RMT312	2023.0791	1		10.67			23%	\$ 3,000,000
E150.023945	Reinforce Lone Oak LOK082 & LOK093	2022.0451	1		0.02			100%	\$ 1,160,000
E150.023953	Reinforce Rogers Lake RLK073	2022.0453	1		3.49			96%	\$ 650,000
E150.023955	Reinforce Rogers Lake RLK Feeders	2022.0309	0		14.66			96%	\$ 2,700,000
E150.023962	Reinforce Hastings HAS022	2022.0308	0		729.94			99%	\$ 100,000
E150.024167	Install Lone Oak LOK TR3	2023.0790	0		0.02			87%	\$ 3,880,000
E150.025518	Extemd Vermilion Feeder VMR062	2024.0895	1		0.22			76%	\$ 3,000,000
E150.025772	Reinforce Cottage Grove TR1 and TR2	2021.0371	1		5.15			96%	\$ 9,000,000
E151.000726	Install Prior PRR TR2	2004.0884	1		6.71			64%	\$ 6,200,000
E151.012409	Install Western WES TR3 & Feeders	2013.0167	1		0.02			48%	\$ 3,900,000
E151.023984	Reinforce Daytons Bluff DBL067	2023.0261	0		0.02			88%	\$ 1,200,000
E151.023987	Reinforce Merriam Park MPK072	2023.0772	0		0.02			84%	\$ 1,625,000
E151.023988	Reinforce Merriam Park MPK081	2023.0774	0		0.02			65%	\$ 1,625,000
E151.023992	Reinforce Merriam Park feeders	2023.0771	0		0.02			87%	\$ 5,700,000
E151.024013	Reinforce Merriam Park MPK085	2023.0777	0		0.02			73%	\$ 785,000
E151.024018	Reinforce Upper Levee UPP081	2023.0466	0		0.02			74%	\$ 954,000

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E151.024029	Reinforce Western WES061 and WES075	2005.0139	1		10.83			92%	\$ 600,000
E151.024039	Reinforce WES065 and WES076	2023.1014	1		0.56			78%	\$ 408,000
E151.024040	Reinforce Western WES062 Feeder	2022.0306	0		0.02			78%	\$ 193,000
E151.024041	Reinforce Western WES074 Feeder	2023.0488	0		0.65			103%	\$ 354,000
E151.027215	N-0 Upper Levee UPP082 78% OL	2023.0467	0		0.03			78%	\$ 14,500,000
E152.024015	Install Tracy Area Substation	2023.0999	0		0.00			99%	\$ 2,200,000
E154.010157	Install Two Transformers Albany ALB	2004.0942	1		0.04			104%	\$ 10,000,000
E154.013603	Convert Bird Island BIS 4kV	2014.0249	0		4.26			88%	\$ 300,000
E154.022738	Install Dayton Area Sub	2022.0385	0		2415.56			88%	\$ 4,300,000
E154.022742	Reinforce Meire Grove TR1	2004.0086	0		0.10			110%	\$ 6,701,571
E154.022828	Install Blue Heron TR2	2004.0950	1		0.04			118%	\$ 9,000,000
E154.024027	Install New Avon-St Joseph Area Substation	2023.0434	0		7.34			105%	\$ 6,800,000
E154.025412	Reinforce Granite City GRC Feeders	2023.0316	0		38.18			100%	\$ 900,000
E154.025422	Reinforce St Cloud SCL311	2023.0849	0		4651.98			93%	\$ 1,100,000
E154.025423	Install Stewart STW TR2	2023.0850	0		0.33			87%	\$ 8,500,000
E154.025426	Install Danube DAN TR2	2023.0848	0		1.02			77%	\$ 100,000
E154.025431	Reinforce Linn Street LNS Feeders	2023.0160	0		1.54			81%	\$ 350,000
E154.025434	Install Atwater ATW TR2	2004.0944	1		0.03			61%	\$ 300,000
E154.025435	Install Lowry LOW TR2	2004.0969	1		0.03			55%	\$ 5,100,000
E154.025436	Install New Clara City Area 23.9 kV Substation	2004.1063	1		0.02			51%	\$ 5,100,000
E154.025440	Install Cokato-Howard Lake Area Substation	2004.0966	1		0.02			51%	\$ 5,500,000
E154.025448	Install Montrose MTR TR2	2023.0475	0		0.32			84%	\$ 1,200,000
E154.025451	Install Douglas County DGC TR4	2015.0478	1		0.03			89%	\$ 4,100,000
E154.025452	Install Brooten Area Substation	2004.0951	1		0.03			80%	\$ 5,100,000
E154.025453	Install Maple Lake MAP TR2	2004.0970	1		0.02			68%	\$ 200,000
E154.025454	Install MNV211-YLM211 Feeder Tie	2014.0559	1		0.03			34%	\$ 2,100,000

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2026 Forecasted Demand kVA	2026 Forecasted Capacity kVA	2026 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E154.025460	Install Wobegon Trail WOB TR2	2015.0482	1		0.03			82%	\$ 3,700,000
E154.025461	Install New Paynesville Transmission PAT Feeder	2024.0724	0		6.78			59%	\$ 900,000
E154.025462	Install Dassel Area Substation	2004.0959	1		0.02			49%	\$ 600,000
E154.025496	Rebuild Sedan SED Substation	2023.0406	0		0.04			93%	\$ 300,000
E154.025498	Convert Watkins WKN 4 kV Substation	2012.0187	1		2.11			39%	\$ 300,000
E154.025547	Install Renville RNV TR2	2004.0998	1		0.02			38%	\$ 3,600,000
E154.025548	Install Kimball KIM TR2	2004.0967	1		0.02			35%	\$ 100,000
E154.025558	Install Lake Lillian LIL TR2	2004.0968	1		0.02			66%	\$ 100,000
E154.025561	Reinforce Maynard MYN021	2004.0971	1		0.02			60%	\$ 4,200,000
E154.025571	Install Villard Area Substation	2004.1007	1		0.02			32%	\$ 300,000
E154.026926	Install St Cloud Area Substation	2018.0826	1		66.71			70%	\$ 16,200,000
E154.026928	Install Sartell Area Substation	2024.0714	0		57.50			53%	\$ 2,600,000
E156.007927	Install Goose Lake GLK TR3	2005.0554	1		0.19			71%	\$ 1,550,000
E156.007927	Install Goose Lake GLK TR3	2005.0554	1		0.19			71%	\$ 1,550,000
E156.010177	Install Kohlman Lake KOL Feeder	2008.0733	1		1.59			59%	\$ 4,520,000
E156.011061	Install Wyoming WYO Feeder	2010.0166	1		0.60			113%	\$ 3,300,000
E156.011749	Reinforce LEX ties	2006.0206	1		0.14			62%	\$ 850,000
E156.011752	Install Lindstrom LIN Feeder	2008.0856	1		0.04			122%	\$ 862,000
E156.011764	Reinforce Tanners Lake TLK Sub Equip	2011.0177	1		0.10			65%	\$ 200,000
E156.011874	Install Birch Area Sub	2013.0062	1		0.02			80%	\$ 5,400,000
E156.013545	Expand AHI substation	2011.0152	1		2.74			88%	\$ 10,000
E156.015811	Reinforce Oakdale OAD073 & OAD075	2012.0572	1		0.08			62%	\$ 175,000
E156.020602	Reinforce Ramsey Feeders RAM063 RAM071	2014.0459	1		0.04			71%	\$ 210,000
E156.025438	Reinforce Oak Park OPK067 OPK073	2023.0357	0		416.77			88%	\$ 275,000
E156.025589	Install Baytown BYT Feeders	2023.0228	0		6.80			90%	\$ 3,000,000
E156.025590	Reinforce Kohlman Lake KOL	2023.0149	0		0.60			78%	\$ 350,000
E156.025591	Reinforce Lexington LEX062	2024.0948	0		0.02			113%	\$ 500,000
E156.025593	Reinforce Oakdale OAD Feeders	2023.0353	0		2.96			81%	\$ 500,000
E156.026934	Reinforce Ramsey RAM072 RAM077	2023.0379	0		12.04			80%	\$ 450,000

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

PROTECTED DATA SHADED

Mitigation #	Investment Summary Information	Risk Number	Risk Type N-0 or N-1	Parent Device	Risk Score	2026 Forecasted Demand kVA	2026 Forecasted Capacity kVA	2026 Forecasted Percent Loading	Planned Spending in 5 Year Budget
E156.026935	Reinforce Wyoming WYO022 WYO031	2025.1122	0		7.03			81%	\$ 150,000
E156.026945	Install Stillwater Lake Elmo Area Substation	2025.1113	0		74.99			77%	\$ 2,600,000
E156.026953	Reinforce Lexington TR1 and TR2	2013.0225	1		0.06			69%	\$ 7,400,000
E156.026954	Reinforce Lexington LEX062 LEX071	2025.1114	0		743.46			113%	\$ 400,000
E156.026957	Install Lindstrom Area Substation	2023.0156	0		5.73			101%	\$ 200,000
E156.026996	Install Oakdale OAD066	2023.0354	0		31.67			98%	\$ 8,800,000
E156.026997	Install Oakdale OAD076	2025.1331	0		0.85			60%	\$ 5,900,000
E156.026998	Reinforce Oakdale OAD073 OAD075	2023.0356	0		253.95			118%	\$ 250,000
E156.027000	Reinforce Tanners Lake TLK061	2023.0445	0		375.03			109%	\$ 550,000
E156.027003	Load Transfer Tanners Lake TLK077 to TLK067	2025.1121	0		162.11			85%	\$ 50,000

...PROTECTED DATA ENDS]

Protected Data Justification

The shaded and marked columns in this spreadsheet contain information Xcel Energy maintains as Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a). The public disclosure or use of this information creates an unacceptable risk that those who want to disrupt our system for political or other reasons may learn which facilities to target to create a disruption of our service. Additionally, these fields for certain feeders contain information that if made public would be counter to our requirement to protect the anonymity of our customers' energy usage information unless we have the customers' consent to disclose it (Commission Order dated January 19, 2017 in Docket No. E,G999/CI-12-1344).

INTRODUCTION

As part of our continued efforts to modernize the distribution system and meet evolving customer needs, the Company is requesting certification of a mobile battery system for use on our Minnesota distribution system. The mobile battery is trailer-mounted, allowing it to be transported and installed at customer sites as needed. This battery will serve as a flexible, deployable asset to temporarily mitigate emergent distribution system capacity constraints for new or expanding customer loads—until permanent infrastructure can be constructed.

The Company will deploy the mobile battery to customer sites under specific circumstances, typically when a customer's new or increased load exceeds available distribution system capacity, and the timeline for constructing traditional infrastructure would delay service. In such cases, we would deploy the mobile battery on the feeder serving that customer to provide peak shaving—discharging during peak hours and charging during off-peak periods—to temporarily alleviate the constraint until permanent infrastructure is built.

Because the battery is mobile, the Company can redeploy it to different locations as needed. This makes it a reusable, scalable, and cost-effective near-term alternative to traditional upgrades in the near term. While we have not previously encountered this exact scenario, the combination of expected load growth and ongoing supply chain challenges for utility infrastructure presents a new and pressing issue. A flexible solution like the mobile battery is essential to maintaining reliability and responsiveness. To ensure readiness, we must act now, given the long lead times associated with procuring this equipment.

This proposal aligns with the Company's broader grid modernization strategy, which includes improving customer interactions, delivering excellent service, anticipating future system needs, and incorporating policy guidance related to customer offerings and grid capabilities. The mobile battery system is also consistent with Minn. Stat. § 216B.2425, subd. 3(b), which allows the Commission to certify a project if it is found to be "in the public interest." The mobile battery system we propose is necessary to modernize the distribution system, as defined in Minn. Stat. § 216B.2425, subd. 2(e), which states energy storage as one of the innovative technologies to "enhance reliability" and "enable demand response." This battery will enhance reliability through temporary capacity relief and support of new or growing customer

load. It will also support demand response by reducing the feeder peak—delaying the need for traditional infrastructure and avoiding other methods customers may choose to use to meet their energy usage needs.

With past certification requests, the Commission has assessed public interest based on factors such as alignment with grid modernization goals, the project objectives and potential benefits to customers, and cost effectiveness. We address these factors, as well as the timeline for implementation of the proposed project, in this certification request. We also propose to streamline the informational requirements for certification requests under Minn. Stat. § 216b.2425, subd 3(b).

Given the anticipated benefits and alignment with statutory goals, the Company respectfully requests that the Commission certify the proposed mobile battery system as a necessary investment in grid modernization and allow it to seek cost recovery through a future Transmission Cost Recovery (TCR) Rider, in accordance with Minn. Stat. §216b.16, subd.7b. We also respectfully request that the Commission approve the Company's proposed streamlined certification informational requirements.

I. THE MOBILE BATTERY IS NECESSARY FOR GRID MODERNIZATION

As discussed in detail in Chapter 1 of the IDP, our existing distribution planning process examines our distribution system's ability to serve customer peak load, identifies areas where there is a risk of overload or equipment failure, and makes plans to mitigate these potential overloads with additional or upgraded equipment. Sometimes, despite our best planning efforts, customers have emergent needs that our traditional planning processes cannot reasonably anticipate. We discuss in this section how the mobile battery we propose supports grid modernization by providing a flexible, rapidly deployable solution that complements our long-term planning. It enables peak shaving and load management, helping to address unforeseen system needs while enhancing reliability and customer service.

A. Capacity Constraints and Temporary Mitigation Needs

When an individual customer requests to add or increase their load on the distribution system, we must determine whether the distribution system has enough available capacity. If there is not enough capacity available, we identify the infrastructure upgrades that are necessary to allow the customer's load to be added to the distribution system without compromising safety or reliability.

When the construction of new or upgraded traditional infrastructure would delay timely service to customers, temporary solutions are essential to bridge the gap. One such solution is the mobile battery we propose, which can be deployed for several months—enough to cover an entire season of capacity constraints. We would deploy the mobile battery on the feeder serving the affected customer to provide peak shaving—discharging during peak hours and recharging during off-peak periods—to temporarily relieve the constraint until the permanent infrastructure can be built. This flexible resource can be reused and relocated to different areas of the distribution system, making it particularly valuable for targeted needs where traditional solutions cannot be implemented quickly enough to meet customers' electrical needs.

For example, the Company is currently deploying a 1 MW / 2 MWh mobile battery in our Public Service of Colorado operating company to address forecasted substation transformer overloads at the Denver Terminal Substation in 2026. This temporary solution is necessary due to lead times in constructing a permanent capacity project caused by supply chain issues, permitting, the crowded footprint of the right of way, and in-depth construction of a new substation transformer, transmission lines, and subsequent feeder. The battery will be installed on a Company-owned parcel along West Colfax Avenue. Once permanent infrastructure is completed, the battery could be repurposed to support other grid needs. This initiative is part of our broader strategy to integrate non-traditional solutions, such as Non-Wires Alternatives (NWAs) and Virtual Power Plants (VPPs) along with testing and becoming familiar with new technologies.

It is advantageous for the Company to procure the mobile battery before a specific deployment need has been identified. While we do not yet have a customer or site selected for initial use, we have a clear understanding of the use case and how the battery would be deployed. Importantly, procuring a mobile battery typically has a long lead time, often 12 to 18 months from order to delivery, plus additional time on the front end for engineering and vendor selection and additional time after delivery to commission the battery into service. If we were to wait until a specific need arises before initiating procurement, we may not be able to provide timely service to the customer, and in some cases, the battery may not arrive any sooner than the traditional infrastructure upgrade itself. By planning ahead and securing the battery now, we ensure that we are prepared to respond quickly when the need arises, enabling us to support customer load growth and system reliability with innovative, flexible solutions.

B. Alternative Solutions to Temporary Mitigation Needs

When new load requirements exceed existing capacity, we analyze various scenarios to temporarily serve new loads, including second-tier switching and serving a portion of the new load. However, this is not ideal when customers need all of their requested load in a shorter timeline than the full construction buildout would take. We are expecting that large electrification loads such as concentrated EV charging and all-electric buildings may be such situations that would drive the need for a temporary solution such as the mobile battery.

II. MOBILE BATTERY OBJECTIVES AND BENEFITS TO CUSTOMERS

The mobile battery will be procured and maintained in Company inventory for flexible deployment as system needs arise. Its primary objective is to provide temporary capacity mitigation at sites experiencing peak load constraints. When such a need is identified, the battery will be deployed to the feeder serving the affected customer(s), operated to reduce peak demand, and then either returned to inventory or relocated to another site once permanent infrastructure is in place. This approach enhances responsiveness to emergent system needs, supports grid modernization, and delivers direct reliability benefits to customers. Over time, we expect to gain insights into additional use cases and the ease of redeployment, further maximizing the battery's value across its useful life.

A. Overview

The mobile battery under consideration will be no larger than 1 MW / 2 MWh, which is the maximum size suitable for a trailer-mounted unit. It must be capable of peak shaving on the feeder and recharging during off-peak hours. Designed to operate at the most common voltage level across our Minnesota service territory (15 kV), it offers broader deployment potential and increased system benefits. It is designed to be deployed more quickly than traditional solutions and includes necessary components for safe and compliant operation.

The costs associated with the purchase of the mobile battery include:

- Mobile battery system module and trailer
- Site Preparation and construction
- Switchgear
- Transformer

- Utility Interconnection
- Fire safety systems
- Training and permitting support
- Operations and Maintenance Costs
- DERMS integration
- Decommissioning and site restoration costs

B. Capabilities and Benefits

The mobile battery provides several key benefits:

- Temporary capacity relief for constrained feeders or substations.
- Quick deployment to meet urgent customer needs.
- Support for electrification and economic development.
- Flexibility to serve multiple customers over time.
- Improved customer satisfaction by enabling timely service.
- Experience evaluating the effectiveness of temporary solutions for capacity mitigation until traditional capacity upgrades are completed.

III. MOBILE BATTERY COST INFORMATION

A. Procurement and Implementation Costs

The total estimated initial cost for the mobile battery, including installation and removal, is \$6-7 million plus tax and overheads. This estimate includes:

- Battery unit
- Interconnection hardware
- Safety systems and training
- Permitting
- Contingency and overheads
- Transformer and Switchgear equipment skid
- Tax
- Decommissioning
- Overheads
- Ongoing O&M

Capital costs are based on budgetary estimates and our Colorado deployment experience; equipment and labor estimates may change over time as economic and industry conditions change, and install and removal costs will differ by site.

B. Cost-Benefit Analysis

Due to the absence of a specific site to deploy the battery at this time, a detailed cost-benefit analysis is not currently feasible. However, in accordance with Minn. Stat. § 216B.2425, subd. 3(b) the Company believes the mobile battery meets the criteria for certification as an investment that is in the public interest. It provides:

- Flexibility to meet emerging customer needs.
- Support for electrification and economic growth.
- Enhanced reliability and customer satisfaction.
- Grid modernization.

C. Detailed Cost Information

Below, we provide available cost information for acquiring the mobile battery. These costs are preliminary and reflect estimates as of August 2025.

Battery Size	1MW/2MWh
Battery Cost	\$3,900,000-\$4,200,000
Associated Equipment (Transformer & Switchgear)	\$200,000 - \$400,000
Contingency (25% of known costs)	\$1,025,000 - \$1,150,000
Taxes	8-9%

Below are additional estimated costs related to the installation and removal of the mobile battery each time it is installed at a new location:

Concrete Masonry Unit Wall	\$400,000
Utility Interconnection	\$250,000
Fire Safety Training	\$50,000
Permitting	\$50,000
Decommissioning	\$25,000
Contingency (25% of known costs)	\$193,750
Overheads	15%-30%

Finally, there will be ongoing O&M costs for the battery, whether it is actively deployed or held in inventory awaiting deployment. We expect these to total approximately \$35,000 per year.

IV. MOBILE BATTERY EXPECTED IMPLEMENTATION TIMELINE

Recognizing the need for a flexible, deployable solution to address temporary distribution constraints from emergent customer needs, the Company is working to evaluate mobile battery options. The selected battery will offer the necessary capacity, mobility, and safety features to support deployment across multiple customer sites as needs arise.

A. Guiding Factors for Selecting a Mobile Battery

Overall, selecting a mobile battery that enables us to meet the temporary capacity needs of our customers is of utmost importance in our evaluation process. Specifically, we see the following three key factors as essential to our selection process: capacity and operational flexibility, scenario applicability, and integration with distribution planning and operations. We discuss each further below.

1. Capacity and Operational Flexibility

We expect the selected mobile battery will be no larger than 1 MW / 2 MWh, as this is the largest allowable size per trailer. Mobile batteries are scalable and multiple battery modules (trailers) could be deployed to meet the load if larger sizes are needed. It must be capable of peak shaving during constrained hours. The Company would design and build an additional skid that would allow connection to most 15 kV feeders across the Minnesota territory for recharging during off-peak periods. This enables temporary mitigation of overloads, provided:

- The overload magnitude is within the battery's rated capacity;
- There is sufficient off-peak capacity available for recharging;
- The customer site or other identified site has adequate space for hosting the battery; and
- Local permitting and safety requirements (e.g., setbacks, firewalls, physical security) can be met and in the timeframe needed for the customer project.

2. Scenario Applicability

The mobile battery must be usable for a variety of scenarios, including:

- New customer facilities under construction.
- Electrification of transportation, building heating, or industrial processes.
- Load increases that outpace traditional infrastructure construction timelines.

While no specific deployment site has been identified yet, the mobile battery would be available for use as these scenarios emerge on the Company's 15 kV distribution system.

3. Integration with Distribution Planning and Operations

The mobile battery would integrate with the Company's grid DERMS system to provide increased visibility around when the constraints would occur and also provide information on how the battery responds during these situations.

B. Evaluation and Selection Process

The Company will review battery options and select a mobile battery based on, but not limited to, the following criteria:

- Initial Cost
- Capacity
- Mobility
- Deployment feasibility
- Timeline to deliver
- On-going O&M costs
- Existing Vendor Contracts
- Lessons learned from the Colorado mobile battery project
- Safety features

C. Near-Term Actions

Within approximately three months of Commission certification, we intend to initiate the process to procure the battery and other equipment. After receiving the equipment, we expect it to take approximately 12 months to complete installation at the first site. We expect this entire process will take approximately 24-30 months from the certification decision. Deployment will follow interconnection and permitting processes, with coordination across Distribution Planning, Distributed Energy Resources (DER) Engineering, and Distribution Operations.

When a qualifying use case is identified, the timeline to deploy the mobile battery will vary depending on a variety of factors such as land availability, local permitting, electrical infrastructure to construct, telemetry to install for communication and the

customer load ramp schedule. The mobile battery would remain in place until the work to install the permanent infrastructure to the site is complete. After the permanent infrastructure is in place, we would “disconnect” and remove the mobile battery and return it to inventory to be used at another location. Just like the cost to install the mobile battery, the cost to remove the battery will vary and be site-specific.

V. REQUEST FOR CERTIFICATION

Pursuant to Minn. Stat. § 216B.2425, subd. 3(b), Xcel Energy respectfully requests that the Commission certify our proposal to procure a mobile battery as an investment in the public interest. Our request also aligns with the requirements of Minn. Stat. § 216B.2425, subd. 2(e), which directs utilities operating under multiyear rate plans to identify modernization investments in their biennial reports. These investments include those that the utilities consider:

... necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.^[1]

The mobile battery supports grid modernization consistent with Minn. Stat. § 216B.2425, subd. 2(e)—which expressly references energy storage as a qualifying investment. Additionally, this mobile matterry will enhance reliability through temporary capacity relief, support of new or growing customer load, support demand response by reducing feeder peak, and delay the need for traditional infrastructure. These capabilities align with the statute’s intent to modernize the distribution system through new technologies.

Consistent with the applicable statutes and our past practice, if certified, we will seek cost recovery of the mobile battery costs in a forthcoming TCR petition. The statute governing the TCR, Minn. Stat. § 216B.16, subd. 7b, “allows [the Company] to recover costs associated with investments in distribution facilities to modernize the [Company’s] grid that have been certified by the commission under section 216B.2425.”² The evidence provided in this IDP, demonstrates that the mobile

¹ Minn. Stat. § 216B.2425, subd. 2(e).

² Minn. Stat. § 216B.16, subd. 7b(b)(5).

battery is consistent with the public interest, warrants certification, and subsequent recovery through the TCR.

A. Striking the Right Balance: Innovation and Oversight in Certification

Under Minnesota Statutes, a project may be certified if the Commission finds that it is “in the public interest” (Minn. Stat. § 216B.2425, subd. 3(b)). Specifically, the statute states that “the Commission may certify a project proposed under subdivision 2, paragraph (e), only if the commission finds the proposed project is in the public interest.”

As noted above, with past certification requests, the Commission has assessed public interest based on factors such as cost-effectiveness, alignment with policy goals, and potential benefits to customers. It has also imposed additional, specific informational requirements with various past certification requests. Some of these specific requirements include cost-benefit analyses, alternatives analyses, and proposed evaluation metrics. These types of information are often not known with certainty until the Company progresses in its procurement or development of the proposed tool or investment. We acknowledge the Commission reasonably expects a sufficient level of detail to determine whether an investment is in the public interest under Minn. Stat. §216b.2425, subd. 3(b). To innovate and modernize the grid, it is essential to monitor trends and technologies, use our expertise to anticipate customer and grid needs, and take deliberate action to ensure we are prepared to meet our customers’ needs. We may not have all of the details before we start pursuing a particular project or concept – but the details will get filled-in as we further develop it.

That is what we are asking the Commission to do with its certification determinations – to generally assess the public interest of the Company’s proposal in the context of the statute. This will allow the Company to further develop the project to determine specific costs, more fully assess specific benefits, and confirm alignment with policy goals. Or, we may decide after we do further development of the project that it needs to change from our original concept, or we may no longer believe it is in our customers’ best interests. In any case, we would return to the Commission to either provide an update on the status of the project or to request cost recovery. The Commission already has existing robust procedures to evaluate investments in cost recovery proceedings. It could, however, require the Company to provide specific information with its request for cost recovery, such as cost-benefit analyses, narrative discussion of qualitative customer benefits, and/or other information to ensure alignment with the certified project. We believe this approach is practicable,

reasonable, and would encourage speed and innovation – and at the same time, ensure there are appropriate guardrails around costs and alignment with the public interest.

To strike a balance between the Company’s need for flexibility and innovation, and the Commission’s need for transparency and accountability, we propose the following certification requirements to support the Commission’s evaluation of whether the proposed project serves the public interest:

1. A description of why the project is necessary for grid modernization;
2. A description of the project, its scope, and its intended objectives;
3. A cost range for the project; and
4. The expected timing for project implementation.

We respectfully request that the Commission adopt these requirements for this certification request and consider applying them to future certification requests. We believe this approach will support innovation while ensuring the Commission has the information it needs to make informed decisions.

CONCLUSION

The proposed mobile battery system represents a forward-looking, flexible solution to address emerging distribution system needs in a timely and cost-effective manner. By proactively investing in this resource, the Company can better support customer load growth, enhance system reliability, and advance grid modernization goals.

We respectfully request that the Commission certify this investment as in the public interest and adopt a streamlined certification framework that enables innovation while maintaining transparency and accountability.

IDP Requirement 3.D.2.j requires that we provide:

Impacts to net present value of system costs (in NPV \$/RR/MWh or MW)

As we have noted in our past IDPs, we understand this requirement to be a calculation similar to that provided in conjunction with an Integrated Resource Plan. We continue to believe there are differing characteristics associated with the distribution system that make this complex to translate. That said, we have not been provided other directions, so we are providing a distribution-level calculation consistent with what we have provided in the past.

Our approach is similar to a jurisdictional cost of service – but for just the Distribution function of the Company. In general, a jurisdictional cost of service study includes the following financial data input sections: (1) capital structure; (2) cost of capital; (3) income tax rates; (4) rate base; (5) income statement; (6) income tax calculations; and (7) cash working capital computation.

We clarify that this “rate base” view of the Distribution function will not match the budget information we provide in this IDP, because the inputs to the NPV Revenue Requirements (RR) calculation are specific to just the distribution system located in Minnesota. As such, only costs that are direct-assigned to Distribution, and distribution assets located in the state of Minnesota are included. Common and general property in support of the Distribution function are not included in this view – but are represented in the distribution budget information provided elsewhere in this IDP. Similarly, other rate base is not included, and we are not including ratemaking treatments such as net operating losses.

Rate base primarily reflects the capital expenditures made by a utility to secure plant, equipment, materials, supplies, and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital. It is generally comprised of the following major items:

- *Net Utility Plant.* Net utility plant represents the Company’s investment in plant and equipment that is used and useful in providing retail electric service to its customers, net of accumulated depreciation and amortization.
- *Construction Work in Progress (CWIP).* In Minnesota, CWIP is included as part of the revenue requirement calculation for base rates. CWIP is the accumulation of construction costs that directly relate to putting a fixed asset into use.
- *Accumulated Deferred Income Taxes (ADIT).* Inter-period differences exist between the book and taxable income treatment of certain accounting transactions. These differences typically originate in one period and reverse in one or more subsequent periods. For utilities, the largest such timing difference typically is the extent to which accelerated income tax depreciation generally exceeds book

depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in rates in previous periods.

- *Pre-Funded Allowance for Funds Used During Construction (AFUDC)*. In Minnesota, AFUDC is included as part of the revenue requirement calculation for base rates. Specifically, during construction, AFUDC is calculated and included in the CWIP balance and is also included in operating income as an offset to the revenue requirement. AFUDC is added to the cost of related capital projects and is reflected in rate base when the related capital project is placed into service. Once a project is placed in service, the recording of AFUDC ceases and the total capital cost of the project including accumulated AFUDC is recovered through depreciation.
- *Other Rate Base*. Other Rate Base is comprised primarily of Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. In general, it includes items such as materials and supplies, fuel inventory, prepayments, and various non-plant assets and liabilities.

Rate base is generally calculated as outlined in Table 1 below.

Table 1
High Level Rate Base Calculation

	<i>Original Average Cost of Electric Plant in Service (Plant)</i>
Less:	Average Accumulated Depreciation Reserve
Less:	Average Accumulated Provision for Deferred Taxes
Plus:	Average Construction Work in Progress
Plus:	Average Working Capital
<i>Equals:</i>	Rate Base

For this Distribution Function NPV RR, we calculated the growth in revenue requirements over the five-year budget period to derive an NPV of \$420.1million (in 2025 dollars).

Northern States Power Company
Distribution Function NPV

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2025 Integrated Distribution Plan
Attachment G – Page 3 of 3

Annual Revenue Requirement
Electric Distribution
2025-2030
Minnesota
(000's)

<u>Rate Analysis</u>	2025	2026	2027	2028	2029	2030
1 <u>Average Balances:</u>						
2 Plant Investment	5,833,616	6,698,639	7,625,452	8,461,134	9,335,468	10,292,071
3 Depreciation Reserve	1,868,891	2,021,066	2,193,267	2,397,741	2,630,883	2,894,258
4 CWIP	209,730	261,204	270,086	296,779	267,540	143,841
5 Accumulated Deferred Taxes	581,258	584,669	601,247	621,942	645,893	671,123
6 Average Rate Base = line 2 - line 3 + line 4 - line 5	3,593,197	4,354,107	5,101,024	5,738,230	6,326,232	6,870,531
7						
8 <u>Revenues:</u>						
9 Interchange Agreement offset = -line 40 x line 52 x line 53						
10						
11 <u>Expenses:</u>						
12 Book Depreciation	208,757	231,894	263,468	291,663	317,433	352,914
13 Annual Deferred Tax	13,109	14,203	19,331	22,273	25,894	24,458
14 ITC Flow Thru	(242)	(222)	(791)	(7,322)	(7,288)	(7,239)
15 Property Taxes	58,728	67,386	78,466	86,689	97,780	108,042
16 subtotal expense = lines 12 thru 15	280,351	313,261	360,474	393,303	433,819	478,175
17						
18 <u>Tax Preference Items:</u>						
19 Tax Depreciation & Removal Expense	262,911	291,522	339,422	375,464	408,859	452,432
20 Tax Credits (enter as negative)	-	-	-	-	-	-
21 Avoided Tax Interest	9,376	15,524	15,146	15,832	18,630	12,781
22						
23 AFUDC	14,630	23,003	23,941	25,656	29,928	19,898
24						
25 <u>Returns:</u>						
26 Debt Return = line 6 x (line 44 + line 45)	77,613	95,790	114,263	129,684	143,605	157,335
27 Equity Return = line 6 x (line 46 + line 47)	174,629	211,610	247,910	278,878	307,455	333,908
28						
29 <u>Tax Calculations:</u>						
30 Equity Return = line 27	174,629	211,610	247,910	278,878	307,455	333,908
31 Taxable Expenses = lines 12 thru 14	221,623	245,875	282,008	306,614	336,039	370,133
32 plus Tax Additions = line 21	9,376	15,524	15,146	15,832	18,630	12,781
33 less Tax Deductions = (line 19 + line 23)	(277,542)	(314,525)	(363,363)	(401,120)	(438,787)	(472,329)
34 subtotal	128,087	158,484	181,701	200,204	223,338	244,492
35 Tax gross-up factor = $t / (1-t)$ from line 50	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
36 Current Income Tax Requirement = line 34 x line 35	51,664	63,925	73,289	80,753	90,083	98,616
37 Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38 Total Current Tax Revenue Requirement = line 36+ line 37	51,664	63,925	73,289	80,753	90,083	98,616
39						
40 Total Capital Revenue Requirements	569,628	661,583	771,995	856,962	945,034	1,048,136
41 = line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42 O&M Expense	110,363	121,693	122,697	124,977	134,983	144,698
43 Total Revenue Requirements	679,991	783,276	894,692	981,939	1,080,017	1,192,834
<u>Capital Structure</u>	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost
44 Long Term Debt	2.1100%	2.1800%	2.2200%	2.2400%	2.2400%	2.2500%
45 Short Term Debt	0.0500%	0.0200%	0.0200%	0.0200%	0.0300%	0.0400%
46 Preferred Stock	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
47 Common Equity	4.8600%	4.8600%	4.8600%	4.8600%	4.8600%	4.8600%
48 Required Rate of Return	7.0200%	7.0600%	7.1000%	7.1200%	7.1300%	7.1500%
49 PT Rate	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
50 Tax Rate (MN)	28.7420%	28.7420%	28.7420%	28.7420%	28.7420%	28.7420%
51 MN JUR Direct	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%
54 Growth in Total Revenue Requirements	-	103,285	111,416	87,247	98,078	112,817
55 Present Value of Growth in Total Revenue Requirements	420,097					

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2025 Integrated Distribution Plan
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Major Category	General Category	Mitigation	Mitigation Desc	Risk Score	2026	2027	2028	2029	2030 Total		
AGIS	AGIS	AGIS	AGIS		NA	16,368,326	29,600,000		45,968,326		
AGIS Total						16,368,326	29,600,000		45,968,326		
Asset Health & Reliability	Blanket	E114.018176	MN - OH Rebuild Tap/Backbone/Sec Blkt	NA	23,831,000	23,739,997	23,627,000	23,233,000	24,007,420	118,438,417	
		E114.018178	MN - OH Services Renewal Blanket	NA	924,003	949,001	975,000	1,000,999	1,031,030	4,880,033	
		E114.018274	MN - UG Conversion/Rebuild Blanket	NA	6,675,998	6,856,000	7,041,000	7,231,000	7,447,928	35,255,966	
		E114.018275	MN - UG Services Renewal Blanket	NA	6,983,999	7,172,999	7,367,003	7,566,001	7,792,979	36,882,989	
		E114.018354	MN - OH Street Light Rebuild Blanket	NA	2,568,002	2,637,000	2,707,997	2,781,003	2,864,429	13,558,431	
		E114.018355	MN - UG Street Light Rebuild Blanket	NA	725,997	745,998	766,000	787,002	810,611	3,835,608	
		E141.017359	MPLS UG Network Vault Blanket	NA	102,996	105,998	108,997	111,998	115,360	545,349	
		E151.016697	STP UG Network Vault Blanket	NA	10,999	10,999	10,999	10,999	11,330	55,326	
		E141.017673	Aldrich Mitigation	0.42	5,500,000	14,325,001	11,325,002	5,999,999	1,409,999	38,660,001	
		E141.023581	Rebuild Garfield Outcline & Feeders	0.02	2,000,000	500,001				2,500,001	
	E141.025586	Extend Moore Lake Feeder M04079	0.02	800,002					800,002		
	E143.026676	Rebuild Willow Creek Rd	0.02	300,002					300,002		
	E143.026987	Upgrade SAV069 Feeder Capacity	0	125,001					125,001		
	E144.011660	ELR Install New Nstrand Sub	0.16	549,997	3,800,000		200,000	3,449,996	3,649,996		
	E144.013622	Convert Lafayette LAF 4kV	0.16	230,001	2,499,997	1,400,000			4,349,997		
	E144.021628	Replace Dundas DND TR02	0.39	230,001					4,129,998		
	E144.021748	ELR Install Gaiter Lake Sub	1	1,300,002	1,000,003				2,300,005		
	E144.024031	Convert Gaylord GAY 4kV	0.02	6,200,004	645,000				6,845,000		
	E144.024225	Essig Substation ELR	NA	300,001	1,300,000				1,600,001		
	E144.024351	ELR Arlington ARL Substation	1	299,999					299,999		
	E144.024979	Rebuild Wakasha Sub	1	750,000	1,699,998	5,205,000			7,654,999		
	E144.025338	Green Isle FRI 4 kV Conversion	0.03			100,001	5,900,002		6,000,003		
	E144.025374	Castle Rock CSR 4 kV Conversion	0.32			100,001	5,299,998		5,399,999		
	E144.025396	Convert Minnesota Lake MNL 4 kV	0.48			100,001	7,999,999		8,100,000		
	E144.025532	Install New Rapidan Area Substation	0.28	500,000	249,999				749,999		
	E144.025535	Retire Dome Pipeline DOM Sub	0.02	500,001					500,001		
	E144.025909	Rebuild Cannon City Bnd poles	0.02	1,000,003					1,000,003		
	E150.022858	Install Inver Hills IVH TRs	0.02			100,001			100,001		
	E150.025276	Intall Raptor RPO_TR2 and Feeders	125.83			4,399,998			4,399,998		
	E150.025772	Reinforce Cottage Grove TR1 and TR2	0.92			4,600,001			4,600,001		
	E151.020496	Rebuild Downtown St. Paul Manholes WEST	Non-Discretionary	1,000,000					1,000,000		
	E151.020871	Relocate STP Tunnel Feeders	1,000,000		47,184	NA			47,184		
	E151.020887	Reinforce Daytonas Bluff DBL Substation	7.16	9,649,998	399,999				10,049,997		
	E151.026367	Convert WES73 transfer to WES074	0.02	441,997					441,997		
	E152.025573	Rebuild Tracy Switching Station T55061	0.02		3,500,002	3,600,001			7,100,003		
	E152.025683	Rebuild Pipestone PIP090	0.02				5,000,002		5,000,002		
	E154.013603	Convert Bird Island BIS 4kV	0.58		100,001	6,099,999			6,200,000		
	E154.013633	Convert Hector HEC 4kV	1.5	100,001		3,600,001			3,700,000		
	E154.013634	Convert Montevideo MTV 4kV	3.23		100,001	2,499,999			2,600,000		
	E154.013635	Convert Sacred Heart SCH Area 4kV	7.14	350,002					350,002		
	E154.023410	T Rebuild Glenwood GLD Feeder Exit	Non-Discretionary	800,000					800,000		
	E154.023463	T Rebuild Cap Banks GLD Sub	Non-Discretionary	200,000					200,000		
	E154.024021	Convert South Haven SOH 4kV	0.03		100,001	4,799,998			4,899,999		
	E154.024027	Install New Avon-St Joseph Area Substation	0.04	100,001	9,299,999	0,000			9,400,000		
	E154.025054	T \$400 Paynesville to Richmond	0.02	424,999					424,999		
	E154.025430	Convert Franklin FRA Substation	0.02		7,300,001				7,300,001		
	E154.025496	Rebuild Sedan SED Substation	0.13	100,001	5,200,001				5,300,002		
	E154.025498	Convert Watkins WKN 4 kV Substation	0.02			100,001	5,699,999		5,800,000		
	E154.025500	Convert Brownston BRW 4 kV Substation	0.07	100,001	4,200,002				4,300,003		
	E154.025402	T Install Horseshoe Lake Substation	Non-Discretionary					299,999	299,999		
	E158.026005	GVW sub 0774 replace jumpers	0.02	299,999					299,999		
	E158.026472	Rebuild REW023 OHUG	0.02	1,400,004					1,400,004		
	E158.027069	REMS Spates Ave Red Wing	0	419,999					419,999		
	E103.001736	MN Failed Sub Equip Replacement	NA	5,906,000	6,082,999	6,387,001	5,675,574	6,796,108	30,847,682		
	E103.016837	MN Failed Sub TR Replacement	NA	1,073,000	1,105,000	1,138,001	1,171,999	1,210,677	5,698,677		
	E103.022271	Reserve TR 69-13.8 kV 28 MVA	NA	1,900,002					1,900,002		
	E103.022524	Reserve TR 67-13.8 kV 25 MVA	NA	1,900,002					1,900,002		
	E103.022832	Reserve TR 115-25 kV 70 MVA	NA	2,350,001					2,350,001		
	E103.022834	Reserve TR 115-13 kV 28 MVA	NA	1,900,002					1,900,002		
	E103.022965	Reserve TR 115-13.8 kV 50 MVA	NA	2,200,000					2,200,000		
	E103.023262	Reserve TR 115-13.8 kV 50 MVA	NA	2,200,000					2,200,000		
	E103.024464	Reserve TR 115-34.5 kV 50 MVA	NA	2,000,000			2,100,000		2,100,000		
	E103.024470	Reserve TR 115-34.5 kV 28 MVA	NA				2,000,000		2,000,000		
	E103.024472	Reserve TR 115-12.5 kV 28 MVA	NA				2,000,000		2,000,000		
	E103.024473	Reserve TR 115-12.5 kV 14 MVA	NA			850,001			850,001		
	E103.024474	Reserve TR 69-4.16 kV 14 MVA	NA			800,000			800,000		
	E103.024475	Reserve TR 34.5-12.5 kV 10.5 MVA	NA			750,001			750,001		
	E103.025537	Reserve TR 69-4 kV 14 MVA	NA	800,000					800,000		
	E103.025538	Reserve TR 69-4 kV 7 MVA	NA	600,000					600,000		
	E103.025539	Reserve TR 69-23.9 kV 14 MVA	NA		800,000				800,000		
	E103.025540	Reserve TR 69-23.9 kV 28 MVA	NA				2,000,000		2,000,000		
	E103.025541	Reserve TR 69-12.5 kV 28 MVA	NA				2,000,000		2,000,000		
	E103.025542	Reserve TR 69-12.5 kV 14 MVA	NA					800,000	1,600,000		
	E103.025543	Reserve TR 115-13.8 kV 28 MVA	NA			4,000,000			6,000,000		
	E103.025544	Reserve TR 115-35 kV 70 MVA	NA			2,100,000			2,100,000		
	E103.025706	Reserve TR 69-13.8 kV 14 MVA	NA	1,030,000					1,030,000		
	E114.018278	MN - Feeder Cable Replacement	NA	6,895,998	7,103,000	7,316,002	7,354,999	7,783,657	36,363,656		
	E143.022168	Wilson WILD87 Cable Replacement	NA	1,300,001					1,300,001		
	E114.018129	MN - Pole Replacement Blanket	NA	55,415,002	55,415,002	23,758,001	23,758,001	24,542,015	182,888,021		
	E103.006458	ELR MN Sub Retirements	NA	599,998	599,998	629,999	648,998	670,417	3,149,410		
	E103.011890	ELR MN Sub Feeder Breakers	NA	7,800,000	8,700,001	9,134,997	9,409,000	9,719,497	47,863,495		
	E103.011891	ELR MN Sub Switches	NA	3,150,002	3,750,001	3,937,999	4,055,999	4,189,847	19,083,848		
	E103.012586	ELR MN Sub Relays	NA	249,999	249,999	249,999	249,999	249,999	1,249,995		
	E103.012603	ELR MN Sub Regulators	NA	750,001	1,250,002	1,313,001	1,352,001	1,396,619	6,061,624		
	E103.012606	ELR MN Sub Fences	NA	1,499,999	1,499,999	1,574,999	1,622,000	1,675,525	7,872,523		
	E103.012612	ELR MN Sub TRs	NA	10,500,000	15,000,000	15,750,001	16,223,003	16,223,003	73,696,007		
	E103.013521	ELR MN Sub RTUs	NA	750,001	599,998	629,999	648,998	670,417	3,299,413		
	E103.017653	ELR MN Sub Batteries	NA	1,300,002	1,300,002	1,365,001	1,406,001	1,452,398	6,823,404		
	E103.020780	ELR Mobile Substation Renewal	NA	6,500,000	4,600,001	4,800,000	4,943,997	5,107,153	29,951,151		
	E114.018179	MN - REMS Blanket	NA	564,001	581,001	598,000	615,999	636,328	2,995,329		
	E114.018180	MN - PPP Blanket	NA	2,252,000	2,320,000	2,390,001	2,462,002	2,543,245	11,967,240		
	E114.018792	MN LED Post Top Conversion	NA	1,749,998					1,749,998		
	E114.021017	MN Low Cost Reclosers (Single Phase)	NA	120,000	160,002	168,000	172,999	178,709	799,710		
	E114.021020	MN High Customer Count Taps	NA	4,000,000	6,000,001	6,300,000	6,489,003	6,489,003	29,278,007		
	E114.021025	MN Porcelain Cutouts	NA	2,800,001	2,800,001	2,800,001	2,884,000	11,284,003	11,284,003		
	E114.021939	MN ELR Reclosers	NA	3,000,000	3,000,000	3,000,000	3,090,000	3,090,000	15,180,000		
	E114.022285	MN Substation Physical Security	NA								
	E114.022430	ELR MN Breaker Mechanisms	NA	500,000	500,000	524,998	541,000	558,854	2,624,852		
	E114.027102	MN Targeted Undergrounding-revised	NA	8,000,001	25,000,000	62,000,000	67,500,002	69,727,498	232,227,501		
	E141.001664	ELR MPLS Vault Tops	NA	1,766,002	1,818,998				3,585,000		
	E141.018795	ELR MPLS Network Protectors	NA	2,685,996	2,817,001	2,901,997			8,404,994		
	E141.019633	ELR MPLS Network TR	NA	1,130,000	1,134,999				2,264,999		
	E144.020922	SE Region Reliability Initiative	NA	3,377,999	3,480,000	3,583,999	3,691,998	3,813,839	17,947,835		
	E151.013639	ELR STP Vault Tops	NA	435,000	474,998				909,998		
	E151.018796	ELR STP Network Protectors	NA	986,000	1,016,000	1,046,001			3,048,001		
	E151.019634	ELR STP Network TR	NA	500,001	514,999				1,015,000		
	E151.020871	Relocate STP Tunnel Feeders	NA	6,090,002	5,552,818	5,189,999	7,949,997		24,782,816		
	E114.018277	MN - URD Cable Replacement Blanket	NA	30,516,000	31,031,999	33,004,000	33,998,000	35,115,802	164,064,999		
	E114.020925	MN Cable Isolation Activities	NA	869,002	901,999	947,000	975,000	1,007,177	4,700,177		
	E143.027057	URD Zarthan Ave S Savage	NA	337,002					337,002		
	E114.018276	MN - Line Asset Health WCF Blanket	NA	25,500,000	25,500,000	25,500,000	25,500,000	26,341,500	128,341,500		
	Asset Health & Reliability Total			295,286,024	327,146,001	328,472,999	327,038,565	279,570,373	1,557,513,962		
	Capacity	Blanket	E114.018181	MN - OH Reinforce Blkt Tap/Back/Sec	NA	2,018,000	2,072,000	2,128,003	2,185,002	2,250,550	10,653,557
			E114.018279	MN - UG Reinforce Blkt Tap/Back/Sec	NA	2,465,002	2,532,000	2,599,998	2,750,098	2,817,000	13,164,098
			E114.018342	MN - New Business Network Blanket	NA	359,000	369,000	379,000	389,000	400,667	1,896,667
			E141.019925	SUBS Reinforce Gopher TR1	1.17						300,003
			E141.019929	Install Midtown MDT Feeder	0.58	3,299,999					3,299,999
			E141.019956	Reinforce Terminal TER073	0.12				1,100,001		1,100,001
			E141.019958	Reinforce Moore Lake M04071	0.66		550,001				550,001
			E141.020729	Reinforce Saint Louis Park SLP092	0.03		4,050,000				4,050,000
E141.021648			Reinforce Elliot Park ELP081	0.59	400,003					400,003	
E141.021663			Extend Southtown Feeder S0U069	0.35	350,						

Major Category	General Category	Mitigation	Mitigation Desc	Risk Score	2026	2027	2028	2029	2030 Total
		E141.022785	Reinforce Elliot Park Feeder ELP084	346.74	500,000				500,000
		E141.022787	Reinforce SLP85 Feeder	0.02		2,710,001			2,710,001
		E141.024062	Install Midtown MDT072 Feeder	17.68	1,500,000				1,500,000
		E141.024064	Extend Elliot Park Feeder ELP082	0.52	309,999				309,999
		E141.024065	Reinforce Medicine Lake MEL073	115.89	1,000,000				1,000,000
		E141.024066	Reinforce Medicine Lake MEL089	0.4		2,160,001			2,160,001
		E141.024119	Install New Midtown MDT064	17.58	5,319,999				5,319,999
		E141.025583	Reinforce Elliot Park ELP071 Feeder	84.39		530,002			530,002
		E141.025584	Reinforce Southtown Feeder SOUT075	3.65	3,599,999				3,599,999
		E141.025596	Reinforce WRR Feeder WRR064	52.03	1,399,997				1,399,997
		E141.025671	Reinforce Moore Lake Feeder MOL066	5.49	3,100,001				3,100,001
		E141.026014	Install Lake Harriet Area Substation	5.46			5,000,000	13,000,001	18,000,001
		E141.026460	New Main Street Sub	0.74	3,000,000			16,000,000	19,000,997
		E141.026464	C Extend ALD071	0.03	5,000,000				19,500,000
		E142.010995	Install Watertown TR2 14MVA	Non-Discretionary	100,000				100,000
		E142.011721	Install Orono ORO TR2 & Feeder	0.16			1,580,002		1,580,002
		E142.013437	Install Excelsior EXC TR2	0.04				199,999	3,900,004
		E142.024045	Install Dahlgren DHL062 Feeder	0.02					3,900,000
		E142.025707	Extend MMD061	5.71	909,999				909,999
		E142.027071	Mound Substation Upgrade	Non-Discretionary			7,749,999	1,950,001	7,749,999
		E143.017702	Install Viking VKG Feeder	0.34	4,194,998				4,194,998
		E143.017703	Blue Lake reinforce banks to 50MVA and add feeder	0.03				199,999	5,746,998
		E143.019054	Reinforce Edina EDA062	0.83	500,000				500,000
		E143.022265	Install Hyland Lake HYL TR01	0.01	3,799,998				3,799,998
		E143.022790	Reinforce Wilson WIL001 Feeder	0.01	750,001				750,001
		E143.022793	Reinforce Wilson WIL072	21.55	400,003				400,003
		E143.022794	Install Wilson Feeder WIL064	2.16	1,545,007				1,545,007
		E143.022795	Extend Hyland Lake HYL074	6.65	600,001				600,001
		E143.024049	Extend East Bloomington EBL066	0.39		550,001			550,001
		E143.024051	Reinforce East Bloomington EBL062	217.08	700,002				700,002
		E143.024054	Install South Airport Substation	0.02				34,000,001	34,000,001
		E143.025546	Install Hyland Lake HYL067	2.44			2,009,999		2,009,999
		E143.025592	Load Transfer BLU071 to BLU064	0			40,000		40,000
		E143.025599	Extend Nine Mile Creek NMC061	0				1,380,002	1,380,002
		E143.025609	Reinforce Wilson Feeders	9.5		5,920,001			5,920,001
		E143.025610	Extend Edina EDA064	30.29		1,159,998			1,159,998
		E143.025703	Reinforce WSG Feeder	90.24	460,001				460,001
		E144.000791	Install La Crescent Area Sub	90.24	600,001				600,001
		E144.000793	Install Zumbrota ZUM TR	0.02	6,049,997				6,049,997
		E144.002712	Install Goodview GVW Feeder	1.68		1,800,001			1,800,001
		E144.008708	Reinforce Cannon Falls CAF TR1	2.07	2,971,893	869,134			3,841,027
		E144.010884	Install Belle Plaine Area Sub	3.84			400,001	6,000,001	6,400,002
		E144.010889	New Pine Island Area Sub	0.02	871,175	4,430,325	2,509,154		7,810,654
		E144.010920	Reinforce Burnside BUR TR2	2.48	199,999	1,500,002	3,200,000		4,900,001
		E144.012525	Install New Dodge Center Area Sub	0.02		400,001	100,001	6,949,999	7,450,001
		E144.013446	Reinforce Waseca WAS TR2	0.02				2,599,997	2,599,997
		E144.013520	Install New Winona Area Sub	0.12			100,001	9,000,002	9,100,003
		E144.013622	Convert Lafayette LAF 4kV	0.16	400,001				400,001
		E144.015692	Install East Mankato Area Substation	0.04			1,900,003	6,529,999	8,430,002
		E144.018971	Reinforce Veseli VES TR1	97.4	49,996				49,996
		E144.020614	Reinforce Faribault FAB TR2	0.02	600,000	3,000,001	8,000,000	1,000,001	12,600,002
		E144.024031	Convert Gaylord GAY 4kV	0.02	400,001				400,001
		E144.024034	Reinforce Waterville TR3	0.02	549,999		499,999	1,500,001	8,550,000
		E144.024037	Install West Byron WEB TR2	29.85	3,222,999				3,222,999
		E144.024038	Relief West Faribault WEF TR7	0.03	1,514,163	6,248,105	104,272		7,866,540
		E144.025161	Reinforce Fair Park FAP TR2	0.02	3,021,962	2,450,001			5,471,963
		E144.025325	Install Altura ALT TR2	0.1		200,000		100,001	5,300,002
		E144.025326	Install Frontenac FRO TR2	0.58		100,001	5,300,002		5,400,003
		E144.025335	Reinforce Eagle Lake EGL Feeders	0.02			400,001		400,001
		E144.025336	Install Gibbon GIB TR2	0.06		200,000		5,100,002	5,400,003
		E144.025338	Green Isle FRI 4 kV Conversion	0.03			300,000		300,000
		E144.025351	Install Henderson HEN TR2	0.12		200,000		100,001	5,100,002
		E144.025352	Install New Lake City Area Substation	0.05		300,000		100,001	5,700,001
		E144.025354	New Mazeppa Area Substation	0.47	100,001	5,600,000			5,700,001
		E144.025365	Reinforce Red Wing REW Feeders	5.08	2,700,003				2,700,003
		E144.025374	Castle Rock CSR 4 kV Conversion	0.32				300,000	5,400,003
		E144.025375	Reinforce Sibley Park SIP Feeders	0.02	500,004				500,004
		E144.025384	Reinforce Eastwood ESW Feeders	0.97	2,500,000				2,500,000
		E144.025395	Reinforce Credit River CTR TR2	0.25			100,001	5,099,999	5,200,000
		E144.025396	Convert Minnesota Lake MNL 4 kV	0.48				300,000	300,000
		E144.025406	Install Northfield Area Substation	0.59			100,001	9,600,001	9,700,002
		E144.025520	Install Medford Junction MDR TR2	0.37	100,001	4,600,000			4,700,001
		E144.025522	Install Zumbro Falls Area Substation	0.02			100,001	6,300,001	6,400,002
		E144.025523	Install Wells Creek WEL TR2	0.17			100,001	4,500,000	4,600,001
		E144.025524	Install Swan Lake SWN TR2	0.1				100,001	5,200,001
		E144.025532	Install New Rapidian Area Substation	0.28	4,750,714	359,654			5,110,368
		E144.026244	C Extend NOR061	Non-Discretionary	350,001				350,001
		E144.026618	Install Cassel Substation	Non-Discretionary	7,099,997	499,999	10,000,003		17,599,999
		E146.024017	Install Averill AVR TR02	0.03			100,001	2,300,000	2,400,001
		E147.011060	Install Meadow Lake Area Sub	0.17				32,000,002	32,000,002
		E147.011656	Reinf. Coon Creek CNC TR1 to 50 MVA	0.02				100,001	2,500,002
		E147.012459	Install 2-50 MVA at Brooklyn Park	0.02				100,001	4,900,002
		E147.013373	Reinforce Bassett Creek BCR TR1	0.08		199,999	2,199,999		2,399,998
		E147.013374	Reinforce Elm Creek TR1 to 50 MVA	0.08			100,001	2,300,000	2,400,001
		E147.013379	Install West Coon Rapids WCR TR	0.03			199,999	3,400,000	3,599,999
		E147.014487	Upgrade TWL061 feeder capacity	2.15	250,000				250,000
		E147.015683	Install Osseo OSS TR3	0.02				199,999	4,400,001
		E147.016682	Reinforce TWL079 and TWL081	8.61	1,000,000				1,000,000
		E147.022783	Reinforce All Osseo OSS Feeders	1.79	9,049,996				9,049,996
		E147.024026	Reinforce Twin Lakes Multiple Feeders	1.48	750,001	12,500,001			13,250,002
		E147.024028	Reinforce Parkers Lake PKL085	4.32		84,998			84,998
		E147.024033	Reinforce Parkers Lake PKL065	5.99		3,700,001			3,700,001
		E147.024193	Reinforce Twin Lakes TWL078	3.16		3,499,998			3,499,998
		E147.024221	Reinforce Brooklyn Park BRP072	29.5	500,000				500,000
		E147.024224	Install New Elm Creek Area Substation	18.48	2,301,005	8,999,999	10,999,999	5,000,000	27,301,003
		E147.024227	Load Transfer CRL033 CRL027 CRL031	15.8		300,000			300,000
		E147.025255	C Extend Elm Creek ECK322	Non-Discretionary	8,700,003				8,700,003
		E147.025578	Install Greenfield GFD TR2	0.01				100,001	3,730,001
		E147.025785	Install New North Brooklyn Park Substation	2.83	800,001	2,000,000	6,999,997	4,000,004	13,800,002
		E147.026950	Reinforce Parkers Lake feeders	0.28				2,249,999	2,249,999
		E150.013216	Install West Hastings WEH TR2	0.35			199,999	5,848,000	6,047,999
		E150.020609	Extend Woodbury WDY321 for WDY312	1.31	583,999				583,999
		E150.021670	Install Cottage Grove CGR TR03	46.65			6,083,002		6,083,002
		E150.021672	Install Chemolite CHE TR03	0.02				199,999	18,985,999
		E150.022038	Install Stockyards STY TR03	44.41	3,000,999				3,000,999
		E150.022705	Reinforce West Hastings WEH TR1	0.39		199,999	5,847,997		6,047,996
		E150.022709	Install Williams Brothers TR4	1.78				5,515,000	5,714,999
		E150.022735	Install Lone Oak LOK Feeder	0.03		199,999			6,999,998
		E150.022858	Install Inver Hills IVH TRs	0.02	12,152,160	2,968,011	2,948,750		18,068,921
		E150.023935	Install Feeder Tie RMT321-RMT312	3.26	3,000,001				3,000,001
		E150.023945	Reinforce Lone Oak LOK082 & LOK093	0.02	1,160,000				1,160,000
		E150.023953	Reinforce Rogers Lake RLK073	3.44	650,004				650,004
		E150.023955	Reinforce Rogers Lake RLK Feeders	7.45	2,790,003				2,790,003
		E150.023962	Reinforce Hastings HAS022	1.71	100,000				100,000
		E150.024167	Install Lone Oak LOK TR3	0.02				199,999	3,680,003
		E150.025282	DER Install RRR Regulators	Non-Discretionary	470,000				470,000
		E150.025518	Extend Vermillion Feeder VMR062	0.12	3,000,000				3,000,000
		E150.025772	Reinforce Cottage Grove TR1 and TR2	0.92		4,500,001	4,500,001		9,000,002
		E150.026739	C Extend WDY321	Non-Discretionary	3,999,999				3,999,999
		E151.000726	Install Prior PRR TR2	2.95	3,680,000	2,599,997			6,279,997
		E151.012409	Install Western WES TR3 & Feeders	0.02					5,299,998
		E151.023984	Reinforce Dayton Bluff DBL067	0.02				1,199,999	1,199,999
		E151.023987	Reinforce Merriam Park MPK072	0.02				1,625,002	1,625,002
		E151.023988	Reinforce Merriam Park MPK081	0.02				1,625,002	1,625,002

Major Category	General Category	Mitigation	Mitigation Desc	Risk Score	2026	2027	2028	2029	2030 Total	
Program	WCF	E151.023992	Reinforce Merriam Park feeders	0.02	11,147,002				11,147,002	
		E151.024003	C Reinforce Western WES072 Feeder	Non-Discretionary	9,999				9,999	
		E151.024004	C Reinforce Western WES064 Feeder	Non-Discretionary	9,999				9,999	
		E151.024013	Reinforce Merriam Park MPK085	0.02	875,000				875,000	
		E151.024018	Reinforce Upper Levee UPP081	0.02				1,046,003	1,046,003	
		E151.024029	Reinforce Western WES061 and WES075	5.8	600,001				600,001	
		E151.024039	Reinforce WES065 and WES076	0.29				407,998	407,998	
		E151.024040	Reinforce Western WES062 Feeder	0.02	193,000				193,000	
		E151.024041	Reinforce Western WES074 Feeder	0.34	354,001				354,001	
		E151.027215	N-Q Upper Levee UPP082 78% OL	0.03		10,000,000			29,500,000	
		E152.024015	Install Tracy Area Substation	0	3,450,002	4,200,000	5,999,996		13,649,998	
		E154.010157	Install Two Transformers Albany ALB	0.03	2,500,000	7,999,999			10,499,999	
		E154.013603	Convert Bird Island BIS 4kV	0.58		300,000			300,000	
		E154.022738	Install Dayton Area Sub	930.6	7,200,001				7,200,001	
		E154.022742	Reinforce Meire Grove TR1	0.06	475,000	6,226,572			6,701,572	
		E154.022828	Install Blue Heron TR2	0.02	1,500,001	3,000,003	5,000,000		9,500,004	
		E154.024027	Install New Avon-St Joseph Area Substation	0.04		300,000			300,000	
		E154.025412	Reinforce Granite City GRC Feeders	0.31	1,299,998				1,299,998	
		E154.025422	Reinforce St Cloud SCL311	2360.91	1,100,001				1,100,001	
		E154.025423	Install Stewart STW TR2	0.07	919,998	7,999,999			8,919,997	
		E154.025426	Install Danube DAN TR2	0.02		5,199,999			5,199,999	
		E154.025431	Reinforce Linn Street LNS Feeders	0.3	350,000				350,000	
		E154.025434	Install Atwater ATW TR2	0.03		100,001	5,300,000		5,400,001	
		E154.025435	Install Lowry LOW TR2	0.02	100,001	5,399,999			5,500,000	
		E154.025436	Install New Clara City Area 23.9 kV Substation	0.02	100,001	7,399,999			7,500,000	
		E154.025440	Install Kokato-Howard Lake Area Substation	0.02	100,001	9,200,000			9,300,001	
		E154.025448	Install Montrose MTR TR2	0.05	1,750,000	7,999,999			9,749,999	
		E154.025451	Install Douglas County DGC TR4	0.02	100,001	4,600,001			4,700,002	
		E154.025452	Install Broomten Area Substation	0.02	100,001	5,849,999			5,950,000	
		E154.025453	Install Maple Lake MAP TR2	0.02				100,001	5,599,999	
		E154.025454	Install MNV211-YLM211 Feeder Tie	0.02	2,500,000				2,500,000	
		E154.025460	Install Webber Trail WBT TR2	0.02				100,001	3,599,999	
		E154.025461	Install New Paynesville Transmission PAT Feeder	0.11	1,299,998				1,299,998	
		E154.025462	Install Dassel Area Substation	0.02		300,000		100,001	5,600,001	
		E154.025496	Rebuild Sedan SED Substation	0.13	300,000				300,000	
		E154.025498	Convert Watkins WKN 4 kV Substation	0.07					300,000	
		E154.025547	Install Renville RNV TR2	0.02	100,001	3,599,998			3,699,999	
		E154.025548	Install Kimball KIM TR2	0.02				100,001	5,099,999	
		E154.025558	Install Lake Lillian LIL TR2	0.02		100,001	5,099,999		5,200,000	
		E154.025561	Reinforce Maynard MYN021	0.02					4,200,000	
		E154.025571	Install Villard Area Substation	0.02	300,000		100,001	8,099,999	8,500,000	
		E154.026402	T Install Horseshoe Lake Substation	Non-Discretionary	736,000	858,000	606,002		2,200,002	
		E154.026926	Install St Cloud Area Substation	0.28	100,001	1,100,001	14,900,001	14,900,001	31,000,004	
		E154.026928	Install Sartell Area Substation	0.02		1,000,000		18,799,998	19,799,998	
		E154.027155	C Extend Sauk River SAK321	NA	3,999,996				3,999,996	
		E156.007927	Install Goose Lake GLK TR3	0.19		100,001	3,650,000		3,750,001	
		E156.010177	Install Kohlman Lake KOL Feeder	0.02			4,519,999		4,519,999	
		E156.011061	Install Wyoming WYO Feeder	0.49	3,300,002				3,300,002	
		E156.011749	Reinforce LEX ties	0.08			1,049,998		1,049,998	
		E156.011752	Install Lindstrom LIN Feeder	0.03	862,000				862,000	
		E156.011764	Reinforce Tanners Lake TLK Sub Equip	0.06				199,999	199,999	
		E156.011874	Install Birch Area Sub	0.02	1,500,872	6,900,002			8,400,874	
		E156.013545	Expand AHI substation	0.02	10,000		199,999	8,264,999	8,474,998	
		E156.015811	Reinforce Oakdale OAD073 & OAD075	0.02		275,000			275,000	
		E156.020602	Reinforce Ramsey Feeders RAM063 RAM071	0.02	209,999				209,999	
		E156.025438	Reinforce Oak Park OPK067 OPK073	211.52				274,999	274,999	
		E156.025589	Install Baytown BYT Feeders	3.15				3,000,001	3,000,001	
		E156.025590	Reinforce Kohlman Lake KOL	0.31			350,001		350,001	
		E156.025591	Reinforce Lexington LEX062	0.02			500,000		500,000	
		E156.025593	Reinforce Oakdale OAD Feeders	1.51			500,000		500,000	
		E156.026934	Reinforce Ramsey RAM072 RAM077	6.12				800,000	800,000	
		E156.026935	Reinforce Wyoming WYO022 WYO031	3.8				149,998	149,998	
		E156.026945	Install Stillwater Lake Elmo Area Substation	38.07				17,800,001	17,800,001	
		E156.026953	Reinforce Lexington TR1 and TR2	0.02					7,400,000	
		E156.026954	Reinforce Lexington LEX062 LEX071	377.32	400,003				400,003	
		E156.026957	Install Lindstrom Area Substation	2.92				13,400,003	13,400,003	
		E156.026996	Install Oakdale OAD066	16.08	9,400,003				9,400,003	
		E156.026997	Install Oakdale OAD076	0.44	6,499,998				6,499,998	
		E156.026998	Reinforce Oakdale OAD073 OAD075	128.89				350,001	350,001	
		E156.027000	Reinforce Tanners Lake TLK061	190.34				575,003	575,003	
		E156.027003	Load Transfer Tanners Lake TLK077 to TLK067	82.28				50,002	50,002	
		E103.018426	SUB MN Feeder Load Monitoring	NA	5,299,999	2,000,000			7,299,999	
		E114.020920	MN Grid Reinforcements	NA	10,000,001	23,000,000	25,000,000	25,000,000	108,000,001	
		E141.023118	MN RMP Resilient Mpls Projects	NA	1,649,998				1,649,998	
		E103.006881	MN Dist Subs Capacity WCF Blanket	NA	3,090,000	3,183,000	3,478,000	3,278,000	16,307,000	
		E114.018281	MN - Line Capacity WCF Blanket	NA	9,590,000	9,590,000	9,590,000	9,590,000	47,950,000	
Capacity Total					239,540,966	234,810,809	187,224,179	293,054,035	1,202,693,312	
Electric Vehicles										
Electric Vehicles Total	EV	E114.020058	MN Electric Vehicle Program	NA	600,000	600,000	658,572	658,572	3,175,716	
		E114.021483	MN EV Residential - Charging Equip	NA	1,770,422	2,124,509	2,549,409	3,059,291	13,174,779	
		E114.023505	MN EV Fleet EVSI	NA	8,000,000				8,000,000	
		E114.023509	MN EV Public EVSI	NA	8,000,000				8,000,000	
FLEET, TOOLS & COMM					18,370,422	2,724,509	3,207,981	3,717,863	4,329,720	
FLEET, TOOLS & COMM	Discrete	E114.026297	MN - Landbase and GPS Conflation	0.02	6,580				6,580	
		E141.025671	Install Downtown Minneapolis Sub	5.46				250,000	250,000	
		E141.026014	Install Lake Harriet Area Substation	0.74				300,000	300,999	
		E141.026460	New Main Street Sub	NA					500,000	
		E141.026475	C COMM Extend ALD071	Non-Discretionary	199,999				199,999	
		E142.027071	Mound Substation Upgrade	Non-Discretionary			1,000,000		1,000,000	
		E144.000793	Install Zumbrota ZUM TR	0.02	300,000				300,000	
		E144.008708	Reinforce Cannon Falls CAF TR1	2.07	177,808	73,870			251,678	
		E144.010889	New Pine Island Area Sub	0.02	500,000				500,000	
		E144.012525	Install New Dodge Center Area Sub	0.02				300,000	300,000	
		E144.013520	Install New Winona Area Sub	0.12				300,000	300,000	
		E144.013622	Convert Lafayette LAF 4kV	0.16	300,000				300,000	
		E144.015692	Install East Mankato Area Substation	0.04	300,000				300,000	
		E144.020614	Reinforce Faribault FAB TR2	0.02			500,000		500,000	
		E144.021628	Replace Dundas DND TR02	0.39	50,000	50,000	100,001		200,001	
		E144.024031	Convert Gaylord GAY 4kV	0.02	300,000				300,000	
		E144.024037	Install West Byron WEB TR2	29.85	300,000				300,000	
		E144.024038	Reinf West Faribault WEF TR7	0.03	100,001				100,001	
		E144.024979	Rebuild Wabasha Sub	1	50,000	50,000	100,001		200,001	
		E144.025161	Reinforce Fair Park FAP TR2	0.02	110,000	25,000			135,000	
		E144.025325	Install Altura ALT TR2	0.1					300,000	
		E144.025326	Install Frontenac FRO TR2	0.58				100,001	100,001	
		E144.025336	Install Gibbon GIB TR2	0.06					100,001	
		E144.025338	Green Isle FRI 4 kV Conversion	0.03		300,000			300,000	
		E144.025351	Install Henderson HEN TR2	0.12					100,001	
		E144.025352	Install New Lake City Area Substation	0.05				300,000	300,000	
		E144.025354	New Mazeppa Area Substation	0.47		300,000			300,000	
		E144.025365	Reinforce Red Wing REW Feeders	5.08		90,000			90,000	
		E144.025374	Castle Rock CSR 4 kV Conversion	0.32		300,000			300,000	
		E144.025395	Reinforce Credit River CTR TR2	0.25		300,000			300,000	
		E144.025396	Convert Minnesota Lake MNL 4 kV	0.48				300,000	300,000	
		E144.025406	Install Northfield Area Substation	0.59					300,000	
		E144.025520	Install Medford Junction MDF TR2	0.37		100,001			100,001	
		E144.025522	Install Zumbro Falls Area Substation	0.02				300,000	300,000	
		E144.025523	Install Wells Creek WEL TR2	0.17				300,000	300,000	
		E144.025524	Install Swan Lake SWN TR2	0.1					300,000	
		E144.026618	Install Casswell Substation	Non-Discretionary	500,000				500,000	
		E147.011060	Install Meadow Lake Area Sub	0.17					300,000	
E147.024224	Install New Elm Creek Area Substation	18.48				75,001	75,001			
E147.025578	Install Greenfield GPD TR2	0.01					100,001			
E147.025785	Install New North Brooklyn Park Substation	2.83				100,001	100,001			
E150.022858	Install Inver Hills IVH TRs	0.02				292,001	292,001			
E151.020897	Reinforce Dayton Bluff DBL Substation	7.16	50,000	50,000			100,000			

Northern States Power Company
Capital Project List

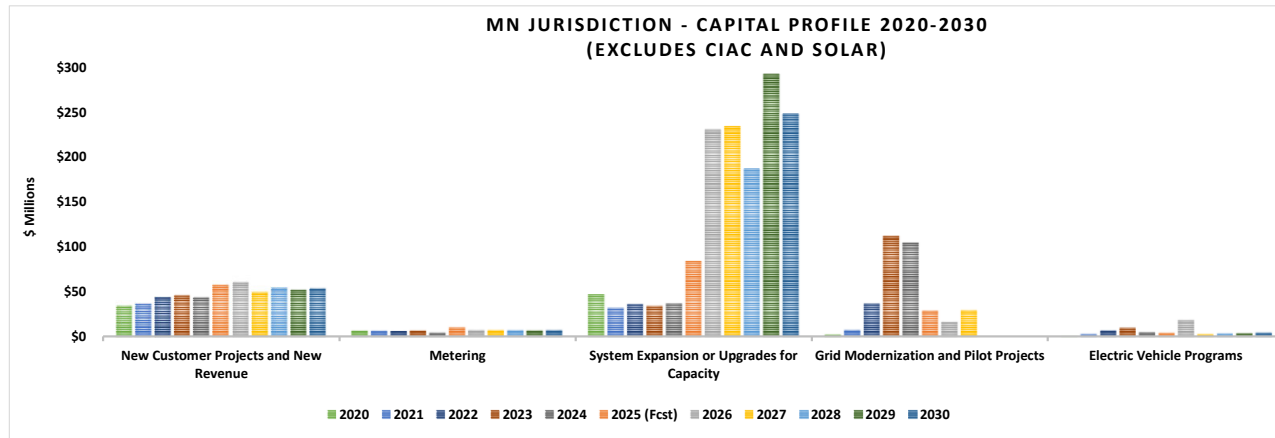
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Major Category	General Category	Mitigation	Mitigation Desc	Risk Score	2026	2027	2028	2029	2030 Total			
		E151.027215	Install Downtown St Paul Substation	0.03					500,000	500,000		
		E154.010157	Install Two Transformers Albany ALB	0.03	300,000					300,000		
		E154.013603	Convert Bird Island BUS 4kV	0.58			300,000			300,000		
		E154.022828	Install Blue Heron TR2	0.03		100,001	399,998			499,999		
		E154.024027	Install New Avon-St Joseph Area Substation	0.04		300,000				300,000		
		E154.025423	Install Stewart STW TR2	0.07		300,000				300,000		
		E154.025426	Install Danube DAN TR2	0.02		300,000				300,000		
		E154.025430	Convert Franklin FRA Substation	0.02		300,000				300,000		
		E154.025434	Install Atwater ATW TR2	0.03			300,000	300,000		300,000		
		E154.025435	Install Lowry LOW TR2	0.02		300,000				300,000		
		E154.025436	Install New Clara City Area 23.9 kV Substation	0.02		300,000				300,000		
		E154.025440	Install Cokato-Howard Lake Area Substation	0.02		300,000				300,000		
		E154.025448	Install Montrose MTR TR2	0.05		300,000				300,000		
		E154.025451	Install Douglas County DGC TR4	0.02		100,001				100,001		
		E154.025452	Install Brooten Area Substation	0.02		300,000				300,000		
		E154.025453	Install Maple Lake MAP TR2	0.02			0.02			300,000	300,000	
		E154.025460	Install Wobegon Trail WOB TR2	0.02						100,001	100,001	
		E154.025461	Install New Paynesville Transmission PAT Feeder	0.11	100,001						100,001	
		E154.025462	Install Dassel Area Substation	0.02						300,000	300,000	
		E154.025496	Rebuild Sedan SED Substation	0.13			300,000				300,000	
		E154.025498	Convert Watkins WKN 4 kV Substation	0.07			300,000				300,000	
		E154.025500	Convert Brownston BRW 4 kV Substation	0.02			300,000				300,000	
		E154.025547	Install Renville RNV TR2	0.02			300,000				300,000	
		E154.025548	Install Kimball KIM TR2	0.02						300,000	300,000	
		E154.025558	Install Lake Lillian LIL TR2	0.02					300,000		300,000	
		E154.025561	Reinforce Maynard MYN021	0.02						300,000	300,000	
		E154.025571	Install Villard Area Substation	0.02						300,000	300,000	
		E154.026402	T Install Horseshoe Lake Substation	Non-Discretionary	207,001	181,003	132,999			300,000	521,003	
		E154.026926	Install St Cloud Area Substation	0.28						300,000	300,000	
		E154.026928	Install Sartell Area Substation	0.51						300,000	300,000	
		E156.026945	Install Stillwater Lake Elmo Area Substation	38.07						300,000	300,000	
		E156.026957	Install Lindstrom Area Substation	2.92						300,000	300,000	
		Misc Program	E103.002265	Capitalized Locating Costs-Elec UG MN	NA	1,093,000			1,182,000	1,217,000	1,257,159	5,875,159
			E103.014467	Sub Fiber Communication Cutover	NA	2,100,000	2,700,001	NA	6,899,999	4,199,998		15,899,998
			E103.018427	COMM MN Feeder Load Monitoring	NA	1,799,999						1,799,999
			E103.022172	SUB Analog Circuit Retirements	NA	140,000						140,000
			E114.022015	SUB MN Security Monitoring & Logging	NA	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	5,000,000
			E141.020919	Install Network Monitoring Mpls	NA	4,399,002	3,599,002	3,707,002	3,000,006	3,000,006		17,705,018
			E141.023118	MN RMP Resilient Mpls Projects	NA	1,150,996						1,150,996
			E103.001738	MN Subs tools & equip	NA	252,057	265,098	272,917		280,742	290,004	1,360,819
			E103.002099	NSPM Metering Sys-Tools & Equipment Blanket	NA	203,384	209,470	219,900		226,853	234,343	1,093,951
			E114.021914	MN Elec Tools and Equip	NA	1,790,484	1,851,325	1,945,192	2,004,295	2,070,435	2,070,435	9,661,730
		E114.022477	Elec Tools & Equip HUGO	NA	43,458	43,458	46,067	47,807	49,382	49,382	230,173	
		FLEET, TOOLS & COMM Total					17,823,771	16,714,231	18,973,081	15,826,701	11,702,331	81,040,116
		Mandates	Blanket	E114.018173	MN - OH Reloc Tap/Backbone/Sec Blkt	NA	10,618,997	10,906,000	11,200,001	11,502,000	11,847,061	56,074,059
				E114.018271	MN - UG Reloc Tap/Backbone/Sec Blkt	NA	8,658,002	8,892,001	9,132,001	9,379,000	9,660,370	45,721,374
			Discrete	E114.018273	MN - UG Service Conversion Blanket	NA	2,015,004	2,069,002	2,125,004	2,182,000	2,247,461	10,638,471
				E141.017929	MPLS Mandates WCF	Non-Discretionary	7,000,000	7,000,000	7,000,000	7,000,000		28,000,000
				E141.024770	Relocate for I-494 expansion	Non-Discretionary	50,001					50,001
				E141.025577	Reinforce Indiana Feeder IDA072	Non-Discretionary	2,900,001					2,900,001
				E141.025734	Relocate Lowry Ave NE	Non-Discretionary	199,997					199,997
				E142.024163	Relocate WWK321 (Hwy 212)	Non-Discretionary	775,002					775,002
				E142.026815	Relocate Carver Cty CR 11	Non-Discretionary	349,999					349,999
				E143.025598	Relocation Southbound EBL Feeders	Non-Discretionary				560,000		560,000
E144.025473	Relocate SMT072 LAE061 for Hwy 22			Non-Discretionary	500,000					500,000		
E147.027070	Relocate BCR fdrz #2,81,62, 63			Non-Discretionary	650,002					650,002		
E151.026323	Relocate DBL feeders 7th St			Non-Discretionary	4,300,001					4,300,001		
E154.026716	Relocate OH UG Albertville			Non-Discretionary	135,000					135,000		
E158.026784	Relocate FROD21 Goodhue Cnty 2			Non-Discretionary	435,001					435,001		
Program WCF	E114.018479		MN - Pole Transfer 3rd Party Blanket	NA	955,001	984,002	1,033,002	1,063,997		4,036,002		
	E114.018175		MN - Mandate WCF Blanket	NA	8,699,000	8,960,000	9,408,000	9,690,000	10,009,771	46,766,771		
	Mandates Total					48,241,008	38,811,005	40,458,008	40,816,997	33,764,663	202,091,681	
NEW BUSINESS												
	Blanket	E114.018045	MN - OH New Street Light Blanket	NA	408,000	419,000	430,000	442,000	455,259	2,154,259		
		E114.018046	MN - UG New Street Light Blanket	NA	412,002	424,000	437,000	450,000	463,501	2,186,503		
		E114.018171	MN - OH Extension Blanket	NA	2,259,002	2,319,998	2,382,998	2,447,002	2,520,408	11,929,408		
		E114.018172	MN - OH New Services Blanket	NA	1,954,000	2,007,000	2,061,000	2,117,000	2,180,511	10,319,511		
		E114.018268	MN - UG Extension Blanket	NA	22,381,999	22,986,001	23,607,000	24,244,000	24,971,320	118,190,320		
		E114.018269	MN - UG New Services Blanket	NA	14,686,000	15,083,000	15,490,000	15,908,000	16,385,241	77,552,241		
	CIAC Discrete	E141.001140	Electric New Construction Contributions in Aid	NA	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)	(4,000,000)	(20,000,000)		
		E142.027058	C Extend Clare Ln Shwd	Non-Discretionary	263,000					263,000		
		E144.027068	C Extend tap 10th St Janesville	Non-Discretionary	110,002					110,002		
		E150.023423	C Extend Rosemount Feeders	Non-Discretionary	250,002					250,002		
		E150.025276	Intall Raptor RPO, TR2 and Feeders	125.83				4,800,000		4,800,000		
		E150.025517	Extend Vermillion Feeder VMR061	0.03	3,000,000					3,000,000		
		E151.026445	JT The Heights	Non-Discretionary	184,999					184,999		
		E154.026758	JT Riverview Preserve	Non-Discretionary	235,001					235,001		
		E103.001040	MN-Electric Meter Blanket	NA	7,331,428	7,184,800	7,038,170	7,038,170	7,270,427	35,862,995		
		E103.001041	MN-New Bus Transformer	NA	40,750,000	43,240,000	51,410,000	51,560,000	51,560,000	238,520,000		
	TRs WCF	E114.018270	MN - New Business WCF Blanket	NA	6,000,000	6,100,000	6,200,000	6,690,000	6,910,771	30,900,771		
		NEW BUSINESS Total					96,385,436	95,763,799	108,856,168	106,896,172	108,717,438	516,619,013
WILDFIRE												
WILDFIRE	WFRM	E114.025958	MN - WFRM	NA	118,066,001	115,963,007	81,000,004	83,300,003	83,300,003	481,629,018		
		E114.026738	MN WFRM - Feb 2025 updates	NA	125,899,999	98,499,996	56,899,998	41,200,000	41,200,000	363,699,993		
WILDFIRE Total					243,966,000	214,463,003	137,900,002	124,500,003	124,500,003	845,329,011		
Grand Total					975,981,953	960,033,357	825,092,418	911,850,336	810,647,851	4,483,605,916		

Northern States Power Company
Distribution Capital Profile Trend (2020-2030)

Docket No. E002/M-25-142
2025 Integrated Distribution Plan
Attachment I - Page 1 of 4

	2020	2021	2022	2023	2024	2025 (Fcst)	2026	2027	2028	2029	2030
New Customer Projects and New Revenue	\$34.5	\$36.1	\$43.3	\$45.9	\$43.5	\$57.4	\$61.0	\$49.3	\$54.4	\$52.3	\$53.9
Metering	\$6.9	\$6.3	\$6.7	\$7.0	\$4.6	\$10.2	\$7.3	\$7.2	\$7.0	\$7.0	\$7.3
System Expansion or Upgrades for Capacity	\$47.4	\$32.1	\$36.7	\$34.5	\$37.1	\$84.7	\$230.6	\$234.8	\$187.0	\$292.9	\$248.1
Grid Modernization and Pilot Projects	\$2.7	\$7.4	\$36.9	\$112.7	\$105.2	\$29.2	\$16.4	\$29.6	\$0.0	\$0.0	\$0.0
Electric Vehicle Programs	\$0.1	\$2.5	\$7.2	\$9.7	\$5.0	\$4.3	\$18.4	\$2.7	\$3.2	\$3.7	\$4.3



New Customer Projects and New Revenue (Extensions, Services, Streetlights)

- Based on estimated cost per meter and growth assumptions.
- Growth assumptions based on historical results, internal growth projections and known trends in service territories.

Metering (Meter Purchases, does not include AMI)

- Includes 'business-as-usual' meter costs, not metering expenditures associated with our AMI plans.
- Decreasing trends driven by AMI rollout.

System Expansion or Upgrades for Capacity (Reinforcements)

- Continued focus on risk minimization including contingency and overload risks. Annual amounts will fluctuate based on needs in North and South Dakota, as well as timing of large projects.
- Includes the Grid Reinforcement and Hosting Capacity programs which is driving the uptick in years 3-5.

Grid Modernization and Pilot Projects

- Includes major grid modernization projects including AMI, FAN, ADMS, and FUSR.

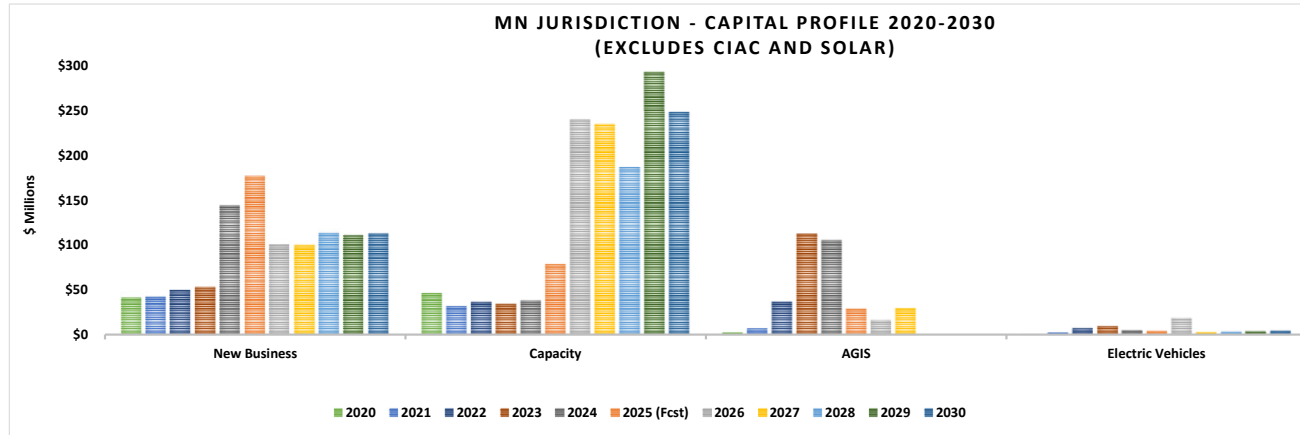
Electric Vehicles Programs

- Includes Electric Vehicle Programs.

Northern States Power Company
Distribution Capital Profile Trend (2020-2030)

Docket No. E002/M-25-142
2025 Integrated Distribution Plan
Attachment I - Page 2 of 4

	2020	2021	2022	2023	2024	2025 (Fcst)	2026	2027	2028	2029	2030
New Business	\$41.4	\$42.4	\$50.0	\$52.9	\$144.5	\$176.3	\$100.4	\$99.8	\$112.9	\$110.9	\$112.7
Capacity	\$47.4	\$32.1	\$36.7	\$34.5	\$38.0	\$78.7	\$239.5	\$234.8	\$187.2	\$293.1	\$248.1
AGIS	\$2.7	\$7.4	\$36.9	\$112.7	\$105.2	\$29.2	\$16.4	\$29.6	\$0.0	\$0.0	\$0.0
Electric Vehicles	\$0.1	\$2.5	\$7.2	\$9.7	\$5.0	\$4.3	\$18.4	\$2.7	\$3.2	\$3.7	\$4.3



New Business (Extensions, Services, Streetlights)

- Based on estimated cost per meter and growth assumptions.
- Growth assumptions based on historical results, internal growth projections and known trends in service territories.
- Purchases of electric meters and transformers to support ongoing customer growth and system needs
- Does not include metering costs related to our AMI plans

Capacity (Reinforcements)

- Continued focus on risk minimization including contingency and overload risks. Annual amounts will fluctuate based on needs, as well as timing of large projects.
- Includes the Grid Reinforcement and Hosting Capacity programs which is driving the uptick in years 3-5.

Advanced Grid Intelligence and Security (AGIS)

- Includes major grid modernization projects including AMI, FAN, ADMS, and FUSR.

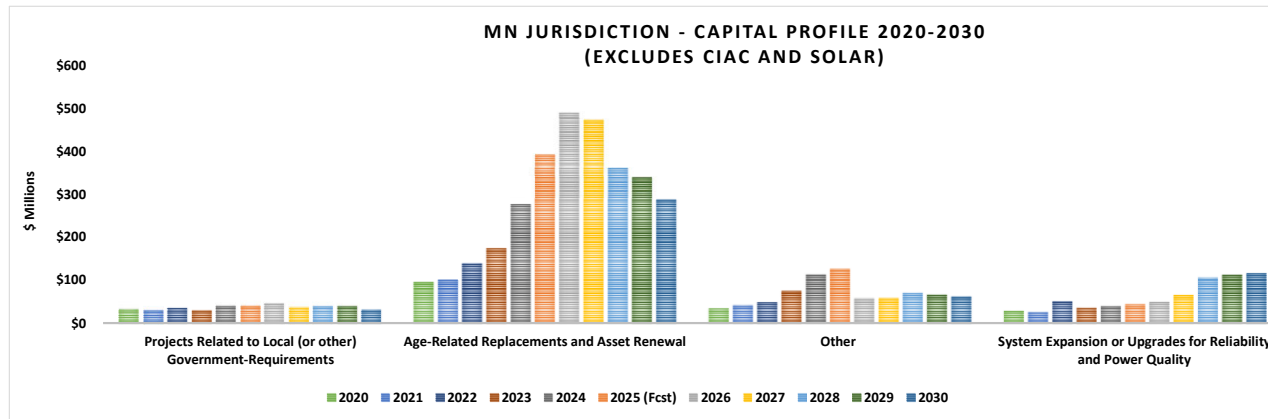
Electric Vehicles

- Includes Electric Vehicle Programs.

Northern States Power Company
Distribution Capital Profile Trend (2020-2030)

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2025 Integrated Distribution Plan
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	2020	2021	2022	2023	2024	2025 (Fcst)	2026	2027	2028	2029	2030
Projects Related to Local (or other) Government-Requirements	\$33.6	\$30.4	\$36.6	\$31.4	\$41.0	\$42.4	\$48.2	\$38.8	\$40.5	\$40.8	\$33.8
Age-Related Replacements and Asset Renewal	\$96.9	\$102.4	\$140.8	\$175.3	\$276.7	\$392.9	\$488.5	\$474.3	\$360.1	\$338.5	\$287.3
Other	\$35.9	\$43.0	\$49.8	\$76.1	\$113.1	\$126.7	\$58.8	\$60.0	\$70.6	\$67.6	\$63.3
System Expansion or Upgrades for Reliability and Power Quality	\$29.8	\$27.9	\$52.6	\$37.4	\$40.2	\$45.5	\$50.7	\$67.3	\$106.3	\$113.1	\$116.8



Projects Related to Local (or other) Government-Requirements (Mandates)

- Outyear budgets assume trends continue. Project schedules and final scopes greatly depend on city/government timelines, approvals and permitting.

Age-Related Replacements and Asset Renewal (Rebuilds, Conversions)

- Comprehensive suite of programs and projects aimed at replacing aging infrastructure. Includes funds for failure restoration and transformer reserves.
- Increasing aging infrastructure population driving increased budgets including pole replacements, substation equipment, network equipment and various discrete projects to address aging infrastructure or reliability.
- Increased funding also includes placeholders for a number of new programs designed to target aging infrastructure, increase reliability and increase system resiliency.
- Includes Wildfire Risk Mitigation program

Other (Fleet, Tools, Communication Equipment, Transformer Purchases, Advanced Planning Tool)

- Increasing trends driven by increasing fleet needs and new programs.
- Includes programs for installing communication in our downtown networks (Network Monitoring), privatizing our substation communication network (Fiber Buildout) and increasing cyber security (Cyber Security).

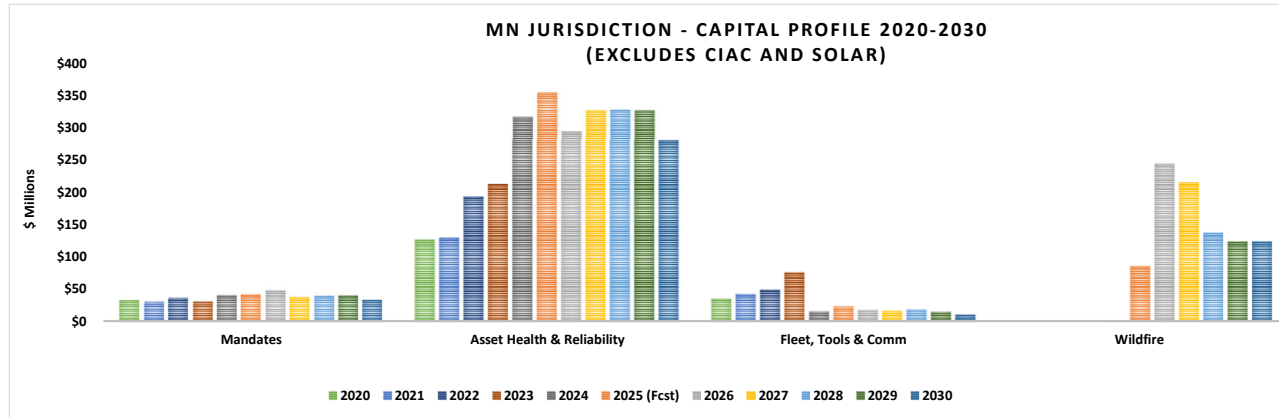
System Expansion or Upgrades for Reliability and Power Quality (Cable Replacement and Reliability Programs)

- Outyear budgets assumes current failure trends continue and ensures current level of reliability is maintained.

Northern States Power Company
Distribution Capital Profile Trend (2020-2030)

Docket No. E002/M-25-142
2025 Integrated Distribution Plan
Attachment I - Page 4 of 4

	2020	2021	2022	2023	2024	2025 (Fcst)	2026	2027	2028	2029	2030
Mandates	\$33.6	\$30.4	\$36.6	\$31.4	\$41.0	\$42.4	\$48.2	\$38.8	\$40.5	\$40.8	\$33.8
Asset Health & Reliability	\$126.7	\$130.3	\$193.4	\$212.7	\$316.9	\$353.7	\$295.3	\$327.1	\$328.5	\$327.0	\$279.6
Fleet, Tools & Comm	\$35.9	\$43.0	\$49.8	\$76.1	\$15.8	\$23.4	\$17.8	\$16.7	\$19.0	\$15.8	\$11.7
Wildfire					\$0.1	\$85.4	\$244.0	\$214.5	\$137.9	\$124.5	\$124.5



Mandates

- Outyear budgets assume trends continue. Project schedules and final scopes greatly depend on city/government timelines, approvals and permitting.

Asset Health & Reliability (Rebuilds, Conversions, Cable Replacement and Reliability Programs)

- Comprehensive suite of programs and projects aimed at replacing aging infrastructure. Includes funds for failure restoration and transformer reserves.
- Increasing aging infrastructure population driving increased budgets including pole replacements, substation equipment, network equipment and various discrete projects to address aging infrastructure or reliability.
- Increased funding also includes placeholders for a number of new programs designed to target aging infrastructure, increase reliability and increase system resiliency.
- Outyear budgets assumes current failure trends continue and ensures current level of reliability is maintained.

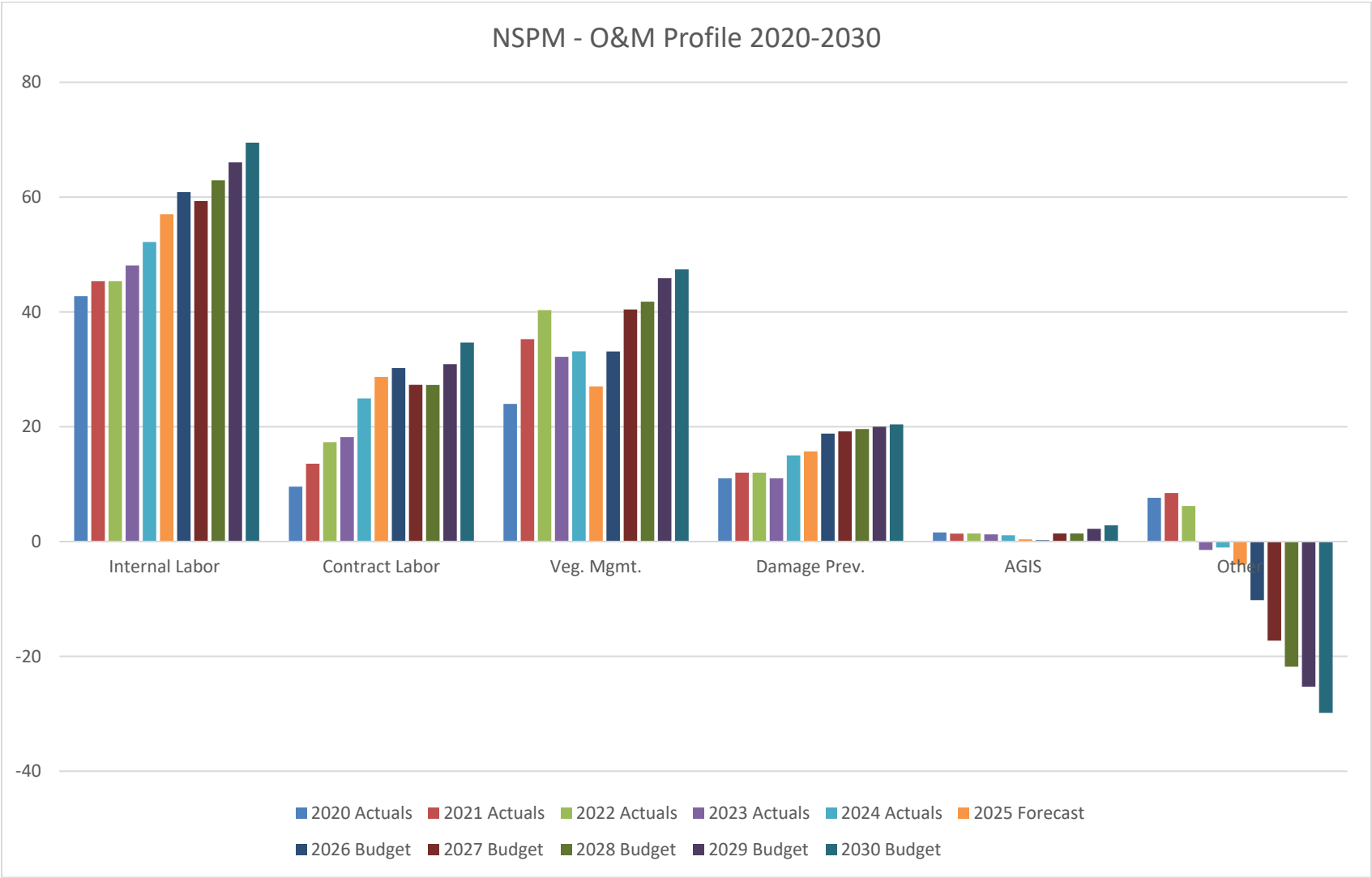
Fleet, Tools & Comm

- Increasing trends driven by increasing fleet needs and new programs.
- Includes programs for installing communication in our downtown networks (Network Monitoring), privatizing our substation communication network (Fiber Buildout) and increasing cyber security (Cyber Security).

Wildfire

- Includes Wildfire Risk Mitigation program formalized 2025.
- Increasing wildfire risk in Minnesota, largely due to climate change and human activity.
- Targeted to reduce wildfire ignition risk in the wildfire risk areas.

Figure 1: Distribution O&M Profile Trend (2020 to 2030)
NSPM – Total Company Electric



Other: Includes materials, employee expenses, transportation costs, first set credits, bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

Community	Carbon/GHG Reduction Goal	Renewable Energy Goal	Efficiency or Electrification Goal	Other
Arden Hills				Community went straight to implementation with the goal of reaching their manufactured home park with energy resources.
Bloomington*	75% for city-wide energy related, 95% for electricity related GHG emissions by 2035		Yes	Strategies for renewables, electrification
Burnsville*	40% by 2030, 80% by 2050 for community-wide GHG emissions	7.5% on-site solar (or REC purchase) for residential and commercial by 2030, 100% for all city owned facilities by 2030	10% decrease in residential and commercial electric use from 2016 numbers by 2030	Creating Energy Action Plan
Columbia Heights			30% increase in energy efficiency program participation among residents and businesses by 2030, Increase energy savings by 63% by 2030	Strategies for Renewables
Coon Rapids	35% by 2030 for GHG emissions			Strategies for renewables
Cottage Grove	Yes	Yes		
Eden Prairie*	30% by 2025, 80% by 2050 for GHG emissions	5% in-boundary by 2025, 10% by 2030		Climate Action Plan, Strategies for renewables, electrification
Edina*	30% by 2025, 80% by 2050 for GHG emissions	100% by 2030 for municipal, 100% by 2050 for community-wide, 10% in-boundary by 2030	10% gas to electric by 2030, full electrification by 2050	Climate Action Plan
Falcon Heights	80% by 2030	50% by 2030	100% of municipal buildings by 2030	Creating Energy Action Plan
Faribault*	Yes		1% annual reduction in energy spending from 2015	Creating Energy Action Plan, Strategies for renewables
Fridley*	5% by 2025, 25% by 2030	Yes	Reduce community energy use by 30% by 2030	
Golden Valley*	30% by 2030	Yes		Strategies for renewables, electrification
Hastings*			DSM Program participation goals	Energy Action Plan
Hennepin County*	45% by 2030, net zero by 2050	Carbon-free electricity for county by 2035, 10% on-site solar by 2030	3%/year reduce operational energy through 2030	Strategies for electrification
Hopkins				Creating Energy Action Plan
Inver Grove Heights*	Avoid 16,000 MTCO2e by 2025 and 28,000 by 2030	Increase on-site solar and renewables	Save 20 GWH of electricity by 2025, 39 GWH by 2030	Energy Action Plan
La Crescent*	Avoid 455 MTCO2e by 2030	Increase on-site solar and renewables	Promote DSM, Save 1.7 GWH by 2030	Energy Action Plan, Strategies for renewables, electrification
Mahtomedi*	30% by 2030, 100% by 2050	Double number of renewable energy subscribers in a year	1.4% annual energy savings, 19% by 2030	
Mankato		Yes		
Maplewood*	20% by 2025, 80% by 2050	50% by 2040, 15% on-site solar by 2030, 100% municipal renewables by 2040		Climate Action Plan/Sustainability Plan, Strategies for renewables, electrification
Minneapolis*	65% by 2030, 90% by 2040, net zero by 2050	100% by 2023 for municipal, 10% in-boundary by 2025, 100% by 2030 community-wide	Reduce energy use 17% by 2025	
Minnetonka*	Reduction of 160,000 MTCO2e energy related GHG emissions by 2031 or 41% by 2030	100% solar for city operations by 2020		Developing Climate Action Plan, Strategies for electrification
◆ New Brighton	Reduce energy-related greenhouse gas emissions 34% by 2030 from a 2021 baseline. (EAP) Reduce community-wide GHG emissions by 42% below 2013 levels by 2030, and achieve carbon neutrality by 2050 (CAP)	Increase residential and commercial & industrial subscribers in Xcel Energy renewable energy subscription offerings by 45% by 2030.□	Increase energy savings by 40% on community-wide electricity and natural gas energy by 2030.□	Developing Energy and Climate Action Plan
Northfield*	100% carbon neutral by 2040	10% in-boundary renewable electricity by 2030		Climate Action Plan, Strategies for renewables, electrification
Plymouth		100% Municipal electricity powered by renewable energy by 2030	Increase energy savings 30% by 2030	
Ramsey County*	30% by 2025, 80% by 2050	Promote on-site solar and renewables	Energy use reduction: 30% by 2025, 80% by 2050	
Red Wing*	80% by 2040 for GHG emissions	100% by 2040 community-wide	Reduce energy consumption 30% by 2030, 50% local vehicle use with electric or non/low-carbon fuels by 2030	Climate Action Plan/Sustainability Plan
Richfield*	15% by 2032 for GHG emissions	On-site solar and renewables		Energy Action Plan
Robbinsdale	Avoid an additional 30% of GHG emissions by 2030	Increase renewable energy in the city but not concrete goal	10 residential participants annually in electrification programs	Energy Action Plan, Strategies for renewables
Rosemount*	15% by 2030, 50% by 2050	75% municipal renewables	Reduce energy use 5% by 2020, 15% by 2030	
Roseville*	80% by 2050	100% renewable for city operations by 2040 with 25% on-site generation		Strategies for electrification
Saint Anthony Village	80% by 2040, 100% from municipal buildings by 2040		10 residential participants annually in electrification programs	Renewable Energy Strategies
Saint Paul*	50% by 2030, 100% by 2050	10% in-boundary, 200 MW by 2030		Climate Action and Resilience Plan, Strategies for renewables, electrification
Scandia	Yes	Yes		
Shoreview		Shoreview will increase renewable energy participation 30% by 2030	Shoreview will save 170,000 MMBtu by 2030. This will save the community \$2.3 million through energy efficiency projects by 2030	Developing Energy Action Plan
◆ Shorewood		Engage 300 or more subscribers in Xcel Energy's Windsource® and/or Renewable*Connect by 2020	Engage Shorewood businesses and residents in 500 energy saving programs annually.	Energy Action Plan
St. Cloud*	100% by 2040	Replace 21.8 GWh for institutions and businesses with renewables by 2026, 100% by 2030	Decarbonization of building energy use, carbon neutral for building energy and transportation by 2038, Save \$9.2M in energy costs	
St. Louis Park*	55% by 2030, 100% carbon neutral by 2040	100% by 2030	30% energy savings by 2030	Climate Action Plan, Strategies for renewables, electrification
Stillwater	Avoid an additional 58% of energy related greenhouse gas emissions by the end of 2025		Save 3.8 million kWh of electricity and 198,000 therms of natural gas by the end of 2025	Renewable Energy Strategies
Vadnais Heights		Increase residential renewable energy participation 15% by 2030,		GreenStep Cities Pilot Program
Washington County*	30% by 2025, 80% by 2050		15% reduction in building energy by 2025	
Wayzata*			Reduce energy use 30% by 2025	Energy Action Plan, Strategies for renewables
Winona*	Carbon neutral by 2050		Reduce energy use 10% by 2025	Sustainability Plan, Strategies for renewables

◆ * Community listed in the April 11, 2022 Letter from the Cities of Edina, Richfield, Saint Paul, and St. Louis Park (Docket No. E002/M-21-694).
Partners in Energy - Minnesota Community Participation
[Plan in adoption process](#)

Please note that the Company is filing a live spreadsheet for Attachment L- Tabular Data for Chapters 1, 6, and 10.

Please note that the Company is filing a live spreadsheet for Attachment M-ELR Cost-Benefit Analysis.

Attachment M is being marked “Not-Public” in its entirety as it comprises information the Company considers to be economic data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential economic data that derives 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. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data. 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.

1. **Nature of the Material:** Cost Benefit Analysis Model developed by the Company
2. **Author(s):** Jessica Terry
3. **Importance:** Contains not-public, proprietary information.
4. **Date the Information was Prepared:** October 2025.

**Please note that the Company is filing a live spreadsheet for Attachment N-
Grid Reinforcement Cost-Benefit Analysis.**

Attachment N is being marked “Not-Public” in its entirety as it comprises information the Company considers to be economic data as defined by Minn. Stat. § 13.37(1)(b). The information contains confidential economic data that derives 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. Additionally, some data contained within the model is also maintained as trade secret based on its economic value from not being generally known and not being readily ascertainable by proper means by other persons who can obtain value from its disclosure or use, and/or contains proprietary customer and system data. 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.

1. **Nature of the Material:** Cost Benefit Analysis Model developed by the Company.
2. **Author(s):** Jessica Terry
3. **Importance:** Contains not-public, proprietary information.
4. **Date the Information was Prepared:** October 2025.

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 No. E002/M-25-142

Dated this 31st day of October 2025

/s/

Victor Barreiro
Regulatory Administrator

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163	Brian	Lydic	brian@irecusa.org	Interstate Renewable Energy Council, Inc.		PO Box 1156 Latham NY, 12110-1156 United States	Electronic Service		No	M-25-142
164	Madeline	Lydon	madeline.k.lydon@xcelenergy.com	Xcel Energy		401 NICOLLET MALL Floor 7 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
165	Richard	Macke	macker@powersystem.org	Power System Engineering, Inc.		10710 Town Square Dr NE Ste 201 Minneapolis MN, 55449 United States	Electronic Service		No	M-25-142
166	Alice	Madden	alice@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	M-25-142
167	Alex	Magerko	amagerko@epri.com	EPRI		942 Corridor Park Blvd Knoxville TN, 37932 United States	Electronic Service		No	M-25-142
168	Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC		961 N Lost Woods Rd Oconomowoc WI, 53066 United States	Electronic Service		No	M-25-142
169	Tom	Mammen	thomas.j.mammen@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
170	Discovery	Manager	discoverymanager@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	M-25-142
171	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis	Electronic Service		Yes	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						MN, 55401 United States				
172	Gregg	Mast	gmast@cleanenergyeconomymn.org	Clean Energy Economy Minnesota		4808 10th Avenue S Minneapolis MN, 55417 United States	Electronic Service		No	M-25-142
173	Jason	Maur	jason.maur@renesolapower.com	Renesola Power Holdings, LLC		850 Canal Street 3rd Floor Stamford CT, 06902 United States	Electronic Service		No	M-25-142
174	Erica	McConnell	emcconnell@elpc.org	Environmental Law & Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25-142
175	Jess	McCullough	jmccullough@mnpower.com	Minnesota Power		30 W Superior St Duluth MN, 55802 United States	Electronic Service		No	M-25-142
176	Sara G	McGrane	smcgrane@felhaber.com	Felhaber Larson		220 S 6th St Ste 2200 Minneapolis MN, 55420 United States	Electronic Service		No	M-25-142
177	Natalie	McIntire	natalie.mcintire@gmail.com	Wind on the Wires		570 Asbury St Ste 201 Saint Paul MN, 55104-1850 United States	Electronic Service		No	M-25-142
178	Matthew	Melewski	matthew@theboutiquefirm.com	Nokomis Energy LLC & Ole Solar LLC		2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-142
179	Thomas	Melone	thomas.melone@allcous.com	Minnesota Go Solar LLC		222 South 9th Street Suite 1600 Minneapolis MN, 55120 United States	Electronic Service		No	M-25-142
180	Michael	Menzel	mike.m@sagiliti.com	Sagiliti		23505 Smithtown Rd. Suite 280 Excelsior MN, 55331 United States	Electronic Service		No	M-25-142
181	Tim	Mergen	tmergen@meeker.coop	Meeker Cooperative Light And Power		1725 US Hwy 12 E. Suite 100 PO Box 68 Litchfield MN, 55355 United States	Electronic Service		No	M-25-142
182	Pontius	Mike	mpontius@mnpower.com			null null, null United States	Electronic Service		No	M-25-142
183	Brian	Millberg	fwengineering@comcast.net			695 Grand Ave #222 Saint Paul MN, 55105 United States	Electronic Service		No	M-25-142
184	Luther	Miller	luther.c.miller@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
185	Marc	Miller	mmiller@soltage.com	Soltage, LLC		66 York Street, 5th Floor Jersey City NJ, 07302 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
186	Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis		350 S. 5th Street Room M 301 Minneapolis MN, 55415 United States	Electronic Service		No	M-25-142
187	Marcus	Mills	marcus@communitypowermn.org	Community Power		2720 E 22nd St Minneapolis MN, 55406 United States	Electronic Service		No	M-25-142
188	Darrick	Moe	darrick@mrea.org	Minnesota Rural Electric Association		11640 73rd Ave N Maple Grove MN, 55369 United States	Electronic Service		No	M-25-142
189	David	Moeller	dmoeller@allete.com	Minnesota Power			Electronic Service		No	M-25-142
190	Dalene	Monsebroten	dalene.monsebroten@nmpagency.com	Northern Municipal Power Agency		123 2nd St W Thief River Falls MN, 56701 United States	Electronic Service		No	M-25-142
191	Brian	Monson	brian.t.monson@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
192	Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP		33 South Sixth St Ste 4200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
193	Susan	Mudd	smudd@elpc.org	Environmental Law and Policy Center		35 E. Wacker Drive, Suite 1600 Chicago IL, 60601 United States	Electronic Service		No	M-25-142
194	Pouya	Najmaie	najm0001@gmail.com	Cooperative Energy Futures		3416 16th Ave S Minneapolis MN, 55407 United States	Electronic Service		No	M-25-142
195	Alex	Nelson	anelson@dakotaelectric.com	Dakota Electric Association		4300 220nd St Farmington MN, 55024 United States	Electronic Service		No	M-25-142
196	Anthony	Nelson	amnelson@otpc.com	Ottertail Power		53233 Sunrise Ln Park Rapids MN, 56470 United States	Electronic Service		No	M-25-142
197	Ben	Nelson	benn@cmpasgroup.org	CMMPA		459 South Grove Street Blue Earth MN, 56013 United States	Electronic Service		No	M-25-142
198	Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment		212 3rd Ave N Ste 560 Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
199	Darin	Nelson	dnelson@minnetonkamn.gov	City of Minnetonka		14600 Minnetonka Blvd Minnetonka MN, 55345 United States	Electronic Service		No	M-25-142
200	David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
201	Sephra	Ninow	sephra.ninow@energycenter.org	Center for Sustainable		426 17th Street, Suite	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
				Energy		700 Oakland CA, 94612 United States				
202	Michael	Noble	noble@fresh-energy.org	Fresh Energy		408 Saint Peter St Ste 350 Saint Paul MN, 55102 United States	Electronic Service		No	M-25- 142
203	Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute		2801 21ST AVE S STE 220 Minneapolis MN, 55407- 1229 United States	Electronic Service		No	M-25- 142
204	Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company		200 1st Street SE PO Box 351 Cedar Rapids IA, 52406- 0351 United States	Electronic Service		No	M-25- 142
205	David	O'Brien	david.obrien@navigant.com	Navigant Consulting		77 South Bedford St Ste 400 Burlington MA, 01803 United States	Electronic Service		No	M-25- 142
206	Logan	O'Grady	logrady@mnseia.org	Minnesota Solar Energy Industries Association		2288 University Ave W St. Paul MN, 55114 United States	Electronic Service		No	M-25- 142
207	Patty	O'Keefe	patty.okeefe@sierraclub.org			2525 Emerson Ave S Apt 2 Minneapolis MN, 55405 United States	Electronic Service		No	M-25- 142
208	Timothy	O'Leary	toleary@llec.coop	Lyon-Lincoln Electric Cooperative, Inc		P.O. Box 639 Tyler MN, 56178-0639 United States	Electronic Service		No	M-25- 142
209	Jeff	O'Neill	jeff.oneill@ci.monticello.mn.us	City of Monticello		505 Walnut Street Suite 1 Monticelllo MN, 55362 United States	Electronic Service		No	M-25- 142
210	Matthew	Olsen	molsen@otpc.com	Otter Tail Power Company		215 South Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25- 142
211	Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District		PO Box 248 Madison SD, 57042-0248 United States	Electronic Service		No	M-25- 142
212	Wendi	Olson	wolson@otpc.com	Otter Tail Power Company		215 South Cascade Fergus Falls MN, 56537 United States	Electronic Service		No	M-25- 142
213	Carol A.	Overland	overland@legalelectric.org	Legalelectric - Overland Law Office		1110 West Avenue Red Wing MN, 55066 United States	Electronic Service		No	M-25- 142
214	Bethany	Owen	bowen@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25- 142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
215	Cezar	Panait	cezar.panait@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142
216	Dan	Patry	dpatry@sunedison.com	SunEdison		600 Clipper Drive Belmont CA, 94002 United States	Electronic Service		No	M-25-142
217	Jeffrey C	Paulson	jeff.jcplaw@comcast.net	Paulson Law Office, Ltd.		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	M-25-142
218	Dean	Pawlowski	dpawlowski@otpc.com	Otter Tail Power Company		PO Box 496 215 S. Cascade St. Fergus Falls MN, 56537-0496 United States	Electronic Service		No	M-25-142
219	Susan	Peirce	susan.peirce@state.mn.us		Department of Commerce	85 Seventh Place East St. Paul MN, 55101 United States	Electronic Service		No	M-25-142
220	Mary Beth	Peranteau	mperanteau@fredlaw.com	Fredrikson & Byron, P.A.		44 East Mifflin Street Suite 1000 Madison WI, 53703 United States	Electronic Service		No	M-25-142
221	Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power		30 West Superior Street Duluth MN, 55802 United States	Electronic Service		No	M-25-142
222	Wess	Pfaff	wes.pfaff@mrenergy.com			null null, null United States	Electronic Service		No	M-25-142
223	Ryan	Pierce	ryan.m.pierce@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
224	Morgan	Pitz	morgan.pitz@us-solar.com	US Solar		100 N 6th St #410B Minneapolis MN, 55403 United States	Electronic Service		No	M-25-142
225	Hannah	Polikov	hpolikov@aee.net	Advanced Energy Economy Institute		1000 Vermont Ave, Third Floor Washington DC, 20005 United States	Electronic Service		No	M-25-142
226	Crystal	Pomerleau	crystal.r.pomerleau@xcelenergy.com	Xcel		null null, null United States	Electronic Service		No	M-25-142
227	Kristel	Porter	kristel@mnrenewablenow.org	MN Renewable Now		null null, null United States	Electronic Service		No	M-25-142
228	Paula	Prahl	paula.prahl@dominiuminc.com	Dominium		2905 Northwest Blvd Ste 150 Plymouth MN, 55441 United States	Electronic Service		No	M-25-142
229	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	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
230	David G.	Prazak	dprazak@otpc.com	Otter Tail Power Company		P.O. Box 496 215 South Cascade Street Fergus Falls MN, 56538-0496 United States	Electronic Service		No	M-25-142
231	Matt	Privratsky	matt@nokomisenergy.com	Nokomis Energy		2639 Nicollet Ave Suite 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-142
232	Elizabeth	Psihos	elizabeth.psihos@idealenergies.com			null null, null United States	Electronic Service		No	M-25-142
233	Bridget	Rathsack	bridget.rathsack@burnsvillemn.gov	City of Burnsville, MN		100 Civic Center Parkway Burnsville MN, 55337 United States	Electronic Service		No	M-25-142
234	Peter	Reese	preese@sundialsolarenergy.com	Sundial Energy, LLC		3363 Republic Ave Saint Louis Park MN, 55426 United States	Electronic Service		No	M-25-142
235	Generic Notice	Regulatory	regulatory_filing_coordinators@otpc.com	Otter Tail Power Company		215 S. Cascade Street Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
236	John C.	Reinhardt		Laura A. Reinhardt		3552 26th Ave S Minneapolis MN, 55406 United States	Paper Service		No	M-25-142
237	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	M-25-142
238	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	M-25-142
239	Micah	Revell	micah.revell@stinson.com	Stinson LLP		50 South Sixth St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
240	Michael	Riewer	mriewer@otpc.com	Otter Tail Power Company		PO Box 4496 Fergus Falls MN, 56538-0496 United States	Electronic Service		No	M-25-142
241	Jonathan	Roberts	jroberts@soltage.com	Soltage		66 York St 5th Floor Jersey City NJ, 07302 United States	Electronic Service		No	M-25-142
242	Noah	Roberts	nroberts@cleanpower.org	Energy Storage Association		1155 15th St NW, Ste 500 Washington DC, 20005 United States	Electronic Service		No	M-25-142
243	Kristi	Robinson	krobinson@star-energy.com	STAR Energy Services, LLC		1401 South Broadway Pelican Rapids MN,	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						56572 United States				
244	Daniel	Rogers	dan@nokomispartners.com			2639 Nicollet Ave Ste 200 Minneapolis MN, 55408 United States	Electronic Service		No	M-25-142
245	Michael	Ruiz	michael.ruiz@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
246	Nathaniel	Runke	nrunke@local49.org			611 28th St. NW Rochester MN, 55901 United States	Electronic Service		No	M-25-142
247	Darla	Ruschen	d.ruschen@bcrea.coop	Brown County Rural Electrical Association		PO Box 529 24386 State Highway 4 Sleepy Eye MN, 56085 United States	Electronic Service		No	M-25-142
248	Delaney	Russell	delaney@mnipl.org	Just Solar Coalition		4407 E Lake Street Minneapolis MN, 55407 United States	Electronic Service		No	M-25-142
249	Kwadwo	Safo	ksafo@dakotaelectric.com	Dakota Electric Association		null null, null United States	Electronic Service		No	M-25-142
250	Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative		P.O. Box 227 Madison SD, 57042 United States	Electronic Service		No	M-25-142
251	Ian	SantosMeeker	ians@ips-solar.com	IPS Solar		null null, null United States	Electronic Service		No	M-25-142
252	Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered		150 S 5th St Ste 700 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
253	Kenric	Scheevel	kjs@dairynet.com	Dairyland Power Cooperative		3200 East Ave S PO Box 817 La Crosse WI, 54602 United States	Electronic Service		No	M-25-142
254	Dean	Schiro	dean.e.schiro@xcelenergy.com	Xcel Energy		null null, null United States	Electronic Service		No	M-25-142
255	Jacob J.	Schlesinger	jschlesinger@keyesfox.com	Keyes & Fox LLP		1580 Lincoln St Ste 880 Denver CO, 80203 United States	Electronic Service		No	M-25-142
256	Jeff	Schoenecker	jschoenecker@dakotaelectric.com	Dakota Electric Association		4300 220th Street W Farmington MN, 55024 United States	Electronic Service		No	M-25-142
257	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	M-25-142
258	Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power		5301 32nd Ave S Grand Forks ND, 58201 United States	Electronic Service		No	M-25-142
259	Matthew	Schuerger	matthew.schuerger@state.mn.us		Public Utilities Commission	121 7th Place East Suite 350 St. Paul MN,	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						55101 United States				
260	Ronald J.	Schwartau	rschwartau@noblesce.com	Nobles Electric Cooperative		22636 U.S. Hwy. 59 Worthington MN, 56187 United States	Electronic Service		No	M-25-142
261	Rob	Scott Hovland	rob.scott-hovland@mrenergy.com	Missouri River Energy Services		3724 W Avera Dr PO Box 88920 Sioux Falls SD, 57109-8920 United States	Electronic Service		No	M-25-142
262	Emma	Searson	esearson@solarunitedneighbors.org	Solar United Neighbors		646 S Barrington Ave Apt 101 Los Angeles CA, 90049 United States	Electronic Service		No	M-25-142
263	Dean	Sedgwick	sedgwick@itascapower.com	Itasca Power Company		PO Box 455 Spring Lake MN, 56680 United States	Electronic Service		No	M-25-142
264	Maria	Seidler	maria.seidler@dom.com	Dominion Energy Technology		120 Tredegar Street Richmond VA, 23219 United States	Electronic Service		No	M-25-142
265	David	Shaffer	david.shaffer@novelenergy.biz	Novel Energy Solutions		2303 Wycliff St Ste 300 St. Paul MN, 55114 United States	Electronic Service		No	M-25-142
266	Patricia	Sharkey	psharkey@environmentallawcounsel.com	Midwest Cogeneration Association.		180 N LaSalle St Ste 3700 Chicago IL, 60601 United States	Electronic Service		No	M-25-142
267	Christopher L.	Sherman	csherman@sherman-associates.com	Solar Holdings LLC		233 Park Ave S Ste 201 Minneapolis MN, 55415 United States	Electronic Service		No	M-25-142
268	Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy		2928 5th Ave S Minneapolis MN, 55408 United States	Electronic Service		No	M-25-142
269	Felicia	Skaggs	fskaggs@meeker.coop	Meeker Cooperative Light & Power		1725 US Highway 12 E Suite 100 Litchfield MN, 55355 United States	Electronic Service		No	M-25-142
270	Glen	Skarbakka	glen@s-pllc.com	Skarbakka PLLC		5411 Bartlett Blvd Mound MN, 55364 United States	Electronic Service		No	M-25-142
271	Anne	Smart	anne.smart@chargepoint.com	ChargePoint, Inc.		254 E Hacienda Ave Campbell CA, 95008 United States	Electronic Service		No	M-25-142
272	Joshua	Smith	joshua.smith@sierraclub.org			85 Second St FL 2 San Francisco CA, 94105 United States	Electronic Service		No	M-25-142
273	Ken	Smith	ken.smith@ever-greenenergy.com	Ever Green Energy		305 Saint Peter St Saint Paul MN, 55102 United States	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
274	Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.		76 W Kellogg Blvd St. Paul MN, 55102 United States	Electronic Service		No	M-25-142
275	Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.		220 South Sixth Street Suite 1300 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
276	Rafi	Sohail	rafi.sohail@centerpointenergy.com	CenterPoint Energy		800 LaSalle Avenue P.O. Box 59038 Minneapolis MN, 55459-0038 United States	Electronic Service		No	M-25-142
277	Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance		570 Asbury Street Suite 201 St. Paul MN, 55104 United States	Electronic Service		No	M-25-142
278	Marcia	Solie	m.solie@bcrea.coop	Brown County Rural Electrical Association		24386 State Hwy. 4, PO Box 529 Sleepy Eye MN, 56085 United States	Electronic Service		No	M-25-142
279	Braden	Solum	braden.solum@idealenergies.com	iDEAL Energies		5810 Nicollet Ave Minneapolis MN, 55419 United States	Electronic Service		No	M-25-142
280	Karl	Sonneman	karl17@hbc.com	Law Office of Karl W. Sonneman		111 Riverfront Suite 202 Winona MN, 55987 United States	Electronic Service		No	M-25-142
281	Brandon	Stamp	brandon.j.stamp@xcelenergy.com	Xcel Energy		401 Nicollet Mall Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
282	Sky	Stanfield	stanfield@smwlaw.com	Shute, Mihaly & Weinberger		396 Hayes Street San Francisco CA, 94102 United States	Electronic Service		No	M-25-142
283	Russ	Stark	russ.stark@ci.stpaul.mn.us	City of St. Paul		Mayor's Office 15 W. Kellogg Blvd., Suite 390 Saint Paul MN, 55102 United States	Electronic Service		No	M-25-142
284	Byron E.	Starns	byron.starns@stinson.com	STINSON LLP		50 S 6th St Ste 2600 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
285	Kristin	Stastny	kstastny@taftlaw.com	Taft Stettinius & Hollister LLP		2200 IDS Center 80 South 8th Street Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
286	Lindsey	Stegall	lindsey.stegall@evgo.com	EVgo Services, LLC		11835 W Olympic Blvd Ste 900E Los Angeles CA, 90064 United States	Electronic Service		No	M-25-142
287	Cary	Stephenson	cstephenson@otpc.com	Otter Tail Power Company		215 South Cascade Street	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
						Fergus Falls MN, 56537 United States				
288	Chad	Stevenson	chad.stevenson@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	445 Minnesota St. Suite 1400 St. Paul MN, 55101 United States	Electronic Service		No	M-25-142
289	Tammy	Sundbom	tsundbom@mnpower.com	Minnesota Power		null null, null United States	Electronic Service		No	M-25-142
290	Sherry	Swanson	sswanson@noblesce.com	Nobles Cooperative Electric		22636 US Highway 59 PO Box 788 Worthington MN, 56187 United States	Electronic Service		No	M-25-142
291	Boratha	Tan	btan@votesolar.org	Vote Solar		null null, null United States	Electronic Service		No	M-25-142
292	Bryant	Tauer	btauer@whe.org	Wright-Hennepin		6800 Electric Dr Rockford MN, 55373 United States	Electronic Service		No	M-25-142
293	Dean	Taylor	dtaylor@pluginamerica.org	Plug In America		6380 Wilshire Blvd, Suite 1000 Los Angeles CA, 90048 United States	Electronic Service		No	M-25-142
294	Whitney	Terrill	whitney@mnipl.org	Minnesota Interfaith Power & Light		null null, null United States	Electronic Service		No	M-25-142
295	Daniel	Tikk	daniel.tikk@state.mn.us		Department of Commerce	85 7th Place East Suite 280 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-142
296	Kate	Tohme	ktohme@newleafenergy.com	New Leaf Energy		null null, null United States	Electronic Service		No	M-25-142
297	Stuart	Tommerdahl	stommerdahl@otpc.com	Otter Tail Power Company		215 S Cascade St PO Box 496 Fergus Falls MN, 56537 United States	Electronic Service		No	M-25-142
298	Taige	Tople	taige.d.tople@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec		414 Nicollet Mall 401 7th Floor Minneapolis MN, 55401 United States	Electronic Service		No	M-25-142
299	Jason	Topp	jason.topp@lumen.com	Qwest Communications Company, LLC.		200 S 5th St Ste 2200 Minneapolis MN, 55402 United States	Electronic Service		No	M-25-142
300	Emma Marshall	Torres	emarshall-torres@convergentep.com			null null, null United States	Electronic Service		No	M-25-142
301	Zack	Townsend	zachary.townsend@brookfieldrenewable.com	Brookfield Renewable		200 Liberty St FL 14 New York NY, 10281 United States	Electronic Service		No	M-25-142
302	Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD		4445 W 77th Street Suite 224 Edina MN, 55435 United States	Electronic Service		No	M-25-142
303	Jeff	Triplett	triplettj@powersystem.org	MREA		10710 Town Square Dr	Electronic Service		No	M-25-142

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
330	Terry	Wolf	terry.wolf@mrenergy.com	Missouri River Energy Services		3724 W Avera Dr PO Box Sioux Falls SD, 57109-8920 United States	Electronic Service		No	M-25-142
331	Curtis	Zaun	curtis@cpzlaw.com			3254 Rice Street Little Canada MN, 55126 United States	Electronic Service		No	M-25-142
332	Brian	Zavesky	brianz@mrenergy.com	Missouri River Energy Services		3724 West Avera Drive P.O. Box 88920 Sioux Falls SD, 57108-8920 United States	Electronic Service		No	M-25-142
333	Christopher	Zibart	czibart@atcllc.com	American Transmission Company LLC		W234 N2000 Ridgeview Pkwy Court Waukesha WI, 53188-1022 United States	Electronic Service		No	M-25-142
334	Kurt	Zimmerman	kwz@ibew160.org	Local Union #160, IBEW		2909 Anthony Ln St Anthony Village MN, 55418-3238 United States	Electronic Service		No	M-25-142
335	Emily	Ziring	eziring@stlouispark.org	City of St. Louis Park		5005 Minnetonka Blvd St. Louis Park MN, 55416 United States	Electronic Service		No	M-25-142
336	Ari	Zwick	ari.zwick@state.mn.us		Department of Commerce	85 7th Place East Suite 280 Saint Paul MN, 55101 United States	Electronic Service		No	M-25-142